SR/OIAF/98-03
Distribution Category UC-950

Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity

October 1998

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Contents

Tables

Figures

Figures (Continued)

Figures (Continued)

Figures (Continued)

Preface

From December 1 through 11, 1997, more than 160 nations met in Kyoto, Japan, to negotiate binding limitations on greenhouse gases for the developed nations, pursuant to the objectives of the Framework Convention on Climate Change of 1992. The outcome of the meeting was the Kyoto Protocol, in which the developed nations agreed to limit their greenhouse gas emissions, relative to the levels emitted in 1990. The United States agreed to reduce emissions from 1990 levels by 7 percent during the period 2008 to 2012.

The analysis in this report was undertaken at the request of the Committee on Science of the U.S. House of Representatives. In its request, the Committee asked the Energy Information Administration (EIA) to analyze the Kyoto Protocol, "focusing on U.S. energy use and prices and the economy in the 2008-2012 time frame," as noted in the first letter in Appendix D. The Committee specified that EIA consider several cases for energy-related carbon reductions in its analysis, with sensitivities evaluating some key uncertainties: U.S. economic growth, the cost and performance of energy-using technologies, and the possible construction of new nuclear power plants.

The energy projections and analysis in this report were conducted using the National Energy Modeling System (NEMS), an energy-economy model of U.S. energy markets designed, developed, and maintained by EIA. NEMS is used each year to provide the projections in the *Annual Energy Outlook* (*AEO*). In its second letter, in Appendix D, the Committee requested that the analysis use the same general methodologies and assumptions underlying the *Annual Energy Outlook 1998* (*AEO98*), published in December 1997; however, some minor modifications were made to allow greater flexibility in NEMS in response to higher energy prices and to incorporate some methodologies that were formerly represented offline. These differences are outlined in Appendix A. The macroeconomic analysis used the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy, which is also used for the economic analysis in the *AEO*.

Chapter 1 of this report provides background discussion of the Kyoto Protocol and the framework and methodology of the analysis. Chapter 2 summarizes the energy market results from the various carbon reduction cases. Chapters 3, 4, and 5 analyze in more detail the issues and results for the end-use demand sectors, the electricity generation sector, and the fossil fuel supply markets, respectively. Chapter 6 provides the results of EIA's analysis of the macroeconomic impacts of carbon reduction under different monetary and fiscal policy assumptions. Chapter 7 compares the results of this study with those from other studies of the costs of carbon reduction, with accompanying tables in Appendix C. Appendix B includes the detailed energy market results from the carbon reduction cases.

Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review earlier versions of this analysis and provide comment. The assistance of the following reviewers in preparing the report is gratefully acknowledged:

Joseph Boyer
Yale University

Lorna Greening
Consultant to Hagler Bailly Services, Inc.

William Hogan
Harvard University

William Nordhaus
Yale University

Dallas Burtraw
Resources for the Future

Richard Newell
Resources for the Future

William Pizer
Resources for the Future

Michael Toman
Resources for the Future

John Weyant
Stanford University Energy Modeling Forum.

The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. This report does not purport to represent the official position of the U.S. Department of Energy or the Administration.

Other EIA reports on the topic of greenhouse gases include the following annual reports:

- *Annual Energy Outlook 1998*, published in December 1997, with projections of domestic energy carbon emissions through 2020
- *International Energy Outlook 1998*, published in April 1998, with projections of international energy carbon emissions through 2020
- *Emissions of Greenhouse Gases in the United States 1996*, published in October 1997, with an inventory of all domestic greenhouse gas emissions
- *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, published in October 1997, reporting voluntary actions in 1995 to reduce greenhouse gases in the United States
- *Greenhouse Gases, Global Climate Change, and Energy*, an information brochure on greenhouse gases.

Executive Summary

Greenhouse Gases and the Kyoto Protocol

Over the past several decades, rising concentrations of greenhouse gases have been detected in the Earth's atmosphere. It has been hypothesized that the continued accumulation of greenhouse gases could lead to an increase in the average temperature of the Earth's surface and cause a variety of changes in the global climate, sea level, agricultural patterns, and ecosystems that could be, on net, detrimental.

The Intergovernmental Panel on Climate Change (IPCC) was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. The most recent report of the IPCC concluded that: "Our ability to quantify the human influence on global climate is currently limited because the expected signal is still emerging from the noise of natural variability, and because there are uncertainties in key factors. These include the magnitudes and patterns of long-term variability and the time-evolving pattern of forcing by, and response to, changes in concentrations of greenhouse gases and aerosols, and land surface changes. Nevertheless, the balance of evidence suggests that there is a discernable human influence on global climate."[1]

The text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4. The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." The signatories agreed to formulate programs to mitigate climate change, and the developed country signatories agreed to adopt national policies to return anthropogenic emissions of greenhouse gases to their 1990 levels.

The first and second Conference of the Parties in 1995 and 1996 agreed to address the issue of greenhouse gas emissions for the period beyond 2000, and to negotiate quantified emission limitations and reductions for the third Conference of the Parties. On December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, to negotiate binding limits on greenhouse gas emissions for developed nations. The resulting Kyoto Protocol established emissions targets for each of the participating developed countries—the Annex I countries[2]—relative to their 1990 emissions levels. The targets range from an 8-percent reduction for the European Union (or its individual member states) to a 10-percent increase allowed for Iceland. The target for the United States is 7 percent below 1990 levels.

Although atmospheric *concentrations* of greenhouse gases are thought to have the potential to affect the global climate, the Protocol establishes targets in terms of *annual emissions*. Non-Annex I countries have no targets under the Protocol, but the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

Should the Protocol enter into force, the emissions targets for the developed countries would have to be achieved on average over the commitment period 2008 to 2012. The greenhouse gases covered by the Protocol are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The aggregate target is based on the carbon dioxide equivalent of each of the greenhouse gases. For the three synthetic greenhouse gases, countries have the option of using 1995 as the base year.

Several provisions of the Protocol allow for some flexibility in meeting the emissions targets. Net changes in emissions by direct anthropogenic land-use changes and forestry activities may be used to meet the commitment, but they are limited to afforestation, reforestation, and deforestation since 1990. Emissions trading among the Annex I countries is also allowed. No rules for trading were established, however, and the Conference of the Parties is required to establish principles, rules, and guidelines for trading at a future date. According to estimates presented by the Energy Information

[1]Intergovernmental Panel on Climate Change, *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996).

[2]Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Turkey and Belarus are Annex I nations that have not ratified the Convention and did not commit to quantifiable emissions targets.

Administration (EIA) in its *International Energy Outlook 1998*,[3] there may be 165 million metric tons of carbon permits available from the Annex I countries of the former Soviet Union in 2010. Greenhouse gas emissions for those countries as a group are expected to be 165 million metric tons below 1990 levels in 2010 as a result of the economic decline that has occurred in the region during the 1990s. Additional carbon permits may also be available, depending on the "carbon price" that is established in international trading.

Joint implementation projects are permitted among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance emissions-absorbing sinks, such as forests and other vegetation, in other Annex I countries. The Protocol also establishes a Clean Development Mechanism (CDM), under which Annex I countries can take credits for projects that reduce emissions in non-Annex I countries. In addition, any group of Annex I countries may create a bubble or umbrella to meet the total commitment of all the member nations. In a bubble, countries would agree to meet their total commitment jointly by allocating a share to each member. In an umbrella arrangement, the total reduction of all member nations would be met collectively through the trading of emissions rights. There is potential interest in the United States in entering into an umbrella trading arrangement with Annex I countries outside the European Union.

In 1990, total greenhouse gas emissions in the United States were 1,618 million metric tons carbon equivalent.[4] Of this total, 1,346 million metric tons, or 83 percent, consisted of carbon emissions from the combustion of energy fuels. By 1996, total U.S. greenhouse gas emissions had risen to 1,753 million metric tons carbon equivalent, including 1,463 million metric tons of carbon emissions from energy combustion. EIA's *Annual Energy Outlook 1998* (*AEO98*)[5] projects that energy-related carbon emissions will reach 1,803 million metric tons in 2010, 34 percent above the 1990 level. Because energy-related carbon emissions constitute such a large percentage of the Nation's total greenhouse gas emissions, any action or policy to reduce emissions will have significant implications for U.S. energy markets.

At the request of the U.S. House of Representatives Committee on Science, EIA performed an analysis of the Kyoto Protocol, focusing on the potential impacts of the Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 time frame. The request specified that the analysis use the same methodologies and assumptions employed in the *AEO98*, with no changes in assumptions about policy, regulatory actions, or funding for energy and environmental programs.

Methodology

The international provisions of the Kyoto Protocol, including international emissions trading between Annex I countries, joint implementation projects, and the CDM, may reduce the cost of compliance in the United States. Guidelines for those provisions, however, remain to be resolved at future negotiating meetings, and rules and guidelines for the accounting of emissions and sinks from activities related to agriculture, land use, and forestry activities must be developed. The specific guidelines may have a significant impact on the level of reductions from other sources that a country must undertake. Reductions in the other greenhouse gases may also offset the reductions required from carbon dioxide. A fact sheet issued by the U.S. Department of State on January 15, 1998, estimated that the method of accounting for sinks and the flexibility to use 1995 as the base year for the synthetic greenhouse gases may reduce the target to 3 percent below 1990 levels.[6] A similar estimate was cited by Dr. Janet Yellen, Chair, Council of Economic Advisers, in her testimony before the House Committee on Commerce, Energy and Power Subcommittee, on March 4, 1998.[7]

Because the exact rules that would govern the final implementation of the Protocol are not known with certainty, the specific reduction in energy-related emissions cannot be established. This analysis includes cases that assume a range of reductions in energy-related carbon emissions in the United States. Each case was analyzed to estimate the energy and economic impacts of achieving an assumed level of reductions.

A reference case and six carbon emissions reduction cases were examined in this report. The cases are defined as follows:

- **Reference Case (33 Percent Above 1990 Levels).** This case represents the reference projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparisons of the energy market impacts in the reduction cases. Although this reference case is

[3]Energy Information Administration, *International Energy Outlook 1998*, DOE/EIA-0484(98) (Washington, DC, April 1998).

[4]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997).

[5]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[6]See web site www.state.gov/www/global/oes/fs_kyoto_climate_980115.html.

[7]See web site www.house.gov/commerce/database.htm.

based on the reference case from *AEO98*, there are small differences between this case and *AEO98*, in order to permit additional flexibility in response to higher energy prices or to include certain analyses previously done offline directly within the modeling framework, such as nuclear plant life extension and generating plant retirements. Also, some assumptions were modified to reflect more recent assessments of technological improvements and costs. As a result of these modifications, the projection of energy-related carbon emissions in 2010 is slightly reduced from the *AEO98* reference case level of 1,803 million metric tons to 1,791 million metric tons.

- **24 Percent Above 1990 Levels (1990+24%).** This case assumes that carbon emissions can increase to an average of 1,670 million metric tons between 2008 and 2012, 24 percent above the 1990 levels. Compared to the average emissions in the reference case, carbon emissions are reduced by an average of 122 million metric tons each year during the commitment period.

- **14 Percent Above 1990 Levels (1990+14%).** This case assumes that carbon emissions average 1,539 between 2008 and 2012, approximately at the level estimated for 1998 in *AEO98*, 1,533 million metric tons. This target is 14 percent above 1990 levels and represents an average annual reduction of 253 million metric tons from the reference case.

- **9 Percent Above 1990 Levels (1990+9%).** This case assumes that energy-related carbon emissions can increase to an average of 1,467 million metric tons between 2008 and 2012, 9 percent above 1990 levels, an average annual reduction of 325 million metric tons from the reference case projections.

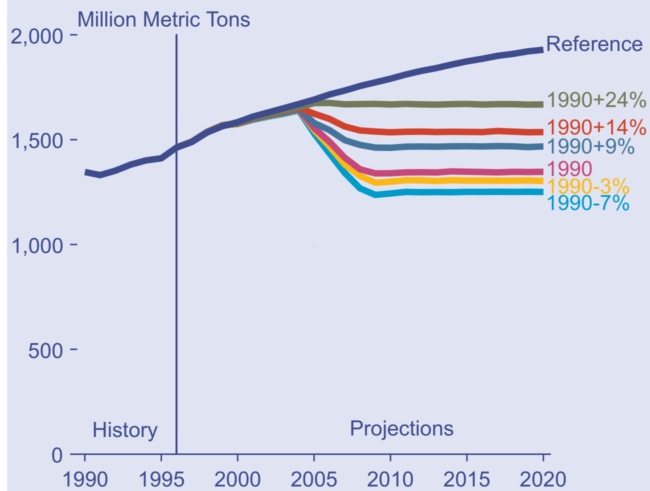
- **Stabilization at 1990 Levels (1990).** This case assumes that carbon emissions reach an average of 1,345 million metric tons during the commitment period of 2008 through 2012, stabilizing approximately at the 1990 level of 1,346 million metric tons. This is an average annual reduction of 447 million metric tons from the reference case.

- **3 Percent Below 1990 Levels (1990-3%).** This case assumes that energy-related carbon emissions are reduced to an average of 1,307 million metric tons between 2008 and 2012, an average annual reduction of 485 million metric tons from the reference case projections.

- **7 Percent Below 1990 Levels (1990-7%).** In this case, energy-related carbon emissions are reduced from the level of 1,346 million metric tons in 1990 to an average of 1,250 million metric tons in the commitment period, 2008 to 2012. Compared to the reference case, this is an average annual reduction of 542 million metric tons of energy-related carbon emissions during that period. This case essentially assumes that the 7-percent target in the Kyoto Protocol must be met entirely by reducing energy-related carbon emissions, with no net offsets from sinks, other greenhouse gases, or international activities.

In each of the carbon reduction cases, the target is achieved on average for each of the years in the first commitment period, 2008 through 2012 (Figure ES1). Because the Protocol does not specify any targets beyond the first commitment period, the target is assumed to hold constant from 2013 through 2020, the end of the forecast horizon (although more or less stringent requirements may be set by future Conferences of the Parties). The target is assumed to be phased in over a 3-year period, beginning in 2005, because the Protocol indicates that demonstrable progress toward reducing emissions must be shown by 2005. The phase-in allows energy markets to begin adjustments to meet the targets in the absence of complete foresight; however, a longer or more delayed phase-in could lower the adjustment costs—an option that is not considered here. In this analysis, some carbon reductions are expected to occur before 2005 as the result of capacity expansion decisions by electricity generators that incorporate their expectations of future increases in energy prices.

Figure ES1. Projections of Carbon Emissions, 1990-2020



Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

There are three ways to reduce energy-related carbon emissions: reducing the demand for energy services, adopting more energy-efficient equipment, and switching to less carbon-intensive or noncarbon fuels. To reduce emissions, a carbon price is applied to the cost of energy. The carbon price is applied to each of the energy fuels relative to its carbon content at its point of consumption. Electricity does not directly receive a carbon fee; however, the fossil fuels used for generation receive the fee, and this cost, as well as the increased cost of investment in generation plants, is reflected in the delivered price of electricity. In practice, these carbon prices could be imposed through a carbon emissions permit system.

In this analysis, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level, reflecting the price the United States would be willing to pay in order to purchase carbon permits from other countries or to induce carbon reductions in other countries. In the absence of a complete analysis of trade and other flexible mechanisms to reduce carbon emissions internationally, the projected carbon prices do not necessarily represent the international market-clearing price of carbon permits or the price at which other countries would be willing to offer permits.

The projections in *AEO98* and in this analysis were developed using the National Energy Modeling System (NEMS), an energy-economy modeling system of U.S. energy markets, which is designed, implemented, and maintained by EIA.[8] The production, imports, conversion, consumption, and prices of energy are projected for each year through 2020, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, costs and performance characteristics of energy technologies, and demographics. NEMS is a fully integrated framework, capturing the interactions of energy supply, demand, and prices across all fuels and all sectors of U.S. energy markets. NEMS provides annual projections, allowing the representation of the transitional effects of proposed energy policy and regulation.

NEMS includes a detailed representation of capital stock vintaging and technology characteristics, capturing the most significant factors that influence the turnover of energy-using and producing equipment and the choice of new technologies. The residential, commercial, transportation, electricity generation, and refining sectors of NEMS include explicit treatments of individual known technologies and their characteristics, such as initial cost, operating cost, date of commercial availability, efficiency, and other characteristics specific to the sector. Unknown technologies are not likely to be developed in time to achieve significant market penetration within the time frame of this analysis. Higher energy prices, as a result of carbon prices, for example, do not alter the characteristics or availability of energy-using technologies. However, higher prices induce more rapid adoption of more efficient or advanced technologies, because consumers would have more incentive to purchase them.

In addition, for new generating technologies, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind plants and for a decline in the costs as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment. In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is somewhat more limited due to limitations on the availability of data for individual technologies; however, technology progress is represented by efficiency improvements in the industrial sector, technological progress in oil and gas exploration and production activities, and productivity improvements in coal production.

Carbon Reduction Cases

Carbon Prices

In 2010, the carbon prices projected to be necessary to achieve the carbon emissions reduction targets range from $67 per metric ton (1996 dollars) in the 1990+24% case to $348 per metric ton in the 1990-7% case (Table ES1 and Figure ES2). In the 1990+24% case, carbon prices generally increase from 2005 through 2020 (Table ES2 and Figure ES2). In the 1990+14% and 1990+9% cases, the carbon prices increase through 2013 and then essentially flatten.

In the three other carbon reduction cases, the carbon price escalates more rapidly in order to achieve the more stringent carbon reductions in the commitment period. The carbon price then declines as cumulative investments in more energy-efficient and lower-carbon equipment, particularly in the electricity generation sector, reduce the marginal cost of compliance in the later years of the forecast. These investments reduce the demand for carbon permits over an extended period of time, offsetting growth in energy demand and moderating the carbon prices. Figure ES3 shows the average carbon prices required to achieve the average carbon reductions.

Sectoral Impacts

As a result of the carbon prices and higher delivered energy prices, the overall intensity of energy use declines in the carbon reduction cases. Energy intensity, measured in energy consumed per dollar of gross

[8] Energy Information Administration, *The National Energy Modeling System: An Overview 1998*, DOE/EIA-0581(98) (Washington, DC, February 1998).

Table ES1. Selected Variables in the Carbon Reduction Cases, 1996 and 2010

Variable	1996	2010 Reference	2010 1990 +24%	2010 1990 +14%	2010 1990 +9%	2010 1990	2010 1990 -3%	2010 1990 -7%
U.S. Carbon Emissions								
(Million Metric Tons)	1,463	1,791	1,668	1,535	1,462	1,340	1,300	1,243
Emissions Reductions								
(Percent Change From Reference Case)	—	—	6.9	14.3	18.4	25.2	27.4	30.6
Total Energy Consumption								
(Quadrillion Btu)	93.8	111.2	106.5	101.9	99.6	95.2	93.9	91.7
(Percent Change From Reference Case)	—	—	-4.2	-8.4	-10.4	-14.4	-15.6	-17.5
Carbon Price								
(1996 Dollars per Metric Ton)	—	—	67	129	163	254	294	348
Carbon Revenue[a]								
(Billion 1996 Dollars)	—	—	110	195	233	333	374	424
Gasoline Price								
(1996 Dollars per Gallon)	1.23	1.25	1.39	1.50	1.55	1.72	1.80	1.91
(Percent Change From Reference Case)	—	—	11.2	20.0	24.0	37.6	44.0	52.8
Average Electricity Price								
(1996 Cents per Kilowatthour)	6.8	5.9	7.1	8.2	8.8	10.0	10.5	11.0
(Percent Change From Reference Case)	—	—	20.3	39.0	49.2	69.5	78.0	86.4
Actual Gross Domestic Product[b]								
(Billion 1992 Dollars)	6,928	9,429	9,333	9,268	9,241	9,137	9,102	9,032
(Percent Change From Reference Case)	—	—	-1.0	-1.7	-2.0	-3.1	-3.5	-4.2
(Annual Percentage Growth Rate, 2005-2010)	—	2.0	1.8	1.7	1.6	1.4	1.3	1.2
Potential Gross Domestic Product								
(Billion 1992 Dollars)	6,930	9,482	9,469	9,455	9,448	9,429	9,420	9,410
(Percent Change From Reference Case)	—	—	-0.1	-0.3	-0.4	-0.6	-0.7	-0.8
(Annual Percentage Growth Rate, 2005-2010)	—	2.0	2.0	1.9	1.9	1.9	1.9	1.9
Change in Energy Intensity								
(Annual Percent Change, 2005-2010)	—	-1.0	-1.6	-2.0	-2.1	-2.7	-2.8	-3.0
(Percent Change From Reference Case)	—	—	55.6	96.4	108.2	161.8	177.0	199.0

[a]The carbon revenues do not include fees on the nonsequestered portion of petrochemical feedstocks, nonpurchased refinery fuels, or industrial other petroleum.

[b]Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW. D080398B.

domestic product (GDP), declines (i.e., improves) at an average annual rate of 1 percent between 2005 and 2010 in the reference case due to the availability and adoption of more efficient equipment. In the carbon reduction cases, higher rates of improvement are projected—from 1.6 percent a year in the 1990+24% case to triple the reference case rate at 3.0 percent a year in the 1990-7% case.

In 2010, reductions in carbon emissions from electricity generation account for between 68 and 75 percent of the total carbon reductions across the cases. Electricity consumption is projected to be lower than in the reference case, with more efficient, less carbon-intensive technologies used for electricity generation. In all the carbon reduction cases except the 1990+24% case, carbon emissions from electricity generation in 2010 are lower than the actual 1990 level of 477 million metric tons of carbon emissions from the electricity supply sector. Electricity generators are expected to respond more strongly than end-use consumers to higher prices because this industry has traditionally been cost-minimizing, factoring future energy price increases into investment decisions. In contrast, the end-use consumers are assumed to consider only current prices in making their investment decisions and to consider additional factors, not only price, in their decisions. In addition, there are a number of more efficient and lower-carbon technologies for electricity generation that become economically available as the cost of generating electricity from fossil fuels increases.

Total electricity generation is lower in the carbon reduction cases because electricity sales range from 4 to 17 percent below the reference case in 2010 (Figure ES4). Reduction in electricity demand in response to higher electricity prices is somewhat mitigated by the change in relative prices. In 2010, electricity prices are between 20 and 86 percent above the reference case across the carbon reduction cases; however, delivered natural gas prices are higher by between 25 and 147 percent. With a smaller percentage price increase, electricity becomes more attractive in those end uses where it competes with natural gas, such as home heating.

Although reduced demand for electricity and efficiency improvements in the generation of electricity contribute to the total reductions in carbon emissions from electricity generation, fuel switching accounts for most

Table ES2. Selected Variables in the Carbon Reduction Cases, 1996 and 2020

Variable	1996	2020 Reference	2020 1990 +24%	2020 1990 +14%	2020 1990 +9%	2020 1990	2020 1990 -3%	2020 1990 -7%
U.S. Carbon Emissions								
(Million Metric Tons)	1,463	1,929	1,668	1,535	1,468	1,347	1,303	1,251
Emissions Reductions								
(Percent Change From Reference Case)	—	—	13.5	20.4	23.9	30.2	32.5	35.1
Total Energy Consumption								
(Quadrillion Btu)	93.8	117.0	108.6	105.6	103.8	100.9	99.9	98.8
(Percent Change From Reference Case)	—	—	-7.2	-9.7	-11.3	-13.8	-14.6	-15.6
Carbon Price								
(1996 Dollars per Metric Ton)	—	—	99	123	141	200	240	305
Carbon Revenue[a]								
(Billion 1996 Dollars)	—	—	162	184	202	263	306	372
Gasoline Price								
(1996 Dollars per Gallon)	1.23	1.24	1.42	1.45	1.49	1.60	1.67	1.80
(Percent Change From Reference Case)	—	—	14.5	16.9	20.2	29.0	34.7	45.2
Average Electricity Price								
(1996 Cents per Kilowatthour)	6.8	5.6	7.3	7.8	8.1	8.7	8.9	9.3
(Percent Change From Reference Case)	—	—	30.4	39.3	44.6	55.4	58.9	66.1
Actual Gross Domestic Product[b]								
(Billion 1992 Dollars)	6,928	10,865	10,815	10,808	10,796	10,799	10,793	10,782
(Percent Change From Reference Case)	—	—	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8
(Annual Percentage Growth Rate, 2005-2020)	—	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Potential Gross Domestic Product								
(Billion 1992 Dollars)	6,930	10,994	10,968	10,961	10,954	10,940	10,933	10.925
(Percent Change From Reference Case)	—	—	-0.2	-0.3	-0.4	-0.5	-0.6	-0.6
(Annual Percentage Growth Rate, 2005-2020)	—	1.7	1.6	1.6	1.6	1.6	1.6	1.6
Change in Energy Intensity								
(Annual Percent Change, 2005-2020)	—	-0.9	-1.4	-1.4	-1.5	-1.6	-1.7	-1.7
(Percent Change From Reference Case)	—	—	46.3	54.0	55.7	72.1	76.9	80.9

[a]The carbon revenues do not include fees on the nonsequestered portion of petrochemical feedstocks, nonpurchased refinery fuels, or industrial other petroleum.

[b]Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW. D080398B.

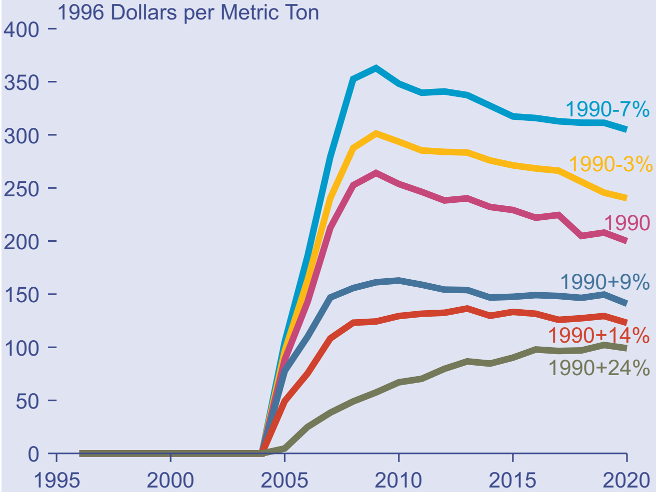
of the reductions (Figure ES5). The delivered price of coal to generators in 2010 is higher by between 153 and nearly 800 percent in the carbon reduction cases relative to the reference case. As a result, coal-fired generation, which accounts for about half of all generation in 2010 in the reference case, has a share between 42 percent and 12 percent in 2010 in the carbon reduction cases. To replace coal plants, generators build more natural gas plants, extend the life of existing nuclear plants, and dramatically increase the use of renewables in the more stringent reduction cases, particularly biomass and wind energy systems, which become more economical with higher carbon prices.

Assuming that carbon emissions from the generation of electricity are shared to each of the end-use demand sectors, based upon their consumption of electricity, the industrial and residential end-use demand sectors account for most of the carbon reductions, and the transportation sector accounts for the least (Figure ES6). In response to higher energy prices, consumers have an incentive to reduce demand for energy services, switch to lower-carbon energy sources, and invest in more energy-efficient technologies.

Because coal is the most carbon-intensive of the fossil fuels, delivered coal prices are most affected by the carbon prices (Figure ES7). Higher electricity prices reflect the increased costs of fossil fuels for generation and the incremental cost of additional investments, although the increase is mitigated by generation from renewables and nuclear power, because their fuel prices are not affected by carbon prices. Although the average carbon content of petroleum products is higher than that of natural gas, the percentage increase in the price of natural gas is higher than that of petroleum. Higher prices for petroleum are partially offset by lower world oil prices, and Federal and State taxes on gasoline also serve to mitigate the percentage increase.

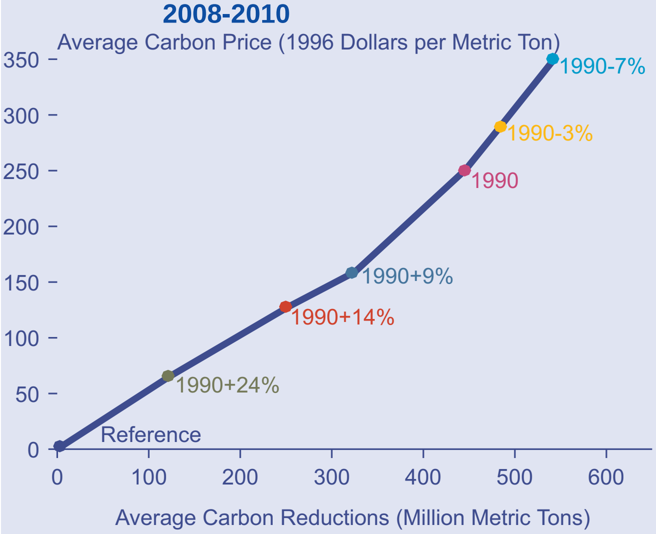
Total carbon emissions from the industrial sector are lower by between 7 and 28 percent in 2010 in the carbon reduction cases, relative to the reference case. Total industrial output is lower because of the impact of higher energy prices on the economy. As energy prices increase, industrial consumers accelerate the replacement of productive capacity, invest in more efficient technology, and switch to less carbon-intensive fuels. In 2010, industrial energy intensity is reduced from

Figure ES2. Projections of Carbon Prices, 1996-2020



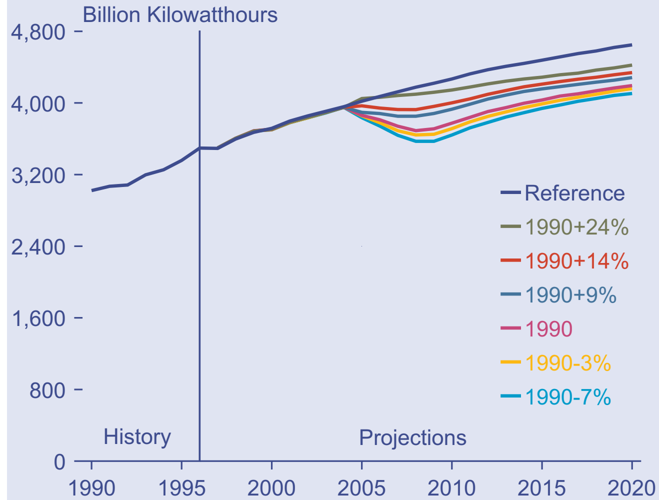
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES3. Average Projected Carbon Prices and Annual Carbon Emission Reductions, 2008-2010



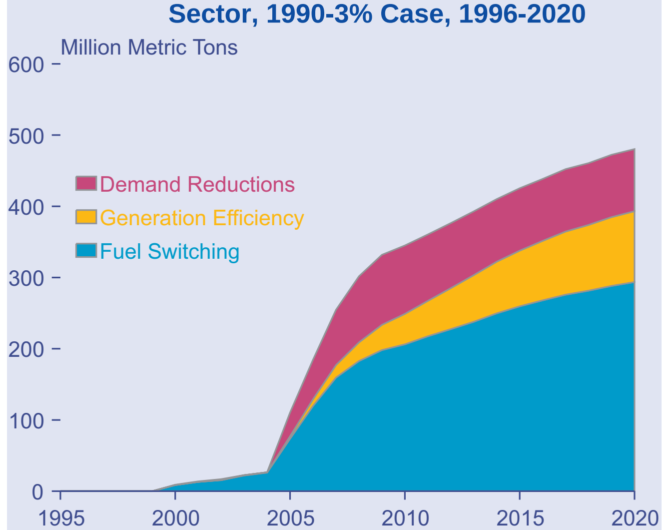
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES4. Projections of U.S. Electricity Generation, 1990-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES5. Projected Reductions in Carbon Emissions From the Electricity Supply Sector, 1990-3% Case, 1996-2020



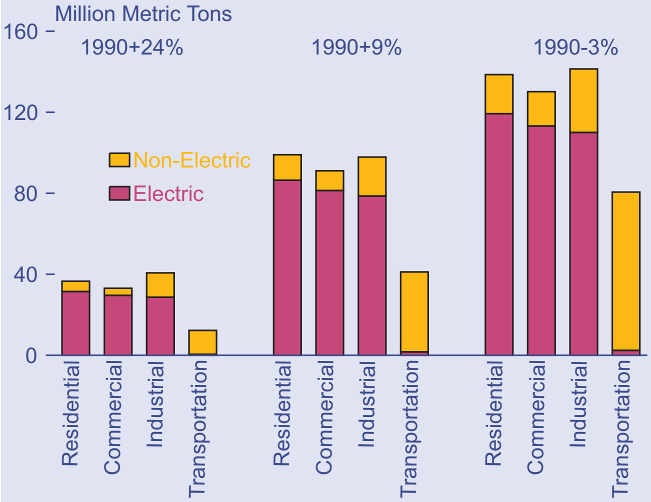
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD03BLW.D080398B.

7.6 thousand British thermal units (Btu) per dollar of output in the reference case to between 7.4 and 7.1 thousand Btu in the carbon reduction cases.

In both the residential and commercial sectors, higher energy prices encourage investments in more efficient equipment and building shells and reduce the demand for energy services. Total carbon emissions in the residential sector are reduced by 11 percent in the 1990+24% case and by 45 percent in the 1990-7% case, relative to the reference case. Because of reduced demand for energy and improved end-use efficiencies, total energy use in 2010 ranges from 145 to 173 million Btu per household in the carbon reduction cases, compared with 184 million Btu per household in the reference case. Space heating and cooling account for the largest share of the change in energy demand; however, energy demand for a variety of miscellaneous appliances, such as computers, televisions, and VCRs, is also reduced.

In the commercial sector, total carbon emissions are lower by between 12 and 51 percent in the carbon reduction cases, compared to the reference case. Total energy use per square foot of commercial floorspace, which is 206 thousand Btu in 2010 in the reference case, is reduced to between 148 and 192 thousand Btu across the

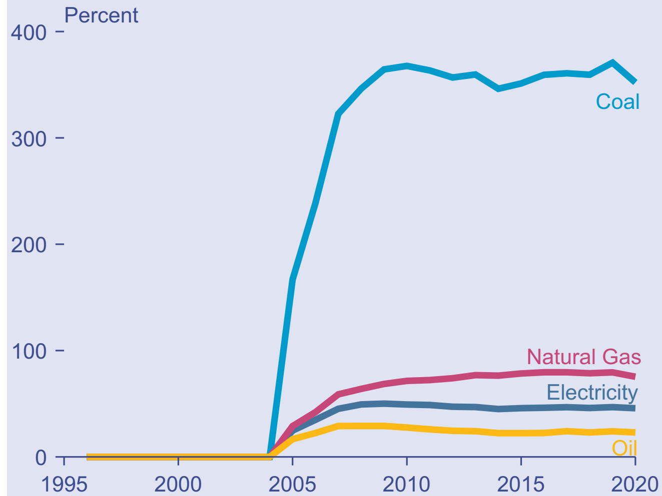
Figure ES6. Projected Reductions in Carbon Emissions by End-Use Sector Relative to the Reference Case, 2010



Note: Electricity emissions are from the fuel used to generate electricity and are attributed to the sectors relative to their shares of electricity consumption.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

Figure ES7. Projected Changes in Average Delivered Prices for Energy Fuels in the 1990+9% Case Relative to the Reference Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A and FD09ABV.D080398B.

cases. Similar to the residential sector, most of the reduction occurs for space conditioning—heating, cooling, and ventilation; however, more efficient lighting and office equipment and reduced miscellaneous electricity use—for example, for vending machines and telecommunications equipment—also contribute to lower energy consumption.

The average price of gasoline in 2010 across the carbon reduction cases is between 11 and 53 percent higher than the projected reference case price. Carbon reductions in the transportation sector in 2010 range from 2 to 16 percent, primarily as the result of reduced travel and the purchase of more efficient vehicles. The relatively low carbon reductions for transportation result from the continued dominance of petroleum, although some increase in market share is projected for alternative-fuel vehicles. Improvements in average fuel efficiency are slowed by vehicle turnover rates. Although new car efficiency in 2010 improves from 30.6 miles per gallon in the reference case to between 32.0 and 36.4 miles per gallon in the carbon reduction cases, total light-duty fleet efficiency rises only from 20.5 miles per gallon to between 20.7 and 21.7 miles per gallon. The impact of carbon prices on the economy lowers light-duty vehicle and airline travel and freight requirements while inducing some efficiency improvements.

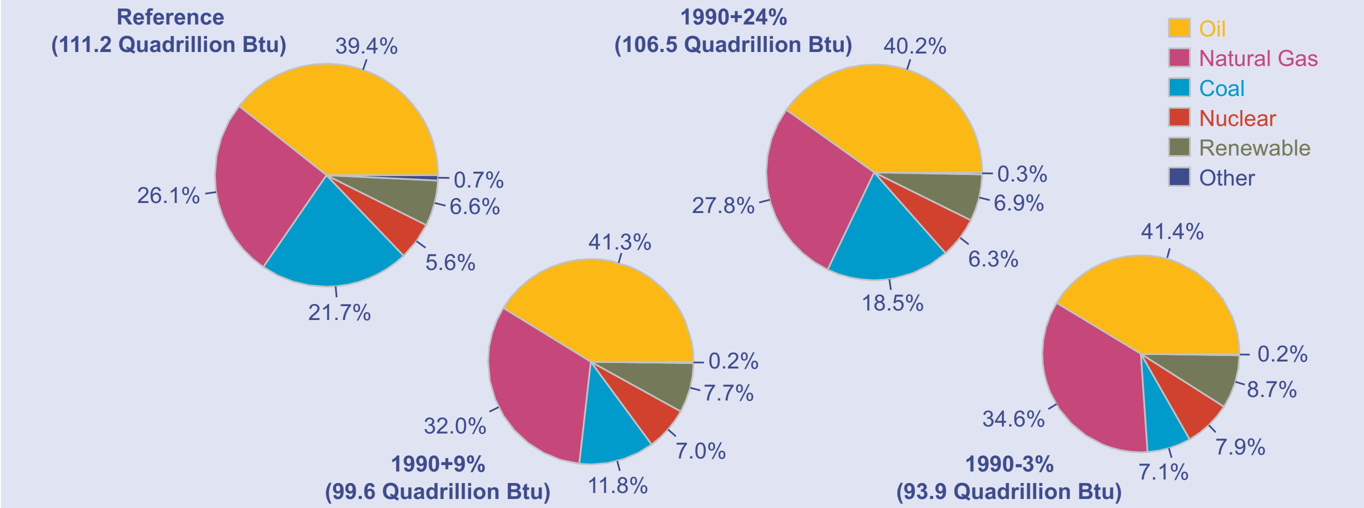
Impacts by Fuel

In order to achieve carbon emission reductions, the slate of energy fuels used in the United States is projected to change from that in the reference case (Figure ES8). Because of the higher relative carbon content of coal and petroleum products, the use of both fuels is reduced, and there is a greater reliance on natural gas, renewable energy, and nuclear power. Although the use of petroleum declines relative to the reference case, it increases slightly as a share because most petroleum is used in the transportation sector, where fewer fuel substitutes are available.

Because of the high carbon content of coal, total domestic coal consumption is significantly reduced in the carbon reduction cases, by between 18 and 77 percent relative to the reference case in 2010 (Figure ES9). Most of the reductions are for electricity generation, where coal is replaced by natural gas, renewable fuels, and nuclear power; however, demand for industrial steam coal and metallurgical coal is also reduced because of a shift to natural gas in industrial boilers and a reduction in industrial output. Coal exports are also lower in the carbon reduction cases, by between 21 and 32 percent, due to lower demand for coal in the Annex I nations.

Although total U.S. coal production is reduced, the average minemouth coal price rises in the carbon reduction cases, by between 3 and 28 percent in 2010, because a larger share of production is from higher-cost eastern coal mines that tend to serve the remaining markets. Production of western coal is further discouraged by the higher cost of fuels used for rail transportation and by reduced incentive for investment in new mines, which are primarily in the West. Because of lower coal production, coal mine employment in 2010 is projected to be 15 to 63 percent lower than in the

Figure ES8. Projections of Fuel Shares of Total U.S. Energy Consumption, 2010



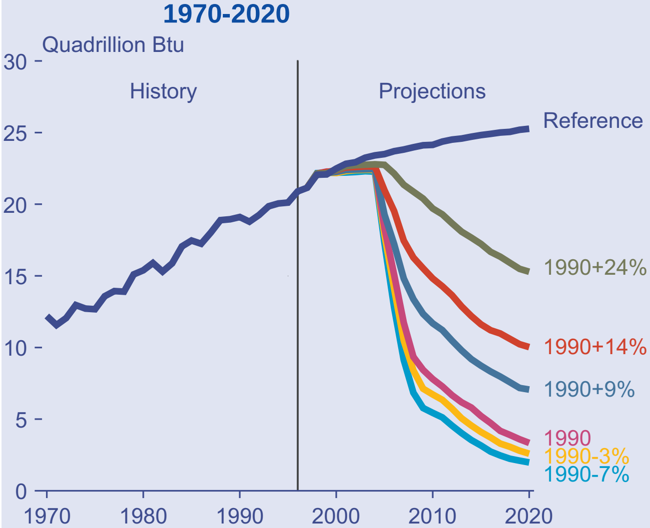
Note: "Other" includes net electricity imports, methanol, and liquid hydrogen.
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

reference case; however, employment in the energy industry related to the production of natural gas and renewable fuels is likely to increase.

Petroleum consumption is lower in all the carbon reduction cases than in the reference case, by between 2 and 13 percent (Figure ES10). Because most of the petroleum is used for transportation, between 68 and 82 percent of the total reduction is in the transportation sector, as travel and freight requirements are reduced and higher-efficiency vehicles are used. Because of lower petroleum demand in the United States and in other developed countries that are committed to reducing emissions under the Kyoto Protocol, world oil prices are lower by between 4 and 16 percent in 2010, relative to the reference case price of $20.77 per barrel. In 2010, net crude oil and petroleum product imports are lower by a range of 3 to 22 percent relative to the reference case. Consequently, the dependency of the United States on imported petroleum is reduced from the reference case level of 59 percent to as little as 53 percent in 2010.

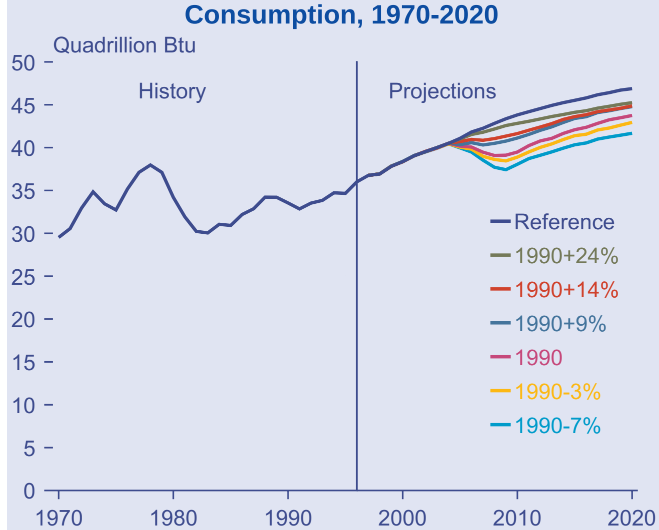
In 2010, natural gas consumption is higher than in the reference case, by a range of 2 to 12 percent across the carbon reduction cases (Figure ES11). Increased use of natural gas in the generation sector is only partially offset by reductions in the end-use sectors. Later in the forecast period, continued growth in natural gas

Figure ES9. Projections of U.S. Coal Consumption, 1970-2020



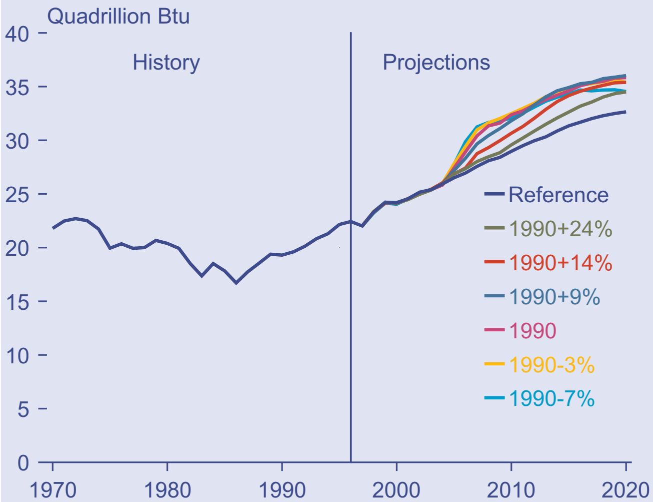
Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES10. Projections of U.S. Petroleum Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES11. Projections of U.S. Natural Gas Consumption, 1970-2020



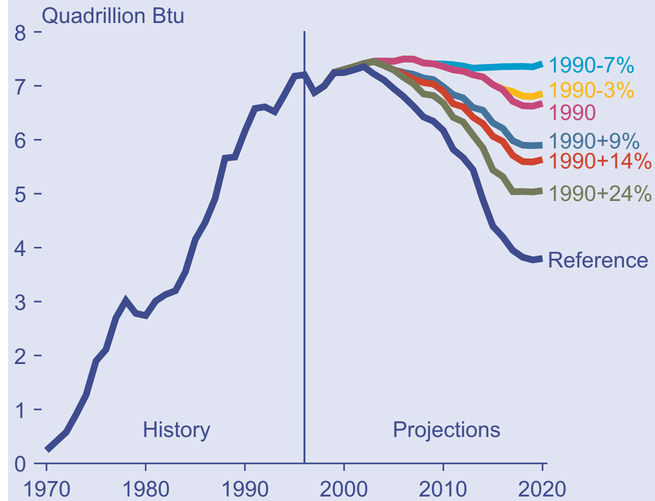
Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

consumption for electricity generation is mitigated by the increasing use of renewables and nuclear power, particularly in the more stringent carbon reduction cases. As a result, in 2020, natural gas use does not necessarily increase with higher levels of carbon reductions. As the result of higher demand, the average wellhead price of natural gas in 2010 is higher in all the carbon cases than in the reference case, by a range of 2 to 30 percent. Although meeting the levels of production that may be required will be a challenge for the industry, sufficient natural gas resources are available. The potential increases in both drilling and pipeline capacity are within levels achieved historically (or about to be achieved) and are not likely to be a constraint, given appropriate incentives and planning.

Nuclear power, which produces no carbon emissions, increases with carbon reduction targets by between 8 and 20 percent in 2010, relative to the reference case (Figure ES12). Although no new nuclear plants are assumed to be built in the carbon reduction cases, extending the lifetimes of existing plants is projected to become more economical with higher carbon prices. In the more stringent carbon reduction cases, most existing nuclear plants are life-extended through 2020, in contrast to the gradual retirement of approximately half of the nuclear plants projected in the reference case.

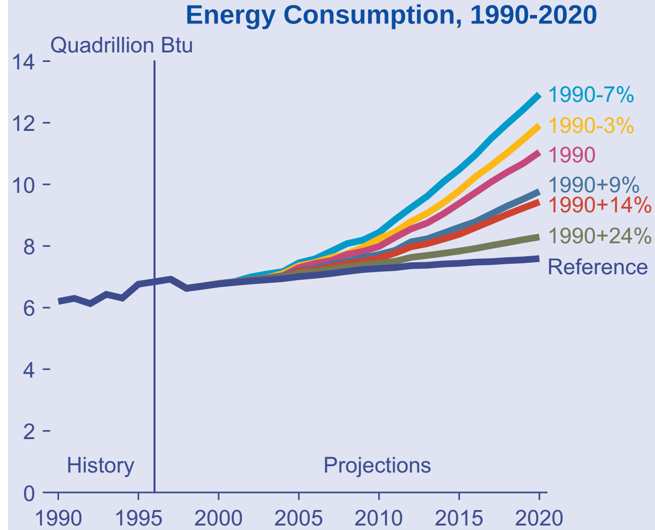
Consumption of renewable energy, which results in no net carbon emissions, is projected to be significantly higher with carbon reduction targets (Figure ES13). Across the carbon reduction cases, renewable energy consumption increases by between 2 and 16 percent in 2010 and by between 9 and 70 percent in 2020. Most of this increase occurs in electricity generation, primarily with additions to wind energy systems and an increase in the use of biomass (wood, switchgrass, and refuse). In the carbon reduction cases, the share of renewable generation is as much as 14 percent in 2010, compared with 10 percent in the reference case, increasing to as high as 22 percent in 2020, compared with 9 percent in the reference case. Because additional renewable technologies become available and economical later in the forecast period, the share of renewable generation continues to increase through 2020.

Figure ES12. Projections of U.S. Nuclear Energy Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure ES13. Projections of U.S. Renewable Energy Consumption, 1990-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Macroeconomic Impacts

In the energy market analyses, the projected carbon prices reflect the prices the United States would be willing to pay to achieve the Kyoto targets, without addressing the international trade in carbon permits. The macroeconomic analysis assumes that the carbon permit trading system would function as an auction run by the Federal Government, and that the United States would be free to purchase carbon permits in an international market at the marginal abatement cost in the United States. The U.S. State Department's assessment of the accounting of carbon-absorbing sinks and offsets from reductions in other greenhouse gases is assumed to reduce the U.S. emissions target to 3 percent below 1990 levels. The 3-percent target is then achieved through a combination of domestic actions and the purchase of permits on the international market. Thus, two flows of funds occur—domestic and international.

On the domestic side, U.S. permits are sold in a competitive auction run by the Federal Government, raising large sums of funds. In the 1990-3% case, where the revenues come entirely from the domestic market, the revenue collected in 2010 is projected to total $585 billion nominal dollars and $317 billion and $128 billion in the 1990+9% and 1990+24% cases, respectively. The collection of this money necessitates a careful consideration of appropriate fiscal policy to accompany the permit auction. Two approaches are considered: first, returning collected revenues to consumers through a personal income tax lump sum rebate and, second, lowering social security tax rates as they apply to both employers and employees. The two policies are meant only to be representative of a set of possible fiscal policies that might accompany an initial carbon mitigation policy.

The second flow of funds is associated with U.S. purchases of international carbon permits and assumes that the carbon price determined in the U.S. energy market analysis is the international price at which permits would be traded. The differences between the reduction level in the 1990-3% case and those in the other cases are assumed to be met by purchases of permits in international markets. Table ES3 shows average carbon reductions, purchases of international permits, and the carbon price for the three cases considered in the macroeconomic assessment for the 2008-2012 period.

The energy market analysis in this report does not address the international implications of achieving a particular target at the projected carbon price. For the macroeconomic assessment, the simplifying assumption is made that in each case the domestic carbon price is the same as the international permit price when different levels of trading are used to achieve the Kyoto target, implying that different international supplies of permits would be available in the alternative cases considered. This is an important simplifying assumption, and the value placed on the overseas transfer of funds to purchase international permits is subject to considerable uncertainty. However, this element must be considered a key factor in performing any assessment of the impacts on the economy, and therefore it is explicitly factored into the analysis.

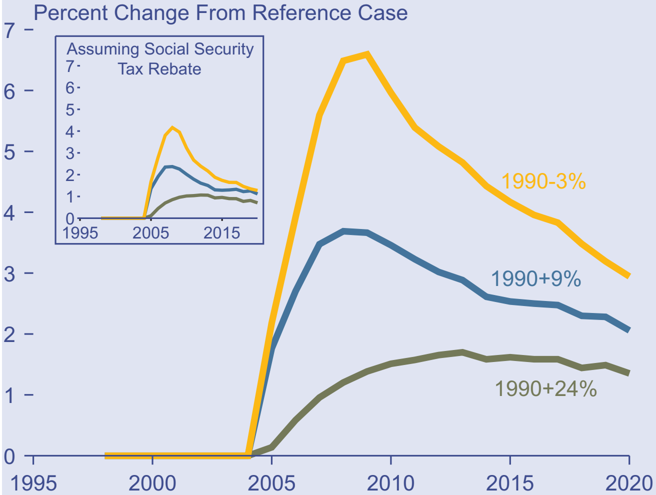
As a direct consequence of the carbon price, aggregate energy prices in the U.S. economy are expected to rise. One way to measure this effect is to look at the percentage change in prices in the economy. For example, in the 1990+9% case, energy prices are 56 percent higher than the reference case projection in 2010 and remain more than 50 percent above the reference case over the rest of the forecast period. The projected energy price increases would also affect downstream prices for all goods and services in the economy as measured by the producer price index. The projected increase in producer prices relative to the reference case in 2010 is 9 percent in the 1990+9% case. Final prices for goods and services in 2009, as shown by the consumer price index (CPI) series, are about 4 percent higher in the 1990+9% case (Figure ES14). Expressed as a rate of change, CPI inflation rises by 0.7 percentage points between 2005 and 2010, as the reference case CPI rises by 3.6 percent a year and the 1990+9% case rises by 4.3 percent a year. These figures suggest the following rule of thumb for the year 2010: each 10-percent increase in aggregate prices for energy may lead to a 1.5-percent increase in producer prices and a 0.7-percent increase in consumer prices.

Table ES3. Energy Market Assumptions for the Macroeconomic Analysis of Three Carbon Reduction Cases, Average Annual Values, 2008 through 2012

Analysis Case	Binding Carbon Emissions Reduction Target (Million Metric Tons)	Average U.S. Carbon Emissions Reductions (Million Metric Tons)	U.S. Purchases of International Permits (Million Metric Tons)	Carbon Price: 1996 Dollars per Metric Ton	Carbon Price: 1992 Dollars per Metric Ton	Value of Purchased International Permits (Billion 1992 Dollars)
1990-3%.	485	485	0	290	263	0
1990+9%	485	325	160	159	144	23
1990+24%	485	122	363	65	59	21

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System.

Figure ES14. Projected Changes in Consumer Price Index Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through reductions in personal income taxes.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

One aspect of the CPI is particularly noteworthy. The CPI measures the prices that consumers face, regardless of the country of origin of the product. Import prices, to the extent that they do not rise at the rate of domestic prices because non-Annex I countries do not face carbon constraints, would dampen the price effects as lower-priced imports find their way into U.S. markets.

Because energy resources are used to produce most goods and services, higher energy prices can affect the economy's production potential. Long-run equilibrium costs are associated with reducing reliance on energy in favor of other factors of production—including labor and capital, which become relatively cheaper as energy costs rise. Short-run adjustment costs, or business cycle costs, can arise when price increases disrupt capital or employment markets. Long-run costs are considered unavoidable. Short-run costs might be avoidable if price changes can be accurately anticipated or if appropriate compensatory monetary and fiscal policies can be implemented. The economic assessment in this analysis considers both the short-run and long-run costs to the economy and focuses on the 1990-3%, 1990+9%, and 1990+24% carbon reduction cases.

The possible impacts on the economy are summarized in Table ES4, which shows average changes from the reference case projections over the period from 2008 through 2012 in the three carbon reduction analysis cases. The *loss of potential GDP* measures the loss in productive capacity of the economy directly attributable to the reduction in energy resources available to the economy. The *macroeconomic adjustment cost* reflects frictions in the economy that may result from the higher prices of the carbon mitigation policy. It recognizes the possibility that cyclical adjustments may occur in the short run. The *loss in actual GDP* for the economy is the sum of the loss in potential and the adjustment cost. The *purchase of international permits* represents a claim on the productive capacity of domestic U.S. resources. Essentially, as funds flow abroad, other countries have an increased claim on U.S. goods and services.

The loss of potential GDP plus the purchase of international permits represent the long-run, unavoidable impact on the economy. The *total cost to the economy* is represented by the loss in actual GDP plus the purchase of international permits (Figure ES15). These costs need to be put in perspective relative to the size of the ecomomy, which averages $9,425 billion between 2008 and 2012. Tables ES5 and ES6 summarize the macroeconomic impacts projected for the years 2010 and 2020.

In the long run, higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher-cost energy, the gradual

Table ES4. Macroeconomic Impacts in Three Carbon Reduction Cases, Average Annual Values, 2008-2012
(Billion 1992 Dollars)

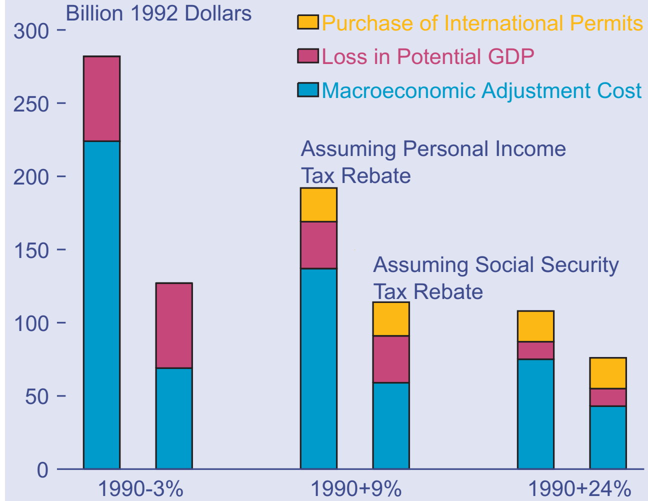
Analysis Case	Loss in Potential GDP	Macroeconomic Adjustment Cost	Loss in Actual GDP	Purchases of International Permits	Total Cost to the Economy
1990-3%					
Personal Income Tax Rebate	58	225	283	0	**283**
Social Security Tax Rebate	58	70	128	0	**128**
1990+9%					
Personal Income Tax Rebate	32	137	169	23	**192**
Social Security Tax Rebate	32	59	91	23	**114**
1990+24%					
Personal Income Tax Rebate	12	76	88	21	**109**
Social Security Tax Rebate	12	44	56	21	**77**

Note: Loss in potential GDP plus the macroeconomimc adjustment cost equals the loss in actual GDP. The actual GDP loss plus purchases of international permits equals the total cost to the economy.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

reduction in energy use would tend to lower the productivity of other factors in the production process. The derivation of the long-run equilibrium path of the economy can be characterized as representing the "potential" output of the economy when all resources—labor, capital, and energy—are fully employed. As such, potential GDP is equivalent to the full employment concept in other analyses that focus on long-run growth while abstracting from business cycle behavior. Figure ES16 shows the losses in the potential economic output, as measured by potential GDP, for the three carbon reduction cases. The shapes of the three trajectories mirror the carbon price trajectories.

The ultimate impacts of carbon mitigation policies on the economy will be determined by complex interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. As such, cyclical impacts on the economy are bound to be characterized by uncertainty and controversy. However, raising the price of energy and

Figure ES15. Projected Annual Costs of Carbon Reductions to the U.S. Economy, 2008-2012



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Table ES5. Projected Impacts on Gross Domestic Product, 2005 and 2010

Variable	1996	2005 Reference	2010 Reference	2010 1990 +24%	2010 1990 +14%	2010 1990 +9%	2010 1990	2010 1990 -3%	2010 1990 -7%
Potential GDP									
(Billion 1992 Dollars)	6,930	8,585	9,482	9,469	9,455	9,448	9,429	9,420	9,410
(Percent Change From Reference Case)	—	—	—	-0.1	-0.3	-0.4	-0.6	-0.7	-0.8
(Annual Growth Rate, 2005-2010, Percent)	—	—	2.0	2.0	1.9	1.9	1.9	1.9	1.9
Actual GDP, Assuming Personal Income Tax Rebate									
(Billion 1992 Dollars)	6,928	8,525	9,429	9,333	9,268	9,241	9,137	9,102	9,032
(Percent Change From Reference Case)	—	—	—	-1.0	-1.7	-2.0	-3.1	-3.5	-4.2
(Annual Growth Rate, 2005-2010, Percent)	—	—	2.0	1.8	1.7	1.6	1.4	1.3	1.2
Actual GDP, Assuming Social Security Tax Rebate									
(Billion 1992 Dollars)	6,928	8,525	9,429	9,369	9,337	9,326	9,291	9,281	9,247
(Percent Change From Reference Case)	—	—	—	-0.6	-1.0	-1.1	-1.5	-1.6	-1.9
(Annual Growth Rate, 2005-2010, Percent)	—	—	2.0	1.9	1.8	1.8	1.7	1.7	1.6

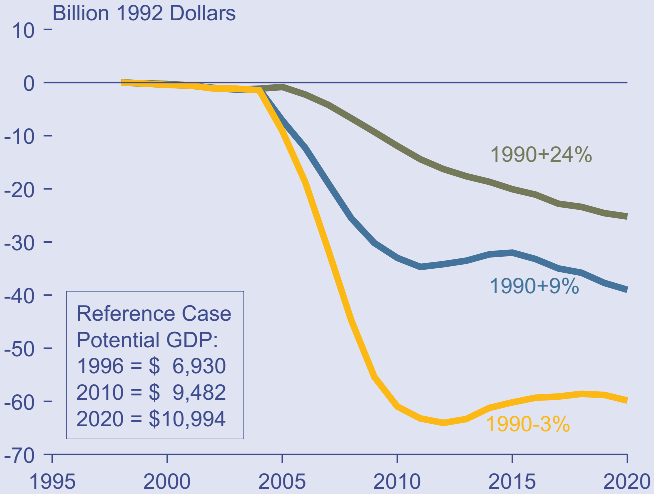
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Table ES6. Projected Impacts on Gross Domestic Product, 2005 and 2020

Variable	1996	2005 Reference	2020 Reference	2020 1990 +24%	2020 1990 +14%	2020 1990 +9%	2020 1990	2020 1990 -3%	2020 1990 -7%
Potential GDP									
(Billion 1992 Dollars)	6,930	8,585	10,994	10,968	10,961	10,954	10,940	10,933	10,925
(Percent Change From Reference Case)	—	—	—	-0.2	-0.3	-0.4	-0.5	-0.6	-0.6
(Annual Growth Rate, 2005-2020, Percent)	—	—	1.7	1.6	1.6	1.6	1.6	1.6	1.6
Actual GDP, Assuming Personal Income Tax Rebate									
(Billion 1992 Dollars)	6,928	8,525	10,865	10,815	10,808	10,796	10,799	10,793	10,782
(Percent Change From Reference Case)	—	—	—	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8
(Annual Growth Rate, 2005-2020, Percent)	—	—	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Actual GDP, Assuming Social Security Tax Rebate									
(Billion 1992 Dollars)	6,928	8,525	10,865	10,840	10,832	10,828	10,833	10,835	10,842
(Percent Change From Reference Case)	—	—	—	-0.2	-0.3	-0.3	-0.3	-0.3	-0.2
(Annual Growth Rate, 2005-2020, Percent)	—	—	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

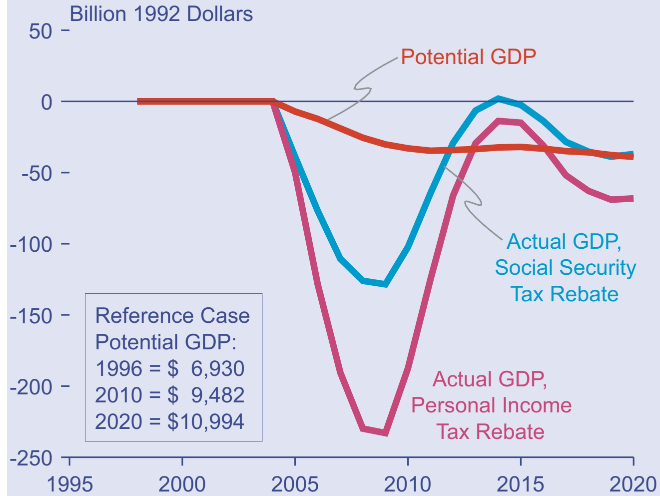
Figure ES16. Projected Dollar Losses in Potential GDP Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through reductions in personal income taxes.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure ES17. Projected Changes in Potential and Actual GDP in the 1990+9% Case Relative to the Reference Case Under Different Fiscal Policies, 1998-2020



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

downstream prices in the rest of the economy could introduce cyclical behavior in the economy, resulting in employment and output losses in the short run. The measurement of losses in actual output for the economy, or actual GDP, represents the transitional cost to the aggregate economy as it adjusts to its long-run path. Resources may be less than fully employed, and the economy may move in a cyclical fashion as the initial cause of the disturbance—the increase in energy prices—plays out over time.

Collection of money from a permit auction system necessitates a careful consideration of appropriate fiscal policy to accompany the carbon reduction policy. Two alternative fiscal policies are analyzed, both returning collected revenue back to agents in the economy: a cut in personal income taxes and a cut in social security taxes as they apply to both employers and employees. In both cases, the Federal deficit is maintained at reference case levels. The personal income tax cut essentially returns collected revenues to consumers, helping to maintain personal disposable income. Like the personal income tax cut, the social security tax cut returns collected funds to the private sector of the economy, ameliorating the near-term impacts of higher energy prices. Although consumers and businesses still would face much higher relative prices for energy than for other goods and services, disposable income is maintained near reference case values to the extent that funds flow back to consumers.

In the fiscal policy settings, higher prices in the economy place upward pressure on interest rates. The Federal Reserve Board seeks to balance the consequences of higher energy prices on the economy and possible adverse effects on output and employment by making adjustments to the Federal funds rate. The adjustments would be designed to moderate the possible impacts on both inflation and unemployment, and to return the economy to its long-run growth path.

Figure ES17 shows the projected impacts on both actual and potential GDP for the two hypothetical fiscal policies (income tax and social security tax cuts) in the 1990+9% case. The figure indicates that, in the 2008 to 2012 period, the short-run cyclical impact on actual GDP is larger than the long-run impact on potential GDP; however, the two output concepts begin to converge by 2015, and by 2020 they have merged into a steady-state path reflected by potential GDP. Monetary policy is instrumental in balancing inflation and unemployment impacts through the adjustment period, acting in a manner to bring the economy back to its long-run growth path.

The choice of the accommodating fiscal policy is also key to the assessment of the ultimate impacts on the economy. While the personal income tax option moderates the impacts through a return of funds to consumers, the social security tax option has cost-cutting aspects of lowering the employer portion of the tax, which serves to reduce inflationary pressures in the aggregate economy. On the employer side, the reduction in employer contributions to the social security system would lower costs to the firm and, thereby, moderate the near-term price consequences to the economy. Since it is the price effect that produces the predominately negative effect on the economy, any steps to reduce inflationary pressures would serve to moderate adverse impacts on the aggregate economy.

Another way to view the macroeconomic effects is by looking at the effects of the carbon reduction cases on the growth rate of the economy, both during the period of implementation from 2005 through 2010 and then over the entire period from 2005 through 2020 (Figures ES18 and ES19). In the reference case, potential and actual GDP grow at 2.0 percent per year from 2005 through 2010. In the 1990+9% case, the growth rate in potential GDP slows to 1.9 percent per year, and the growth rate in actual GDP slows to 1.6 percent per year when the personal income tax rebate is assumed or 1.8 percent per year when the social security tax rebate is assumed. However, through 2020, with the economy rebounding back to the reference case path, there is no appreciable change in the projected long-term growth rate. The results for the 1990+24% and 1990-3% cases are similar.

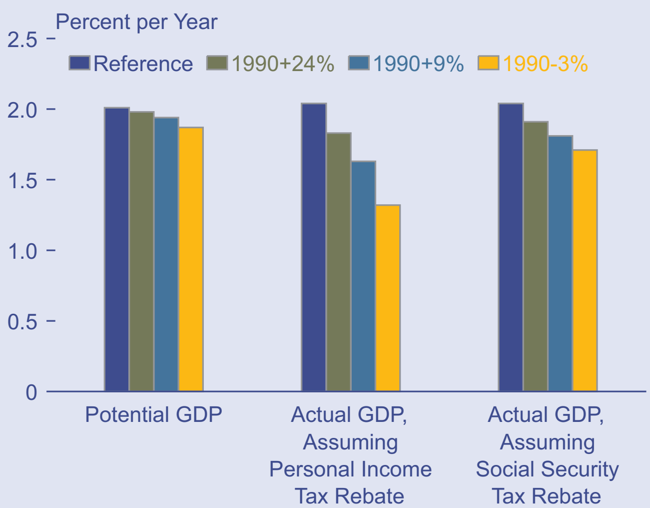
Aggregate impacts on the economy, as measured by potential and actual GDP, are shown in Table ES7 in terms of losses in GDP per capita. In the 1990+9% case, the loss in potential GDP per capita is $106; however, the loss in actual GDP for in the 1990+9% case is $567 assuming the personal income tax rebate and $305 assuming the social security tax rebate. Again, the lower value (loss in potential GDP) represents an unavoidable loss per person, and the higher values (loss in actual GDP) reflect the highly uncertain, but significant, impacts that individuals could experience as the result of frictions within the economy. To provide perspective, actual GDP per capita averages $31,528 in the reference case between 2008 and 2012.

Sensitivity Cases

This analysis includes several sensitivity cases designed to examine alternative assumptions that may have significant impacts on energy demand and carbon emissions over the next 20 years, including higher and lower economic growth, faster and slower availability and rates of improvement in technology, and the construction of new nuclear power plants. The sensitivity cases illustrate how such factors influence the results of the carbon reduction cases. With the exception of the nuclear power case, the sensitivity cases are analyzed relative to the 1990+9% case.

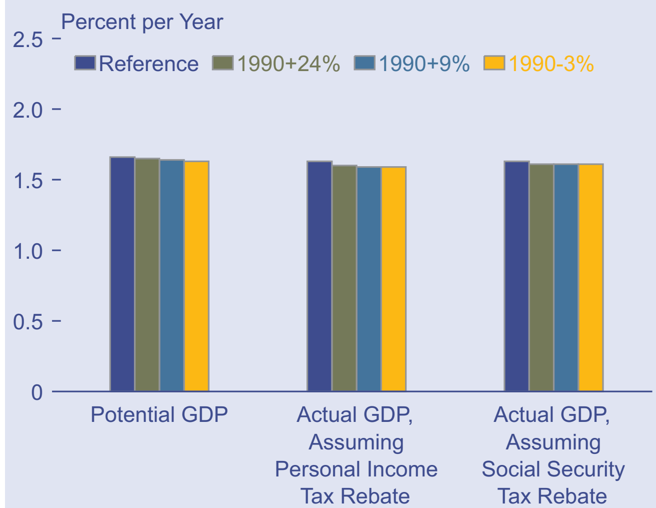
Because each sensitivity case is constrained to the same level of carbon emissions as the case to which it is compared, the primary impact is not on the carbon emissions levels, or even on aggregate energy consumption, but rather on the carbon price required to meet the emissions target. For example, in the high technology case, projected carbon emissions during the

Figure ES18. Projected Annual Growth Rates in Potential and Actual GDP, 2005-2010



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure ES19. Projected Annual Growth Rates in Potential and Actual GDP, 2005-2020



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Table ES7. Projected Losses in Potential and Actual GDP per Capita, Average Annual Values, 2008-2012 (1992 Dollars per Person)

Analysis Case	Loss in Potential GDP per Capita	Loss in Actual GDP per Capita, Personal Income Tax Rebate	Loss in Actual GDP per Capita, Social Security Tax Rebate
1990-3%	193	947	428
1990+9%	106	567	305
1990+24	40	294	187

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

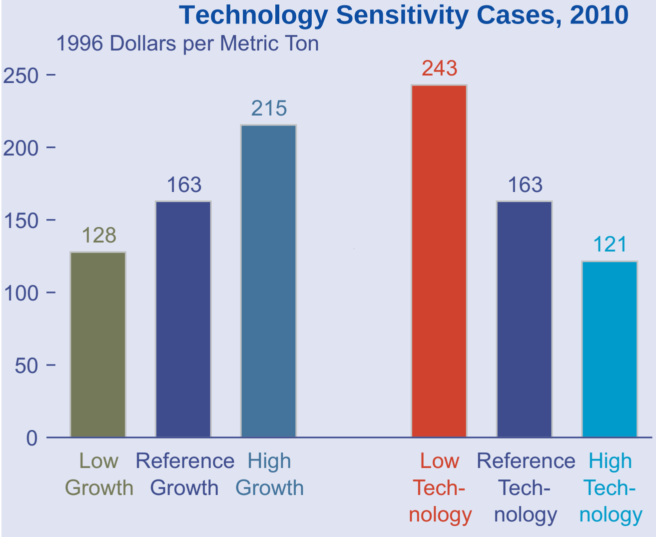
compliance period are the same as in the corresponding reference technology case. What differs is the cost of meeting the target, as reflected in the required carbon price.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on the projection of energy consumption and, therefore, on the projected levels of carbon emissions. Two sensitivity cases explore the effects of higher and lower economic growth on the cost of reducing carbon emissions to the 1990+9% level. Higher economic growth results from higher assumed growth in population, the labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, GDP increases at an average rate of 2.4 percent a year through 2020, compared with a growth rate of 1.9 percent a year in the reference case. With higher macroeconomic growth, energy demand grows faster, as higher manufacturing output and higher income increase the demand for energy services, resulting in higher carbon emissions. Assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.3 percent in the low economic growth case, resulting in lower carbon emissions.

With higher economic growth, both industrial output and energy service demand are higher. As a result, carbon prices must be correspondingly higher to attain a given carbon emissions target. In the high macroeconomic growth case, the carbon price in 2010 is $215 per metric ton, $52 per metric ton higher than the carbon price of $163 per metric ton in the 1990+9% case with reference growth assumptions (Figure ES20). In the low

Figure ES20. Projected Carbon Prices in the 1990+9% High and Low Economic Growth and High and Low Technology Sensitivity Cases, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B, LMAC09.D080698A, HMAC09.D080598A, FREEZE09. D080798A, and HITECH09.D080698A.

macroeconomic growth case, the carbon price in 2010 is $128 per metric ton. The higher carbon prices necessary to achieve the carbon reductions with higher economic growth have a negative impact on the economy and the energy system. Nevertheless, total energy consumption in 2010 is higher with higher economic growth, by 2.2 quadrillion Btu relative to the 1990+9% case, which assumes the same economic growth rate as the reference case. In the low economic growth case, total energy consumption is lower by 2.2 quadrillion Btu in 2010.

In order to meet the carbon reduction targets with higher economic growth, there is a shift to less carbon-intensive fuels and higher energy efficiency. On a sectoral basis, higher economic growth affects total energy consumption in the industrial and transportation sectors more significantly than in the other end-use sectors. Total consumption of both renewables and natural gas is higher, primarily for electricity generation but also in the industrial sector. Coal use for generation is lower, and the use of nuclear power is higher as a result of the higher carbon prices. Petroleum consumption is also higher with higher economic growth, both in the transportation and industrial sectors.

Total energy intensity is lower in the high economic growth case, partially offsetting the increases in the demand for energy services caused by the higher growth assumption. With higher economic growth, there is greater opportunity to turn over and improve the stock of energy-using technologies. In addition, the higher carbon price induces more efficiency improvements and some offsetting reductions in energy service demand, moderating the impacts of higher economic growth. With higher economic growth, aggregate energy intensity declines at an average annual rate of 1.9 percent through 2010, compared to 1.6 percent with reference economic growth. The opposite effects on energy intensity occur with lower economic growth, with the decline in energy intensity slowing from 1.6 percent to 1.3 percent between 1996 and 2010.

Technological Progress

The rates of development and market penetration of energy-using technologies have a significant impact on projected energy consumption and energy-related carbon emissions. Faster development of more energy-efficient or lower-carbon-emitting technologies than assumed in the reference case could reduce both consumption and emissions; however, because the reference case already assumes continued improvement in both energy consumption and production technologies, slower technological development is also possible.

To analyze the impacts of technology improvement, high technology assumptions were developed by experts in technology engineering for each of the energy-consuming sectors, considering the potential impacts of increased research and development for more advanced technologies. The revised assumptions included earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than assumed in the reference case.[9] Also, this sensitivity case assumed the availability of carbon sequestration technology for coal- and natural-gas-fired power plants, which would remove carbon dioxide and store it in underground aquifers; however, the technology is uneconomical relative to other technologies because of its high operating and storage costs.

These technological improvements were developed under the assumption of increased research and development, and they are distinct from the more rapid adoption of advanced technologies that occurs with higher energy prices in the carbon reduction cases. It is possible that further technology improvements could occur beyond those in the high technology sensitivity case if a very aggressive research and development effort were established. The low technology sensitivity case assumes that all future equipment choices are made from the end-use and generation equipment available in 1998, with new building shell and industrial plant efficiencies frozen at 1998 levels. Comparing this sensitivity case to a case with reference technology assumptions demonstrates the importance of technology improvement in the reference case.

Because faster technology development makes advanced energy-efficient and low-carbon technologies more economically attractive, the carbon prices required to meet carbon reduction levels are significantly reduced. Conversely, slower technology improvement requires higher carbon prices (Figure ES20). With high technology assumptions, the carbon price in 2010 is $121 per metric ton, $42 per metric ton lower than the carbon price of $163 per metric ton in the 1990+9% case with the reference technology assumptions. With the low technology assumptions, the carbon price increases to $243 per metric ton in 2010.

In the high technology sensitivity case, total energy consumption in 2010 is lower by 2.1 quadrillion Btu, or about 2 percent, than in the 1990+9% case with reference technology. Delivered energy consumption in both the industrial and transportation sectors is lower as efficiency improvements in industrial processes and most transportation modes outweigh the countervailing effects of lower energy prices. In the residential and commercial sectors, the effect of lower energy prices balances the effect of advanced technology, and consumption levels are at or near those in the reference technology (1990+9%) case. In the generation sector, coal use for generation is 40 percent higher than with reference technology assumptions, due to efficiency improvements and the lower carbon price.

In the low technology sensitivity case, the converse trends prevail. In 2010, total energy consumption is higher by 1.5 quadrillion Btu than in the 1990+9% case with reference technology assumptions. Delivered energy consumption is higher in the industrial and transportation sectors and lower in the residential and commercial sectors, suggesting that industry and transportation are more sensitive to technology changes than to price changes, and the residential and commercial sectors are more sensitive to price changes. With the higher carbon prices in the low technology case, coal use is further reduced in the generation sector, and more natural gas, nuclear power, and renewables are used to meet the carbon reduction targets.

Nuclear Power

In the reference case, nuclear electricity generation declines significantly because 52 percent of the total nuclear capacity available in 1996 is assumed to be retired by 2020. A number of units are retired before the end of their 40-year operating licenses, as suggested by industry announcements and analysis of the age and operating costs of the units. In the carbon reduction cases, life extension of the plants can occur if it is economical; and there is an increasing incentive to invest in nuclear plant refurbishment with higher carbon prices. However, these cases do not allow the construction of new nuclear power plants, given continuing high capital investment costs and institutional constraints associated with nuclear power. A nuclear power sensitivity case examines the impact of allowing new plants to be constructed. Because nuclear plants still are not economically competitive with fossil and renewable plants in the 1990+9% case, the nuclear power sensitivity case was analyzed against the 1990-3% case. In addition to allowing new nuclear plants, the higher costs assumed in the reference case for the first few advanced nuclear plants were reduced in this sensitivity.

Relative to the 1990-3% case, 1 gigawatt of new nuclear capacity is added by 2010 in the nuclear power sensitivity case, and 41 gigawatts, representing about 68 new plants of 600 megawatts each, are added by 2020. With most of the impact from the new nuclear plants coming after the commitment period of 2008 through 2012, there is little impact on carbon prices in 2010. By 2020, however, carbon prices are $199 per metric ton with the assumption of new nuclear plants, as compared with $240 per metric ton in the 1990-3% case with the reference nuclear assumptions. In 2010, total energy consumption is about the same in this sensitivity case as in

[9]The design of the high technology sensitivity case differs from the high technology cases in *AEO98*, which generally did not include an analysis of improvements for specific technologies.

the 1990-3% case, but in 2020 it is about 1.8 quadrillion Btu higher. Somewhat lower energy prices induce higher consumption in all sectors, and the availability of more carbon-free nuclear generation allows the carbon reduction target to be met with higher end-use consumption.

Uncertainties in the Analysis

The reference case projections in both *AEO98* and this analysis represent business-as-usual forecasts, given known trends in technology and demographics, current laws and regulations, and the specific methodologies and assumptions used by EIA. Because EIA does not include future legislative and regulatory changes in its reference case projections, the projections provide a policy-neutral baseline against which the impacts of policy initiatives can be analyzed.

Results from any model or analysis are highly uncertain. By their nature, energy models are simplified representations of complex energy markets. The results of any analysis are highly dependent on the specific data, assumptions, behavioral characteristics, methodologies, and model structures included. In addition, many of the factors that influence the future development of energy markets are highly uncertain, including weather, political and economic disruptions, technology development, and policy initiatives. Recognizing these uncertainties, EIA has attempted in this study to isolate and analyze the most important factors affecting future carbon emissions and carbon prices. The results of the various cases and sensitivities should be considered as relative changes to the comparative baseline cases.

In addition to the uncertainties concerning the final interpretation and implementation of the Kyoto Protocol, specific actions that might be taken to reduce greenhouse gas emissions in the United States have not been formulated. Actions taken by other Annex I countries to reduce emissions, future growth in worldwide energy consumption and emissions, and the opportunities for reducing emissions through joint implementation and the CDM are unknown, and they are likely to have important impacts on the international trade of carbon permits and the carbon permit price. This analysis assumes that auctioned permits will constrain carbon emissions and raise the price of fossil fuels, with revenues from the auction recycled to consumers either through personal income tax or social security tax rebates. Alternative carbon reduction programs and fiscal policies would be likely to change the cost of carbon reduction from the costs in this analysis. The timing of carbon reduction programs and the amount of adjustment time allowed could also be important in determining costs.

Future technology development also cannot be known with certainty and may have a significant effect on the cost of achieving carbon reductions. The technology sensitivity cases in this analysis explore some of the potential impacts, but even the high technology sensitivity does not include possible breakthrough or speculative technologies. On the other hand, even the reference case technology assumptions include continued development of more energy-efficient and renewable technologies, which serve to mitigate the costs of carbon reduction. Those technology improvements are likely, but not certain.

Finally, consumer response to carbon initiatives is uncertain. Because energy price changes that have occurred in the past may not provide sufficient evidence about the reaction of consumers to sustained high energy prices, changes in demand as a result of the higher carbon fees cannot be projected with confidence. In addition to price-induced changes, consumers might also respond to climate change initiatives and a national commitment to reduce emissions by adopting more energy-efficient or renewable technologies sooner than expected. Finally, public acceptance of large-scale renewable technologies or the continuation of nuclear power—both of which make important contributions to the achievement of the carbon emissions reductions at the costs projected in this analysis—cannot be known with certainty.

1. Scope and Methodology of the Study

Background

The Greenhouse Gas Effect

The greenhouse effect is a natural process by which some of the radiant heat from the Sun is captured in the lower atmosphere of the Earth, thus maintaining the temperature of the Earth's surface. The gases that help capture the heat, called "greenhouse gases," include water vapor, carbon dioxide, methane, nitrous oxide, and a variety of manufactured chemicals. Some are emitted from natural sources; others are anthropogenic, resulting from human activities.

Over the past several decades, rising concentrations of greenhouse gases have been detected in the Earth's atmosphere. Although there is not universal agreement within the scientific community on the impacts of increasing concentrations of greenhouse gases, it has been theorized that they may lead to an increase in the average temperature of the Earth's surface. To date, it has been difficult to note such an increase conclusively because of the differences in temperature around the Earth and throughout the year, and because of the difficulty of distinguishing permanent temperature changes from the normal fluctuations of the Earth's climate. In addition, there is not universal agreement among scientists and climatologists on the potential impacts of an increase in the average temperature of the Earth, although it has been hypothesized that it could lead to a variety of changes in the global climate, sea level, agricultural patterns, and ecosystems that could be, on net, detrimental.

The most recent report of the Intergovernmental Panel on Climate Change (IPCC) concluded that: "Our ability to quantify the human influence on global climate is currently limited because the expected signal is still emerging from the noise of natural variability, and because there are uncertainties in key factors. These include the magnitudes and patterns of long-term variability and the time-evolving pattern of forcing by, and response to, changes in concentrations of greenhouse gases and aerosols, and land surface changes. Nevertheless, the balance of evidence suggests that there is a discernable human influence on global climate."[1]

U.S. Greenhouse Gas Emissions

In 1990, total greenhouse gas emissions in the United States were 1,618 million metric tons carbon equivalent,[2] according to 1997 estimates published by the Energy Information Administration (EIA).[3] Of this total, 1,346 million metric tons, or 83 percent, was due to carbon emissions from the combustion of energy fuels—the focus of this report. By 1996, total U.S. greenhouse gas emissions had risen to 1,753 million metric tons carbon equivalent, including 1,463 million metric tons of carbon emissions from energy combustion. EIA's *Annual Energy Outlook 1998* (*AEO98*)[4] projects that energy-related carbon emissions will reach 1,577 million metric tons in 2000, 17 percent above the 1990 level. Projected emissions continue to rise at an average annual rate of 1.5 percent a year from 1996 to 2010, reaching 1,803 million metric tons of carbon emissions in 2010, 34 percent above the 1990 level. Because energy-related carbon emissions are a large portion of total greenhouse gas emissions, any efforts to reduce greenhouse gas emissions will likely have a significant impact on the energy sector; however, as discussed later, there are a number of factors outside the domestic energy market that also affect emissions levels.

To put U.S. emissions in a global perspective, the United States produced about 24 percent of the worldwide energy-related carbon emissions in 1996, which totaled 6.6 billion metric tons, as noted in EIA's *International Energy Outlook 1998* (*IEO98*).[5] Although continued increases in carbon emissions are expected for the United States and other industrialized countries, much

[1]Intergovernmental Panel on Climate Change, *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996).

[2]Greenhouse gases differ in their impacts on global temperatures. For comparison of emissions from the various gases, they are often weighted by global warming potential (GWP), established by the Intergovernmental Panel on Climate Change, which is a measure of the impact of each gas on global warming relative to that of carbon dioxide, which is defined as having a GWP equal to 1.

[3]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997).

[4]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[5]Energy Information Administration, *International Energy Outlook 1998*, DOE/EIA-0484(98) (Washington, DC, April 1998).

more rapid increases are projected for the developing countries of Asia, the Middle East, Africa, and Central and South America. As a result, global carbon emissions from energy use are expected to increase at an average annual rate of 2.4 percent from 1996 through 2010, reaching 8.3 billion metric tons, to which the United States would contribute about 22 percent.

The Framework Convention on Climate Change

As a result of increasing warnings by members of the climatological and scientific community about the possible harmful effects of rising greenhouse gas concentrations, the IPCC was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. A series of international conferences followed, and in 1990 the United Nations established the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change. After a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4.

The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." The signatories agreed to "formulate, implement, . . . and . . . update . . . programmes containing measures to mitigate climate change by addressing anthropogenic emissions by sources and removals by sinks" and to prepare periodic emissions inventories, promote development and diffusion of technologies for emissions control, and cooperate in adaptation. In addition, the developed country signatories agreed to "adopt national policies and take corresponding measures on the mitigation of climate change" and to "communicate . . . detailed information on its policies and measures . . . with the aim of returning individually or jointly to their 1990 levels these anthropogenic emissions of carbon dioxide and other greenhouse gases." The Convention excludes chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), greenhouse gases that are deemed to cause damage to the Earth's stratospheric ozone and are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

The Framework Convention established the Conference of the Parties to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." In 1995, the first Conference of the Parties met in Berlin and issued the Berlin mandate, an agreement to "begin a process to enable it to take appropriate action for the period beyond 2000." The second Conference of the Parties, held in Geneva in July 1996, called for negotiations on quantified limitations and reductions of greenhouse gas emissions and policies and measures for the third Conference of the Parties in Kyoto, Japan, in December 1997.

The Climate Change Action Plan

Responding to the Framework Convention, on April 21, 1993, President Clinton called upon the United States to stabilize greenhouse gas emissions by 2000 at 1990 levels. Specific steps to achieve U.S. stabilization were enumerated in the Climate Change Action Plan (CCAP),[6] published in October 1993, which consists of a series of 44 actions to reduce greenhouse gas emissions. The actions include voluntary programs, industry partnerships, government incentives, research and development, regulatory programs including energy efficiency standards, and forestry actions. Greenhouse gases affected by these actions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). At the time CCAP was developed, the Administration estimated that the actions it enumerated would reduce total net emissions[7] of these greenhouse gases in the United States to 1990 levels by 2000.

In addition to the climate-related actions of CCAP, the Energy Policy Act of 1992 (EPACT), Section 1605(a), provided for an annual inventory of U.S. greenhouse gas emissions, which is contained in the EIA publication series, *Emissions of Greenhouse Gases in the United States*.[8] Also, Section 1605(b) of EPACT established the Voluntary Reporting Program, permitting corporations, government agencies, households, and voluntary organizations to report to EIA on actions that have reduced or avoided emissions of greenhouse gases. The results of the Voluntary Reporting Program are reported annually by EIA, most recently in *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*,[9] which reports 1995 activities. Entities providing data to the Voluntary Reporting Program include some participants in government-sponsored voluntary programs, such as the

[6]President William J. Clinton and Vice President Albert Gore, Jr., *The Climate Change Action Plan* (Washington, DC, October 1993).

[7]Carbon dioxide is absorbed by growing vegetation and soils. Defining the total impacts of CCAP as net reductions accounts for the increased sequestration of carbon dioxide as a result of the forestry and land-use actions in the program.

[8]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997).

[9]Energy Information Administration, *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, DOE/EIA-0608(96) (Washington, DC, October 1997).

Climate Wise and Climate Challenge programs, which are cosponsored by the U.S. Environmental Protection Agency and the U.S. Department of Energy to foster reductions in greenhouse gas emissions by industry and electricity generators. Voluntary activities for 1996 and 1997 will be available in the fall of 1998.

The Kyoto Protocol

Prior to the third Conference of the Parties, at the June 26, 1997, Earth Summit+5 Conference at the United Nations, President Clinton pledged U.S. support for binding emissions targets and announced three initiatives: a pledge of $1 billion over 5 years by the United States for the development of more energy-efficient and alternative energy technologies in developing countries; the strengthening of environmental guidelines for U.S. companies investing overseas; and a partnership with private industry to install solar panels on 1 million rooftops in the United States by 2010.

On October 22, 1997, President Clinton proposed that developed countries should stabilize emissions at 1990 levels between 2008 and 2012, with reductions below 1990 levels in the following 5-year period. He also indicated his support for joint implementation projects and international emissions trading and declared that participation by developing countries was necessary for the United States to assume binding obligations. At the same time, the President announced additional initiatives to address greenhouse gas emissions: a $5 billion program of tax incentives and research and development spending for energy-efficient and lower-carbon technologies; the establishment of an emissions trading system with credit for early reductions; the restructuring of the electricity industry; and reductions of emissions from Federal sources. Funding for the program was increased to $6.3 billion in the Administration's 1999 budget request.

Representatives from more than 160 countries met in Kyoto on December 1 through 11, 1997. The resulting Kyoto Protocol established binding emissions targets for developed nations, relative to their emissions levels in 1990, for an overall reduction of about 5 percent.[10] The individual targets for the Annex I countries[11] range from an 8-percent reduction for the European Union (EU) (or its individual member states) to a 10-percent increase allowed for Iceland. Australia and Norway also are allowed increases of 8 and 1 percent, respectively, while New Zealand, the Russian Federation, and the Ukraine are held to their 1990 levels. Other Eastern European countries undergoing transition to market economies have reduction targets of between 5 and 8 percent. The reduction targets for Canada and Japan are 6 percent and, for the United States, 7 percent. Although atmospheric *concentrations* of greenhouse gases ultimately have the potential to affect the global climate, the Protocol establishes targets in terms of *annual emissions*.

The greenhouse gases included in the targets are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.[12] For the latter three gases, individual nations have the option of using 1995 as the base year from which to achieve reductions, instead of 1990. The aggregate target is established using the carbon dioxide equivalent of each of the greenhouse gases. Other greenhouse gases are not limited by the Protocol, although CFCs and HCFCs are controlled by the Montreal Protocol. This analysis focuses on carbon emissions from the combustion of energy fuels, which constituted 83 percent of all U.S. greenhouse gas emissions in 1990. Carbon dioxide emissions from sources other than energy use are not included in the analysis, nor are emissions of the five other gases covered by the Kyoto Protocol; however, reductions in those gases may lessen the required reductions in energy-related carbon emissions, as discussed below.

The established targets must be achieved over the period 2008 to 2012, the first commitment period. Essentially, each country can average its emissions over that 5-year period to establish compliance, smoothing out short-term fluctuations that might result from economic cycles or extreme weather patterns. Each country must have made demonstrable progress by 2005. No targets are established for the period after 2012, although lower targets may be set by future Conferences of the Parties.

Sources of emissions include fuel combustion, fugitive emissions from fuels, industrial processes, solvents, agriculture, and waste management and disposal. The Protocol does not prescribe specific actions to be taken but lists a number of potential actions, including energy efficiency improvements, enhancement of carbon-absorbing sinks, such as forests and other vegetation, research and development of sequestration technologies, phasing out of fiscal incentives and subsidies that

[10]The text of the Kyoto Protocol is available at web site www.unfccc.de.

[11]Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Turkey and Belarus are Annex I nations that have not ratified the Convention and did not commit to quantifiable emissions targets.

[12]Hydrofluorocarbons are a non-ozone-depleting substitute for CFCs; perfluorocarbons are byproducts of aluminum production and are also used in semiconductor manufacturing; and sulfur hexafluoride is used as an insulator in electrical equipment and in semiconductor manufacturing.

may inhibit the goal of emissions reductions, and reduction of methane emissions in waste management and in energy production, distribution, and transportation.

Several provisions of the Protocol allow for some flexibility in meeting the emissions targets. Net changes in emissions by direct anthropogenic land-use changes and forestry activities will also be used in meeting the commitment; however, these are limited to afforestation, reforestation, and deforestation since 1990. Emissions trading among the Annex I countries is permitted. No rules for trading are established, however, and the Conference of the Parties is required to establish principles, rules, and guidelines for trading at a future date. Joint implementation projects are also allowed among the Annex I countries, whereby a nation could take emissions credits for projects that reduce emissions or enhance sinks in other countries. It is specifically indicated that trading and joint implementation are supplemental to domestic actions.

The Protocol also establishes a Clean Development Mechanism (CDM), under which Annex I countries can take emissions credits for projects that reduce emissions in non-Annex I countries, provided that the projects lead to measurable, long-term benefits. Reductions from such projects undertaken from 2000 until the first commitment period can be used to assist compliance in the commitment period. This provision calls for the establishment of an executive board to oversee the projects. In addition, an unspecified share of the proceeds from the project activities must be used to cover administrative expenses and to assist with adaptation those countries that are particularly vulnerable to climate change.

Banking—the carrying over of unused allowances from one commitment period to the next—is allowed; however, the borrowing of emissions allowances from a future commitment period is not permitted. Under the Protocol, Annex I countries, such as the nations of the European Union (EU), may create a bubble or umbrella to meet the total commitment of all the member nations. In a bubble, countries agree to meet the total commitment jointly by allocating a share to each member. In an umbrella arrangement, the total reduction of all member nations is met collectively through the trading of emissions rights. There is potential interest in the United States in entering into an umbrella trading arrangement.

Non-Annex I countries have no targets under the Protocol, although it reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs and to promote the development and diffusion of environmentally sound technologies and processes. Developing countries can voluntarily enter into the Protocol by full amendment of the Protocol.

The Protocol became open for signature on March 16, 1998, for a 1-year period. Under its provisions, it enters into force 90 days following acceptance of at least 55 Parties, including Annex I countries accounting for at least 55 percent of the total 1990 carbon dioxide emissions from Annex I nations. Signature by the United States would need to be followed by Senate advise and consent to ratification.

There are a number of uncertainties and issues to be resolved at future Conferences of the Parties. As indicated in the Protocol, rules and guidelines for the accounting of emissions and sinks from activities related to agriculture, land use, and forestry activities must be developed. The specific guidelines may have a significant impact on the level of reductions from other sources that a country must undertake. This issue was directed to the IPCC by subsequent climate change talks in Bonn in June 1998. In addition, rules and guidelines must be established for emissions trading, joint implementation projects, and the CDM.

Other issues covered in the Protocol but deferred to subsequent sessions include flexibility for Annex I countries undergoing transition to market economies, commitments for subsequent periods, climate change adaptation actions, sanctions for failure to meet commitments, guidelines for the reporting and review of emissions and sinks, and international cooperation in education, research and development, and technology transfer.

Emissions Trading

Even before the Kyoto Protocol, many analyses of the impacts of greenhouse gas emissions reductions have favored emissions trading programs, including joint implementation programs, as a means of achieving emissions reductions. In the United States, the Clean Air Act Amendments of 1990 (CAAA90) established a trading program for emissions of sulfur dioxide (SO_2) by electricity generators in order to reduce emissions to fixed specified levels. Permits issued to electricity generators allow them to emit up to a specified level of SO_2, with the total number of issued permits equal to the national limit on emissions. Generators may reduce emissions by using lower-sulfur coals, installing scrubbers, or increasing the utilization of cleaner-generating plants. Generators that reduce emissions below their allowed levels can sell excess emissions permits, which can be purchased by other generators for whom it is more cost-effective to purchase permits at the prevailing market price than to reduce emissions. Emissions permits can also be banked for future use. Compared with traditional control programs that mandate specific compliance options or require uniform reductions, this SO_2 trading program is credited with reducing the overall cost of compliance by allowing reductions to be made in the most cost-effective manner.

Unlike SO_2, carbon emissions are primarily an international, rather than domestic, issue. In theory, a similar trading scheme for carbon emissions could be formulated either internationally or within individual countries to achieve fixed emissions levels. Indeed, the Kyoto Protocol provides for international emissions trading but defers the determination of specific guidelines and rules for establishing an open trading market and managing the international flow of funds for the purchase of permits. Additional complexities may arise in establishing baseline projections against which to monitor and verify net emissions reductions, particularly with regard to the CDM.

Even within the United States, carbon emissions trading may be more complicated than the current SO_2 trading plan for several reasons. The largest sources of SO_2 are a small number of large coal-burning generation plants. This makes it relatively easy to monitor their fuel use and emissions and to build and maintain an allowance trading system to ensure compliance. In contrast, there are a large number of entities that emit carbon, including households, commercial establishments, industrial facilities, automobiles, trucks, airplanes, ships, and fossil-fired generating stations. The development and operation of a monitoring and trading system for carbon emissions would thus be much more complicated. In addition, there were technologies available to reduce SO_2 emissions at generation plants at the time the allowance trading program was initiated, and switching to low-sulfur coal was an option. Although research is ongoing, there are no readily available pre- or post-combustion technologies for removing carbon from fossil fuels (although the high technology sensitivity case included in this analysis assumes that carbon sequestration technologies will become available for electricity generators). Therefore, the options for carbon reduction are limited to fuel switching to lower-carbon or carbon-free fuels, efficiency improvements, and reductions in energy demand.

Methodology of the Analysis

In March 1998, the U.S. House of Representatives Committee on Science requested that the EIA perform an analysis of the Kyoto Protocol, focusing on the impacts of the Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 time frame for a number of emissions targets. (See letters of request in Appendix D.) The request specified that the analysis use the same reference case assumptions as in *AEO98* unless changes in the assumptions could be justified on the basis of the Protocol—that is, there should be no changes in assumptions regarding policy, regulatory actions, or funding of energy or environmental programs, including the energy-related provisions of the Administration's revenue proposals of February 1998.

Each target in the analysis was to be achieved on average between 2008 and 2012, phasing in beginning in 2005 and stabilizing at the target level after 2012, although targets beyond 2012 have not yet been established and may in fact be more stringent. The Committee indicated that no new nuclear plants should be allowed, although economical life extensions of nuclear plants should be permitted. Construction of new nuclear plants, variations in economic growth, and different assumptions concerning technology characteristics were all to be analyzed as sensitivities to the target cases.

Numerous studies have been conducted on the topic of reducing greenhouse gas emissions. They can be clustered into several broad categories. One group of studies are cost-benefit analyses, which seek to establish an optimal level of either emissions reductions or emissions prices with a goal of balancing the costs and benefits of emissions reductions, explicitly accounting for the mitigation of damage as a result of emissions controls. A second category of studies address the cost-effectiveness of alternative paths for emissions reductions. Assuming a level of global concentrations of greenhouse gases, these analyses derive an optimal timing strategy for the imposition of emissions controls.

Other studies are more narrowly focused on the costs of achieving specific emissions reductions or on the impacts of policies and technology on emissions levels. Before the Conference of the Parties in Kyoto, analyses examined the costs of emissions targets under a variety of assumptions about the possible level and timing of the targets. Since the Conference, analyses have focused on the levels and timing specified in the Kyoto Protocol and studied the costs of achieving those levels under a range of assumptions about the international provisions and other flexibility measures in the Protocol. Some of those analyses are included in the comparison of results in Chapter 7. This EIA analysis is among this final category of studies, with more detail on U.S. energy markets and the economy than other analyses but not addressing the potential benefits of emissions reductions, optimal timing, or international trade.

The Protocol includes a number of international provisions—including international emissions trading, joint implementation projects, and the CDM—that may reduce the cost of compliance. Because EIA cannot fully address these aspects of the Protocol at this time, the analysis focuses on domestic impacts and includes a range of cases with different levels of energy-related carbon emissions. Although any impact on the global climate will likely be caused by atmospheric concentrations of greenhouse gases, the targets in the Kyoto Protocol are in terms of annual emissions. This analysis addresses the annual emissions targets as specified in the Protocol.

The National Energy Modeling System

At the request of the Committee, this analysis uses the same basic assumptions and methodologies that were used for *AEO98*. The projections in *AEO98* were developed using the National Energy Modeling System (NEMS), an energy-economy modeling system of U.S. energy markets, which is designed, implemented, and maintained by EIA.[13] The production, imports, conversion, consumption, and prices of energy are projected for each year through 2020, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, costs and performance characteristics of energy technologies, and demographics. NEMS is a fully integrated framework, capturing the interactions of energy supply, demand, and prices across all fuels and all sectors of U.S. energy markets.

Reference case projections are developed annually using NEMS and published in the *Annual Energy Outlook* (*AEO*). NEMS is also used to analyze the effects of existing and proposed laws, regulations, and standards related to energy production and use; the impacts of new and advanced energy technologies; the savings from higher energy efficiency; the impacts of energy tax policy on the U.S. economy and energy system; and the impacts of environmental policies, such as the CAAA90 and regulations on alternative and reformulated fuels. Special analyses of these and other topics are performed at the request of the U.S. Congress, other offices in the U.S. Department of Energy, and other government agencies. Because NEMS provides annual projections, it is well suited to represent the transitional effects of proposed energy policy and regulation.

Within NEMS, four end-use demand modules represent energy consumption in the residential, commercial, industrial, and transportation sectors, subject to fuel prices, macroeconomic factors, and the characteristics of energy-using technologies in those sectors. The fuel supply and conversion modules represent the domestic production, imports, transportation, and conversion processes to meet the domestic and export demand for coal, petroleum products, natural gas, and electricity, accounting for resource base characteristics, industry infrastructure and technology, and world market conditions. The modules of NEMS interact to solve for the economic supply and demand balance for each fuel.

In order to capture regional differences in energy consumption patterns and resource availability, NEMS is a regional model. The end-use demand for energy is represented for each of the nine Census divisions. The supply and conversion modules use the North American Electric Reliability Council regions and subregions for electricity generation; aggregations of the Petroleum Administration for Defense Districts for refineries; and production regions specific to oil, natural gas, and coal supply and distribution.

NEMS incorporates interactions between the energy system and the economy and between domestic and world oil markets. Key macroeconomic variables, including the gross domestic product (GDP), disposable personal income, industrial output, housing starts, employment, and interest rates, drive energy consumption and investment decisions. In turn, changes in energy prices and energy activity affect economic activity, a feedback captured within NEMS. Also, an international energy module in NEMS represents world oil prices, production, and demand and the interactions between the domestic and world oil markets. Within this module, world oil prices and supplies respond to changes in U.S. demand and production.

Technology Representation in NEMS

A key feature of NEMS is the representation of technology and technology improvement over time. The residential, commercial, transportation, electricity generation, and refining sectors of NEMS include explicit treatments of individual technologies and their characteristics, such as initial cost, operating cost, date of commercial availability, efficiency, and other characteristics specific to the sector. In addition, for new generating technologies, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind plants and for a decline in the costs as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment. In addition, in the electricity generation sector, fossil-fired and nuclear generating units can be retired before the end of their useful lives if it is more economical to bring on a replacement unit than to continue to operate the existing unit.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is somewhat more limited due to limitations on the availability of data for individual technologies. In the industrial sector, technology improvement for the major processing steps of the energy-intensive industries is represented by technology possibility curves of efficiency improvements over time. In the oil and gas supply sector, technology progress for exploration and production activities is represented by trend-based improvement in

[13] See Energy Information Administration, *The National Energy Modeling System: An Overview 1998*, DOE / EIA-0581(98) (Washington, DC, February 1998), for a summary description. Detailed documentation is available through the National Energy Information Center at 202 / 586-8800 or on the EIA web site at www.eia.doe.gov.

finding rates, success rates, costs, and the size of the resource base. Productivity improvements over time represent technological progress in coal production.

Because of the detailed representation of capital stock vintaging and technology characteristics, NEMS captures the most significant factors that influence the turnover of energy-using and producing equipment and the choice of new technologies. New, more advanced technologies for buildings and equipment are generally characterized by the technology costs, performance, and availability, existing standards, and energy prices. Equipment that does not meet efficiency standards is not available as a choice.

The relative costs of purchasing and operating different types of equipment are factored into consumer choices, which are represented by elasticities and discount rates derived from the analysis of available data. Within the residential sector, for example, housing stocks are calculated by region and housing type, using aggregate housing starts from the macroeconomic forecast and assumed retirement rates. Stocks of energy-using equipment are also tracked, reflecting equipment retirement, replacements, and new housing starts. Choices for new equipment and efficiency levels for new houses are influenced by the characteristics of available technology, existing standards, energy prices, and consumer preferences as reflected in past decisions. In the end-use sectors, all technology choices are based on the assumption that future energy prices will remain at the same level as the prices for the year in which the decision is being made, this being the most likely representation of how customer decisions are made. However, in the generation and refining sectors, which are cost minimizers, capacity expansion decisions include foresight of future energy prices and demand.

In all sectors, technology improvement occurs even in a reference case because new, more efficient technology will be adopted as demand for energy services increases and existing buildings and equipment are retired. The characteristics of the technologies include initial dates of commercial availability of more advanced technologies as well as changes in efficiency and cost that are assumed to occur in the future. Higher energy prices may accelerate the adoption of more efficient technologies. Past improvements in energy efficiency have resulted in part from efficiency standards that are included in the analysis; future efficiency standards assumed are those approved standards with specified efficiency levels.

The detailed characterization of energy consumption patterns and technology decisions in NEMS allows for an explicit representation of the introduction of new energy-using equipment and the improvement of the capital stock. Because longer-term forecasting models typically are not annual models, they tend not to capture the gradual transition of energy markets, including the capital stock vintaging and turnover, as NEMS does. In addition, because of the longer time horizon, longer-term models tend to have less detailed representations of energy markets.

Although prices play a role in consumers' decisions on energy-consuming equipment, there are other factors that come into play. Consumers tend to make decisions based on a number of personal preferences and lifestyle choices, in which energy prices may be only a part of the decisionmaking process. Preferences for larger televisions or higher horsepower vehicles are examples of factors that may outweigh energy costs. As another example, in the residential sector, home rental instead of purchase and frequent moving tend to lower the incentive to invest in more energy-efficient equipment. Information also has a major role in consumer decisions and will likely continue to do so in the adoption of new, more advanced technologies. Particularly when a more efficient or alternatively fueled technology carries a significantly higher cost or has different operational characteristics than more conventional technologies, information on the benefits of the new technology will be key to its adoption and penetration. Ultimately, the success of a given technology will depend not on the behavior of the marginal consumer, who may be particularly cost-conscious or innovative, but on the behavior of the average consumer, whose decision rests on a number of considerations.

Technology improvements, even when adopted in the market, may not necessarily lead to reductions in energy demand. In the transportation sector, for example, the use of more advanced technologies that could improve vehicle efficiency has been offset by increasing demand for larger and higher horsepower vehicles. To the extent that energy prices are a factor in consumer decisions, efficiency improvements may also increase energy demand. Efficiency gains may lower the cost of driving or operating other equipment, perhaps encouraging more travel, larger homes, and purchases of more equipment and increasing the demand for energy services.

New or tightened efficiency standards could also reduce the demand for energy, but stock turnover would still limit the speed of penetration. Standards have also been suggested to encourage the use of renewable fuels for electricity generation, such as those in the proposed Electric System Public Benefits Protection Act of 1997, the proposed Electric Consumers Protection Act of 1997, and the Administration's proposed Comprehensive Electricity Competition Act; however, proposed and possible future standards, legislation, and programs are not included in the analysis.

The *Annual Energy Outlook 1998*

At the request of the Committee on Science, this study of the impacts of the Kyoto Protocol is based on the reference case assumptions of *AEO98*. In accordance with the requirement that the reference case EIA projections be policy-neutral, the *AEO98* projections assume that all Federal, State, and local law, regulations, policies, and standards in effect as of July 1, 1997, remain unchanged through 2020. Potential impacts of pending or proposed legislation, proposed standards, or sections of existing legislation for which funds had not been appropriated are not included in the projections. In general, the *AEO98* projections were prepared using the most current data available as of July 31, 1997.

The *AEO98* projections assume continued growth in the U.S. economy, with GDP growing at an average annual rate of 1.9 percent through 2020. Additional key factors underlying the projections are the assumptions concerning world oil markets. Continued technological improvement in the production of oil and the expansion of production capability worldwide hold the increase in the real, inflation-adjusted world oil price to an average growth rate of 0.4 percent a year. Domestically, with technological advances in the exploration and production of natural gas, the average annual growth in the average wellhead price is projected to be 0.5 percent even with rapid growth in the demand for natural gas. The average price of coal declines throughout the projection period due to increasing productivity in coal production and the expansion of production from lower-cost western sources.

AEO98 represents the ongoing restructuring of the electricity industry by assuming lower operating, maintenance, and administrative costs, as noted in the trends of recent data; early retirements of higher-cost coal-fired and nuclear power plants; and lower capital costs and efficiency improvements for coal- and natural-gas-fired generation technologies. Additional assumptions include a revised financial structure that features a higher cost of capital in competitive markets. Specific restructuring plans are included for those regions that have announced plans. California, New York, and New England are assumed to begin competitive pricing in 1998 with stranded cost recovery phased out by 2008. The provisions of the California legislation for stranded cost recovery and price caps are incorporated. With these assumptions and declining coal prices, electricity prices decline at an average annual rate of 1 percent in the *AEO98* projections.

Electricity generation from nuclear power declines significantly in the projections. About 20 percent of the nuclear capacity available in 1996 is assumed to be retired by 2010, with no new plants constructed. It is assumed that nuclear units would be retired as early as 10 years before the expiration of their operating licenses, based on utility announcements and on analysis of the age and operating costs of the units. To offset the decline of nuclear power and to meet the growth of electricity demand, coal and natural gas generation expand in the projections, particularly the gas technologies. The financial assumptions for restructuring weigh against more capital-intensive projects, such as coal and baseload renewable technologies.

With decreases or moderate increases in the prices of energy and continued economic growth, total energy consumption in *AEO98* increases by 1 percent a year on average through 2020. Consumption in all end-use sectors grows in the projections; however, demand in the transportation sector increases most rapidly, reflecting increased travel and slow improvement in the efficiency of vehicles. Total energy intensity, measured as energy use per dollar of GDP, declines in the projections at an average annual rate of 0.9 percent. This rate is considerably less than the 2.3-percent decline in energy intensity experienced between 1970 and 1986 when rapid price increases and a shift to less energy-intensive industries led to rapid energy intensity improvements. On average, energy intensity has been flat between 1986 and 1996. The projected improvement still reflects continued improvements in energy efficiency that partially offset increases in the demand for energy services.

As noted earlier, projected carbon emissions from energy combustion in *AEO98* reach 1,803 million metric tons in 2010, 34 percent above the 1990 level of 1,346 million metric tons, rising to 1,956 million metric tons in 2020. Total emissions are projected to increase at an average annual rate of 1.5 percent between 1996 and 2010 in the reference case, and per capita emissions also increase at an average annual rate of 0.7 percent during that period, as continued economic growth and moderate price increases encourage growth in energy services and energy consumption. Between 2010 and 2020, efficiency improvements tend to offset continued growth in the demand for energy services, and per capita emissions nearly flatten. During that period, total emissions increase at an average rate of 0.8 percent a year. Over the entire projection period, the slow growth of renewable technologies and the decline of electricity generation from nuclear power plants also contribute to the growth of emissions.

Projections of carbon emissions in *AEO98* include EIA's analysis of the impacts of CCAP for the 31 of the 44 CCAP actions that relate to carbon dioxide emissions from energy combustion. The analysis does not account for the remaining actions related to non-energy programs, gases other than carbon dioxide, or forestry and land use. The analysis of CCAP represents EIA's estimate of the effects of incorporating assumptions concerning behavioral change as a result of CCAP and does not result in the reductions estimated by the developers of CCAP. The initial estimates of the impacts of the CCAP actions by the Administration projected stabilization of net greenhouse gas emissions in 2000 at 1990 levels; however, a more recent review and update of CCAP significantly reduces the expected impact.[14] In *AEO98*, carbon emissions in 2010 are reduced by about 36 million metric tons as a result of CCAP, compared with the more recent estimate by the sponsors of about 95 million metric tons for the energy-related actions in CCAP. Differences between the CCAP impacts estimated by EIA and by the program sponsors are due primarily to differences in the estimated impacts of voluntary programs; some estimates by the sponsors that include ongoing trends that would occur even in the absence of CCAP; and regulatory actions included by the sponsors but not included by EIA because they are not yet enacted or finalized.

The *Annual Energy Outlook 1995* (*AEO95*)[15] was the first *AEO* to include the impacts of CCAP in the projections. Even then, the goal of stabilizing carbon emissions in 2000 at 1990 levels seemed unlikely. *AEO95* projected that energy-related carbon emissions would reach 1,471 million metric tons in 2000, a level nearly reached in 1996 when emissions were 1,463 million metric tons. Each subsequent *AEO* has raised the estimate of carbon emissions, primarily because of lower price projections that encourage energy use and reduce the penetration of renewable sources of energy.

There are several reasons that the target specified by CCAP for 2000 is unlikely to be realized. First, U.S. economic growth has been slightly higher than assumed at the time the CCAP programs were formulated. Second, energy prices have increased at a more moderate rate than initially assumed in the early 1990s. Both these factors have contributed to higher growth in energy consumption than earlier assumed, leading to higher emissions levels. Third, the funding for a number of the CCAP programs is lower than initially requested. Finally, some voluntary programs have proven less effective than initially estimated by the Administration.

Carbon Reduction Cases

The Kyoto Protocol specifies that the U.S. target for total greenhouse gas emissions in the first commitment period will be 7 percent below the level of emissions in 1990. This analysis focuses on the carbon dioxide emissions from the use of energy, which constituted 83 percent of total U.S. greenhouse emissions in 1996 (1,463 million metric tons of energy-related carbon emissions in the total greenhouse gas emissions of 1,753 million metric tons carbon equivalent).

The specific reduction in energy-related carbon emissions that will be required is highly dependent on a number of factors outside the domestic energy sector. Programs to reduce emissions of the other five greenhouse gases covered by the Protocol may decrease the requirement for reductions in carbon dioxide emissions. Similarly, forestry, agriculture, and land use programs may also offset some carbon dioxide emissions; however, the rules to account for agriculture and forestry emissions and sinks have yet to be developed and are subject to considerable uncertainty. According to a fact sheet prepared by the U.S. Department of State on January 15, 1998, discussing the Kyoto negotiations, the method of accounting for sinks and the flexibility to use 1995 as the base year for the synthetic greenhouse gasses may mean that the reduction would be no more than 3 percent below 1990 levels, based on the Administration's estimates.[16] Similar estimates were cited by Dr. Janet Yellen, Chair, Council of Economic Advisers, in her testimony before the House Committee on Commerce, Energy and Power Subcommittee, on March 4, 1998.[17] Finally, because this analysis does not fully represent international energy markets and other activities, the potential role of international emissions trading and the CDM in alleviating U.S. reductions of carbon dioxide is not directly represented in the analysis. Even those analyses that do include international trade must make assumptions about the activities, because the development of guidelines and mechanisms has been deferred.

The success of programs to reduce greenhouse gases at relatively low costs may depend on the success of international trade of carbon permits, joint implementation projects, and the CDM. Some analyses of greenhouse gas reductions that have low costs of compliance assume that a number of relatively low-cost carbon permits will be available from Annex I countries with less expensive opportunities to reduce emissions. Based on EIA's analysis in *IEO98*, there may be 165 million metric tons of carbon permits available from the Annex I countries in the former Soviet Union in 2010, because of the economic decline of those countries in the 1990s, and additional permits may be available as a result of carbon reduction projects. The total estimate of such opportunities is highly uncertain, however, and it is also unclear whether those countries would choose to sell available permits immediately or bank them for later use as their economies and populations grow. The potential transaction costs of international trading are also unknown.

[14]U.S. Department of State, Office of Global Change, *Climate Action Report*, Department of State Publication 10496 (Washington, DC, July 1997).

[15]Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95) (Washington, DC, January 1995).

[16]See web site www.state.gov/www/global/oes/fs_kyoto_climate_980115.html.

[17]See web site www.house.gov/commerce/database.htm.

The role of developing countries is another area of uncertainty for international activities. In July 1997, the Senate unanimously passed the Byrd-Hagel resolution, sponsored by Senators Robert Byrd of West Virginia and Chuck Hagel of Nebraska, resolving "that the United States should not be a signatory to any protocol to, or other agreement regarding, the United Nations Framework Convention on Climate Change . . . which would mandate new commitments to limit or reduce greenhouse gas emissions for the Annex I Parties, unless the protocol or other agreement also mandates new specific scheduled commitments . . . for Developing Country Parties within the same compliance period or would result in serious harm to the economy of the United States."[18] President Clinton has declared on several occasions that he will not submit the Protocol for ratification without pledges of meaningful participation by developing countries. While participation by developing countries may be key to the acceptance of the Protocol, development of specific guidelines and rules for the international programs has been deferred, including the means to establish baseline projections and to monitor and verify emissions reductions.

There is also a possibility that investments to reduce carbon emissions in developing countries could be limited. First, such bilateral ventures may be viewed as substitutes for or additions to foreign aid, a political concern to both the United States and developing countries. Also, it is possible that the continuing discussions about the implementation of the Protocol will raise the topic of trade limits—restrictions on the amount of reductions that any one country can satisfy through international programs. The Protocol states that such activities are to be supplemental to domestic actions. In the views of some countries, there is a potential problem with certain nations undertaking little internal action.

Because the potential impacts of forestry and agricultural sinks, offsets from other greenhouse gases, international trading, and other international activities are uncertain, a single target for the required reductions in energy-related carbon emissions in the United States cannot be developed at present. This analysis includes a number of cases, as requested by the Committee, assuming different levels of reductions in energy-related carbon emissions, in order to develop the energy and economic impacts of achieving those reductions. By establishing this range of carbon reductions, the analysis allows others to perform their own analyses of the impacts of sinks, offsets, and international programs, derive their own targets for energy-related carbon emissions, and use one of the EIA target cases to assess the energy and economic impacts of the carbon reductions in that case.

In addition to a reference case, six targets for reductions in energy-related carbon emissions are considered.

- **Reference Case (33 Percent Above 1990 Levels).** This case represents the reference projections of energy markets and carbon emissions without any enforced reductions and is presented as a comparison for the energy market impacts in the reduction cases. Although this reference case is based on the reference case from *AEO98*, as specified by the Committee, there are small differences between this case and *AEO98*. Some modifications were made in order to permit additional flexibility in NEMS in response to higher energy prices or to include certain analyses previously done offline directly within the modeling framework, such as nuclear plant life extension and generating plant retirements. Also, some assumptions were modified to reflect more recent assessments of technological improvements and costs. Significant changes to NEMS and its assumptions relative to *AEO98* are noted in Appendix A. As a result of these modifications, the projections of carbon emissions in the reference case for this analysis are slightly lower than those in the *AEO98* reference case—1,791 million metric tons in 2010 compared with 1,803 million metric tons. The carbon emissions projections in the reference case, as well as in all the carbon reduction cases, include EIA's estimate of the impacts of CCAP.

- **24 Percent Above 1990 Levels (1990+24%).** This case assumes that carbon emissions can increase to an average of 1,670 million metric tons in the commitment period 2008 to 2012, 24 percent above the 1990 levels, but 122 million metric tons below the average emissions in the reference case during that period.

- **14 Percent Above 1990 Levels (1990+14%).** This case assumes that carbon emissions in the commitment period average 1,539 million metric tons, which is approximately the level estimated for 1998 in *AEO98* and is 14 percent above 1990 levels. This requires the average annual carbon emissions between 2008 and 2012 to be reduced by 253 million metric tons.

- **9 Percent Above 1990 Levels (1990+9%).** This case assumes that energy-related carbon emissions can reach an average of 1,467 million metric tons in the commitment period, 9 percent above 1990 levels, an average reduction of 325 million metric tons from the reference case projection.

- **Stabilization at 1990 Levels (1990).** This case assumes that carbon emissions are stabilized approximately at the 1990 level of 1,346 million metric tons, averaging 1,345 million metric tons during

[18] The discussion about the resolution can be accessed in the *Congressional Record* of July 25, 1997, from web site www.access.gpo.gov/su_docs/aces/aces150.html.

the commitment period, a reduction of 447 million metric tons from the reference case.

- **3 Percent Below 1990 Levels (1990-3%).** This case assumes that energy-related carbon emissions are reduced to an average of 1,307 million metric tons in the commitment period. A reduction of 485 million metric tons from the reference case level is required.

- **7 Percent Below 1990 Levels (1990-7%).** In this case, energy-related carbon emissions are reduced to an average of 1,250 million metric tons in the commitment period, a reduction of 542 million metric tons from the reference case projection. This case essentially assumes that energy-related carbon emissions must meet the 7-percent target in the Kyoto Protocol with no net offsets from sinks, other greenhouse gases, or international activities.

Reductions in both the 1990-3% and 1990-7% cases would likely come from domestic actions only. The reductions in the other carbon reduction cases imply some international trade in carbon permits, CDM activity, or joint implementation projects, but this analysis does not address the shares that might result from international and domestic actions.

In each of the carbon reduction cases, the target is achieved on average for each of the years in the first commitment period, 2008 through 2012, in accordance with the Kyoto Protocol. The Protocol provides the flexibility for the target to be achieved on average over the 5-year commitment period, to accommodate short-term fluctuations that might occur, such as severe weather or unanticipated economic growth. Because the Protocol does not specify any targets beyond the first commitment period, the target is assumed to hold constant from 2013 through 2020, the end of the NEMS forecast horizon. This assumption may be optimistic in that the possibility of further reductions has been advocated.

The target is assumed to be phased in over a 3-year period, beginning in 2005; that is, one-fourth of the reduction is imposed in 2005, one-half in 2006, and three-fourths in 2007. This analytical simplification allows energy markets to begin adjustments to meet the reduction targets in the absence of complete foresight, although a longer or delayed phase-in may lower the adjustment cost. Phase-in is also consistent with the requirement in the Protocol that countries achieve demonstrable progress toward the reductions by 2005; however, reductions prior to the commitment period are not credited against the required reductions.

Given the scope and potential costs of compliance with the reduction targets of the Protocol, there is a possibility that consumers might react differently—either taking more immediate action or waiting. Consumers could begin to modify their energy decisions even before the 3-year phase-in period, either in anticipation of future price increases or because of a national commitment to reduce greenhouse gases. On the other hand, it is possible that consumers could delay actions either until or beyond energy price changes, taking a cautionary approach to the magnitude and duration of price increases or even anticipating a reversal of policy.

Although each of the six reduction cases is modeled using NEMS, the analysis in this report focuses on three of the cases, the 1990+24%, 1990+9%, and 1990-3% cases. Three cases are chosen in order to keep the subsequent presentation and discussion of the results manageable, particularly since many of the basic trends are the same across the reduction cases, varying only in the magnitude of the impact. Where there are specific trends to note in any of the other cases, they are included in the appropriate section of this report. The full results of each of the cases are presented in Appendix B, and results across all cases are presented graphically, where practical. Any of the reduction targets may be plausible; however, it is likely that some mitigation of the 7-percent target will be achieved through a combination of offsets from forestry and agriculture, reductions in other greenhouse gases, international trading, and other flexible international mechanisms.

Carbon Prices

Each of the carbon reduction targets is achieved by assuming that a carbon price is applied to the cost of energy, which could result from a carbon emissions permit system. The carbon price is applied to each of the energy fuels at its point of final consumption relative to its carbon content. Imported energy products receive the same carbon price at the point of consumption, but no carbon price is levied on other imported products. Of the fossil fuels, coal has the highest carbon content. Natural gas produces about half the carbon emissions of coal per unit of energy content. Average emissions from petroleum products are between those for coal and natural gas. Nuclear generation and renewable fuels produce no net carbon emissions. As an example, the carbon emissions factors and energy costs for a hypothetical carbon price of $100 dollars per metric ton are shown in Table 1.

Electricity produces no carbon emissions at the point of use; however, its generation currently produces about 35 percent of the total carbon emissions in the United States. The carbon price is applied to the fuels used to generate electricity, and the higher prices are reflected in the delivered price of electricity.

Placing a value on the carbon released during the combustion of fossil fuels affects energy consumption and emissions in three ways. First, consumers may reduce the demand for energy services by driving less, reducing the use of appliances, or shifting to less energy-intensive

Table 1. Carbon Emissions Factors for Major Energy Fuels and Calculated 1996 Delivered Energy Prices With a Carbon Price of $100 per Metric Ton

Parameter	Steam Coal	Gasoline	Natural Gas
Carbon Emissions Factor			
(Kilograms of Carbon per Million Btu)	25.49	19.19	14.40
Average Delivered Price in 1996			
(1996 Dollars per Million Btu)	1.32	9.89	4.13
(1996 Dollars per Fuel Unit)[a]	27.52	1.23	4.25
Average Delivered Price With Carbon Price of $100 per Metric Ton			
(1996 Dollars per Million Btu)	3.87	11.81	5.57
(1996 Dollars per Fuel Unit)[a]	80.68	1.47	5.73

[a]Fuel units are short ton (coal), gallon (gasoline), and thousand cubic feet (natural gas).
Source: Office of Integrated Analysis and Forecasting.

goods and services, as examples. Second, more energy-efficient equipment may be chosen, reducing the amount of energy required to meet the demand for energy services. Finally, there may be a shift to noncarbon or less carbon-intensive fuels, reducing the carbon released per unit of energy consumed.

In the energy market analysis in this report, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level or, conversely, the value of consuming the last metric ton of carbon. Although there may be a number of easy, low-cost options for reducing energy use and emissions, higher levels of reductions will require more expensive investment and changes in patterns of energy demand. The projected carbon prices reflect the price that the United States would be willing to pay to achieve a given emissions reduction target. The energy market analysis does not address the international implications of achieving a particular target at the projected carbon price. In the absence of modeling international trade of emissions permits, the energy market analysis makes no link between the U.S. carbon price and the international market-clearing price of permits, or the price at which other countries would be willing to offer permits for sale in the United States.

Carbon prices, or similar mechanisms, are used by most analysts in assessing the implementation and impacts of the Kyoto Protocol or other emissions reduction targets, such as carbon stabilization. Carbon prices are used because they effect all three ways of reducing emissions—demand reduction, improved efficiency, and fuel switching—and may be the most efficient mechanism. Estimates of the carbon price necessary to achieve reductions vary widely. Lower estimates are suggested by those who assume that there are a number of low-cost options to reduce energy use or to shift to low-carbon or noncarbon fuels that are readily available and will be quickly adopted with higher energy prices. Higher estimates are suggested by analysts who think that the effective price of carbon-intensive fuels will have to be raised significantly to encourage changes in consumer choices and the development of additional alternative technologies.

The projected energy market costs in this study represent only the marginal cost of reducing energy-related carbon emissions and do not reflect other costs that could occur as a result of business cycle fluctuations, capital constraints, or implementation of emissions reductions through less efficient mechanisms. No costs are included for damage or adaption to potential climate change. In addition, no benefits for avoided damage or other ancillary benefits are included, unlike some analyses that represent the net cost of emissions reductions, net of benefits.

Macroeconomic Analysis

EIA analyzes the macroeconomic impacts of the carbon reduction cases using the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy. The DRI Model is a representation of the U.S. economy with detailed output, price, and financial sectors, incorporating gradual adjustment of the economy to policy changes. Macroeconomic models focus on adjustment processes of the economy associated with changing market conditions, including economic policies. Real-world economic behavior involves adapting to changes in conditions of supply and demand, which can lead to dislocations and less than optimal use of resources in the short run. Short-run movements in actual income are portrayed against projected long-run levels of potential output.

The linkage between the DRI macroeconomic model and NEMS is a set of energy variables. Twenty-seven energy variables in the DRI macroeconomic model are directly related to similar NEMS variables by ensuring that the DRI variables show the same percentage change from the baseline as the NEMS variables. These energy variables include energy prices, energy production, and energy consumption by different end uses, and the revenue from auctioned carbon permits. Energy prices include world oil prices; residential heating oil, electricity, and natural gas prices; transportation fuel prices for both diesel and gasoline; residual fuel oil prices; average refined oil price; wellhead natural gas price; and industrial coal and electricity prices. Coal, natural gas, and crude oil production from NEMS is used in the DRI macroeconomic model as well as the end-use demand for oil, natural gas, electricity, and coal.

Energy prices and end-use demands for fuels are the key energy inputs, along with the level of auctioned carbon revenues, because energy prices affect inflation, and the end-use fuel demand represents energy in the DRI aggregate production function, which describes the supply potential of the economy. The amount of auctioned carbon revenue dictates how much energy consumers can expect to receive as rebated revenue, which in turn affects disposable income. Changes in the values of these variables relative to the reference case would have major impacts on the macroeconomy.

When a system is developed for the trading of carbon permits within the United States, a number of initial decisions must be made: How many permits will be available? Will they be freely allocated or sold by competitive auction? If they are allocated, how will the initial allocations be made? If they are sold, what will be done with the revenues? How many permits will be bought in international markets? If the permits are traded in a free market, holders of permits who can reduce carbon emissions at a cost below the permit price will sell their permits, and those with higher costs of reduction will buy permits, resulting in a transfer of funds between private parties. If the permits are sold by competitive auction, there will be a transfer of funds from emitters of carbon to the Federal treasury. This analysis makes the explicit assumption that the permits will be sold in a competitive auction run by the Federal Government.[19]

The macroeconomic analysis in Chapter 6 considers the flow of funds overseas that would be represented by international purchases of carbon permits, explicitly assuming that the carbon price determined in the NEMS model is the international price at which permits would be traded. Although the U.S. target established by the Protocol is a 7-percent reduction in greenhouse gas emissions relative to 1990 levels, the method of accounting for sinks and the flexibility to use 1995 as the base year for the synthetic greenhouse gasses may mean that the reduction would be no more than 3 percent below 1990 levels, according to the U.S. State Department. The differences between the reduction level in the 1990-3% case and the reductions in the cases with higher levels of energy-related carbon emissions are assumed to be met by permits purchased in the international market at the carbon price calculated for each case.

Many analyses of carbon mitigation have used a class of models that are characterized as computable general equilibrium (CGE) models. The CGE structure focuses on the interconnectedness of the economy and calculates the equilibrium of the economy in the long term, abstracting from the short-run adjustment processes. Most often the time horizon of these models is much longer—20, 50, or 100 years into the future. In contrast, the DRI macroeconomic model used in this analysis focuses on the adjustment of the economy over time, allowing for dislocations within the economy that yield less than optimal levels of economic activity. While climate change can arguably be considered a long-run phenomenon, the policies and measures to induce change may take effect in a near-term horizon.

Chapter 7 gives a more detailed comparison of the similarities and differences in the alternative model structures and results. Models of both types can contribute to the assessment of the possible impacts on the economy of greenhouse gas reduction. However, past analyses of the issue using CGE and macroeconomic models have often disagreed with each other over the concepts of the full employment GDP of the CGE models and the actual GDP measure presented in the macroeconomic models. Potential GDP is a concept calculated within the DRI Model but rarely presented as an output measure. The discussion in Chapter 6 considers the alternative views and introduces the concept of potential GDP into the discussion of the economic impacts of the Protocol.

International Energy Markets

The focus of the analysis is U.S. energy markets; however, changes in international markets may have a significant influence on the United States. In particular, crude oil and petroleum products constitute an international market, and the world price of oil has a strong impact on consumption and production of oil in the United States. Conversely, U.S. demand for and production of oil affects the world price of oil. The feedback of U.S. oil markets on international markets is represented within the NEMS framework. World oil prices are determined by means of a price reaction function, assuming that the Organization of Petroleum Exporting Countries will expand oil production capacity to meet world oil demand.

For this analysis, it is assumed the other Annex I countries will reduce their consumption of oil in order to help meet their reduction targets. Each country is assumed to

[19]A permit auction system is identical to a carbon tax as long as the marginal abatement reduction cost is known with certainty by the Federal Government. If the target reduction is specified, as in this analysis, then there is one true price, which represents the marginal cost of abatement, and this also becomes the appropriate tax rate. In the face of uncertainty, however, the actual tax rate applied may over- or undershoot the carbon reduction target. Auctioning of the permits by the Federal Government is evaluated in this report. To investigate a system of allocated permits would require an energy and macroeconomic modeling structure with a highly detailed sectoral breakout beyond those represented in the NEMS and DRI models. For a comparison of emissions taxes and marketable permit systems, see R. Perman, Y. Ma, and J. McGilvray, *Natural Resources and Environmental Economics* (New York, NY: Longman Publishing, 1996), pp. 231-233.

reduce its oil demand by the same percent that the United States reduces oil demand from the reference case level. Oil consumption in non-Annex I countries is assumed to respond to changes in the world price of oil with no additional reactions as a result of carbon reduction policies.

Coal exports are a significant portion of U.S. coal production, with exports going to both Annex I and non-Annex I countries. Because Annex I countries must reduce carbon emissions, it is assumed that coal production and imports in Western Europe and coal imports in Japan would be reduced and that coal consumption in those countries would be reduced by more than their emissions reductions in the Protocol. In the target cases where U.S. carbon emissions are allowed to rise above 1990 levels in 2010, U.S. steam coal exports to Europe in 2010 are assumed to be lower by 16 million tons, and exports to Asia are 4 million tons lower than in the reference case. In the more stringent target cases, exports to Europe and Asia are 26 and 7 million tons lower, respectively, in 2010.

As a result of the Kyoto Protocol, energy prices in the Annex I countries may be higher than in the non-Annex I countries, which do not have emissions reduction targets in the Protocol. As a result, it is possible that more energy-intensive industries could shift from those countries with higher energy costs. Energy-intensive industries also may face reduced demand as consumers shift their consumption patterns to less energy-intensive goods and services. Consequently, the composition of U.S. industrial output is likely to change toward the less energy-intensive industries. Because this analysis does not cover international energy markets, international trade, or the international activities of the Protocol, a complete analysis of potential changes in U.S. industrial output is not possible (for discussion, see the box on "Industrial Composition" in Chapter 3).

Sensitivity Cases

A number of factors combine to determine the NEMS projections of energy consumption and carbon emissions. Typically, *AEO* explores a wide range of cases that vary the reference case assumptions on economic growth, world oil markets, technology improvement, and potential regulatory changes. In this analysis, a variety of sensitivity cases are used to examine the factors that have the most significant impacts on energy demand and carbon emissions. With the exception of the nuclear power sensitivity case, all the sensitivity cases are analyzed relative to the 1990+9% case.

Low and High Economic Growth

These cases analyze the effects of different assumptions about U.S. economic growth. The *AEO98* reference case assumes that the output of the Nation's economy, measured by GDP, will increase by an average of 1.9 percent a year between 1996 and 2020. The same assumption is used in all the carbon reduction cases in this analysis, although there is a feedback within the NEMS framework that alters the baseline economic assumptions as a result of changes in energy prices. Therefore, as emissions reductions become more stringent and the resulting carbon prices become higher, there will be a reduction in economic growth.

In order to reflect the uncertainty in potential economic growth, *AEO98* included high and low economic growth cases. The same alternative assumptions are used in this analysis. The high economic growth case includes higher population, labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, the GDP increases at an average rate of 2.4 percent a year through 2020. The opposite assumptions in the low economic growth case lead to an average annual growth rate of 1.3 percent.

Low and High Technology

These sensitivity cases examine the effects of assumptions about the development and penetration of energy-consuming technologies on the analysis results. The reference cases in this analysis and in *AEO98* include continued improvement in technologies for both energy consumption and production—for example, improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. Additional technology improvements in the end-use demand sectors and in the electricity generation sector could reduce energy consumption and energy-related carbon emissions below their projected levels in the reference case. Conversely, slower improvement than that assumed in the reference could raise both consumption and emissions.

AEO98 presented alternative cases that varied key assumptions concerning technology improvement and penetration in the end-use demand and electricity generation sectors. This analysis uses the same low technology assumptions for a low technology sensitivity. In the residential and commercial sectors, it is assumed that all future equipment purchases will be made only from the equipment available in 1998 and that building shell efficiencies will be frozen at 1998 levels. Similarly, in the transportation sector, efficiencies for new equipment are fixed at 1998 levels for all travel modes. In the industrial sector, plant and equipment efficiencies are fixed at 1998 levels. No new advanced generation technologies are assumed to be available during the projection period.

Technology Improvement in the Reduction Cases and the Sensitivity Cases

In *AEO98*, energy intensity—primary energy consumption per dollar of GDP—is projected to decline by an annual average of 0.9 percent between 1996 and 2020. This decline is significant but considerably less than the decline in the 1970s and early 1980s, which averaged 2.3 percent a year between 1970 and 1986. Approximately half the decline in energy intensity during that period resulted from shifts in the economy to service industries and other less energy-intensive industries; however, the other half of the decline was due to the use of more energy-efficient technologies, resulting, in part, from the rapid escalation in the price of energy from the mid-1970s through the mid-1980s. The decline in energy intensity slowed during the late 1980s and early 1990s as the growth in energy prices slowed and growth in some energy-intensive industries resumed. In the reference case projections, continued modest increases in the price of energy and growing demand for certain energy services, such as appliances, office equipment, and travel, moderate further declines in energy intensity.

Energy intensity improvement results from opposing forces of growth in energy service demand and improvement in the stock of energy-using equipment. New, more efficient technology must be developed and available, but it also must be adopted in order to contribute to energy efficiency improvements. Energy prices play a role in the consumer's decision when purchasing new equipment; however, other factors also influence equipment choice. More advanced, energy-efficient technology is typically more expensive than standard equipment. The methodology for technology choice accounts for the relative roles of first cost and energy cost savings over the life of the equipment through the use of the discount rate, the implied payback period for the consumer who is considering the choice of more efficient equipment. Perceived consumer preferences are also a factor in technology choice—for example, preferences for larger, higher horsepower vehicles and larger televisions, and for purchases of new heating equipment that uses the same fuel as the equipment it replaces. Improvements in energy intensity can be slowed by continued growth in energy services—more travel, household appliances, and office equipment, larger homes, and higher industrial output—some of which are assumed to respond to energy prices.

In the carbon reduction cases, energy prices rise with increasingly stringent reduction targets. Intensity improvements in those cases result both from reductions in energy service demand and from the choice of more efficient equipment as a result of higher prices. These cases use the same assumptions of technology availability and characteristics. Additional research and development in energy-efficient or alternatively fueled technologies would likely expand the slate of choices available to consumers, leading to further improvements in energy efficiency. The high technology case explores the impacts of improvements in the availability, characteristics, and costs of technology as a result of increased research and development, thus separating the impacts of energy prices and technology development.

Efficiency standards have contributed to past improvements in energy intensity. The Corporate Average Fleet Efficiency and National Appliance Energy Conservation Act of 1987 standards, among others, are included in the *AEO98* reference case; however, no new efficiency standards or improvements in current standards are assumed. The same assumptions are used for all the carbon reduction and sensitivity cases in this analysis.

High technology assumptions were developed specifically for this analysis by experts in technology engineering for each of the energy-consuming sectors, considering the potential impacts of increased research and development for more advanced technologies. The assumptions include earlier years of introduction, lower costs, high maximum market potential, and higher efficiencies than assumed in the reference case. In addition, the high technology sensitivity case includes carbon sequestration technology for coal- and natural-gas-fired generators to remove carbon dioxide and store it in underground aquifers. By design, the effect of the high technology assumptions is distinct from the technology changes that are induced by the higher energy prices in the carbon reduction cases. Because the future costs of the public and private investment that would be needed to develop and deploy more advanced technologies are not known, they are not represented in the analysis; thus, the full economic cost may be understated. It is possible that further technology improvements could occur beyond those represented in the high technology sensitivity case if a very aggressive research and development effort were established. Innovative, breakthrough technologies not foreseen in the analysis of technology could also be developed and lead to improvements beyond those represented in the high technology assessment, but limited time is available for such technologies to become economically competitive and achieve significant market share by 2010.

New Nuclear Capacity

The nuclear power sensitivity case examines the role of nuclear generation in reducing carbon emissions. In *AEO98*, electricity generation from nuclear plants declines significantly over the forecast period. It is assumed that 65 units, about 51 percent of the total nuclear capacity available in 1996, will be retired by 2020. Twenty-four units are assumed to be retired before the end of their 40-year operating licenses, based on industry announcements and analysis of the age and operating costs of the units. No new nuclear plants are constructed by 2020.

In all the carbon reduction cases, nuclear plants are life-extended if economical; however, in this sensitivity case, new nuclear plants can be built if they are economically competitive with other generating technologies. In the 1990+9% case, nuclear plants are not projected to be economically competitive with other plants. They do become competitive, however, with the higher carbon prices projected in the 1990-3% case. Therefore, this sensitivity case is analyzed against the 1990-3% case.

Use of Models for Analysis

The reference case projections in both *AEO98* and this analysis represent business-as-usual trend forecasts, given known trends in technology and demographics, current laws and regulations, and the specific methodologies and assumptions used by EIA. Because EIA does not include future legislative and regulatory changes in its reference case projections, the projections provide a policy-neutral baseline against which the impacts of policy initiatives can be analyzed.

Results from any model or analysis are highly uncertain. By their nature, energy models are simplified representations of complex energy markets. On the other hand, models provide a structured accounting framework that allows analysts to capture the interrelationships of a complex system in a consistent manner. Also, the assumptions and data underlying a model can be explicitly cited, in contrast to a more *ad hoc* analysis. The results of any analysis depend on the specific data, assumptions, behavioral characteristics, methodologies, and model structures included. In addition, many of the factors that will influence the future development of energy markets are inherently uncertain, including weather, political and economic disruptions, technology development, and policy initiatives. Recognizing these uncertainties, EIA has attempted in this study to isolate and analyze the most important factors affecting future carbon emissions and carbon prices. The results of the various cases and sensitivities should be considered in terms of the relative changes from the baseline cases with which they are compared.

It has been suggested that models may be inherently pessimistic in analyzing the potential impacts of policy changes. For example, in the *Annual Energy Outlook 1993* (*AEO93*),[20] the first EIA analysis of CAAA90 compliance, the cost of a SO_2 allowance was projected to be $423 a ton in 2000, in 1996 dollars, rising to $751 a ton in 2010. Currently, the cost of an allowance is $95 a ton, and *AEO98* projects that the cost will be $121 a ton in 2000 and $189 in 2010. Projected coal prices in *AEO98* are 34 and 48 percent lower in 2000 and 2010, respectively, than those projected in *AEO93*, reflecting recent improvements in mine design and technology, economies of scale in the mining industry, and lower transportation costs induced by rail competition. There has been more fuel switching to low-sulfur, low-cost Western coal than previously anticipated (it was initially assumed that many eastern coal-fired plants would not be able to burn western coal without considerable loss of performance). There has also been downward pressure on short-run allowance costs because generators have taken actions to comply with the SO_2 limitations earlier than anticipated.[21] Finally, technology improvements have lowered the costs of flue-gas desulfurization technologies, or scrubbers, from $313 per kilowatt for scrubber retrofitting as assumed in 1993 to $191 per kilowatt in 1998. The cost of SO_2 compliance was overestimated to a large extent because compliance relied on scrubbing, a relatively new technology with which there was little experience. On the other hand, the current analysis of carbon reduction does not rely on a single technology but rather on fuel switching and efficiency improvements, both issues of long experience in energy markets.

In contrast, however, analyses of policies can also be too optimistic. As noted earlier, reductions in greenhouse gas emissions as a result of CCAP have been overestimated. In addition, some early analyses of the potentially beneficial impacts of price controls on oil and natural gas proved in error because of the negative effects on production and competition in the industry.

A number of uncertainties may affect the costs of achieving emissions reductions. As previously noted, the interpretation and implementation of many provisions of the Kyoto Protocol are undetermined at this time. The flexibility allowed by the international activities may considerably lower the costs of the Protocol.

[20]Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC, January 1993).

[21]A.E. Smith, J. Platt, and A.D. Ellerman, "The Cost of Reducing SO_2," *Public Utilities Fortnightly* (May 15, 1998).

The availability and costs of technology remain one of the more significant factors in determining the cost of emissions reductions, and this analysis seeks to quantify that uncertainty to some degree with low and high technology sensitivity cases. Although it is sometimes hypothesized that more cost-effective technologies are developed once the requirements are established, it must be noted that the cost and availability of some of the more advanced technologies in the reference case are not certain, and even the reference assumptions may be optimistic.

Although the Kyoto Protocol specifies reduction targets, signature and ratification by the United States would need to be followed by the formulation of policies and programs to achieve the carbon reductions. This analysis has chosen one possible mechanism, the imposition of a carbon fee with revenue recycling by two alternative methods. Other programs—voluntary initiatives, mandatory standards, or other nonmarket policies—could result in higher or lower costs. Even with a carbon fee, other fiscal policies for recycling the revenues, including not recycling, are likely to have different impacts on the U.S. economy.

The timing of policy initiatives may also be an important factor in the cost of emissions reductions. Given that the Kyoto Protocol includes a specific timetable for reducing emissions, policies and initiatives that begin earlier may allow for more gradual adoption and a less costly transition, particularly if consumers react with foresight of anticipated price increases and emissions restrictions. Consumer response to anticipated or realized price increases and other policy initiatives is likely to be another significant determinant of the cost of the Kyoto Protocol. Finally, other energy policies formulated for purposes other than the Protocol, such as electricity industry restructuring and other emissions controls, may have ancillary impacts on carbon emissions.

In the next chapter, Chapter 2, the results from the carbon emissions reduction cases and the sensitivity cases are summarized. Chapters 3 through 6 present more detailed analysis of the results for the end-use demand sectors, electricity generation, fossil fuel markets, and the macroeconomy, respectively. Chapter 7 concludes with a comparison of this analysis and similar studies of the costs of carbon emissions reductions.

2. Summary of Energy Market Results

This chapter summarizes the energy market results of the carbon reduction and sensitivity cases evaluating the effects of the Kyoto Protocol in the National Energy Modeling System (NEMS). The first set of cases examine the impacts of six carbon emissions reduction targets, relative to a reference case without the Kyoto Protocol, as described in Chapter 1. The remaining cases examine the sensitivity of those results to variations in key assumptions—the macroeconomic growth rate, the rate of technological progress, and the role of nuclear power. More detailed analyses of the energy market results are presented in Chapters 3, 4, and 5. The macroeconomic results are described in Chapter 6. Although the results of the carbon reduction cases are consistent with the assumptions made, the projected impacts are subject to considerable uncertainty—particularly with the more stringent carbon reduction targets—because the cases reflect significant changes in energy markets.

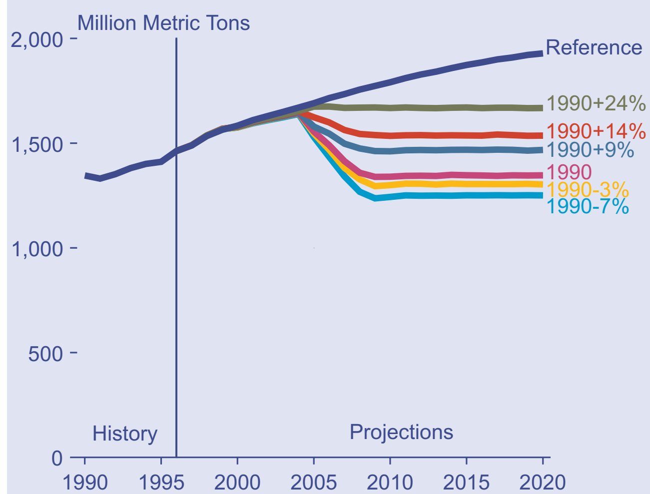
Carbon Reduction Cases

Carbon Prices

Under the Kyoto Protocol, the United States is committed to reducing greenhouse gas emissions to 7 percent below 1990 levels in the period 2008 through 2012. The reduction in energy-related carbon emissions that the United States must achieve to comply with the greenhouse gas reduction target in the Protocol depends on the level of emissions offsets credited for sinks, reductions in other greenhouse gases, international permit trading, joint implementation, and the Clean Development Mechanism (CDM). A set of six cases examines a range of carbon emissions reduction targets, ranging from 7 percent below 1990 levels, an average of 1,250 million metric tons during the period 2008 to 2012, to 24 percent above 1990 levels, or an average of 1,670 million metric tons. The most stringent case assumes that the target of reducing greenhouse gases to 7 percent below 1990 levels is the domestic goal for energy-related carbon emissions, with no offsets from sinks, offsets, international trade, the CDM, or compensating changes in other greenhouse gases.

The six carbon reduction cases are compared against a reference case similar to the one published in the *Annual Energy Outlook 1998* (*AEO98*) (Figure 1). The Protocol indicates that the greenhouse gas reductions must be achieved on average in each of the years between 2008 and 2012, and the targets are assumed to hold on average for that period. At the specification of the Committee, the targets were held constant after 2012 through the forecast horizon of 2020. To provide energy markets time to adjust, mandatory carbon reduction targets were phased in beginning in 2005, the year when the Protocol indicates that progress toward compliance must be demonstrated.

Figure 1. Projections of Carbon Emissions, 1990-2020



Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

In order to reduce carbon emissions, demand for energy services must be reduced, more efficient energy-consuming technologies used, or less carbon-intensive fuels consumed. Thus, to constrain the overall level of carbon emissions to a given target, a price on carbon emissions is included in the delivered price of fuels. The carbon price is equivalent to the cost of a carbon permit under a market-based program within the United States to regulate the overall level of carbon emissions. In such a program, the purchase of fossil fuels would require the exchange of carbon permits, and a market for carbon permits would operate to allocate the overall supply of permits among U.S. energy consumers. More restrictive carbon targets would lead to higher market-clearing prices for carbon.

In analyzing the carbon emissions reduction targets, the carbon prices are incorporated as an added cost of consuming energy; that is, as an increase in the delivered price of energy. The added cost is in direct proportion to the carbon permit price and the carbon content of the fuel consumed. As a result, energy consumers face higher energy costs—both for the fossil fuels they consume directly, such as gasoline, and for the indirect use of fossil energy used to generate electricity. The higher energy costs also affect the cost of producing goods and services throughout the economy and, as a result, have macroeconomic effects beyond the impacts on the energy sector.

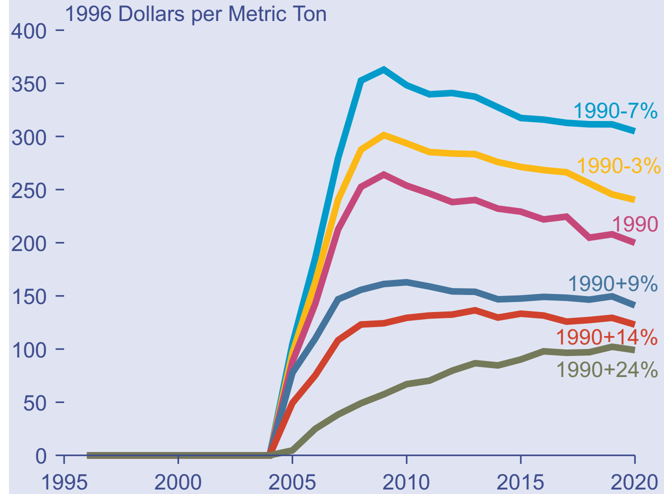
As indicated in Figure 1, some carbon reductions occur before 2005, based on anticipatory behavior, primarily as a result of forward-looking capacity planning decisions assumed in the electricity industry. For the electricity industry, where fossil fuel purchases are a predominant operating cost, planners are assumed to incorporate future fuel costs in their economic evaluation of generating plant alternatives.[22] As a result, some capacity choices reflected in the reference case before 2005 are altered in the carbon reduction cases based on carbon prices beginning in 2005, thus lowering carbon emissions before the assumed start of carbon permit trading.

Table 2 presents a summary of the key results in 2010 and 2020 for the reference case, the 24-percent-above-1990 (1990+24%) case, the 9-percent-above-1990 (1990+9%) case, and the 3-percent-below-1990 (1990-3%) case. Tables of the complete results for all the carbon reduction cases are included in Appendix B.

Figure 2 depicts the estimated carbon prices, in constant 1996 dollars, necessary to achieve the carbon emissions reduction targets. Generally, the highest permit price occurs early on in the commitment period. The carbon price declines over time as cumulative investments in more energy-efficient and lower-carbon equipment, particularly in the electricity generation industry, tend to reduce the marginal cost of compliance in later years.

For most of the cases, the trend of carbon prices includes some relatively minor year-to-year fluctuations. Also, particularly in the more stringent reduction cases, the carbon price generally peaks in 2008, the first year of the commitment period, because of the 3-year phase-in period. A longer adjustment period might reduce the price; however, early reductions do not count toward the required reductions in the commitment period. In some cases, 1- to 2-year declines in prices occur as

Figure 2. Projections of Carbon Prices, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

electricity generators complete construction of low-carbon replacement plants. The new plants allow generators to shift from coal to lower-carbon energy sources, reducing their need to purchase carbon permits and holding down carbon prices. Because the additions of replacement capacity occur in discrete amounts, the year-to-year changes in carbon prices can be somewhat uneven. The short-term fluctuations in projected carbon prices are consistent with, but probably understate, the degree of short-term price movements that would be expected in a market for carbon permits.

The carbon prices from 2008 to 2012 average $159 per metric ton in the 1990+9% case, which represents a carbon reduction averaging 325 million metric tons a year relative to the reference case (Figure 3). In the more stringent 1990-3% case, the average carbon price from 2008 to 2012 is $290 per metric ton, achieving an average annual carbon reduction during that period of 485 million metric tons. In the 1990+24% case, carbon prices average $65 per metric ton in the compliance period, with average carbon reductions of 122 million metric tons.

Carbon prices decline in most of the cases after 2012, despite continued growth in the demand for energy as the carbon target is held constant. While increased energy demand would be expected to exert upward pressure on carbon prices over time, downward pressure results from the cumulative effect of investments to improve energy efficiency and switch to lower-carbon energy sources. These long-lived

[22] The modeling approach assumes perfect foresight of carbon prices for capacity planning in the electricity industry. Perfect foresight, in this context, means that the carbon prices that are anticipated during planning are later realized. An algorithm solves for the path of carbon prices in which anticipated and realized carbon prices are approximately the same, while ensuring that the carbon prices clear the carbon permit market each year. In the end-use demand sectors, foresight is assumed not to have a material influence on energy equipment decisions, and such decisions are modeled on the basis of prices in effect at the time of the decision.

investments tend to reduce the demand for carbon permits over an extended period of time, outweighing the opposing effect of moderate growth in energy demand. Thus, although high carbon prices must be sustained over several years to induce such investments, carbon prices eventually moderate.

Table 2. Summary Comparison: Reference, 1990+24%, 1990+9%, and 1990-3% Cases, 2010 and 2020

Summary Indicators	1996	2010 Reference	2010 1990 +24%	2010 1990 +9%	2010 1990 -3%	2020 Reference	2020 1990 +24%	2020 1990 +9%	2020 1990 -3%
Carbon Price (1996 Dollars per Metric Ton)	**NA**	**NA**	**67**	**163**	**294**	**NA**	**99**	**141**	**240**
Delivered Energy Price (1996 Dollars per Million Btu)									
Coal	1.32	1.12	2.82	5.24	8.57	1.01	3.50	4.57	7.18
Natural Gas	4.13	3.76	4.71	6.45	8.49	3.96	5.69	6.95	8.30
Motor Gasoline	9.89	10.11	11.23	12.53	14.49	10.00	11.45	12.04	13.48
Jet Fuel	5.52	5.62	6.69	8.15	10.24	5.76	7.32	8.01	9.66
Distillate Fuel	7.84	7.81	8.91	10.50	12.71	7.67	9.21	9.79	11.49
Electricity	20.19	17.22	20.92	25.70	30.68	16.31	21.44	23.77	26.10
Primary Energy Use (Quadrillion Btu)									
Natural Gas	22.60	28.97	29.57	31.82	32.49	32.65	34.50	36.02	35.39
Petroleum	36.01	43.82	42.83	41.12	38.89	46.88	45.25	44.78	42.94
Coal	20.90	24.14	19.70	11.68	6.72	25.27	15.28	7.06	2.59
Nuclear	7.20	6.17	6.68	6.98	7.36	3.80	5.06	5.90	6.86
Renewable	6.91	7.27	7.44	7.72	8.23	7.59	8.29	9.77	11.91
Other[a]	0.39	0.80	0.25	0.25	0.23	0.83	0.26	0.26	0.25
Total	94.01	111.18	106.48	99.57	93.93	117.02	108.64	103.79	99.94
Electricity Sales (Billion Kilowatthours)	**3,098**	**3,865**	**3,696**	**3,492**	**3,286**	**4,240**	**3,972**	**3,837**	**3,718**
Carbon Emissions by Fuel (Million Metric Tons)									
Natural Gas	318	415	424	456	466	468	495	517	507
Petroleum	621	752	735	704	660	805	777	767	727
Coal	524	621	506	299	172	652	393	181	66
Total	1,463	1,791	1,668	1,462	1,300	1,929	1,668	1,468	1,303
Carbon Emissions by Sector (Million Metric Tons)									
Residential	286	337	301	238	199	375	291	224	181
Commercial	230	277	244	186	147	299	225	168	130
Industrial	476	559	519	462	418	582	505	449	405
Transportation	471	617	605	576	536	673	647	626	588
Total	1,463	1,791	1,668	1,462	1,300	1,929	1,668	1,468	1,303
Electricity Generation	517	657	567	409	312	726	519	351	246
Carbon Reductions by Sector (Million Metric Tons)									
Residential	NA	NA	37	99	139	NA	85	151	195
Commercial	NA	NA	33	91	130	NA	73	131	169
Industrial	NA	NA	41	98	141	NA	77	133	177
Transportation	NA	NA	12	41	81	NA	26	47	85
Total	NA	NA	123	329	491	NA	261	461	625
Electricity Generation	NA	NA	90	248	345	NA	207	375	481
Electricity Generation as Percent of Total	NA	NA	74	75	70	NA	79	81	77
Energy Fuel Expenditures (Billion 1996 Dollars)	**560**	**637**	**726**	**834**	**952**	**674**	**807**	**862**	**945**
Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	**13.57**	**11.80**	**11.42**	**10.78**	**10.33**	**10.78**	**10.05**	**9.62**	**9.27**
Carbon Intensity (Kilograms per Million Btu)	**15.6**	**16.1**	**15.7**	**14.7**	**13.8**	**16.5**	**15.4**	**14.1**	**13.0**

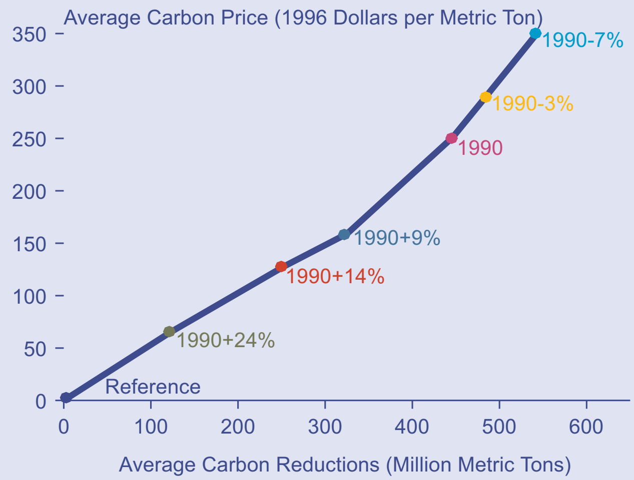
[a]Includes net electricity imports, methanol, and liquid hydrogen.

NA = not applicable.

Note: Totals may not equal sum of components due to independent rounding.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 3. Average Annual Carbon Emission Reductions and Projected Carbon Prices, 2008-2012



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Energy Prices

With the carbon prices included in the delivered cost of energy, the prices under the various carbon targets rise significantly above the reference case. Figures 4, 5, and 6 show the average delivered prices of coal, natural gas, petroleum, and electricity in the 1990+24%, the 1990+9% and the 1990-3% cases, respectively. In percentage terms, coal prices are most affected by the carbon prices, with the delivered price of coal in the 1990+9% case increasing 346 to 368 percent above the reference case price in the 2008 to 2012 period (Figure 7). Natural gas prices in the 1990+9% case increase 64 to 74 percent above the reference case prices, and oil prices increase by 25 to 29 percent. Electricity prices, reflecting the higher costs of fossil fuels used for generation, as well as the incremental cost of additional plant investments to reduce carbon emissions by replacing coal-fired plants, increase to 47 to 50 percent above the reference case level.

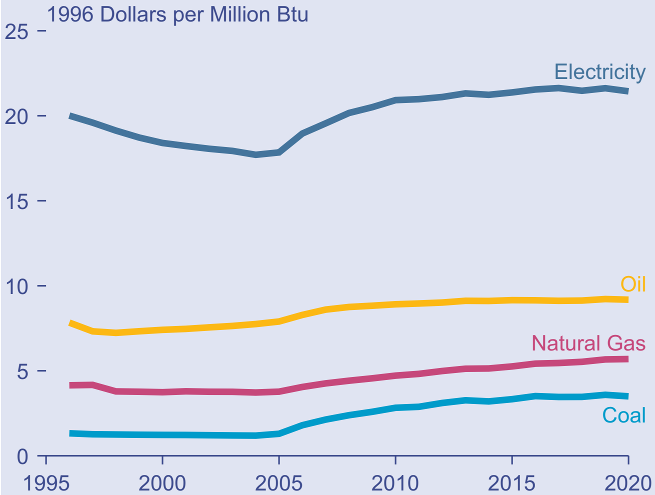
Compared with the changes in coal and natural gas prices, the average increase in electricity prices is relatively low. Larger amounts of electricity would be generated from renewable and nuclear power, for which fuel costs are unaffected by carbon prices. In addition, cost-of-service electricity pricing is assumed for most of the country, so that fuel costs would be only a partial determinant of electricity prices. Nonfuel operating and maintenance costs and capital equipment costs have a larger role in setting electricity prices under cost-of-service pricing. In regions where electricity prices are assumed to be set competitively on the basis of marginal costs (California, New York, and New England), carbon prices would have a more significant influence on electricity prices, particularly when coal-fired plants are the marginal generators. On the other hand, those regions are less dependent on coal than are many other areas of the country.

The pattern of projected delivered energy prices matches the trend for carbon prices, especially in the more restrictive carbon reduction cases. In these cases, the carbon prices become a dominant component of the delivered cost of fossil energy; however, market forces continue to play a role in energy prices, especially for petroleum products. The reduced demand for oil under the various carbon reduction targets tends to reduce world oil prices. World oil prices are projected to fall as demand is reduced in the United States and in other developed countries that are committed to reducing emissions under the Kyoto Protocol. In 2010, world oil prices are projected to be about $20.00 per barrel in the 1990+24% case, $18.70 in the 1990+9% case, and $17.80 in the 1990-3% case, as compared with $20.80 per barrel in the reference case. With lower world oil prices, the change in delivered petroleum product prices with the various carbon prices is not as high as for natural gas prices, despite the higher carbon content of petroleum.[23]

In contrast to petroleum, coal prices are unlikely to be moderated by competitive forces. Much of the demand for coal by electricity generators is eliminated in the carbon reduction cases, particularly with the more stringent targets. Coal consumption for other uses, including industrial steam coal and metallurgical coal, is also reduced but on a smaller percentage basis than for electricity generation. Although coal produced for export is also lower in the carbon reduction cases due to lower demand in the Annex I nations, the change is relatively small in comparison with the reductions in production for domestic use. Coal exports, projected at 113 million short tons in 2010 in the reference case, are 89 million short tons in 2010 in the 1990+24% and 1990+9% cases and 76 million short tons in the 1990-3% case. Because the industrial and export coal markets are served primarily by eastern coal producers, eastern production declines less in the carbon reduction cases than does production from western mines, which primarily serve the electricity generation market. Thus, while regional minemouth prices generally decline in the carbon reduction cases relative to the reference case, the national

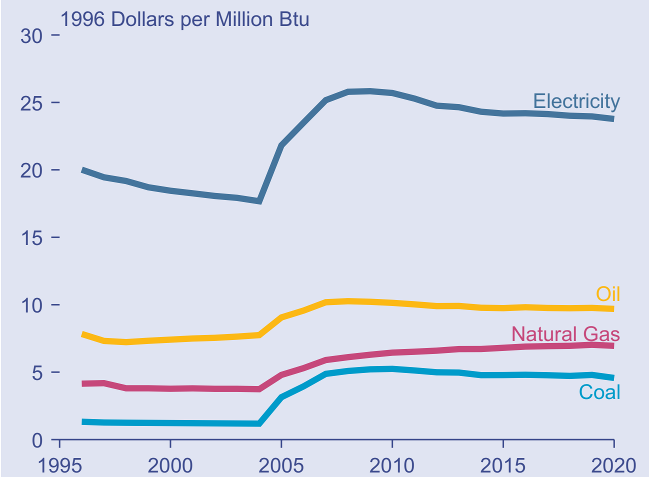
[23] A related factor influencing the effect of carbon prices on gasoline demand is that the price of gasoline already includes Federal and State excise taxes averaging 37 cents per gallon in 1996, equivalent to a carbon permit price of $155 per metric ton. When additional carbon permit prices are included in the delivered price of gasoline, the percentage increase in price is not as high as it would be if gasoline were untaxed initially. In turn, the percentage change in gasoline demand due to the carbon price is not as high as it would be if gasoline were not already taxed.

Figure 4. Average Delivered Prices for Energy Fuels in the 1990+24% Case, 1996-2020



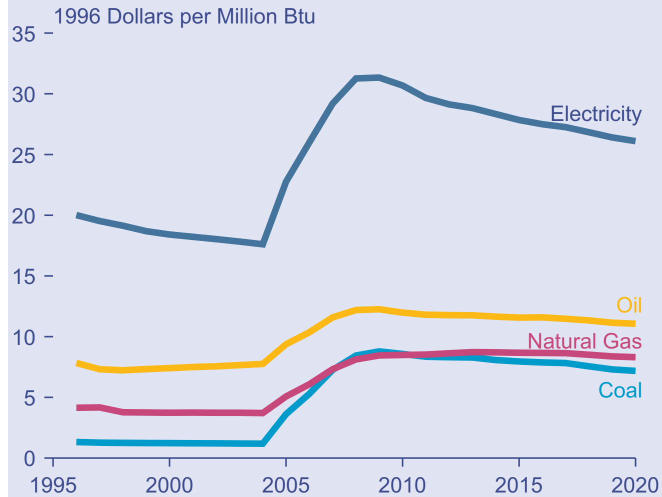
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD24ABV.D080398B.

Figure 5. Average Delivered Prices for Energy Fuels in the 1990+9% Case, 1996-2020



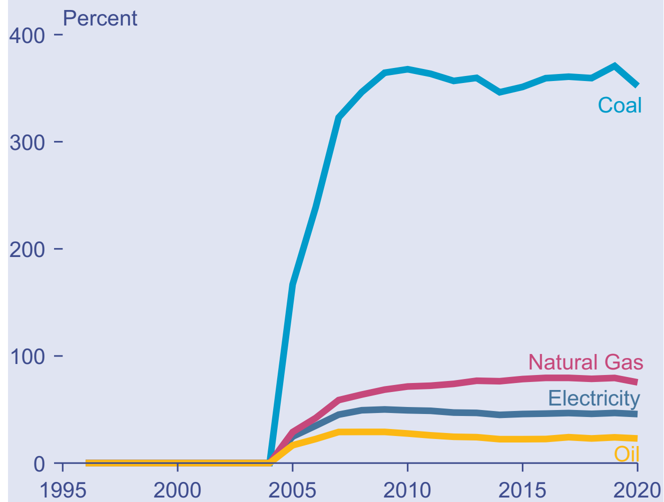
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD09ABV.D080398B.

Figure 6. Average Delivered Prices for Energy Fuels in the 1990-3% Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD03BLW.D080398B.

Figure 7. Projected Changes in Average Delivered Prices for Energy Fuels in the 1990+9% Case Relative to the Reference Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A and FD09ABV.D080398B.

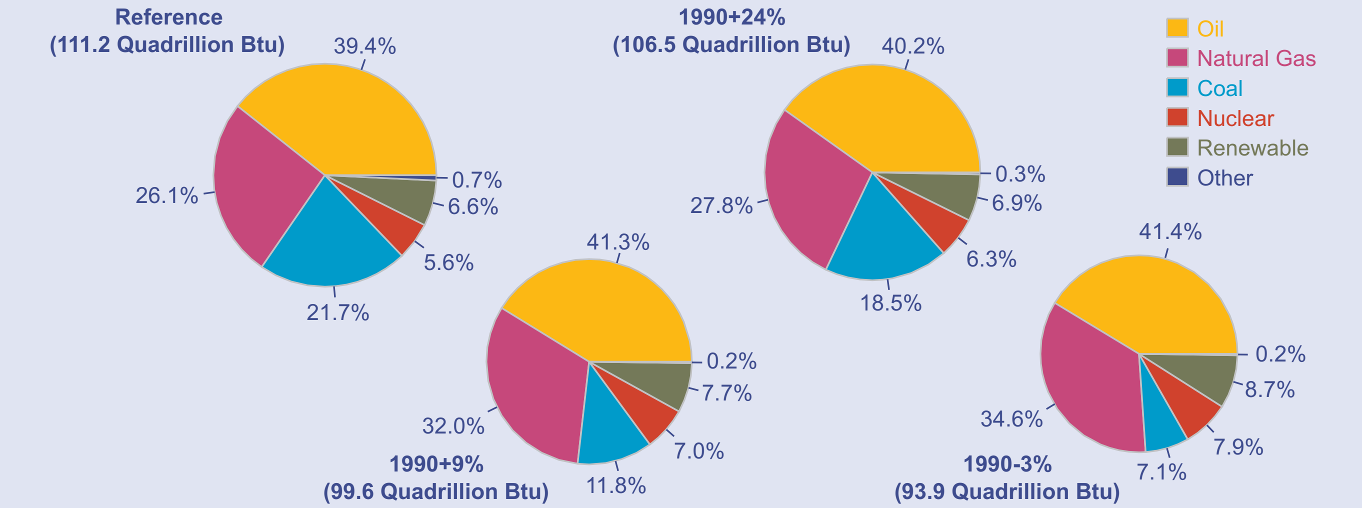
average minemouth price increases because of the shift in share to the higher-priced coal mined in the East. Western coal production is also discouraged by higher rail transportation costs and reduced incentive for the development of new mines.

Natural gas demand is higher in the carbon reduction cases relative to the reference case primarily because of higher use in the electricity generation sector, offsetting reductions in the end-use demand sectors. As a result, the average wellhead price of natural gas, excluding any carbon price, is higher relative to the reference case in all the carbon reduction cases. The higher wellhead prices are an indication that greater reliance on natural gas under the Kyoto Protocol could benefit some domestic energy producers.

Impacts by Fuel

To meet the required carbon emissions reductions, the mix of energy fuels consumed would change dramatically from that projected in the reference case (Figure 8). Relative price changes cause a reduction in coal and petroleum use, coupled with greater reliance on natural gas, renewable energy, and nuclear power (see Figures 9 through 13). Coal, with its high carbon content and relatively low end-use efficiency, is severely curtailed in the more stringent cases, replaced by more use of natural gas, renewable fuels, and nuclear power in electricity generation. Coal's share of generation is reduced from 52 percent in 1996 to 42 percent, 26 percent, and 15 percent in 2010 in the 1990+24%, 1990+9%, and 1990-3% cases. By 2020, coal is nearly

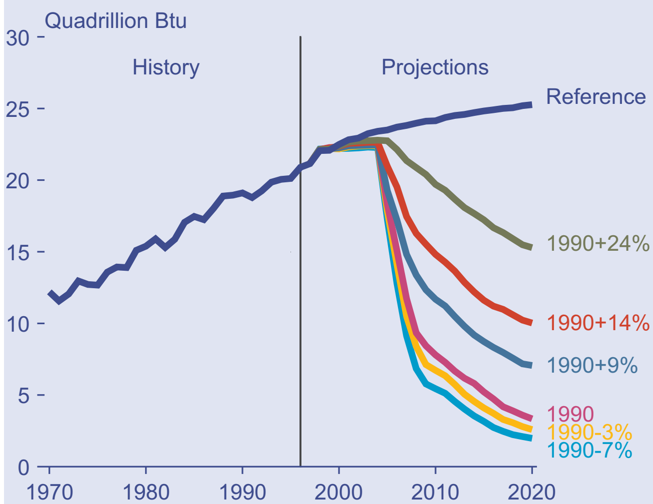
Figure 8. Projections of Fuel Shares of Total U.S. Energy Consumption, 2010



Note: "Other" includes net electricity imports, methanol, and liquid hydrogen.

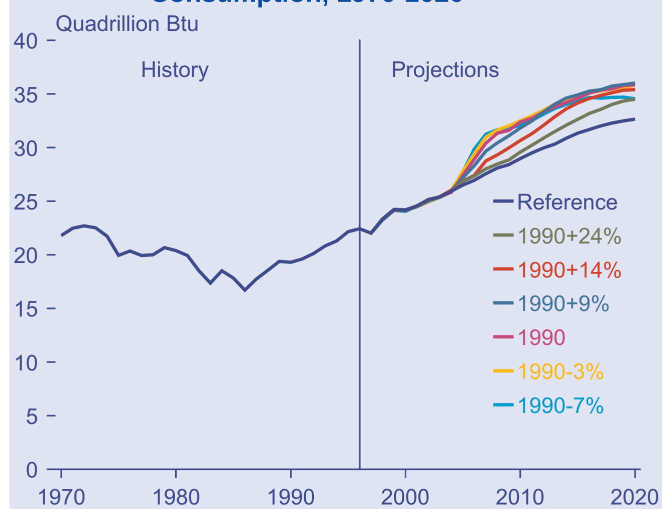
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 9. Projections of U.S. Coal Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV .D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW. D080398B.

Figure 10. Projections of U.S. Natural Gas Consumption, 1970-2020



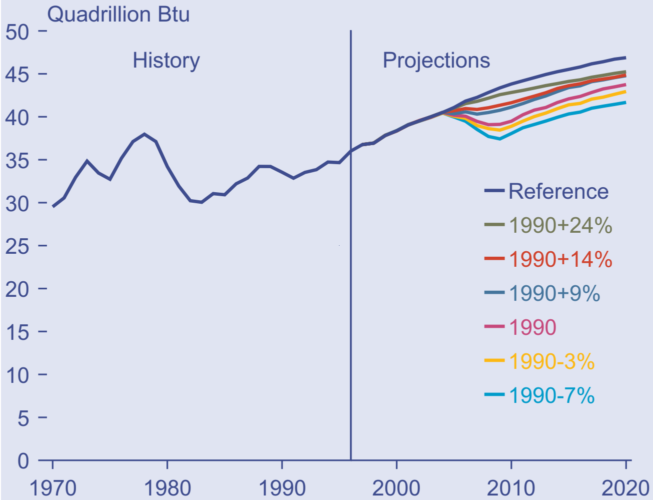
Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV. D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW. D080398B.

eliminated from electricity generation in the 1990-3% case (Figure 9). Some reduction in coal use, compared with the reference case, occurs before the start of the carbon permit program in 2005. These changes occur as the result of anticipatory behavior in the electricity industry, where capacity planning decisions in advance of 2005 are affected by the prospects of carbon prices in the future.

Natural gas consumption is higher than in the reference case, as greater use of natural gas in the generation sector outweighs the reductions in the residential, commercial, and industrial sectors (Figure 10). In those cases with less stringent carbon reduction targets, and correspondingly lower carbon prices, generators find it more economical to substitute natural gas for coal than to invest in renewable technologies. In the more stringent cases, with high carbon prices, increasing use of renewable fuels eventually leads to reductions in the demand for natural gas by generators. This pattern is reflected in Figure 10, as natural gas consumption in the more stringent cases falls below that in the less stringent cases toward the end of the forecast period. In the earlier portion of the forecast, the rapid growth of natural gas use exerts pressure on suppliers and distributors to increase production and pipeline capacity. The ability of the gas industry to respond to higher demand growth is discussed in Chapter 5.

Petroleum, used primarily for transportation, is lower in all the carbon reduction cases (Figure 11). Motor gasoline demand, accounting for 43 percent of total

Figure 11. Projections of U.S. Petroleum Consumption, 1970-2020



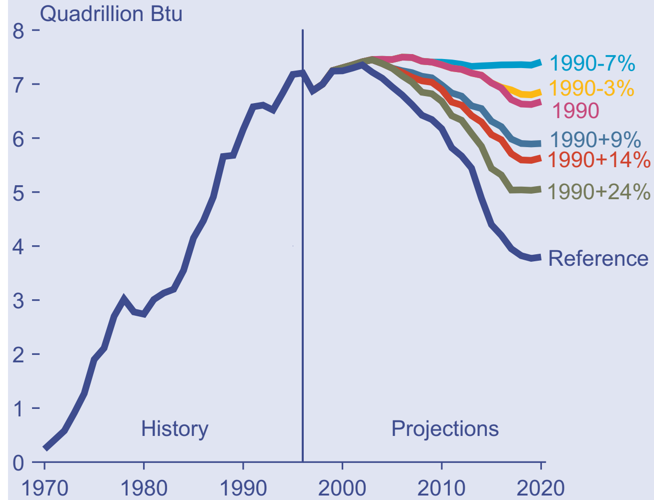
Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

petroleum consumption in 1996, is lower by 15 percent in 2010 in the 1990-3% case, by 8 percent in the 1990+9% case, and by 3 percent in the 1990+24% case than in the reference case. Consumers respond to higher gasoline prices by reducing miles driven and purchasing more efficient vehicles.

Nuclear power, which produces no carbon emissions, becomes more attractive under carbon reduction targets. While no new nuclear plants are allowed to be built in the carbon reduction cases, extending the lifetimes of existing plants is projected to become more economical with higher carbon prices. In the reference case, approximately half of the nuclear capacity now in operation is expected to be retired by 2020, reducing U.S. nuclear capacity by 53 gigawatts between 1996 and 2020. Much of that capacity would be life-extended in the carbon reduction cases (15 gigawatts, 26 gigawatts, and 38 gigawatts in the 1990+24%, 1990+9%, and 1990-3% cases, respectively). As a result, the use of nuclear power for electricity generation is projected to be higher in all three cases than in the reference case (Figure 12).

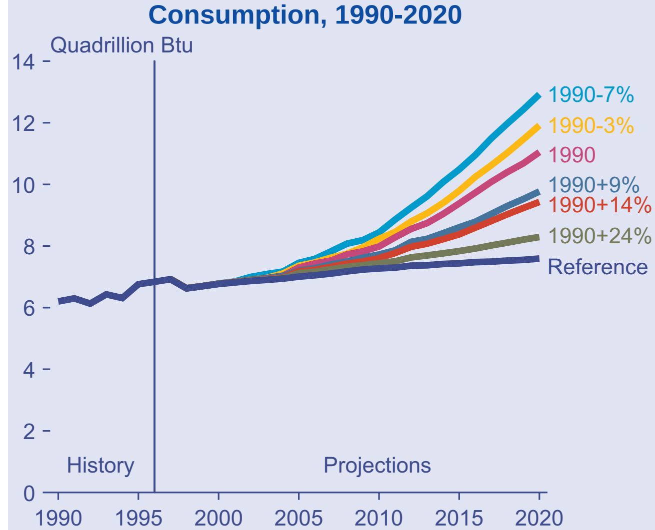
Consumption of renewable energy, which results in no net carbon emissions, is projected to be higher with carbon reduction targets (Figure 13). Most of the increase is in electricity generation, primarily with additions to wind energy systems and an increase in the use of biomass (wood, switchgrass, and refuse). The share of generation supplied by renewables increases from 9 percent in 2020 in the reference case to 11 percent, 15 percent, and 20 percent in the 1990+24%, 1990+9%, and 1990-3% cases, respectively. Most of the increase in renewable generation occurs after the 2008-2012 compliance period, reflecting a relatively prolonged

Figure 12. Projections of U.S. Nuclear Energy Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 13. Projections of U.S. Renewable Energy Consumption, 1990-2020

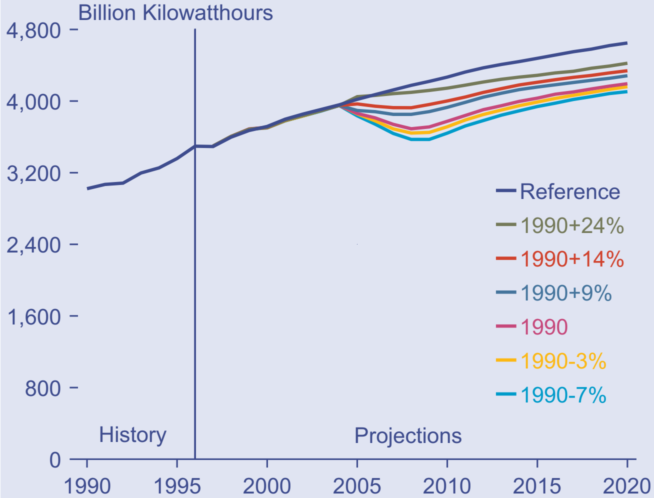


Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

period of market penetration as renewable technology costs and performance improve over time.

Electricity generation, which accounted for 35 percent of energy-related carbon emissions in 1996, is also significantly lower across all the cases (Figure 14). In the 1990-3% case, electricity sales in 2010 are 15 percent below the reference case projection, with percentage reductions of about 13 percent occurring in the residential and industrial sectors and about 19 percent in the commercial sector. The relative changes in electricity

Figure 14. Projections of U.S. Electricity Generation, 1990-2020

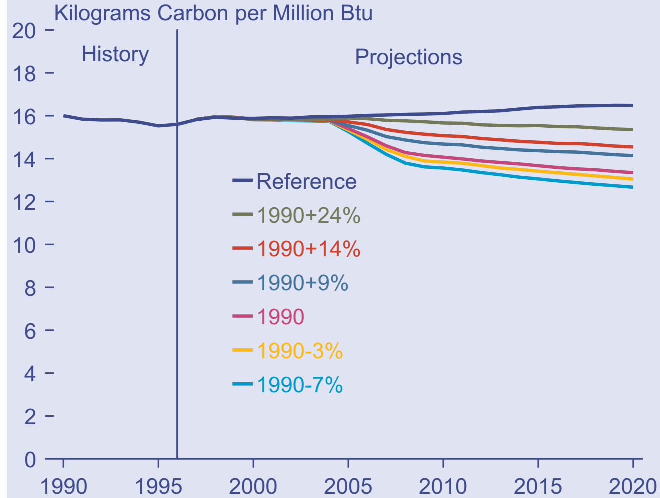


Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

sales by sector are similar in the 1990+9% and 1990+24% cases, but the overall percentage reductions are smaller (9 percent and 4 percent). One factor mitigating the response of electricity demand to higher electricity prices in these sectors is the relative change in energy prices. For example, the percentage changes in electricity prices, relative to the reference case, are smaller than the changes in natural gas prices. With a smaller percentage price increase, electricity becomes relatively attractive in those end uses where it competes with natural gas, such as home heating.

As the results have indicated, reductions in carbon emissions are also met through substitution away from carbon-intensive fuels, not just through energy efficiency improvements and reductions in energy services. The degree to which this occurs is indicated by the change in aggregate carbon intensity of energy use, or carbon emissions per unit of energy consumption. For example, natural gas has a carbon intensity at full combustion of 14.5 kilograms per million Btu, whereas coal averages about 25.7; thus, switching from coal to natural gas tends to reduce carbon intensity. Aggregate carbon intensity declined from 16 kilograms per million Btu in 1990 to 15.6 in 1996, but it is projected to increase in the reference case after 2000, reaching a level of 16.1 kilograms per million Btu by 2010 (Figure 15), even though energy intensity continues to decline. In the carbon reduction cases, carbon intensity begins to decline with the phase-in of the carbon targets. By 2010, carbon intensity declines to 15.7 kilograms per million Btu in the 1990+24% case, 14.7 in the 1990+9% case, and 13.8 in the 1990-3% case.

Figure 15. Projections of U.S. Carbon Emissions per Unit of Primary Energy Consumption, 1990-2020



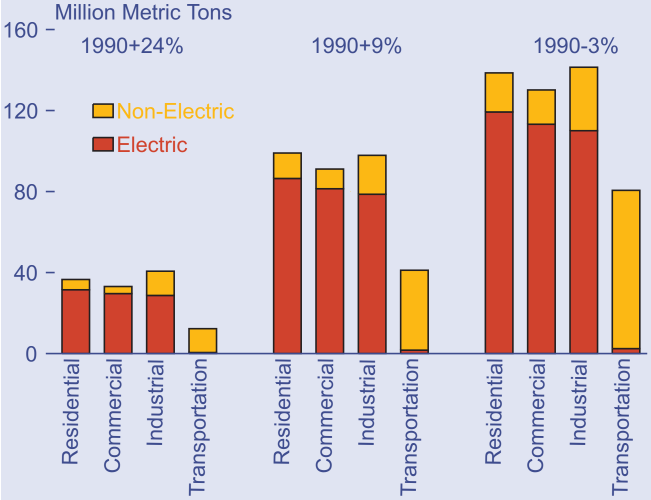
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Sectoral Impacts

Energy demand across each of the end-use sectors—residential, commercial, industrial, and transportation—will respond to different degrees to the incentives imposed by a carbon permit price. In all sectors, however, consumers will have greater incentive to conserve energy, switch to lower-carbon energy sources, and invest in more energy-efficient technologies.

Figure 16 illustrates the contribution of each sector toward meeting the carbon reduction goals in 2010 under three of the cases. The residential and industrial sectors (including electricity losses) account for the greatest carbon reduction, and transportation accounts for the least. As shown in Figure 16, most of the carbon reductions for the four end-use sectors occur in electricity, stemming from both reduced electricity demand and the use of more efficient, less carbon-intensive sources of generation. Reductions in carbon emissions from electricity generation account for about 75 percent of the total carbon reductions in both the 1990+24% and 1990+9% cases in 2010, and for about 70 percent in the 1990-3% case. A variety of factors contribute to the central role played by the electricity sector in meeting the carbon reduction targets: the industry's current dependence on coal; the availability and economics of technologies to switch from coal to less carbon-intensive energy sources; and the comparative economics of fossil-fuel switching in other sectors, particularly at lower carbon prices. As discussed in more detail in Chapter 3, the extent to which end-use energy consumers respond to prices is often limited by institutional factors.

Figure 16. Projected Reductions in Carbon Emissions by End-Use Sector Relative to the Reference Case, 2010



Note: Electricity emissions are from the fuels used to generate electricity and are attributed to the sectors relative to their shares of total electricity consumption.

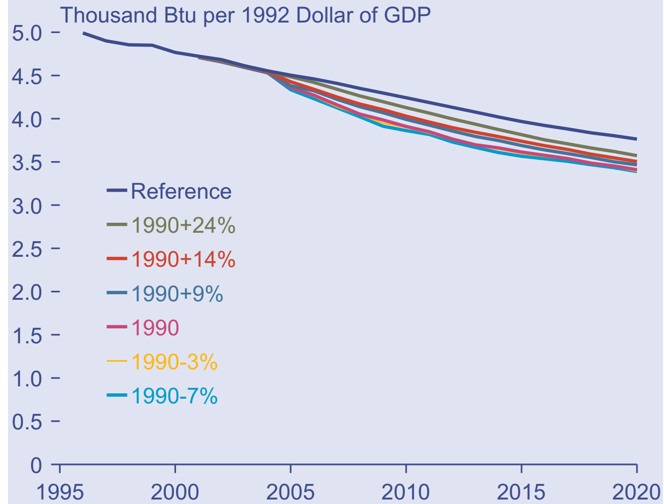
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

In the industrial sector, some of the carbon reductions can be attributed to reductions in manufacturing output that result from the impact of higher energy prices on the economy. In addition, industrial firms respond by replacing productive capacity faster, investing in more efficient technology, and switching to less carbon-intensive fuels. Improvements in efficiency are indicated by reductions in energy intensity, as measured by the energy use per dollar of gross domestic product (GDP). In 2010, industrial energy intensity is reduced from 4.2 million Btu per dollar of GDP in the reference case to 4.1 million Btu per dollar in the 1990+24% case, 4.0 million Btu per dollar in the 1990+9% case, and 3.9 million Btu per dollar in the 1990-3% case (Figure 17). Taking into account fuel switching and efficiency improvements, carbon emissions per unit of GDP in 2010 for the industrial sector are reduced from 60 kilograms per thousand dollars of GDP in the reference case to 55, 50, and 46 kilograms per thousand dollars of GDP in the 1990+24%, 1990+9%, and 1990-3% cases, respectively.

Carbon reductions in the transportation sector occur primarily as the result of reduced travel and the purchase of more efficient vehicles in response to higher energy prices. Compared with the reference case, light-duty vehicle travel (cars, vans, pickup trucks, and sport-utility vehicles) in 2010 is lower by 1 percent in the 1990+24% case, by 5 percent in the 1990+9% case, and by 11 percent in the 1990-3% case (Figure 18). At the same time, more efficient cars and light trucks are purchased, raising overall fleet efficiency (Figure 19). In 2010, the average fuel efficiency for the light-duty vehicle fleet is 20.7, 21.2, and 21.5 miles per gallon in the 1990+24%, 1990+9%, and 1990-3% cases, respectively, compared with 20.5 miles per gallon in the reference case. The results of those increases are reductions of 3 percent, 8 percent, and 15 percent, respectively, from the reference case level of motor gasoline demand in 2010 (Figure 20). Travel reductions and efficiency improvements also occur in the air and freight sectors, further reducing carbon emissions. Overall, transportation energy consumption in 2010 is lower by 2 percent in the 1990+24% case, by 6 percent in the 1990+9% case, and by 12 percent in the 1990-3% case, than in the reference case.

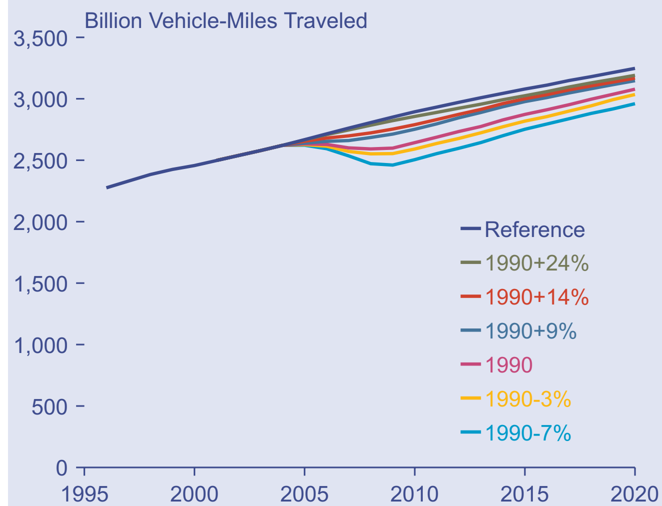
In the residential and commercial sectors, higher energy prices encourage investments in more efficient equipment and building shells and also reduce the demand

Figure 17. Projections of U.S. Industrial Energy Intensity, 1996-2020



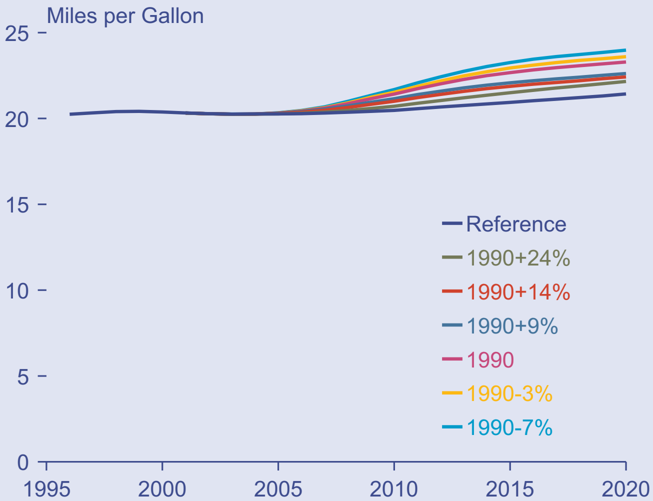
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 18. Projections of U.S. Light-Duty Vehicle Travel, 1996-2020



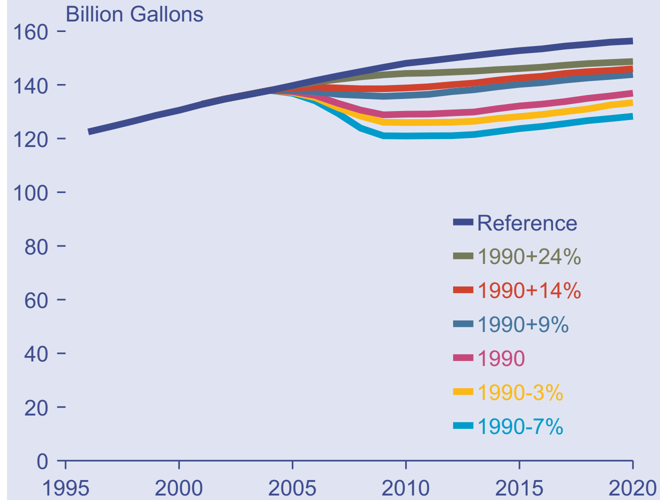
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B..

Figure 19. Projections of Average Fuel Efficiency for the Light-Duty Vehicle Fleet, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 20. Projections of U.S. Motor Gasoline Consumption, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

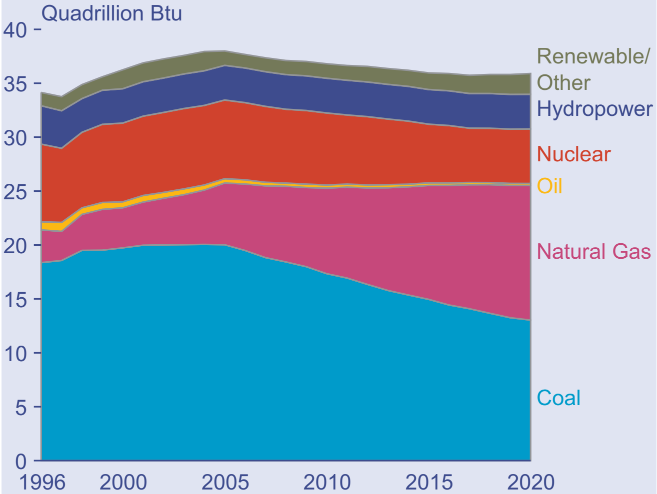
for energy services. In the residential sector, delivered energy use per household in 2010 drops by 4 percent in the 1990+24% case, 10 percent in the 1990+9% case, and 15 percent in the 1990-3% case compared with the reference case. Energy consumption for space conditioning accounts for 59 to 62 percent of the change in the three cases. Those energy services for which appliance efficiency standards are already in place, such as for refrigerators and freezers, are not expected to change greatly in the carbon reduction cases, because the standards reflect very efficient technology that already reduces fuel consumption substantially in the reference case. The fastest-growing segment of residential electricity consumption, categorized as miscellaneous and including a variety of appliances such as computers and VCRs, accounted for approximately 22 percent of residential electricity consumption in 1996. Relative to the reference case, miscellaneous electricity consumption per household is lower by 5 percent in 2010 in the 1990+24% case, by 10 percent in the 1990+9% case, and by 14 percent in the 1990-3% case.

The energy demand response is somewhat stronger in the commercial than in the residential sector. Overall, delivered energy use per square foot of commercial floorspace in 2010 drops by 5 percent in the 1990+24% case, 13 percent in the 1990+9% case, and 21 percent in the 1990-3% case. As in the residential sector, significant energy reductions are projected for heating, cooling, and ventilation (29 to 31 percent of the change in the three cases); however, more than half the energy reduction comes from more efficient lighting and office equipment and in the category of miscellaneous electricity uses, including such appliances as vending machines and telecommunications equipment.

The electricity generation sector is expected to respond strongly to the incentives imposed by a carbon price. Generation from coal, which currently accounts for more than half of all electricity, drops significantly as the cost of coal to generators increases by factors of 3 to 8 times the reference case level in 2010. To replace coal plants, generators build natural-gas-fired combined-cycle plants, extend the life of existing nuclear plants, and dramatically increase the use of renewables, particularly biomass and wind energy systems, which become economical once a carbon price is imposed. These changes, coupled with the expected reduction in electricity demand, result in carbon emissions of 567 million metric tons in the 1990+24% case, 409 million metric tons in the 1990+9% case, and 312 million metric tons in the 1990-3% case. In comparison, actual 1990 emissions in the electricity generation sector are estimated at 477 million metric tons. The issues related to plant capacity changes in the electricity industry are discussed in detail in Chapter 4.

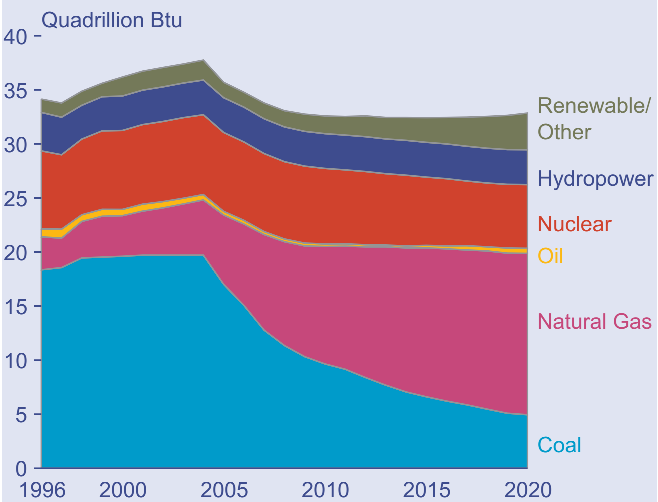
The mix of fuels used for electricity generation is projected to change rapidly as new plants come on line (Figures 21, 22, and 23). In the aggregate, cumulative investments by generators to reduce carbon emissions tend to bring down the carbon price over time. A slowdown in most new plant additions occurs at the end of the initial compliance period in 2012, but the growth in renewable capacity continues throughout the forecast horizon.

Figure 21. Projected Fuel Use for Electricity Generation by Fuel in the 1990+24% Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD24ABV.D080398B.

Figure 22. Projected Fuel Use for Electricity Generation by Fuel in the 1990+9% Case, 1996-2020

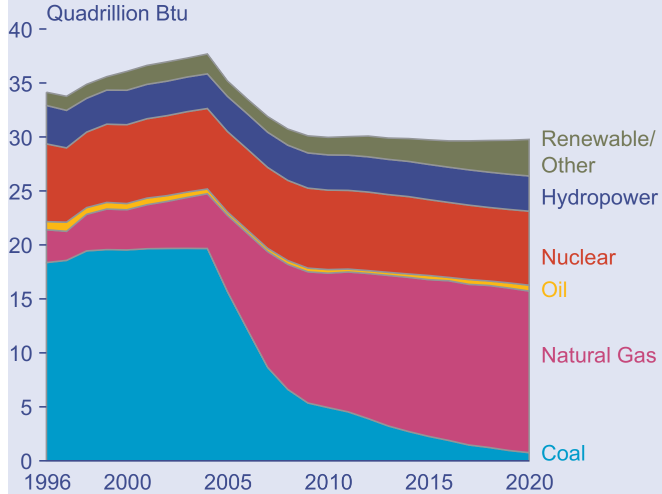


Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD09ABV.D080398B.

Sensitivity Cases

Among the sources of uncertainty in the effects of carbon mitigation polices over the next 20 years are the assumed rate of economic growth, the speed of adoption of advanced technologies, and the role of nuclear power. A series of sensitivity cases illustrate how these factors influence the results of the carbon reduction cases. The sensitivity cases were analyzed against the 1990+9% case. The nuclear power sensitivity case was analyzed against the 1990-3% case, because new nuclear power plants were found to be economical only with the higher carbon prices in that case.

Figure 23. Projected Fuel Use for Electricity Generation by Fuel in the 1990-3% Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD03BLW.D080398B.

Because each of the sensitivity cases is constrained to the same level of carbon emissions as the case to which it is compared, the primary impact is not on the carbon emissions levels, or even aggregate energy consumption, but rather on the carbon prices required to meet the emissions target. For example, in the high technology case, with an emissions reduction target of 9 percent above 1990 levels, projected carbon emissions during the compliance period are the same as in the corresponding reference technology case (1990+9%) with emissions at the same level. What differs is the cost of meeting the target, as reflected in the required carbon price or in expenditures for energy services. As a result, the carbon price and energy expenditures are the primary measures by which the sensitivity cases are compared in this report, in contrast to the presentation of similar sensitivities in *AEO98*. Because the technology sensitivities in the *AEO* typically are run with energy prices and macroeconomic assumptions held constant and without any target for carbon emissions, sensitivities are normally compared on the basis of levels of energy consumption.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on the projection of energy consumption and, therefore, on the projected levels of carbon emissions. In *AEO98*, the high economic growth case includes higher growth in population, the labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, GDP increases at an average rate of 2.4 percent a year from 1996 to 2020, compared with a growth rate of 1.9 percent a year in the reference case. With higher macroeconomic growth, energy demand grows more rapidly, as higher manufacturing output and higher income increase the demand for energy services. In *AEO98*, total energy consumption in the high economic growth case is 117 quadrillion Btu in 2010, compared with 112 quadrillion Btu in the reference case. Carbon emissions are 80 million metric tons, or 4 percent, higher than the reference case level of 1,803 million metric tons.

Assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.3 percent in the *AEO98* low economic growth case between 1996 and 2020. With lower economic growth, energy consumption in 2010 is reduced from 112 quadrillion Btu to 107 quadrillion Btu, and carbon emissions are 90 million metric tons, or 5 percent, lower than in the reference case. Thus, the effect of higher or lower macroeconomic growth can have a significant impact on the ease or difficulty of meeting the carbon targets.

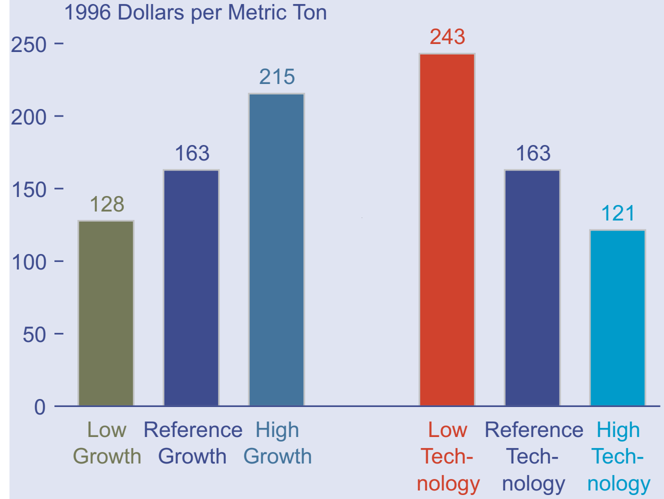
To reflect the uncertainty of potential economic growth, high and low economic growth sensitivity cases were analyzed against the 1990+9% case, using the same higher and lower economic growth assumptions as in *AEO98*. With higher economic growth, the industrial output and energy service demand are higher. As a result, carbon prices must be correspondingly higher to attain a given carbon emissions target. With low economic growth, the effects are reversed, leading to lower carbon prices. In addition to industrial output, some of the most important economic drivers in NEMS are disposable personal income, housing stock, housing size, commercial floorspace, industrial output, light-duty vehicle sales, and travel.

Figure 24 shows the effect of the high and low macroeconomic growth assumptions on the projections for 2010 in the 1990+9% case. The carbon price in 2010 is $215 per metric ton in the high economic growth case, or $52 per metric ton higher than the price of $163 per metric ton in the 1990+9% case with reference economic growth. In the low economic growth case, the carbon permit price in 2010 is $128 per metric ton or $35 per metric ton lower than in the 1990+9% case.

The higher carbon prices necessary to achieve the carbon reductions with higher economic growth will tend to moderate the growth rates of the economy as a whole and the economic drivers in the energy system. Despite this price effect, total energy consumption in 2010 is higher with higher economic growth, by 2.2 quadrillion Btu relative to the 1990+9% with reference economic growth. Similarly, the lower economic growth assumption results in lower carbon prices, which offset a portion of the projected reduction in energy consumption that would otherwise be expected when economic growth slows. Lower economic growth lowers total energy consumption by 2.2 quadrillion Btu.

To meet a carbon reduction target with higher economic growth and energy consumption, there is a shift to less

Figure 24. Projected Carbon Prices in the 1990+9% High and Low Economic Growth and High and Low Technology Sensitivity Cases, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B, LMAC09.D080698A, HMAC09.D080598A, FREEZE09.D080798A, and HITECH09.D080698A.

carbon-intensive fuels and higher energy efficiency; however, economic growth affects energy consumption in the industrial and transportation sectors more significantly than in the other end-use sectors. With higher economic growth, renewable energy and natural gas consumption is higher, primarily for generation but also in the industrial sector. Coal use for generation is lower, and more nuclear capacity is life-extended as a result of the higher carbon prices. Petroleum consumption is also higher with higher economic growth, in both the transportation and industrial sectors. As shares of total energy consumption, natural gas and renewables are higher with higher economic growth, coal is lower, and nuclear and petroleum remain approximately the same. Opposite trends for fuel consumption and fuel shares are seen when lower economic growth is assumed.

Total energy intensity is lower in the high economic growth case, partially offsetting the changes in energy consumption caused by the different growth assumptions. There are three reasons for the improvement in energy intensity. First, although demand for energy services is higher with higher economic growth, there is greater opportunity to turn over and improve the stock of energy-using technologies. In the *AEO98* cases, aggregate energy efficiency in the high economic growth case decreases at a rate of 1.0 percent a year through 2020, compared with 0.9 percent in the reference case and 0.8 percent in the low economic growth case. Second, with higher carbon prices, additional efficiency improvements are induced by higher energy prices. Finally, the higher energy prices lead to some reductions in energy service demand, moderating the impacts of higher economic growth. In the 1990+9% carbon reduction case, aggregate energy intensity declines at an average annual rate of 1.6 percent through 2010. In the 1990+9% high economic growth sensitivity case, the annual decline increases to 1.9 percent. In the 1990+9% low economic growth case, the decline in energy intensity slows to 1.3 percent per year.

Technological Progress

The assumed rate of development and penetration of energy-using technology has a significant impact on projected energy consumption and energy-related carbon emissions. Faster development of more energy-efficient or lower carbon-emitting technologies than assumed in the reference case could reduce both consumption and emissions; however, because the *AEO98* reference case already assumes continued improvement in both energy consumption and production technologies, slower technological development is also possible.

To examine the influence of technology improvement, two sensitivity cases were analyzed relative to the 1990+9% case. The high technology case includes more optimistic assumptions on the costs, efficiencies, market potential, and year of availability for the more advanced generating and end-use technologies, assuming increased research and development activity. This sensitivity case also assumes a carbon sequestration technology for coal- and natural-gas-fired electricity generation, which would capture the carbon dioxide emitted during fuel combustion and store it in underground aquifers; however, use of the technology is not projected to be economical relative to other technologies within the time frame of this sensitivity case because of high operating costs and storage difficulties. The low technology case assumes that all future equipment choices are made from the end-use and generation equipment available in 1998, with building shell and industrial plant efficiencies frozen at 1998 levels.

Because faster technology development makes advanced energy-efficient and low-carbon technologies more economically attractive, the carbon prices required to meet carbon reduction levels are reduced. Conversely, slower technology improvement requires higher carbon prices (Figure 24). In the 1990+9% case with high technology assumptions, the carbon price in 2010 is $121 per metric ton—$42 per metric ton lower than the price of $163 per metric ton in the 1990+9% case with reference technology assumptions. With the low technology assumptions, the projected carbon price is $243 per metric ton in 2010.

Total energy consumption in 2010 is lower by 2.1 quadrillion Btu in the high technology case, about 2 percent below the projection in the 1990+9% case, and average energy prices, including carbon prices, are 10 percent lower. As a result, direct expenditures on energy are 13 percent lower in the high technology case. Demand in both the industrial and transportation sectors is lower as efficiency improvements in industrial processes and most transportation modes outweigh the countervailing effects of lower energy prices. In the residential and commercial sectors, the effect of lower energy prices balances the effect of advanced technology, and consumption levels are at or near those in the 1990+9% case. With the high technology assumptions in the generation sector, coupled with the lower carbon permit price, coal use for generation is 3.8 quadrillion Btu higher than the 9.7 quadrillion Btu level associated with reference technology assumptions.

In the low technology case, the converse trends prevail. In 2010, total consumption is higher by 1.5 quadrillion Btu with the low technology assumptions, and energy expenditures are 17 percent higher. Industrial and transportation demand is higher, and residential and commercial demand lower, suggesting that industry and transportation are more sensitive to technology changes than to price changes, and that the residential and commercial sectors are more sensitive to price changes. With the higher carbon prices in the low technology case, coal use is further reduced in the generation sector, with more natural gas, nuclear power, and renewables used to meet the carbon reduction targets.

Nuclear Power

In the *AEO98* reference case, nuclear generation declines significantly, because 52 percent of the total nuclear capacity available in 1996 is expected to be retired by 2020. A number of units are retired before the end of their 40-year operating licenses, based on industry announcements and analysis of the age and operating costs of the units. In the carbon reduction cases, life extension of the plants can occur, if economical, and there is an increasing incentive to invest in nuclear plant refurbishment with higher carbon prices; however, no construction of new nuclear power plants is assumed, given continuing high capital investment costs and institutional constraints associated with nuclear power.

A nuclear power sensitivity case was developed to examine the potential contribution of new nuclear plant construction to carbon emissions reductions, assuming that new nuclear capacity would be built when it was economically competitive with other generating technologies. In the nuclear power sensitivity case, electricity generators were assumed to add nuclear power plants when it became economical to do so. In addition, the reference case assumptions about higher costs incurred for the first few advanced nuclear plants were relaxed by reducing the premium in costs for the first phase of new nuclear plant additions.

In the 1990+9% case, even with the nuclear power sensitivity assumptions, nuclear plants are not competitive with fossil and renewable plants. In the 1990-3% case, however, when the new nuclear assumptions are used, 1 gigawatt of new nuclear capacity is added by 2010, and

41 gigawatts, representing about 68 new plants of 600 megawatts each, are added by 2020. (In a trial case in which first-generation cost premiums were left unchanged, only 3 gigawatts of nuclear capacity was added.) The availability of this no-carbon capacity offsets about 25 million metric tons of carbon emissions from additional natural gas plants in 2020; on the other hand, more coal is used, because the projected carbon prices are lower. Most of the impact from the new nuclear plants comes after the commitment period of 2008 through 2012. As a result, there is little impact on carbon prices in 2010. By 2020, however, carbon prices are $199 per metric ton with the assumption of new nuclear plants, as compared with $240 per metric ton in the 1990-3% case with the reference nuclear assumptions.

In the 1990-3% case, total energy consumption is about the same in 2010 with new nuclear plants allowed and higher by about 1.8 quadrillion Btu in 2020. Somewhat lower energy prices induce higher consumption in all sectors, and the greater availability of carbon-free nuclear generation allows the carbon reduction target to be met with higher end-use consumption.

3. End-Use Energy Demand

Background

This chapter provides in-depth analyses of the carbon emissions reduction cases for the four end-use demand sectors—residential, commercial, industrial, and transportation. Additional analyses are included for a number of alternative cases, including low and high technology sensitivity cases, which have the most direct impacts on energy end use.

Primary and Delivered Energy Consumption

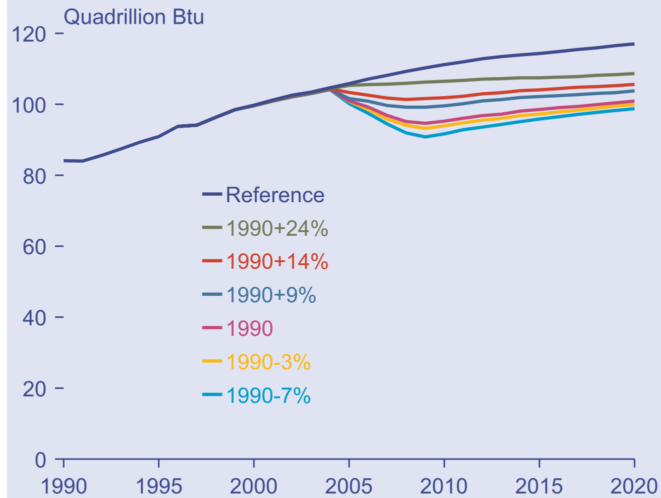
In each of the reduction cases, carbon emissions are reduced through a combination of switching to carbon-free or lower-carbon fuels, reductions in energy services, and increased energy efficiency. The latter two options lower total energy consumption (Figure 25).

Electricity generation typically consumes about three times as much energy, on the basis of British thermal units (Btu), as is contained in the electricity delivered to final consumers. In *AEO98*, total delivered energy consumption in 1996 is estimated at 70.4 quadrillion Btu, compared with total primary energy consumption of 94.0 quadrillion Btu (Table 3). The difference comes from electricity-related generation and transmission losses and, consequently, is relatively small for the transportation sector, where little electricity is consumed. Although the delivered price of electricity per Btu generally is more than three times the delivered price of other energy sources, the convenience and efficiency of electricity use outweigh the price difference for many applications.

Because consumers base their fuel and equipment choices on performance at the point of use, the analysis of end-use energy consumption presented in this chapter focuses on energy delivered to final consumers. When consumers choose to purchase a particular type of energy-consuming equipment or to use a particular fuel, their decisions are based on the cost and performance characteristics of the technology, mandated efficiency standards, and energy prices. End-use energy prices include all the direct costs of providing energy to the point of use.

The distinction between end-use and primary energy consumption is an important one for the evaluation of efficiency standards and other energy policies. Reducing electricity demand through the use of more efficient technologies reduces primary energy consumption by a factor of three. In addition, although electricity at its point of use produces no carbon emissions, reductions in electricity use produce savings in emissions from the fuels used for its generation.

Figure 25. Projections of Primary Energy Consumption, 1990-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW.D080398B.

Table 3. Primary and End-Use Energy Consumption by Sector, 1996

Sector	End-Use Consumption		Primary Consumption	
	Quadrillion Btu	Percent of Total	Quadrillion Btu	Percent of Total
Residential	11.1	16	19.4	21
Commercial	7.5	11	15.0	16
Industrial	27.1	38	34.8	37
Transportation	24.7	35	24.9	26
Total	**70.4**	**100**	**94.0**	**100**

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

Integrated Energy Market Analysis

The analysis in this report is a fully integrated analysis of U.S. energy markets, representing the interactions of energy supply, demand, and prices across all fuels and sectors. For example, initiatives to lower energy consumption may lower the prices of the energy supplied, causing some offsetting increase in energy consumption. An integrated market analysis can capture such feedback effects, which may be missed in an analysis that focuses on end-use demand for energy without accounting for impacts on energy prices.

The Energy Information Administration's *Annual Energy Outlook 1998* (*AEO98*), includes results from a number of alternative sensitivity cases in addition to its reference case projections. Sensitivity cases generally are designed by varying key assumptions in one of the demand, conversion, or supply modules of the National Energy Modeling System (NEMS), in order to isolate the impacts of the revised assumptions. For example, the high technology sensitivity cases for the end-use demand sectors in *AEO98* do not include any feedback effects from energy prices, and energy consumption in each sector is lower than in the reference case solely due to the revised assumptions about technology costs and efficiencies. The sensitivity cases described in this report, in contrast, were combined into an integrated analysis. As a result, lower energy consumption in the high technology case leads to lower energy prices, which in turn produce some offsetting increases in consumption.

Carbon emission reduction targets and carbon prices further complicate the integrated market analysis. In the high technology sensitivity cases presented in this chapter, the carbon reduction targets are the same as those in the comparable cases that use the *AEO98* reference case technology assumptions. For example, the 9-percent-above-1990 (1990+9%) case and the 1990+9% high technology sensitivity case have the same carbon emissions target. The effect of the high technology assumptions is to lower the projected carbon price that would be required to achieve the same level of carbon emissions, which also reduces the delivered price of fuel. With lower carbon prices, adverse impacts on the macroeconomy and on energy markets are moderated. Assuming that the technological advances posited in the high technology cases for the various end-use sectors could in fact be achieved, energy consumption levels would not necessarily be lower in each sector. Rather, the carbon price would be lower, and it would be less costly to achieve a given emissions reduction target.

Residential Demand

Background

As the largest electricity-consuming sector in the United States, households were responsible for 20 percent of all carbon emissions produced in 1996, of which 63 percent was directly attributable to the fuels used to generate electricity for the sector. Electricity is a necessity for all households, and with electricity use per household growing at 1.5 percent per year since 1990, the projected increase in residential sector electricity consumption has become a central issue in the debate over carbon stabilization and meeting the goals of the Kyoto Protocol.

The number of occupied households is the most important factor in determining the amount of energy consumed in the residential sector. All else being equal, more households mean more total use of energy-related services. From 1980 to 1996, the number of U.S. households grew at a rate of 1.4 percent per year, and residential electricity consumption grew by 2.6 percent per year. In the reference case, the number of households is projected to grow by 1.1 percent per year through 2010, and residential electricity consumption is projected to grow by 1.6 percent per year. Strong growth in the South, which features all-electric homes more prominently than do other areas of the country, and the advent of many new electrical devices for the home have significantly contributed to high electricity growth since 1980. Although these trends are projected to continue through 2010, efficiency improvements—due in part to recent Federal appliance standards, utility demand-side management programs, building codes, and nonregulatory programs (e.g., Energy Star)—should dampen electricity growth somewhat as residential appliances are replaced with newer, more efficient models.

Within the residential sector, all of the major end-uses (heating, cooling, lighting, etc.) are represented by a variety of technologies that provide necessary services. Technologies are characterized by their cost, efficiency, dates of availability, minimum and maximum life expectancies, and the relative weights of the choice criteria—installed cost and operating cost. The ratio of the weight of installed cost to that of operation cost gives an estimate of the "hurdle rate" used to evaluate the energy efficiency choice.[24] When more emphasis is placed on installed cost, the hurdle rate is higher. The hurdle rates for residential equipment range from 15 percent for space heating technologies to more than 100 percent for some water heating applications. The range in part reflects differences in the way consumers purchase the two technologies. In the case of water heaters, for example, purchases tend to occur at the time of equipment failure, which tends to restrict the choice to equipment readily available from the plumber. Space conditioning equipment, on the other hand, is not used all year round, allowing some latitude in terms of timing the replacement of an older unit. It is assumed that residential consumers expect future energy prices to remain at the current level at the time of purchase when calculating the future operating cost of a particular technology.

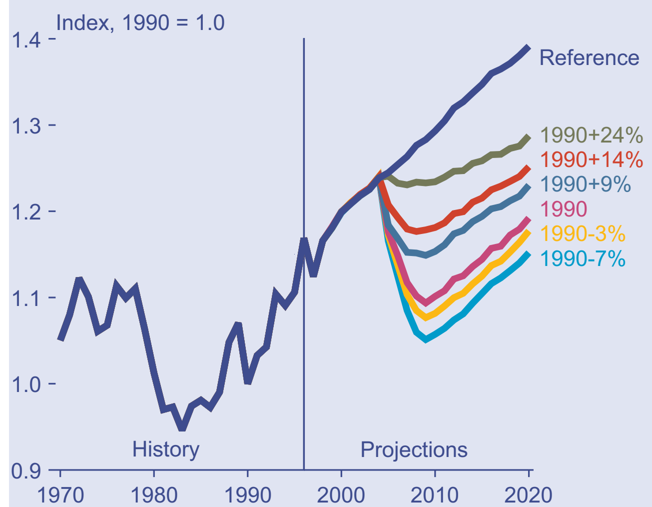
Technological advances and availability play a large role in determining future energy savings and carbon emission reductions. Even in today's marketplace, there exist many efficient technologies that could substantially reduce energy consumption and carbon emissions, however the relatively high initial cost of these technologies restricts their widespread penetration. Over time, the costs of more advanced technologies are assumed to fall as the technology matures, one example being natural gas condensing water heaters. In addition, technologies that are not available today but are nearing commercialization are assumed to become available in the future. Three technology menus are used in the analysis below: a reference technology menu, a high technology menu (reflecting more aggressive research and development), and a "frozen" menu limited to equipment available today. In all cases, the menu options and characteristics are fixed. In the high technology sensitivity case, for example, the cost of a condensing natural gas water heater is assumed to fall by almost 75 percent by 2005, relative to the reference case, and a natural gas heat pump water heater becomes available for purchase, by 2005.

In response to energy price changes, residential elasticities, defined as the percent change in energy consumed with a 1-percent change in price, range from -0.24 to -0.28 in the short run, depending on the fuel type, to -0.33 to -0.51 in the longer term. The elasticities reported here are derived from NEMS by a series of simulations with only one energy price varying at a time, beginning in 2000.[25] These price elasticities reflect changes in both the demand for energy services and the penetration rate of more efficient technologies. In the absence of energy price changes, energy intensity, as defined as delivered energy consumption per household, declines at an average rate of 0.5 percent per year through 2010. This non-price-induced intensity improvement reflects the efficiency gain brought about by ongoing stock turnover, equipment standards, new housing stock, and the future availability of new technologies.

Energy consumption, including the combustion of various fossil fuels, is the major source of U.S. carbon emissions. Energy use in the residential sector is greatly affected by year-to-year variations in seasonal temperatures, particularly in the winter, as illustrated by the decline in delivered energy use in 1990 (Figure 26), which was one of the warmest winters on record. The projections in this analysis assume normal seasonal temperatures over the 1996-2020 forecast period.

In the 3-percent-below-1990 (1990-3%) carbon reduction case, which assumes an emissions target of 3 percent below 1990 levels for the United States, a sharp drop in residential energy use is projected between 2005, when

Figure 26. Index of Residential Sector Delivered Energy Consumption, 1970-2020

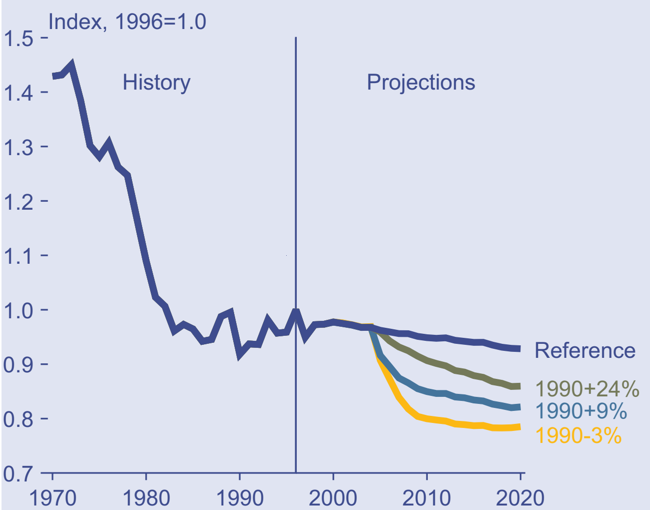


Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

[24]The "hurdle rate" for evaluating energy efficiency investments has also been referred to as the "implicit discount rate" (i.e., the empirically based rate required to simulate actual purchases—the one implicitly used). These rates are often much higher than would be expected if financial considerations alone were their source. Among the reasons often cited for relatively high apparent hurdle rates are uncertainty about future energy prices and future technologies, lack of information about technologies and energy savings, additional costs of adoption not included in the calculations, relatively short tenure of residential home ownership, hesitancy to replace working equipment, attributes other than energy efficiency that may be more important to consumers, limited availability of investment funds, renter / owner incentive differences, and builder incentives to minimize construction costs. For a good discussion of potential market barriers and the economics of energy efficiency decisions, see Jaffe and Stavins, "Energy Efficiency Investments and Public Policy," *The Energy Journal*, Vol. 15, No. 2 (1994), pp. 43-65.

the target is implemented, and 2010 (Figure 26). However, the projected decline is nearly identical to that seen historically from 1978 to 1983, in terms of both consumption and intensity (Figure 27). Housing starts, a major predictor of residential energy use, fell from 2.02 million units in 1978 to 1.062 million in 1982.[26] The drop in housing starts was tied directly to mortgage rates, which increased from 9.6 percent in 1978 to over 16 percent in 1981-1982. In addition, real energy prices to the residential sector increased by 87 percent from 1978 to 1982, similar to the 82-percent real price increase projected in the 1990-3% case. In the carbon reduction cases, delivered energy consumption in the residential sector never reaches its 1990 level, which has been used as a benchmark in setting carbon reduction targets. Given the uncertainty regarding technology and consumer behavior in a high-price energy world, additional sensitivities are examined here to analyze the effects of variations in the level of optimism associated with assumptions about both technology advances and consumer responsiveness.

Figure 27. Index of Residential Sector Delivered Energy Intensity, 1970-2020

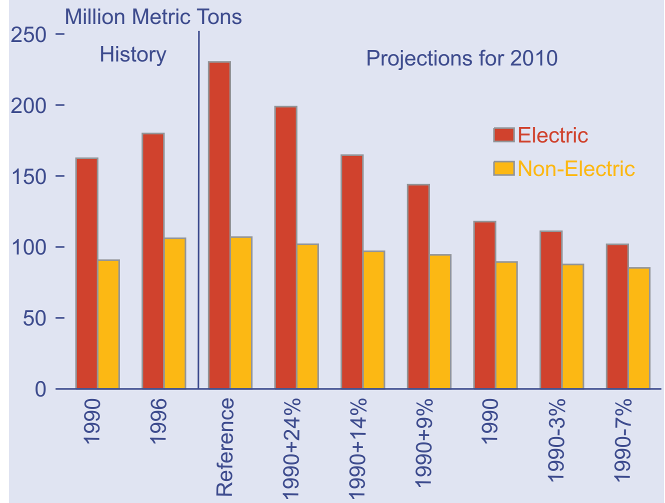


Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997) and Data Resources Incorporated. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Carbon Reduction Cases

Carbon emissions associated with electricity generation are the largest component of emissions from the residential sector, in terms of both the levels and projected growth in the reference case, and in terms of the projected declines in the carbon reduction cases. In the reference case, which does not include the Kyoto Protocol, 98 percent of the projected increase in residential sector carbon emissions by 2010 results from increasing electricity use and the fuels used for electricity generation. In the 1990+9% case, 87 percent of the sector's decline in carbon emissions is related to reduced electricity demand and changes in electricity generation (Figure 28). The following discussion focuses on the results of three carbon reduction cases—1990-3%, 1990+9%, and 24-percent-above-1990 (1990+24%)—in which carbon emissions, averaged across all energy sectors, reach targeted levels relative to 1990 in the 2008-2012 period.

Figure 28. Residential Sector Carbon Emissions, 1990, 1996, and 2010



Note: Electricity emissions are from the fossil fuels used to generate the electricity used in this sector.

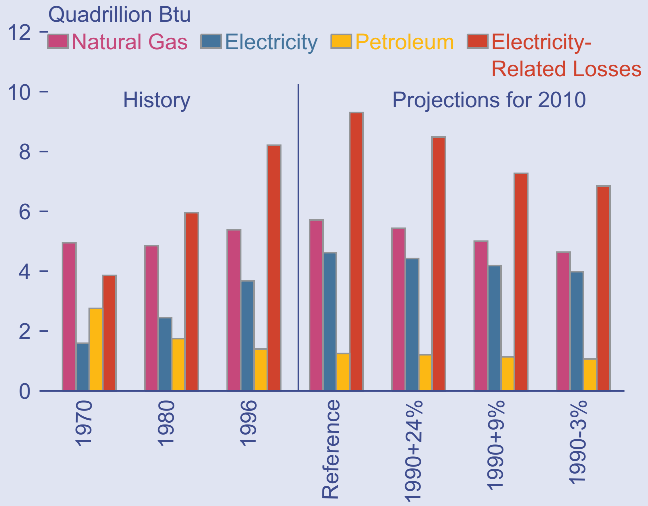
Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Although the use of electricity contributes most to the projected growth in emissions in the residential sector, natural gas consumption, which emits relatively low levels of carbon per Btu burned compared with coal (the major fuel used to generate electricity), is projected to remain the most important fuel in the sector as measured by delivered energy. Figure 29 shows delivered energy consumption by major fuel as well as the losses associated with electricity generation. On a delivered basis, natural gas use is projected to decrease the most in the three carbon reduction cases by 2010. Relative to the projected level of consumption in the reference case in 2010, delivered energy consumption is projected to be 10 percent lower in the 1990+9% case and electricity-related losses 22 percent lower. Of the 2.0 quadrillion Btu savings in electricity-related losses in 2010 in the 1990+9% case, 43 percent (0.9 quadrillion Btu) can be attributed to reduced electricity demand in the residential sector. The remaining 1.1 quadrillion Btu (57 percent) of the savings in electricity-related losses comes from efficiency gains and/or fuel switching for

[25] The long-run elasticities reflect the effects of altered prices after 20 years for the last year of the forecast, 2020.

[26] U.S. Bureau of the Census, *Construction Reports*, series C20.

Figure 29. Delivered Energy Consumption in the Residential Sector by Major Fuel, 1970, 1980, 1996, and 2010



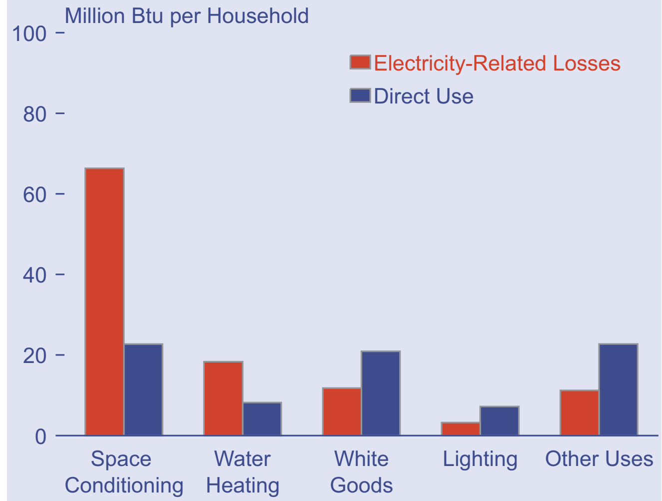
Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV. D080398B, and FD03BLW.D080398B.

electricity generation. Thus, changes in electricity supply, absent any major technological or behavioral changes in residential end use over the next 12 years, are the key to controlling carbon emissions for the residential sector.

Energy is used in the residential sector to provide a number of different services, which vary in end-use intensity (energy consumption per household) (Figure 30). Space conditioning (which includes heating, cooling, and ventilation) is clearly the most energy-intensive end use in the sector, and it accounts for most of the direct use of fossil fuels. "White goods" (which include refrigerators, freezers, dishwashers, clothes washers and dryers, and stoves), lighting, and other uses are almost entirely powered by electricity and, therefore, are responsible for most of the electricity-related losses.

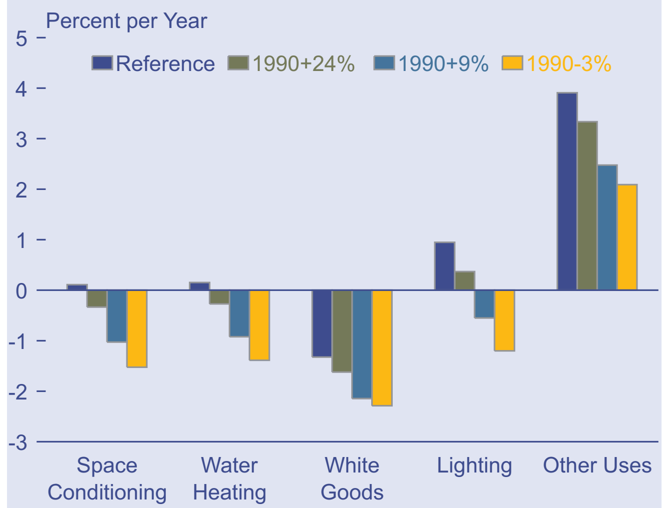
In the reference case, most of the projected growth in residential energy consumption between 1996 and 2010 comes from increasing use of miscellaneous electric devices, such as personal computers and home security systems (Figure 31). The rate at which energy consumption changes over time depends on factors such as equipment turnover rates, ability to control unit operation (thermostatic controls), energy prices, household size (people per house), housing unit size (square feet), and the efficiency of newly purchased appliances. Stock turnover can provide drastic reductions in energy intensity, even without future gains in appliance efficiency. On average, a new refrigerator purchased in 1995 used

Figure 30. Residential Sector Energy Use per Household, 1996



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

Figure 31. Average Projected Annual Growth in Residential Sector Energy Consumption by End Use, 1996-2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV. D080398B, and FD03BLW.D080398B..

62 percent less electricity than one purchased 20 years earlier.[27] Conversely, slow stock turnover can limit the role of energy efficiency gains in the future. Equipment purchased in the 1990s that lasts 20 years or more will not be eligible for replacement until after 2010.

With the exception of white goods, increases in total energy consumption for all the major residential energy services are projected from 1996 to 2010 in the reference case. The negative growth in total energy consumption for white goods results from a decline in energy use for

[27] Association of Home Appliance Manufacturers, *Fact Book 1996*.

refrigeration, as aggressive Federal efficiency standards[28] taking effect in 1993 and 2001 reduce the amount of energy needed to provide the same level of service. In the carbon reduction cases, increasing energy prices act to reduce the growth in energy consumption for all major services relative to their growth in the reference case. In the absence of mandatory standards, residential consumers traditionally have been reluctant to purchase highly efficient appliances. However, faced with the higher energy prices projected in the carbon reduction cases, it is expected that consumers will respond by purchasing more efficient appliances (Table 4). The extent of consumer response and its impact on average equipment efficiencies would also depend on the purchase price of the new equipment (the initial investment required).

Table 4. Change in Projected Average Efficiencies of Newly Purchased Residential Equipment in Carbon Reduction Cases Relative to the Reference Case, 2010
(Percent)

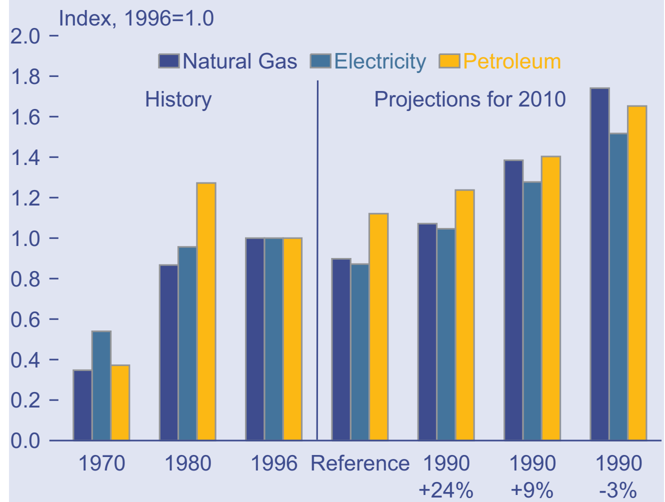
Technology	1990+24%	1990+9%	1990-3%
Air-Source Heat Pump	1.3	3.6	5.7
Electric Water Heater	0.3	2.4	13.6
Natural Gas Water Heater . .	1.1	3.7	4.8
Building Shell	1.0	3.3	5.5

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

In the reference case, the real (inflation-adjusted) prices of electricity and natural gas to residential consumers are projected to decline between 1996 and 2010 (Figure 32), by 8 and 10 percent, respectively. The outlook for prices in the carbon reduction cases, however, is much different. Without major changes in energy policy, technology, or consumer response, prices to the residential sector are expected to be as much as 94 percent higher in 2010 in the 1990-3% case. In response to the higher prices, total residential energy consumption is projected to decline by more than 20 percent by 2010 in the 1990-3% case.

The factors that contribute to lower consumption include behavioral responses, such as adjusting the thermostat or turning off the lights when leaving the room, and, to a lesser extent, the acquisition of more efficient appliances. The rate of improvement in average appliance efficiency is constrained by the rate of stock turnover. For example, it is not uncommon for major energy-using appliances, such as furnaces, to last for 30 years or more. More immediate responses to higher energy prices can be achieved through retrofits to improve the thermal efficiency of building shells. During the energy price shocks of the 1970s, for example, homeowners increased insulation levels substantially,[29] with the immediate effect of conserving energy and lowering energy bills. The potential for similar improvement between 1996 and 2010 is reduced, given the improvements already made.

Figure 32. Index of Residential Sector Energy Prices, 1970, 1980, 1996, and 2010



Sources: **History:** Energy Information Administration, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Sensitivity Cases

High and Low Technology. Technology improvements over time can take the form of increased efficiency, decreased cost, or both. To examine the effects of assumptions about the rate at which technologies will improve in the future, two sets of sensitivity cases were analyzed. The low technology sensitivity cases assume that none of the improvements assumed in the reference case will occur. In other words, future technologies are assumed to be "frozen" at their 1998 cost and efficiency levels. Technological improvement occurs in this case as older units are retired and are replaced with 1998 technologies. Engineering technology experts were consulted to develop the high technology case, which assumes more rapid advances than those in the reference case, due to research and development (Table 5).[30] In the high technology case, for example, the efficiency of the best available natural gas water heater is assumed to improve by 63 percent over the 1998 level by 2015, and the cost is assumed to decline by 15 percent,

[28] These standards represent updates to previous standards authorized by the National Appliance Energy Conservation Act of 1987.

[29] U.S. Department of Energy, *Progress in Residential Retrofit*, Based on Owens-Corning Marketing Research.

[30] Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998).

Renewables and Dispersed Electricity Generation

Dispersed renewable energy use in the residential sector includes wood, solar thermal, geothermal energy, photovoltaic cells, and fuel cells.[a] Wood is used as a main or secondary heating source in some households. Geothermal energy is used to power ground-source heat pumps, which exchange energy with below-ground earth or water, extracting heat in the winter and delivering heat to the earth (and cooling the building) in the summer. Solar thermal energy is used mainly to heat water for swimming pools and household use. Photovoltaics provide small-scale electricity generation, often in remote locations, using semiconductors to transform sunlight directly into electricity, which may be used for a variety of functions, such as water pumps or remote lighting systems. Fuel cells convert liquid fossil fuels into electricity through electrochemical processes.

The share and quantity of wood as a primary heating fuel in the residential sector has been falling for nearly two decades. In 1982, 6.7 percent of all U.S. households heated with wood, but its share fell to 3.2 percent in 1993. The aggregate quantity of wood consumed as primary heating in households has fallen as well, from 28.7 million cords in 1982 to 12.6 million cords in 1993.[b] The decline has resulted in part from local laws restricting wood burning. In addition, the convenience of natural gas heating and the decline in real oil and gas prices over the past decade have led many households to choose gas or oil over wood.

While wood has declined as a primary residential heat source, its use as a backup or secondary heat source has not. Wood use as a secondary heat source increased from 16 percent of households in 1980 to 20 percent in 1993, suggesting that wood stoves are being kept as backup heating systems. If the prices of other fuels rise significantly, however, the use of wood as a primary household heating fuel may well increase. In the reference case for this analysis, wood energy use is projected to be 0.61 quadrillion Btu in 2010. In the most stringent carbon reduction case (7 percent below 1990 levels), higher energy prices lead to wood use of 0.63 quadrillion Btu in 2010, increasing to 0.67 quadrillion Btu in 2020.

The market for solar energy systems has undergone substantial changes over the past three decades, largely as a result of the introduction, removal, and subsequent reintroduction of Federal energy tax credits for photovoltaic cells and solar thermal collection systems. With the introduction of a Federal tax credit in 1978, shipments of solar thermal collectors to the residential and commercial sectors nearly doubled to 10 million square feet from 5.8 million square feet in 1976. The annual growth inshipments averaged 8 percent per year until 1985, when the tax credits were repealed. Subsequently, shipments fell sharply from 19.1 million square feet in 1985 to 9.1 million in 1986. The energy tax credit was reintroduced for the commercial sector in 1986, followed by a small increase in shipments, but since 1991 there has been little growth in the industry. Residential sales of solar thermal systems are not expected to increase substantially in the reference case, given current tax policy and projected declines in real energy prices.

Domestic shipments in the photovoltaic market (including both dispersed and grid-connected system) have grown significantly since the 1980s, but they also were affected by the repeal of the tax credit. From 10,717 peak kilowatts shipped in 1983, shipments were down to 3,224 peak kilowatts in 1986 after the tax credit repeal, a 32-percent average annual decline.[c] The market recovered somewhat in the next decade, with 1992 shipments reaching 5,760 peak kilowatts. Since then, the industry has been developing steadily, particularly after 1992, with 23-percent average annual growth to 13,016 peak kilowatts shipped in 1996.

Fuel cells have the potential for future integration into both grid-connected and off-grid applications in every sector. When their cogenerative capabilities are used, capturing excess heat from the chemical reaction for space and water heating, fuel cell efficiencies can rise to two or three times those of typical energy combustion plants, emitting only half the amount of carbon dioxide per unit of useful energy obtained.[d]

To date, fuel cells have not been used extensively. With their relatively recent development and only one major manufacturer worldwide, there are only 160 medium-sized (200-kilowatt) units in use.[e] Smaller units have been tested in the space program and in the automobile industry, but the first unit designed for the residential market was not built until 1998.[f] Fuel cells are a promising technology for the residential sector, but their current high costs do not favor extensive market penetration. Costs can be expected to fall as production volumes increase, and depending on the timing and extent of the cost reductions, fuel cells could become an important source of dispersed electricity generation.

[a] Dispersed renewable energy is the direct use of power from a renewable energy system such as a photovoltaic array, disconnected from the electric power grid. The production and sale of electricity from utilities using renewable energy fuels are not included.

[b] Energy Information Administration, *Housing Characteristics 1980*, DOE/EIA-0312 (Washington, DC, June 1982), p. 101; *Housing Characteristics 1982*, DOE/EIA-0314(82) (Washington, DC, August 1984), pp. 47-98; and *Household Energy Consumption and Expenditures 1993*, EIA/DOE-0321(93) (Washington, DC, October 1995), pp. 37-62.

[c] Energy Information Administration, *Renewable Energy Annual 1997*, Vol. 1, DOE/EIA-0603(97/1) (Washington, DC, February 1998), p. 19.

[d] When byproduct heat is used, average total efficiency of the system increases to approximately 80 percent, significantly more than a standard coal-fired utility plant, which operates at around 30 percent efficiency. Source: U.S. Department of Energy, Office of Fossil Energy, Technology Center, *Climate Change Fuel Cell Program*, NG001.1197M.

[e] Fred Kemp, Manager of Government Programs, International Fuel Cells (South Windsor, CT), personal communication, August 1998.

[f] *New York Times* (June 17, 1998).

Table 5. Cost and Efficiency Indexes of Best Available Technologies for Selected Residential Appliances, 2015
(1998 Values = 1.00)

Technology	Cost: 1990+9% Low Technology	Cost: 1990+9%	Cost: 1990+9% High Technology	Efficiency: 1990+9% Low Technology	Efficiency: 1990+9%	Efficiency: 1990+9% High Technology
Air-Source Heat Pump	1.00	0.99	0.98	1.00	1.09	1.18
Ground-Source Heat Pump	1.00	0.86	0.56	1.00	1.05	1.08
Natural Gas Heat Pump	1.00	0.81	0.75	1.00	1.00	1.00
Natural Gas Water Heater	1.00	0.76	0.85	1.00	1.00	1.63
Solar Water Heater	1.00	1.00	0.73	1.00	1.00	1.67
Electric Water Heater	1.00	1.00	0.73	1.00	1.04	1.17

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A, computed from *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998).

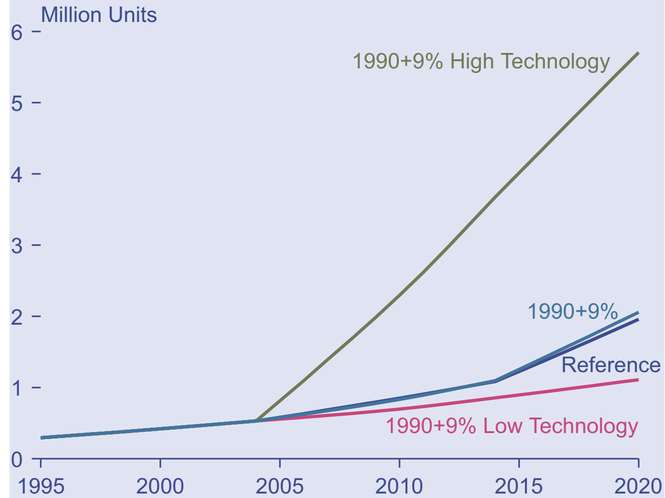
while ground-source heat pumps, which do not realize much gain in efficiency, are assumed to decline in cost by 44 percent in the high technology case by 2015.

Ground-source heat pumps, which draw stored heat from the ground beneath the frost line, provide an efficient and comfortable (in terms of delivered heat) alternative to the more common air-source heat pumps. The cost of the unit and the placement of the ground loop have been major barriers to wide market acceptance, however. Different levels of stocks of ground-source heat pumps are projected in the reference case, the 1990+9% carbon reduction case, and the 1990+9% case low and high technology cases (Figure 33). Given that significant market acceptance is seen only in the high technology case, it can be concluded that the costs associated with the technology restrict its acceptance. Space heating technologies, in general, have the lowest hurdle rates (15 percent) of all residential appliances, primarily because of the large energy costs of home heating, relative to other energy-using services.

Figure 34 shows that improvements in technology can indeed dampen the impact carbon restrictions have on residential energy prices. Given the amount of time needed for technology to penetrate the market, one would expect that over a longer period of time, the prices in the high technology sensitivity would fall relative to the other cases. After 2008, prices in the high technology sensitivity begin to fall, as reduced energy demand caused by more efficient technology penetrating the market begin to make an impact. Relative to the price in the 1990+9% case, the composite real residential energy price in 2010 is 11 percent less in the high technology case. Conversely, if technology were frozen at the level available in 1998, 2010 prices are expected to be 17 percent higher than the 1990+9% case, indicating that energy efficiency plays a significant role in the cases with reference technology assumptions.

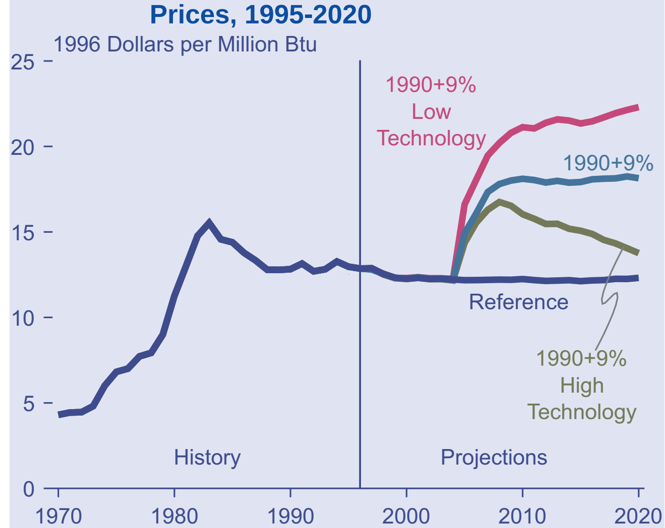
Energy fuel expenditures are a good indication of the success that technological advancement achieves in

Figure 33. Projected Stocks of Ground-Source Heat Pumps, 1995-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

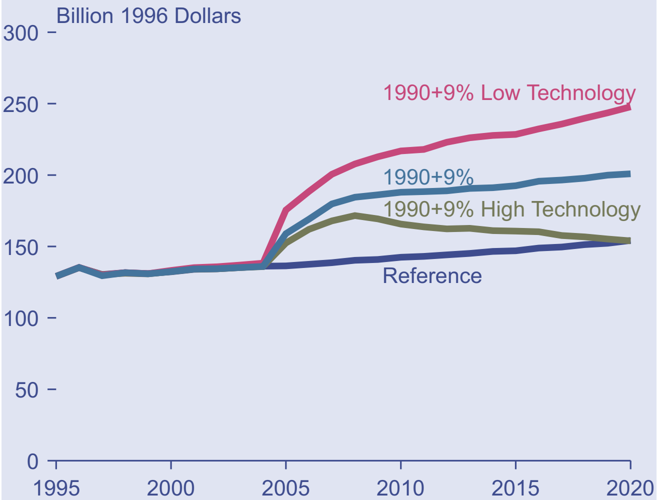
Figure 34. Average Residential Sector Energy Prices, 1995-2020



Sources: **History:** Energy Information Administration, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

lessening the impact on the consumer in a carbon-restricted environment. Figure 35 details residential sector energy expenditures for the 1990+9% case and technology sensitivities. For the high technology sensitivity, energy expenditures in 2020 are 23 percent less than those realized in the 1990+9% case, saving consumers over $440 billion from 2008 to 2020.

Figure 35. Projected Energy Expenditures in the Residential Sector, 1995-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

Increased Consumer Response. Residential energy consumers have traditionally been reluctant to invest in energy efficiency, even with ample financial benefits. Many market barriers tend to create what are known as high hurdle rates for consumer investments in energy efficiency. As of 1993, 35 percent of all homes were occupied by renters,[31] most of whom were responsible for paying energy bills but not for purchasing major energy-consuming appliances. Such households tend to buy the least expensive equipment on the market, which also tends to be the least energy-efficient. The same reasoning can be applied to many newly constructed homes as well, because the builders, not the occupants, are tasked with equipping them with most of the major energy-using appliances. Other barriers include equipment availability (e.g., whether plumbing contractors have high-efficiency water heaters available when they make service calls) and lack of information.

To examine the effects that lower hurdle rates could have on both energy prices and expenditures in the carbon reduction cases, and at the same time differentiate those effects from the effects of technological advances, an increased consumer response sensitivity case was analyzed. This sensitivity case includes assumptions of lower discount rates, higher short-run elasticities of demand, greater inclination to change fuels when purchasing equipment, and lower growth in miscellaneous electricity use.[32]

Impacts of Increased Consumer Response and Advanced Technology. In order to gauge the impact of assumptions regarding technological advancement and consumer behavior with respect to delivered energy consumption, sensitivity cases were analyzed relative to the 1990+9% case where delivered energy prices were the same across all cases. These cases serve to isolate the impact of each of the key variables separately, and to understand the impact of implementing the sensitivities simultaneously. This section evaluates the relative impact that each of these concepts could have on future energy intensity at a price level realized in the 1990+9% case.

Changes in technological development and the value residential consumers place on energy related issues can significantly affect the pattern of energy consumption—and carbon emissions—in the future. The availability of high-efficiency technologies in itself does not guarantee increased energy efficiency. Without the willingness of consumers to purchase the more efficient products, which usually cost significantly more, technology may not have much of an impact on future energy consumption patterns. Conversely, in a world where energy conservation was of paramount concern to energy consumers, yet at the same time high-efficiency products were unavailable, future energy consumption patterns would probably not be greatly affected either.

Given the detailed nature regarding technological development and consumer choice with regards to different technologies, it is important to analyze the results at the technology level, as well as the overall level. With nearly 40 million households (38 percent) using electric water heaters in 1995, and given the relatively high intensity associated with using electric water heaters, the projected impact of increased energy efficiency can have a large impact on future electricity use for this service. Electric resistance water heaters have traditionally exhibited slow growth in energy efficiency. In fact, the highest efficiency unit available today is not likely to see any efficiency improvement due to thermal limits and diminishing returns on controlling heat loss.[33] This implies that future gains in efficiency for electric water

[31] Energy Information Administration, *Housing Characteristics 1993*.

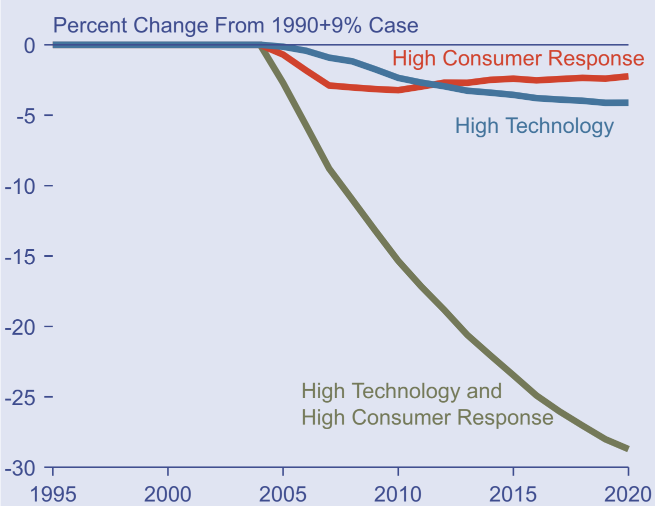
[32] Assumptions include lowering hurdle rates to 15 percent real, increasing the price sensitivity parameters to switch fuels, increasing short-run price elasticities from -0.25 to -0.40, and decreasing miscellaneous electricity penetration.

[33] Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998).

heating must be achieved through the increased penetration of electric air-source heat pump water heaters, which achieve higher efficiency levels by extracting heat from the air surrounding the unit. The current cost of this technology, however, is several times that of a traditional resistance unit, and coupled with observed implicit discount rates of over 100 percent, has led to very limited market penetration.

Assumptions regarding technological advances through improved performance and reduced cost, as well as changes in consumer behavior, can significantly affect the market penetration of emerging technologies. Figure 36 details the relative importance of varying assumptions regarding technological advances and consumer behavior with respect to the intensity of the electric water heating end use.[34] Relative to the 1990+9% case, intensity drops faster when assumptions regarding consumer behavior are changed, as compared to changes in technology characteristics. Over time, however, the intensity decline in the technology case outpaces that projected for the behavior case as more and more equipment is purchased at higher efficiency levels. Combining both sets of assumptions, that is, changing both technology characteristics and consumer behavior together, results in over a 25 percent decline in energy intensity for electric water heating over time. This indicates that a combination of both technology and consumer behavior changes can bring about large declines in energy intensity for this service, all else being equal.

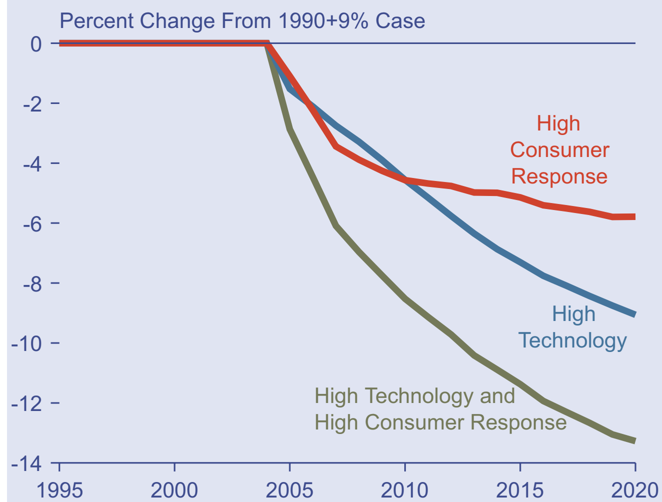
Figure 36. Changes From Reference Case Projections of Energy Intensity for Residential Water Heating in Three Sensitivity Cases, 1995-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B, KYTECH.D081098C, KYBHAVE.D081098D, and KYBOTH.D081098A.

Overall annual energy consumption per household, or energy intensity, for these sensitivity cases follows the general pattern described for electric water heating. Again, technology advances exhibit a greater potential for energy intensity decline in the long run (Figure 37), but the combination of the two cases yields roughly half of the intensity decline projected for electric water heating. This is due to the fact that all other major technologies exhibit much lower observed hurdle rates and less range in terms of high-efficiency products. For example, natural gas furnaces, the largest energy consuming product class in terms of delivered energy in the U.S., has already matured in terms of product efficiency, and at the same time hurdle rates are at 15 percent.

Figure 37. Changes From Reference Case Projections of Residential Energy Consumption in Three Sensitivity Cases, 1995-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B, KYTECH.D081098C, KYBHAVE.D081098D, and KYBOTH.D081098A.

Commercial Demand

Background

The commercial sector consists of businesses and other organizations that provide services. Stores, restaurants, hospitals, and hotels are included, as well as a wide range of facilities that would not be considered "commercial" in a traditional economic sense, such as public schools, correctional institutions, and fraternal organizations. In the commercial sector, energy is consumed mainly in buildings, and relatively small amounts are used for services, including street lights and water supply.

[34]Intensity here is the average annual consumption of electricity for water heating in homes with electric water heaters.

The commercial sector is currently the smallest of the four demand sectors in terms of energy use, accounting for 11 percent of delivered energy demand in 1996. The commercial sector is also responsible for fewer carbon emissions than the other sectors, emitting 230 million metric tons, or 16 percent of total U.S. carbon emissions, in 1996. The sector has a larger share of emissions than its share of energy use because of the importance of commercial electricity use. The emissions associated with electricity-related losses are included in the calculation of emissions from electricity use.

Several factors determine energy use and, consequently, carbon emissions in the commercial sector. One of the most important is floorspace. Building location, age, and type of activity also affect commercial energy use. Currently, total commercial floorspace in the United States exceeds the area of the State of Delaware and amounts to about 200 square feet for every U.S. resident. Mercantile (retail and wholesale stores) and service businesses are the most common type of commercial buildings, and offices and warehouses are also common.[35]

Because of the relatively long lives of buildings, the characteristics of the stock of commercial floorspace change slowly. Over half of the commercial buildings in the United States were built before 1970, and the reference case used for this analysis projects that total commercial floorspace will grow at about the same rate as population, 0.8 percent annually, through 2020. This limits the effects that new, more efficient building practices can achieve in the near term, but as time passes and building stock "turnover" occurs, current and future building practices will have a greater effect on commercial energy use.

The composition of end-use services is another determinant of the amount of energy consumed and the type of fuel used. The majority of energy use in the commercial sector is for lighting, space heating, cooling, and water heating. In addition, the proliferation of new electrical devices, including telecommunications equipment, personal computers, and other office equipment, is spurring growth in electricity use. Electricity use currently accounts for 45 percent of delivered energy consumption in the sector, and that share is projected to grow to about 48 percent by 2010 in the reference case.

Consideration of end-use services leads to another determining factor in commercial energy consumption—the effects of turnover and change in end-use technologies. The stock of installed equipment changes with normal turnover as old, worn-out equipment is replaced and new buildings are outfitted with newer versions of equipment that tend to be more energy-efficient. Equipment with even greater energy efficiency is expected to be available to commercial consumers in the future. Energy prices have both short-term and long-term effects on commercial energy use. Fuel prices influence energy demand in the short run by affecting the use of installed equipment and in the long run by affecting the stock of installed equipment.

Legislated efficiency standards also affect energy use, by imposing a minimum level of efficiency for purchases of several types of equipment used in the commercial sector. Two mandates currently affect commercial appliances: the National Energy Policy Act of 1992 (P.L. 102-486, Title II, Subtitle C, Section 342), which specifically targets larger-scale commercial equipment and fluorescent lighting, and the National Appliance Energy Conservation Amendments (NAECA), which affect commercial buildings that install smaller residential-style equipment. Examples include standards for heat pumps, air conditioning units, boilers, furnaces, water heating equipment, and fluorescent lighting.

Effects of Technology Availability and Choice

The degree to which energy-efficient equipment can affect energy consumption, and in turn carbon emissions, in the commercial sector is limited by the level of efficiency available to commercial consumers and the rate at which more efficient equipment is purchased. Technologies for all the major end uses (lighting, heating, cooling, water heating, etc.) are defined by their installed cost, operating cost, efficiency, average useful life, and first and last dates of availability. These parameters are considered, along with fuel prices at the time of purchase, in the selection of technologies that provide end-use services. Commercial consumers are not assumed to anticipate any future changes in fuel prices when choosing equipment. The commercial sector encompasses a wide variety of buildings, and not all consumers will have the same requirements and priorities when purchasing equipment. Major assumptions that take these differences in behavior into account and affect commercial technology choices are described below.

In making the tradeoffs between equipment cost and equipment efficiency, the purchase behavior of the commercial sector is represented by distributing floorspace over a variety of hurdle rates. Rates of return on investments in energy efficiency (referred to in financial parlance as "internal rates of return") are required to meet or exceed the hurdle rate. Floorspace is distributed over hurdle rates that range from a low of about 18 percent to rates high enough to cause choices to be made solely by

[35]General characteristics of the commercial sector provided in the above paragraphs are from Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures*, DOE/EIA-0318(95) (Washington, DC, September 1998).

minimizing the costs of installed equipment (i.e., future potential energy cost savings are ignored at the highest hurdle rate).[36] The distribution of hurdle rates used in all the cases for this analysis is not static: as fuel prices increase, the nonfinancial portion of each hurdle rate in the distribution decreases.[37]

For a proportion of commercial consumers, it is assumed that newly purchased equipment will use the same fuel as the equipment it replaces. This proportion varies by building type and by type of purchase—whether it is for new construction, to replace worn-out equipment, or to replace equipment that is economically obsolete. Purchases for new construction are assumed to show the greatest flexibility of fuel choice, while purchases for replacement equipment have the least flexibility. For example, when space heating equipment in large office buildings is replaced, 8 percent of the purchasers are assumed to consider all available equipment using any fuel or technology, while 92 percent select only from technologies that use the same fuel as the equipment being replaced. The proportions used are consistent with data from EIA's Commercial Buildings Energy Consumption Survey and from published literature.[38] Considerations such as owner versus developer financing, past experience, ease of installation, and fuel availability all play a role in fuel choice. This assumption also accounts for some of the factors that influence technology choices but cannot be measured. For example, a hospital adding a new wing has an economic incentive to use the same fuel that is used in the existing building.

The availability and costs of advanced technologies affect the degree to which they can contribute to future energy savings and carbon emission reductions. Many efficient technologies currently available to commercial consumers could significantly reduce energy consumption; however, their high purchase costs and the current low level of fuel prices have limited their penetration to date. As more advanced technologies mature over time, their costs are expected to decline (compact fluorescent lighting is an example). New technologies, beyond those available today, may also enter the market in the future. For example, the high technology sensitivity case, described below, assumes that by 2005 a triple-effect absorption natural-gas-fired commercial chiller will be widely available, and that "typical" heat pump water heaters will cost 18 percent less than assumed in the reference case.

The combination of technology and behavior assumptions determines the commercial-sector price elasticity for each of the major fuels—that is, how commercial-sector demand projections are affected by changes in energy prices. Specifically, the commercial-sector price elasticity for a particular fuel is the percent change in demand for that fuel in response to a 1-percent change in its delivered price. In the reference case, short-run price elasticities for fuel use in the commercial sector are -0.34 for electricity, -0.39 for natural gas, and -0.39 for distillate fuel oil. Long-term price elasticities in the reference case are higher, reflecting changes in both the use of existing equipment and the adoption rates for more efficient equipment: -0.36 for electricity, -0.44 for natural gas, and -0.45 for distillate fuel oil.[39] The similarity of the short-run and long-run elasticities for electricity has two main causes. First, electric equipment becomes more efficient even with the reference case assumptions, thus reducing opportunities for further reductions when prices are higher. For example, electric lighting efficiency in the reference case increases on average by 0.6 percent per year from 1996 through 2020. Electric space cooling and ventilation improve on average by 1.1 and 0.7 percent per year, respectively, over the same period. Second, miscellaneous electric end uses capture a growing share of commercial electricity consumption and exhibit the same response in the long run as in the short run. Building codes, equipment standards, and improvements in technology costs and performance contribute to reduced energy intensity in the commercial sector (i.e., annual energy consumption per square foot of floorspace) even in the absence of price changes. With constant real energy prices, energy intensity declines on average by 0.1 percent per year through 2010.

Carbon Reduction Cases

In the 1990-3% case, commercial sector energy use in 2010 is projected to be below the 1996 level (Figure 38), and carbon emissions attributable to the commercial sector are projected to be 29 percent below their 1990 levels (Figure 39), despite 1-percent annual growth in commercial floorspace from 1996 to 2010. Projected fuel prices in 2010 in the 1990-3% case are more than twice as high as the reference case projection, and they are higher in real terms than they have been in any year since 1980 (Figure 40). As a result, energy consumption in 2010 is 22 percent lower in the 1990-3% case than in the reference

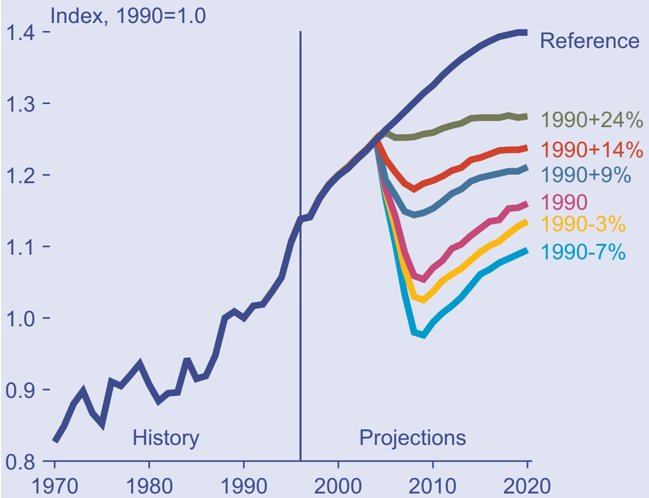
[36]The hurdle rates consist of both financial and nonfinancial components, as described for the residential sector.

[37]For the purposes of this study, the financial portion of the hurdle rates is considered to be 15 percent in real terms.

[38]Current assumptions use an analysis of data from EIA's 1992 commercial buildings survey. Sources for data on consumer behavior are listed on page A-18 of Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(98) (Washington, DC, January 1998).

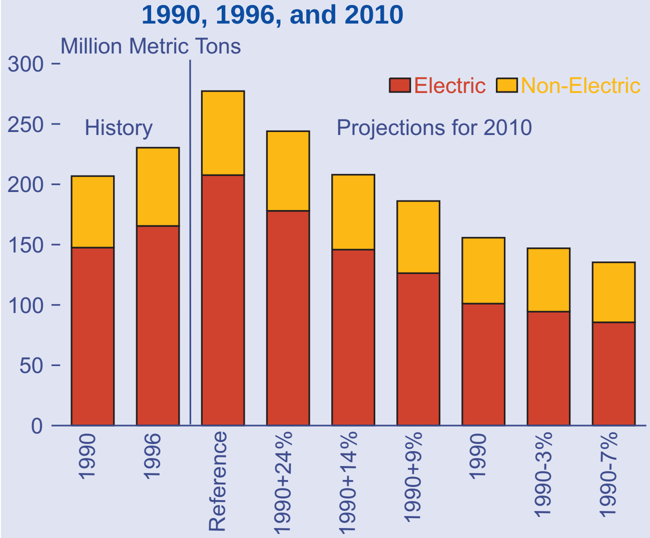
[39]As in the residential model, the long-run elasticities are for 2020 and represent the effects after 20 years of altered price regimes.

Figure 38. Index of Commercial Sector Delivered Energy Consumption, 1970-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 39. Commercial Sector Carbon Emissions, 1990, 1996, and 2010

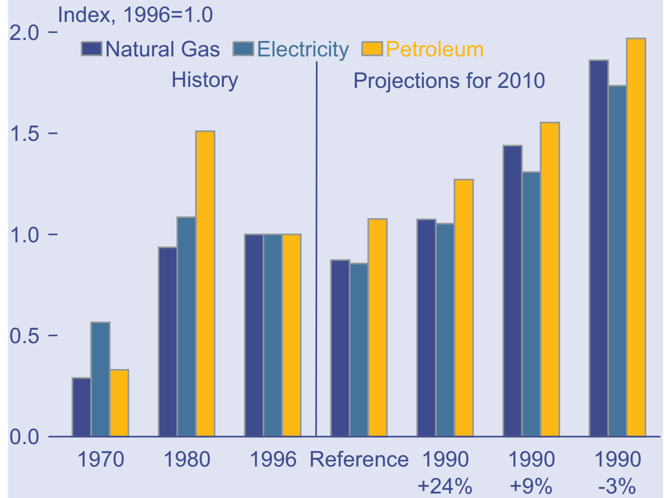


Note: Electricity emissions are from the fossil fuels used to generate the electricity used in this sector.

Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW.D080398B.

case, and expenditures for energy purchases are 52 percent higher. Energy consumption starts to increase again later in the 1990-3% case, as demand reductions lead to a decline in fuel prices. Energy consumption in the 1990+24% and 1990+9% cases does not rebound as much, because prices do not fall at the rate seen in the 1990-3% case.

Figure 40. Real Prices for Delivered Energy in the Commercial Sector by Fuel, 1970, 1980, 1996, and 2010

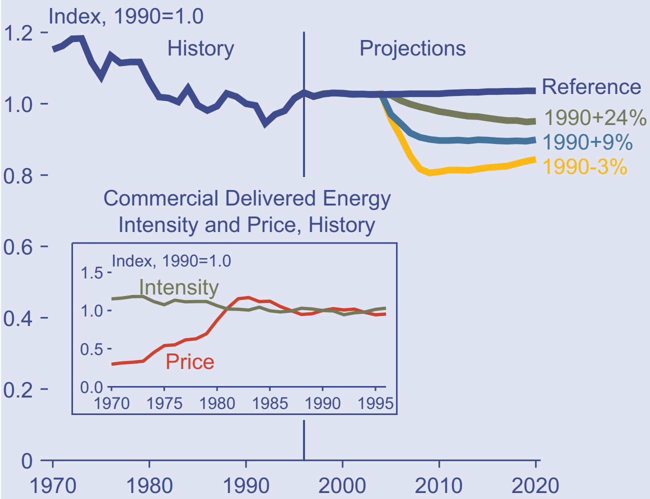


Sources: **History:** Energy Information Administration, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Floorspace expansion in the commercial sector will lead to growth in energy consumption if other factors remain the same. Figure 41 removes the effects of floorspace growth by presenting commercial energy intensity in terms of delivered energy consumption per square foot of commercial floorspace. Although total energy consumption continued to increase when energy prices were rising from 1970 through 1982, commercial energy intensity declined by about 12 percent. Delivered energy intensity in the reference case is projected to remain essentially flat throughout the forecast. Projected commercial sector growth is offset by the availability and continued development of energy-efficient technologies, existing equipment efficiency standards, and voluntary programs such as those for the Climate Change Action Plan. In the carbon reduction cases, with higher energy prices, the energy intensities projected for 2010 are below the 1996 level. The projections for commercial delivered energy intensity in 2010 in the 1990+24%, 1990+9%, and 1990-3% cases are 5 percent, 13 percent, and 21 percent below the reference case projection, respectively.

When energy prices rise, consumers are expected to reduce energy use by purchasing more efficient equipment and by altering the way they use energy-consuming equipment. In addition to buying more efficient boilers and chillers, commercial customers in the 1990-3% case are expected to choose more heat pumps, heat pump water heaters, and efficient lighting technologies than they would in the reference case (Table 6). The same trends toward purchasing efficient technologies and monitoring energy use are projected in the 1990+9% case and in the 1990+24% case, but to a lesser degree than projected for the 1990-3% case.

Figure 41. Index of Delivered Energy Intensity in the Commercial Sector, 1970-2020



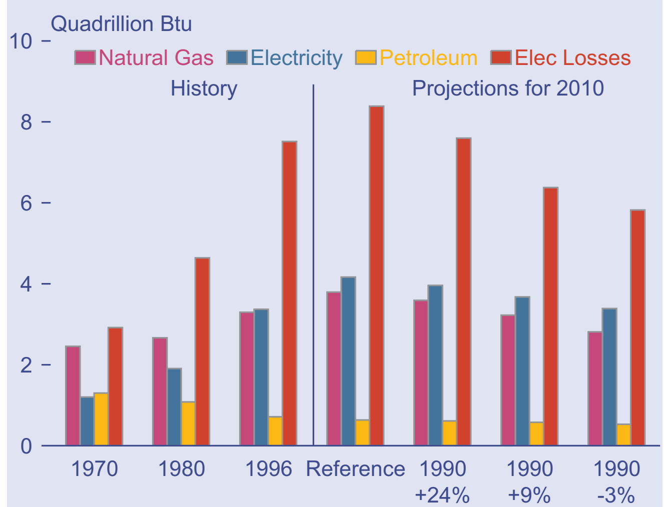
Sources: **History:** Energy Information Administration (EIA), *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997); EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997); and EIA, Commercial Buildings Energy Consumption Survey 1992 Public Use Data. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

The adoption of more efficient technologies reflects the reaction to rising fuel prices and a change in the way commercial consumers are expected to look at purchase decisions involving energy efficiency if carbon emissions are severely limited. Most commercial consumers give some consideration to fuel costs when buying equipment. A significant increase in fuel prices is expected to cause consumers to give energy costs greater weight in the purchase decision, by seeking out more information about energy efficiency options and by accepting a longer time period to recoup the additional initial investment typically required to obtain greater energy efficiency. While taking client comfort and employees' working conditions into consideration, commercial energy consumers would also be expected to turn thermostats down (up) a few degrees during cooler (warmer) weather and to be more conscientious about turning off lights and office equipment not in use.

The vast majority of the projected commercial sector reductions in carbon emissions in the carbon reduction cases are related to electricity use (see Figure 39). Two factors contribute to electricity-related carbon savings: reductions in the level of carbon emitted during the generation of a given amount of electricity (as discussed in Chapter 4), and reductions in electricity consumption. The projections for delivered electricity consumption in the commercial sector in 2010 for the 1990-3% and 1990+9% cases are 19 percent and 12 percent lower, respectively, than the reference case projection (Figure 42), and the 1990+24% case is 5 percent lower.

Historically, steady growth in electricity consumption has been seen in the commercial sector during times of both rising and falling prices. The growth has resulted in part from expansion in the sector and, more importantly, from an increasing number of end uses for electricity (i.e., increasing electricity intensity). The reference case projects further growth in electricity use between 1996 and 2010. In the 1990-3% case, however,

Figure 42. Delivered Energy Use and Electricity-Related Losses in the Commercial Sector, 1970, 1980, 1996, and 2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV. D080398B, and FD03BLW.D080398B.

Table 6. Change in Projected Penetration Rates for Selected Technologies in the Commercial Sector Relative to the Reference Case, 2010
(Percent)

Technology	1990+24%	1990+9%	1990-3%
High-Efficiency Boiler	19	97	205
Air-Source Heat Pump	2	9	10
Ground-Source Heat Pump	0	27	150
High-Efficiency Chiller	4	18	23
Heat Pump Water Heater	29	102	167
Compact Fluorescent Lights	6	14	24
Electronic Ballast Fluorescent Lights With Reflectors or Controls	14	26	32

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

the electricity consumption projected for 2010 falls to 1996 levels. The growth in commercial sector electricity intensity is projected to slow in the reference case for the same reasons that apply to energy intensity, and further reductions are expected in the carbon reduction cases.

The projected share of total end-use energy services that each major fuel provides to the commercial sector in 2010 is fairly stable across the different carbon reduction cases, and each fuel's share of energy consumption within specific end uses (space heating, cooling, water heating, etc.) shows little change. Electricity does increase slightly in share, however—up to 2 percentage points in 2010 in the 1990-3% and 7-percent-below-1990 (1990-7%) cases relative to the reference case.

Because the carbon prices required to meet emissions reduction targets cause a greater percentage increase in natural gas prices than electricity prices relative to those in the reference case, commercial consumers are expected to curtail their use of equipment powered by natural gas more than their use of electrical equipment. In addition, because of its critical nature, the usage pattern of existing commercial refrigeration equipment is not assumed to change in response to price changes, limiting projected reductions in electricity use for refrigeration to those caused by potential earlier retirements and purchases of more efficient equipment when prices are higher.

Finally, the fastest-growing commercial end uses, under reference case assumptions, include office equipment and miscellaneous devices powered by electricity (e.g., telecommunications equipment, medical imaging equipment, ATM machines), which are continuing to penetrate the commercial sector. Although electricity consumption for these end uses would be responsive to the price signals resulting from emissions reduction efforts, their growth still is expected to be faster than growth in the end uses that consume fossil fuels (primarily space heating and water heating).

The expected effects of carbon emission reduction efforts on the average efficiencies of equipment stocks in the commercial sector are exemplified by the projections for natural-gas-fired space heating equipment. In the reference case, the average efficiency of natural gas space heating systems in the commercial sector is projected to increase by 0.6 percent per year through 2010, and gas heating equipment purchased in 2005 is projected to be about 6.4 percent more efficient than the average system in use at that time. The 1990+24% case projects the same level of efficiency improvement and purchased efficiency. With 2010 natural gas prices expected to be near 1996 levels in this case (see Figure 40), there is little incentive for purchasers to invest additional capital in more efficient gas heating systems. In the 1990+9% case, however, the projected higher gas prices yield a projected 0.7-percent annual increase in average stock efficiency and an average efficiency for new equipment purchases in 2005 that is 7.2 percent higher than the stock average. Similarly, in the 1990-3% case, the average stock efficiency for gas heaters in the commercial sector increases by 0.8 percent per year, and new gas heating systems are 7.5 percent more efficient, on average, than the stock average in 2005. Heating systems typically are purchased only for new construction, for major renovations, or when an existing system needs to be replaced. Once in place, they typically last over 20 years. Therefore, the energy savings realized from purchases of more efficient equipment take time to accumulate.

Sensitivity Cases

Sensitivity case assumptions were developed for the 1990+9% case, to examine uncertainties about technology development in the commercial sector. Similar assumptions were developed for each of the demand sectors, and results were derived from integrated model runs requiring the entire U.S. energy system, not the commercial demand sector individually, to meet the specified emission reduction goals. Much different results might be expected if only commercial sector assumptions were modified and/or only the commercial sector was required to meet a specific emissions target, independent from other demand sectors and utilities.

The low technology sensitivity case assumes that all future equipment purchases will be made only from the equipment available to commercial consumers in 1998, and that commercial building shell efficiencies will remain at 1998 levels. Alternatively, the high technology sensitivity assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies.[40] The high technology sensitivity case includes technologies with higher efficiencies and/or lower costs than those assumed to be available in the reference case.

The projected carbon prices and fuel prices in the different sensitivity cases (Table 7) reflect the possible impacts that changes in the level of technological progress, across all sectors, may have on the fuel costs required for the United States to meet a specific emissions level. Different actions expected in the residential, commercial, industrial, transportation, and electricity generation sectors all contribute to meeting the emissions target. The combination of these actions results in the projected carbon prices, as each sector is

[40] Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998).

Photovoltaics and Fuel Cells

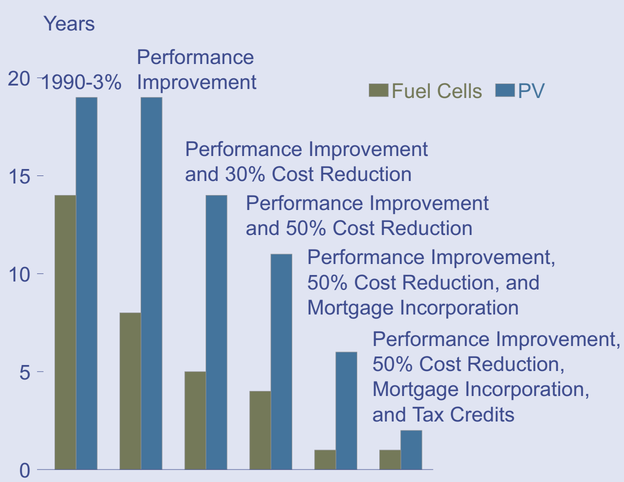
In every carbon reduction case considered in this report, neither photovoltaics nor fuel cells are projected to gain significant market penetration, because of their high costs. With payback periods of more than 20 years, the success of these technologies seems largely dependent on reducing production costs and increasing efficiency (which would result in further cost reductions for the consumer). Federal financial assistance would also play a role in their success.

Currently, electricity from photovoltaics and fuel cells is approximately 1.4 to 5.8 times the price to consumers of electricity from utility grids. Average prices in 1998 were 79 mills per kilowatt for utility power, 112 mills for phosphoric acid fuel cells (with no cogeneration), and 461 mills for photovoltaic systems. To increase the market penetration rates of the alternative technologies, their costs would have to be more competitive.

Photovoltaic and fuel cell technologies are examined here on the basis of their potential for further market penetration in 2010 for the 1990-3% case and in sensitivity cases assuming cost reductions (30 to 50 percent), performance improvements (50 percent for fuel cells, 70 percent for photovoltaics), and Federal subsidies and credits. Payback periods are calculated for the regions where these technologies are most likely to penetrate.

The effects of various private and government-assisted financing plans, such as rolling the cost of the alternative technology into a mortgage plan, tax credits, and depreciation, are summarized in the chart below. The first pair of bars shows the projected payback periods in 2010 for the 1990-3% case with current technology performance and costs. The other projections incorporate performance improvements of 50 percent for fuel cells and 70 percent for photovoltaics, as well as the cumulative effects of various methods for reducing the payback periods. The second set of bars shows the effects of the assumed performance improvement. The third includes a 30-percent production cost reduction, the fourth includes a 50-percent cost reduction, the fifth includes the incorporation of capital costs into a mortgage plan, and the sixth includes a tax credit for photovoltaics and depreciation adjustments for businesses. It is important to note that the substantial cost reductions and improvements in efficiency (50 percent for fuel cells, 70 percent for photovoltaics) are merely arbitrary assumptions and are not calculated projections for future costs and efficiencies. These assumptions are not included in the carbon reduction cases or sensitivity cases presented in this report.

Projected Payback Periods for Photovoltaic and Fuel Cell Purchases Under Different Assumptions, 2010



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Under the most favorable assumptions shown in the graph, payback periods could be reduced to less than 1 year for fuel cells and 2 years for photovoltaics. Although penetration levels are hard to predict from payback periods, it can generally be assumed for the commercial and residential sectors that paybacks within 3 to 4 years would be needed for significant penetration. In the National Appliance Energy Conservation Act, the Federal efficiency payback standard for appliances is 3 years or less for investments to be non-burdensome to the consumer. Although some utilities may have payback periods on their plants of 20 years, building consumers are more likely to spend their money for efficient technologies elsewhere if payback periods are over 4 years. To achieve 3- to 4-year paybacks, both the current performance and the costs of these alternatives would have to be improved by the levels shown here; however, the likelihood of such substantial improvements in the next two decades is small.

Production costs for photovoltaic modules have fallen from $100 per watt to $4 per watt over the past three decades, an 11-percent annual decline, but since 1990 they have declined by an annual average of only 3.9 percent.[a] To meet the cost reduction assumptions in these scenarios, the production costs for photovoltaic cells and modules would have to decline at an average annual rate of 5.6 percent through 2010.

The energy production efficiency of photovoltaic modules has also improved, to approximately 12 percent today from 9 percent in 1980.[b] Reaching the goal of 70 percent improvement in performance, as assumed for this sensitivity analysis, would require an efficiency level of 20 percent in 2010. Since 1980, the rate of improvement in performance for photovoltaics has been less than 2 percent annually, whereas a 4.3-percent annual rate would be needed to achieve a 70-percent improvement by 2010, and that improvement would also have to be accompanied by cost improvements to achieve a 3- to 4-year payback period. Fuel cells have been on the market for only a short time, and historical information is not available. Neither technology appears to be on course to accomplish such a goal during the period of this analysis, however, and thus extensive market penetration is not probable for either photovoltaics or fuel cells.

[a]Energy Information Administration, *Solar Collector Manufacturing Activity 1991*, DOE/EIA-0174(91), p. 18; and P. Maycock, "Photovoltaic Energy Conversion: PV Technology, Cost, Products, Markets, and Systems—Forecast 2010," ASES Conference (Albuquerque, NM, June 1998).

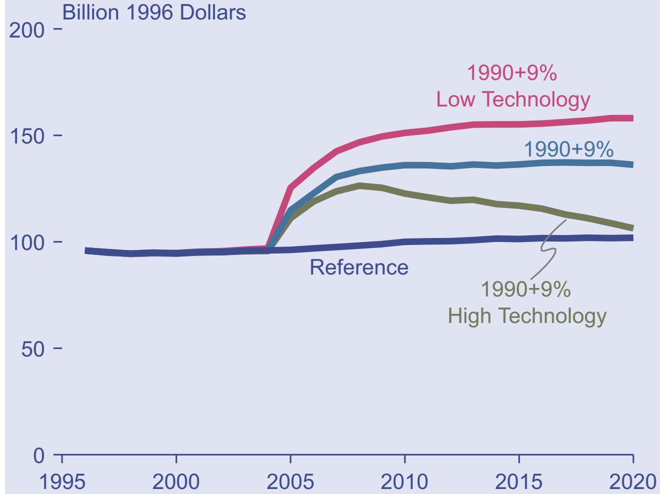
[b]Paul Maycock, PV Energy, personal communication, August 1998.

Table 7. Projected Carbon Prices and Average Fuel Prices for the Commercial Sector in Technology Sensitivity Cases, 2010

Analysis Case	Carbon Price (1996 Dollars per Metric Ton)	Average Fuel Price (1996 Dollars per Million Btu)
Reference	—	11.51
1990+9%.	163	17.99
1990+9% Low Technology	243	21.66
1990+9% High Technology.	121	15.75

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

Figure 43. Projected Fuel Expenditures in the Commercial Sector in Low and High Technology Cases, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

expected to reduce demand in a way suitable to that particular sector.

Among the technology cases the highest carbon prices, and thus the highest fuel prices, in 2010 are projected in the 1990+9% low technology sensitivity case. Due to the lack of technological progress in all sectors, higher fuel prices are required to achieve the demand reductions needed to reach the emissions target. The projected price of fuel to the commercial sector is 20 percent higher in the low technology case than in the 1990+9% case, resulting in 7 percent less commercial energy use. Commercial expenditures for fuel are also expected to be highest under these conditions (Figure 43). Fewer options for increased efficiency limit the potential for energy savings in the low technology case. The average efficiency of the equipment stock in this case continues to improve as normal turnover takes place and older equipment is replaced, but the most energy-efficient equipment available for purchase in 2010 or 2020 is what is available today (Table 8).

In the 1990+9% high technology sensitivity case, advanced technologies are expected to penetrate the market in all sectors over time as normal stock turnover results in the replacement of older, less efficient equipment. Projected technological advances throughout the energy market result in a carbon price in 2010 that is 25 percent lower than that projected in the 1990+9% case (see Table 7). In turn, the expected commercial fuel price in 2010 is 12 percent lower than in the 1990+9% case, resulting in 4 percent more energy consumption. Even though more advanced technologies are available in the high technology case, with less price incentive, commercial consumers are not as likely to purchase more costly equipment. For technologies such as commercial natural gas water heaters, where high

Table 8. Projected Highest Available and Average Efficiencies for Newly Purchased Equipment in the Commercial Sector, 2015

Technology	1998	1990+9% Low Technology	1990+9%	1990+9% High Technology
Highest Available Efficiency[a]				
Air-Source Heat Pump	2.70	2.70	2.93	3.22
Natural Gas Chillers and Air Conditioners	3.52	3.52	3.81	4.40
Heat Pump Water Heater.	2.00	2.00	2.50	2.80
Natural Gas Water Heater	0.91	0.91	0.91	0.91
Average Purchased Efficiency[a]				
Electric Space Heating.	1.10	1.13	1.13	1.11
Natural Gas Space Cooling	1.32	1.73	1.62	1.59
Electric Water Heating	0.95	1.03	1.00	0.98
Natural Gas Water Heating	0.79	0.82	0.82	0.84

[a]The efficiencies shown (Btu of output divided by Btu of input) generally are seasonal efficiencies or include some measure of losses incurred during normal use.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

technology assumptions specify lower costs in 2015 for the most efficient equipment, as compared with the reference case technology assumptions, more consumers are expected to adopt the efficient technology (see Table 8). The projected reduction in energy demand in other sectors causes commercial fuel prices to decline in the later years of the forecast, lowering commercial expenditures for fuel (Figure 43).

Industrial Demand

Background

The industrial sector includes agriculture, mining, construction, and manufacturing activities. The sector consumes energy as an input to processes that produce the goods that are familiar to consumers, such as cars and computers. The industrial sector also produces a wide range of basic materials, such as cement and steel, that are used to produce goods for final consumption. Energy is an especially important input to the production processes of industries that produce basic materials. Typically, the industries that are energy-intensive are also capital-intensive. Industries within the sector compete among themselves and with foreign producers for sales to consumers. Consequently, variations in input prices can have significant competitive impacts. The most significant determinant of industrial energy consumption is demand for final output.

Although energy is an important factor of production, it is not large in terms of annual manufacturing expenditures. In 1995, for example, purchased energy expenditures were 2.3 percent of annual manufacturing outlays.[41] Technology usually plays a minor role in the pattern of energy consumption, because technology tends to be used to produce new and improved final products rather than to reduce energy consumption; however, when new investments are undertaken to introduce improved production technology, steps to increase energy efficiency also are undertaken. Overall, energy prices and technological breakthroughs tend to have a rather small impact on industrial energy consumption.[42]

The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital additions, and the mix of fuels used. This analysis uses “technology bundles” to characterize technological change in the energy-intensive industries. This approach is dictated by the number and complexity of processes used in the industrial sector and the absence of systematic cost and performance data for the components. These bundles are defined for each production process step (e.g., coke ovens) for five of the industries and for end use (e.g., refrigeration) in two of the industries. The process-step industries in the NEMS model are pulp and paper, glass, cement, steel, and aluminum.[43] The industries for which technology bundles are defined by end use are food and bulk chemicals.

The rate at which the average industrial energy intensity declines is determined primarily by the rate and timing of additions to manufacturing capacity. The rate and timing of additions are functions of retirement rates and industry growth rates. Typical retirement rates range from 1 percent to 3 percent annually. The current model also allows retirement rates and the energy intensity of new additions to vary as a function of price. Price elasticity of demand, which indicates the responsiveness of energy consumption to changes in energy prices, is not an explicit assumption in the model; however, the typical 20-year price elasticity ranges between -0.2 and -0.3, which indicates that a 1-percent price increase would reduce demand by 0.2 to 0.3 percent. Because the reference case approximates a constant price regime, the reference case results do not differ greatly from a situation in which all prices are held constant.

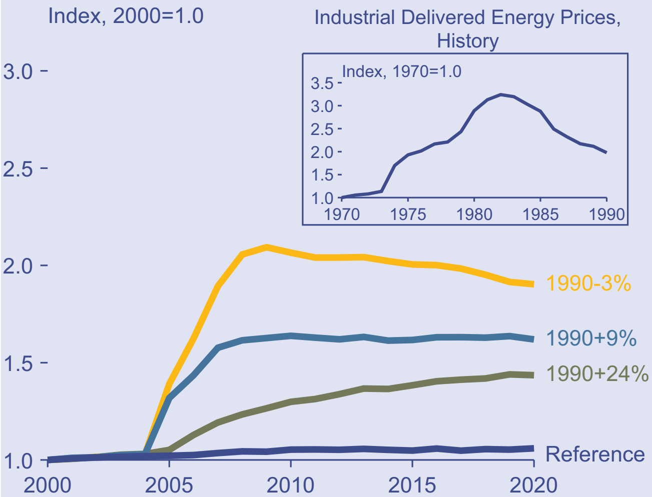
In 1996, the industrial sector’s consumption of 34.6 quadrillion Btu accounted for more than one-third of all U.S. energy consumption. The associated emissions of 476 million metric tons of carbon accounted for one-third of all U.S. carbon emissions. In 1996, although industrial energy prices were more than 50 percent lower than in 1980 (Figure 44), delivered energy consumption was only 13 percent higher than in 1980. Industrial output increased by more than 30 percent over that period. As a result, energy intensity (thousand Btu consumed per dollar of output) fell by 20 percent.

[41] Calculated form U.S. Department of Commerce, *1995 Annual Survey of Manufactures*, pp. 1-7 and 1-36.

[42] For a variety of views, see Boyd et al., “Separating the Changing Composition of U.S. Manufacturing Production from Energy Efficiency Improvements: A Divisia Index Approach,” *The Energy Journal*, Vol. 8, No. 2 (1987); Doblin, “Declining Energy Intensity in the U.S. Manufacturing Sector,” *The Energy Journal*, Vol. 9, No. 2 (1988); Howarth, “Energy Use in U.S. Manufacturing: The Impacts of the Energy Shocks on Sectoral Output, Industry Structure, and Energy Intensity,” *The Journal of Energy and Development*, Vol. 14, No. 2 (1991); Jacard, Nyober, and Fogwill, “How Big is the Electricity Conservation Potential in Industry?” *The Energy Journal*, Vol. 14, No. 2 (1993); Steinmeyer, “Energy Use in Manufacturing,” in Hollander, ed., *The Energy-Environmental Connection* (Island Press, 1992), Chapter 10; and U.S. Department of Energy, *Comprehensive National Energy Strategy* (Washington, DC, April 1998), pp. 13-14.

[43] The refining industry is modeled separately in the Petroleum Market Module of NEMS.

Figure 44. Index of Industrial Sector Energy Prices, 2000-2020



Sources: **History:** Energy Information Administration, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Most of the drop in energy intensity in the U.S. industrial sector occurred between 1980 and 1985, when prices for both energy and capital inputs were rising and the ability of U.S. manufacturers to compete internationally was deteriorating. The recessions of 1980 and 1981-1982 forced many less efficient plants to close, many permanently. Particularly hard hit were the primary metals industries and motor vehicle manufacturing. Output of the U.S. steel industry has never recovered to the levels of the late 1970s. Manufacturing profits did not return to the levels attained in 1981 until 1988.[44] Energy prices certainly played a role in shaping these changes in the industrial sector, but general economic conditions, recession, record high interest rates, and reduced ability of key industries to compete in international markets were more important determinants of change.[45]

In the reference case, industrial energy prices are projected to increase very slightly or fall through 2010. For example, the price of natural gas is projected to increase by 0.5 percent, and the price of electricity is projected to fall by 16 percent. From 1996 to 2010, industrial output is projected to grow by 39 percent and energy consumption by only 16 percent. Industrial intensity falls by 17 percent during the same period, approximating the intensity decline between 1980 and 1996. The factors that are expected to produce the rapid decline in industrial energy intensity despite moderate changes in energy prices include a relative shift from energy-intensive to less energy-intensive industries; replacement of existing equipment with less energy-intensive equipment as existing capacity is retired; adoption of improved and less energy-intensive technologies; and the pressures of international competition.

Carbon Reduction Cases

In the carbon reduction cases, the combined effect of reduced demand for U.S. industrial output and higher energy prices produces lower energy consumption than in the reference case. Compared with the reference case in 2010, industrial output is $69 billion (1 percent) lower in the 1990+24% case, $157 billion (3 percent) lower in the 1990+9% case, and $308 billion (6 percent) lower in the 1990-3% case (see Table 29 in Chapter 6).

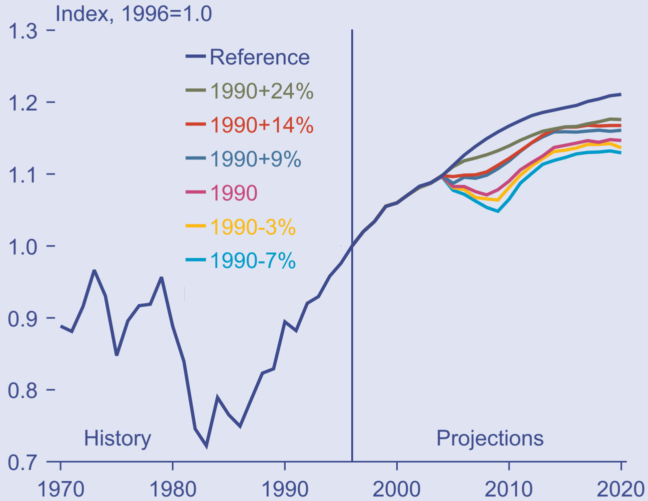
Compared with the reference case, average energy prices in the industrial sector in 2010 are projected to be 22 percent higher in the 1990+24% case, 55 percent higher in the 1990+9% case, and 95 percent higher in the 1990-3% case. In comparison, the industrial sector's average energy price increased by almost 189 percent from 1970 to 1980. Prices of all fuels are projected to be higher in the carbon reduction cases, with coal prices 135 percent higher than the reference case in 2010 in the 1990+24% case and natural gas prices 33 percent higher. The projected price increase for coal is attributable solely to the projected carbon price, whereas the carbon price and higher demand contribute about equally to the increase for natural gas. In the 1990+9% case, natural gas and coal prices are projected to be 93 percent and 328 percent higher, respectively, than in the reference case, and in the 1990-3% case they are 162 percent and 589 percent higher.

Lower projections of industrial output and higher projected energy prices reduce the projections for delivered energy consumption in the industrial sector by 0.7 quadrillion Btu (2 percent) in the 1990+24% case, by 1.3 quadrillion Btu (4 percent) in the 1990+9% case, and by 2.3 quadrillion Btu (7 percent) in the 1990-3% case in 2010 relative to the reference case (Figure 45). In the 1970-1980 period, industrial consumption was unchanged even though prices increased by 189 percent. Year-to-year industrial energy consumption began to fall in 1980, and the decline accelerated when general economic conditions began to deteriorate during the 1980 and 1981-1982 recessions. Energy consumption reached its minimum in 1983, even though prices had begun to decline. These events reinforce the concept that while energy prices do play a role in industrial energy

[44]Council of the Economic Advisers, *Economic Report of the President* (Washington, DC, February 1995), p. 381.

[45]For example, see Boyd and Karlson, "Impact of Energy Prices on Technology Choice in the U.S. Steel Industry," *The Energy Journal*, Vol. 14, No. 2 (1993). More general discussion can be found in Berndt and Wood, "Energy Price Shocks and Productivity Growth: A Survey," in Gordon et al., eds., *Energy: Markets and Regulation* (Cambridge, MA: MIT Press, 1987); and Berndt, "Energy Use, Technical Progress and Productivity Growth: A Survey of Economic Issues," *Journal of Productivity Analysis*, Vol. 2 (1990).

Figure 45. Index of Delivered Energy Consumption in the Industrial Sector, 1970-2020



Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(96) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

consumption, general and industry-specific economic conditions also play an important role.

Coal consumption is projected to drop sharply in the carbon reduction cases, given its extreme price disadvantage. In the 1990+24% case, coal consumption in 2010 is lower by 422 trillion Btu (16 percent) than in the reference case; in the 1990+9% case it is 737 trillion Btu (28 percent) lower; and in the 1990-3% case it is about 1 quadrillion Btu (36 percent) lower. The projected reductions in coal consumption are predominantly due to projected reductions in boiler fuel use.

The industrial sector consumes coal mainly as a boiler fuel and for production of coke in the iron and steel industry. For example, 75 percent of manufacturing consumption of steam coal was used in boilers in 1994.[46] Coal-fired boilers have substantially higher capital costs than do gas-fired boilers, because of their materials handling requirements. For large steam loads, however, coal's price advantage over natural gas offsets its capital cost disadvantage. But in the carbon reduction cases, coal suffers from both a capital cost and a fuel cost disadvantage. As a result, a substantial amount of boiler fuel use switches from coal to natural gas and petroleum products.

The projected reduction in total steam coal consumption in the industrial sector in 2010 (including for uses other than boiler fuel) in the 1990-3% case relative to the reference case is more than 50 percent. Still, the reduction is less severe than that projected for the electric utility sector. Electricity generators, in addition to switching to natural gas, also have the available options of nuclear power and renewable energy sources.

Consumption of metallurgical coal, which is used to produce coke for iron and steel production, also is reduced sharply in the carbon reduction cases. The reduction has several causes: substitution of natural gas in production processes, replacement of domestic coke production with coke imports, replacement of some coke-based steelmaking capacity with electricity-based capacity, and reduced production of domestic steel.

In the carbon reduction cases, natural gas consumption is subject to two countervailing effects. The effect of generally higher energy prices, and consequent lower levels of industrial activity, is to reduce natural gas consumption. On the other hand, natural gas prices do not increase by as much as the prices of competing fuels. As noted above, this results in relatively greater use of natural gas as a boiler fuel. The carbon reduction cases also induce additional cogeneration using natural gas, which increases natural gas consumption and reduces requirements for other boiler fuels.

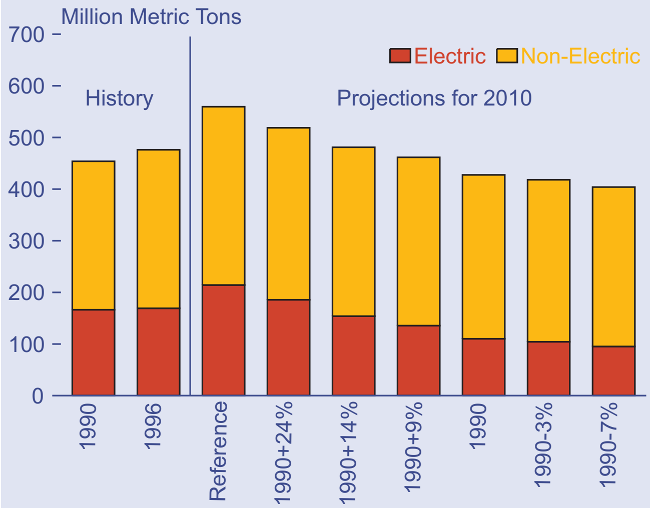
In the 1990+24% and 1990+9% cases, natural gas consumption is projected to increase slightly, because the impact of increased boiler fuel use outweighs the reduction caused by lower industrial output. In the 1990-3% case, natural gas consumption is unchanged from the reference case in 2010. Here, the drop in industrial output and the substitution for other boiler fuels have offsetting effects.

In the reference case, industrial carbon emissions are projected to be 83 million metric tons higher in 2010 than they were in 1996 (Figure 46). Emissions attributable to increased electricity consumption account for more than half the increase. In contrast, electricity-based emissions account for more than 70 percent of the emissions reductions in the carbon cases. For example, in the 1990+9% case, electricity-based carbon emissions in 2010 are 79 million metric tons lower than in the reference case. A reduction of 19 million metric tons in carbon emissions from the combustion of fossil fuels brings industrial sector emissions to approximately their 1990 level. Carbon emissions in the 1990-3% case fall to 418 million metric tons, 58 million tons below the 1996 level and 35 million tons below the 1990 level. Again, electricity-based emissions account for three-fourths of the reduction from projected levels in the reference case.

Part of the reduction in electricity-based carbon emissions for the industrial sector is due to lower electricity consumption in the carbon reduction cases

[46] Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), p. 168.

Figure 46. Industrial Sector Carbon Emissions, 1990, 1996, and 2010



Note: Electricity emissions are from the fossil fuels used to generate the electricity used in this sector.

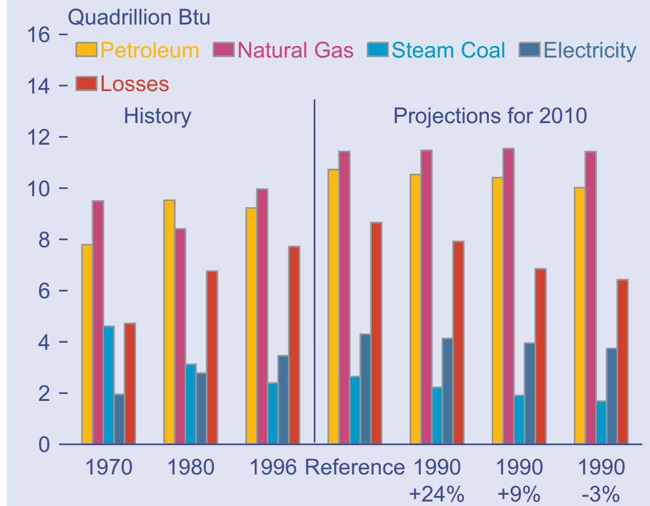
Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

(Figure 47). A larger part of the reduction results from sharply lower carbon intensity of electricity production. In the reference case, approximately 16.5 million metric tons of carbon are emitted in the production of 1 quadrillion Btu of delivered electrical energy, as compared with only 12.6 million metric tons in the 1990+9% case and only 10.2 million metric tons in the 1990-3% case (38 percent less than in the reference case).

Industrial energy intensity fell by 17 percent between 1980 and 1996. In 1996, approximately 7,100 Btu of energy was required to produce a dollar's worth of industrial output. In the reference case energy intensity continues to fall, and in 2010 it is projected that only 5,900 Btu will be required for each dollar of industrial output. The impact of the carbon reduction cases on industrial energy intensity results from opposing effects. The effect of higher energy prices is to reduce energy intensity, whereas reduced or falling output growth limits the amount of new, less energy-intensive capital equipment that will be added to the existing stock, thereby retarding the rate of decline in energy intensity. Additional structural shifts in the composition of industrial output further reduce energy intensity. (Fuel switching contributes to reduced carbon but does not affect energy intensity.)

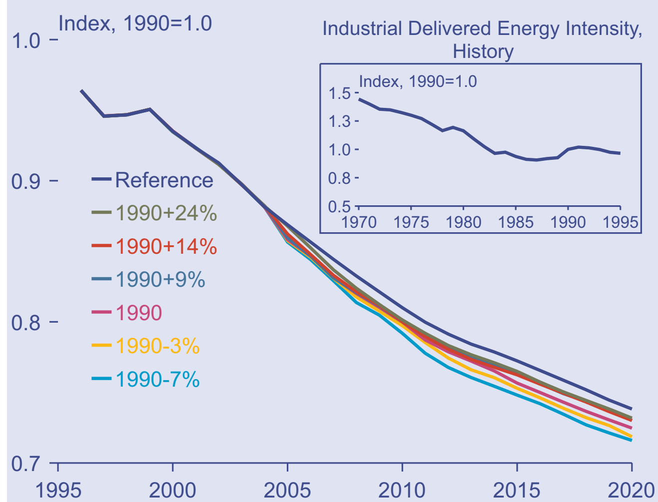
The projected rate of decline in industrial energy intensity is smaller in the more stringent carbon reduction cases (Figure 48). Some process steps in the energy-intensive industries approach the minimum level of energy intensity assumed to be practically achievable. In addition, in the more stringent carbon reduction cases, industrial output is more severely

Figure 47. Industrial Sector Energy Consumption by Fuel, 1970, 1980, 1996, and 2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(96) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 48. Projected Energy Intensity in the Industrial Sector, 1995-2020

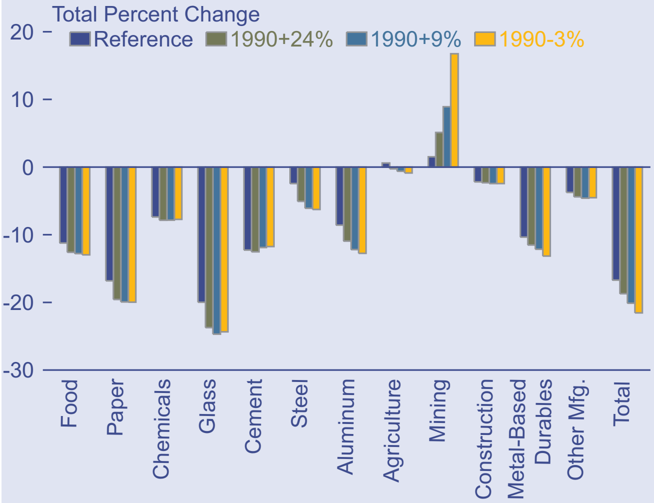


Sources: **History:** Consumption: Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(96) (Washington, DC, December 1997). Output: Constructed by Standard & Poor's DRI from U.S. Department of Commerce, "Benchmark Input-Output Accounts for the U.S. Economy, 1992: Make, Use, and Supplementary Tables," Survey of Current Business, November 1997, and predecessor benchmark tables. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

reduced, resulting in smaller incentives for the addition of new, less energy-intensive capital equipment. The changes in energy intensity for the industrial subsectors (Figure 49) indicate that slower growth in output can lead to less pronounced declines in energy intensity in the more stringent carbon reduction cases.

The change in aggregate industrial energy intensity can be decomposed into two effects. One is the change in energy intensity that results from a change in the composition of industrial output. For example, if the

Figure 49. Projected Change in Industrial Sector Energy Intensity, 1996-2010

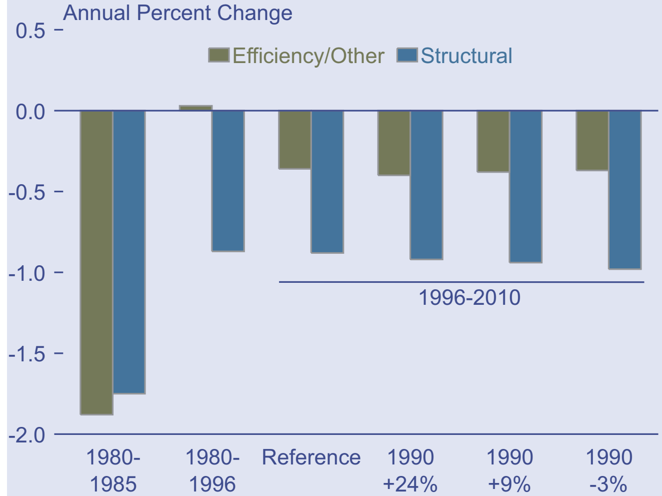


Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

output of the most energy-intensive industries grows more slowly than other parts of the industrial sector, aggregate energy intensity will fall even though no individual industry's energy intensity has changed. This is the "structural" effect. The other is increased energy efficiency and shifts toward less energy-intensive products in individual industries (the "efficiency/other" effect). The relative contributions of these two effects to the reduction in aggregate industrial intensity have varied substantially over time (Figure 50).[47] For example, between 1980 and 1985, when aggregate industrial intensity fell by 3.6 percent annually, the structural and efficiency/other effects made equal contributions to the decline. Over a longer period, from 1980 to 1996, the structural effects dominated the reduction in aggregate industrial energy intensity. Similarly, in the projections, the structural and efficiency/other effects can be decomposed. About two-thirds of the projected reduction in aggregate industrial intensity is attributable to the structural effect, which is slightly larger in the carbon reduction cases than in the reference case.

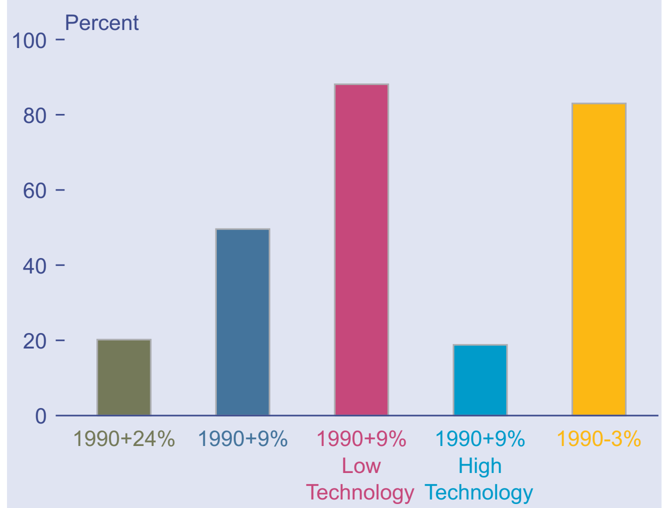
Total expenditures for energy purchases in the industrial sector are projected to be $121 billion in 2010 in the reference case. In the carbon reduction cases, the effects of higher energy prices are reduced by fuel switching and reduced consumption. Nevertheless, energy expenditures in 2010 are projected to be $24 billion (20 percent) higher in the 1990+24% case and $60 billion (50 percent) higher in the 1990+9% case than in the reference case, and in the 1990-3% case they are projected to be even higher—$101 billion (83 percent) higher than in the reference case at $222 billion (Figure 51).

Figure 50. Structural and Efficiency/Other Effects on Industrial Energy Intensity, 1980-1985, 1980-1996, and 1996-2010



Sources: **History:** Consumption: U.S. Department of Commerce, National Technical Information Service, National Energy Accounts, PB89-187918 (Springfield, VA, February 1989). Output: Constructed by Standard & Poor's DRI from U.S. Department of Commerce, "Benchmark Input-Output Accounts for the U.S. Economy, 1992: Make, Use, and Supplementary Tables," Survey of Current Business, November 1997, and predecessor benchmark tables. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 51. Change From Projected Reference Case Energy Expenditures in the Industrial Sector for Alternative Carbon Reduction Cases, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FREEZE09.D080798A, HITECH09.D080698A, and FD03BLW.D080398B.

[47] The decomposition is done with the divisia index. For an explanation of the calculation of the index, see Boyd et al., "Separating the Changing Composition of U.S. Manufacturing Production from Energy Efficiency Improvements: A Divisia Index Approach," *The Energy Journal*, Vol. 8, No. 2 (1987). Alternative decomposition methods are discussed in Greening et al., "Comparison of Six Decomposition Methods: Application of Aggregate Energy Intensity for Manufacturing in Ten OECD Countries," *Energy Economics*, Vol. 19 (1997). Note that using different time periods or subsector aggregations may also yield different results.

Sensitivity Cases

The projections of industrial sector energy expenditures in the carbon reduction cases are based on the reference case assumptions about technology improvements and likely industrial response. Expenditures would be much higher if technology improvements occurred at a slower rate than in the reference case. On the other hand, a more optimistic technology outlook would reduce energy expenditures.

To span the technology alternatives, low and high technology sensitivity cases, based on the 1990+9% carbon reduction case, were analyzed. The low technology case assumes that no additional technology changes (as reflected in energy intensity) will occur after 1998. Normal turnover of capital, however, would result in some decline in energy intensity as old equipment is replaced with currently available equipment with lower energy intensity. The high technology case assumes an aggressive private and Federal commitment to energy-related research and development, which results in successful commercialization of energy-saving technologies.[48]

As noted earlier, the analysis uses technology bundles to characterize technological change in the energy-intensive industries. This approach is illustrated in Table 9. For example, the energy intensity of the

Table 9. Projected Energy Intensities for Industrial Process Steps and End Uses

Industry/Process Step or End Use	1990+9% Low Technology	1990+9%	1990+9% High Technology
Food	**1.00**	**0.89**	**0.79**
Direct Fuel	1.00	0.88	0.79
Hot Water/Steam	1.00	0.89	0.79
Refrigeration	1.00	0.90	0.79
Other Electric	1.00	0.90	0.79
Pulp and Paper	**1.00**	**0.78**	**0.64**
Paper Making	1.00	0.77	0.62
Bleaching	1.00	0.86	0.78
Waste Fiber Pulping	1.00	0.94	0.87
Mechanical Pulping	1.00	0.92	0.96
Semi-Chemical	1.00	0.86	0.91
Kraft, Sulfite, misc.	1.00	0.78	0.61
Wood Preparation	1.00	0.95	0.92
Bulk Chemicals	**1.00**	**0.95**	**0.85**
Electrolytic	1.00	0.91	0.83
Other Electric	1.00	0.90	0.83
Direct Fuel	1.00	0.88	0.83
Steam/Hot Water	1.00	0.89	0.83
Feedstocks	1.00	0.99	0.87
Glass	**1.00**	**0.73**	**0.59**
Post-Forming	1.00	0.91	0.94
Forming	1.00	0.89	0.88
Melting/Refining	1.00	0.63	0.41
Batch Preparation	1.00	0.96	0.99
Cement	**1.00**	**0.85**	**0.77**
Finish Grinding	1.00	0.82	0.72
Dry Process	1.00	0.83	0.66
Wet Process	1.00	0.93	0.97
Steel	**1.00**	**0.81**	**0.50**
Cold Rolling	1.00	0.56	0.33
Hot Rolling	1.00	0.65	0.37
Ingot Casting/Primary Rolling	1.00	1.00	1.00
Continuous Casting	1.00	1.08	1.06
Blast Furnace/Basic Oxygen Furnace	1.00	1.10	0.50
Electric Arc Furnace	1.00	1.00	0.62
Coke Oven	1.00	1.00	0.98
Primary Aluminum	**1.00**	**0.87**	**0.71**

Notes: The energy intensity for the low technology case is defined as 1.0. The 1990+9% case and high technology case energy intensities are indexed against the energy intensity for the low technology case. The intensities are not additive within an industry.

Source: The high technology sensitivity case is based in part on an analysis prepared by Arthur D. Little, Inc., *Aggressive Technology Strategy for the NEMS Model* (1998).

[48]The high technology sensitivity case is based in part on an analysis prepared by Arthur D. Little, Inc., *Aggressive Technology Strategy for the NEMS Model* (1998).

Cogeneration Systems

In every carbon reduction case considered in this report, neither photovoltaics nor fuel cells are projected to gain significant market penetration, because of their high costs. With payback periods of more than 20 years, the success of these technologies seems largely dependent on reducing production costs and increasing efficiency (which would result in further cost reductions for the consumer). Federal financial assistance would also play a role in their success.

A key issue facing power producers and their customers is whether the types of cogeneration systems currently used in the United States will be extended to include district energy systems and advanced turbine systems (ATS). Cogeneration systems, also called combined heat and power systems, simultaneously produce heat in the form of hot air or steam and power in the form of electricity by a single thermodynamic process, usually steam boilers or gas turbines, reducing the energy losses that occur when process steam and electricity are produced independently. Thus, cogeneration systems could play a significant role in reducing U.S. greenhouse gas emissions.

In 1996, electric utilities used more than 21 quadrillion Btu of energy from the combustion of coal, natural gas, and oil to produce the equivalent of only 7 quadrillion Btu of electricity available at the plant gate, representing a conversion loss of 67 percent.[a] Consequently, unused waste heat at utility plants accounted for 346 million metric tons or nearly 24 percent of U.S. carbon emissions in 1996. Additional losses on the order of 7 percent are incurred during transmission and distribution of electricity to customers.[b] Because cogeneration systems capture and use a significant portion of the waste heat energy, they are nearly twice as efficient as conventional power plants in extracting usable energy. About 6 percent of total U.S. generating capacity includes some type of cogeneration system, in such diverse industries as manufacturing, mining, and refining.[c]

Some energy analysts believe that there is even greater potential to increase the penetration of cogeneration systems and reduce carbon emissions by wide-scale construction of district energy systems.[b] District energy systems distribute chilled water, steam, or hot water to buildings to provide air conditioning, space heating, domestic hot water, and industrial process energy. About 5,800 district energy systems are installed in the United States, serving more than 8 percent of commercial floorspace—primarily military bases, universities, hospitals, downtown areas, and other group buildings.[d]

The greatest growth potential for district energy systems is in the area of utility-financed cooling systems for downtown areas where there is a large amount of commercial floorspace located in a relatively small area; however, significant hurdles must be overcome if the potential is to be realized. Siting one or more power and steam generators in an area already dense with buildings could prove to be a challenge, as could the installation, maintenance, and repair of lines to carry steam and hot or chilled water supplies in cities with under-street congestion of existing gas, water, sewage, and electricity lines. Also, construction costs for district energy systems are about one-third higher than those for conventional generating technologies.

Although it is possible that fuel cost savings over the life of a district energy plant could offset its higher initial construction cost, electricity producers might be reluctant to invest significant capital during a period of regulatory reform. Even after the current restructuring process in U.S. electricity markets is completed, the risk of nonrecovery of capital for capital-intensive technologies in a competitive environment will make finding investors in such projects a challenge. Moreover, the development of a district energy system involves the coordinated effort of local and State governments, investors, and the community as a whole, together with the subsequent legal, financial, and environmental issues that arise with the inclusion of many and diverse stakeholders.

Another technology that some energy analysts believe could significantly reduce greenhouse gas emissions is the next-generation, very-high-efficiency ATS. These turbines are expected to operate, at minimum, 5 to 10 percent more efficiently than steam boilers and to cost less than $350 per kilowatthour when used as a simple-cycle turbine.[b] Their small size (5 megawatts) and short construction and delivery schedule (18 months) result in relatively smaller capital outlays and faster capital recovery, which are expected to give them an economic advantage over large central-station turbines.

Commercialization of ATS turbines is not expected until 2001, and penetration is expected to occur first where there is a need to satisfy internal power and steam requirements at industrial and large commercial establishments. But large-scale penetration of the ATS technology as envisioned by its advocates depends on the development of a significant niche market for this cogeneration system—a market characterized as having a small, but not constant, demand for steam. ATS in electric-only mode may not be competitive with other primary power technologies, and a constant demand for steam could be satisfied more economically by conventional gas and combined-cycle steam boilers.[b] Consequently, the competitiveness of ATS with other generating technologies depends on locating markets with an optimal demand for steam during part of the day and maximum demand for electricity for the remainder of the day, even during off-peak periods. Few, if any, power markets would meet such stringent criteria.

[a]Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997).
[b]Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, "Scenarios of U.S. Carbon Reductions," LBNL-40533, ORNL/CON-444 (September 1997).
[c]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).
[d]See web site www.energy.rochester.edu/us/climate/abstract.htm, "District Energy in U.S. Climate Change Strategy."

paper-making process step in the pulp and paper industry is 19 percent lower in the 1990+9% case than in the low technology sensitivity case. For the same process step, energy intensity is 36 percent lower in the high technology case than in the low technology case. For some process steps where the change in intensity is very small, the higher energy prices in the 1990+9% case lead to a slightly lower intensity than in the high technology case, where energy prices are lower. (The technology cases were modeled across all sectors simultaneously. The resulting lower consumption in the high technology case also resulted in lower prices.)

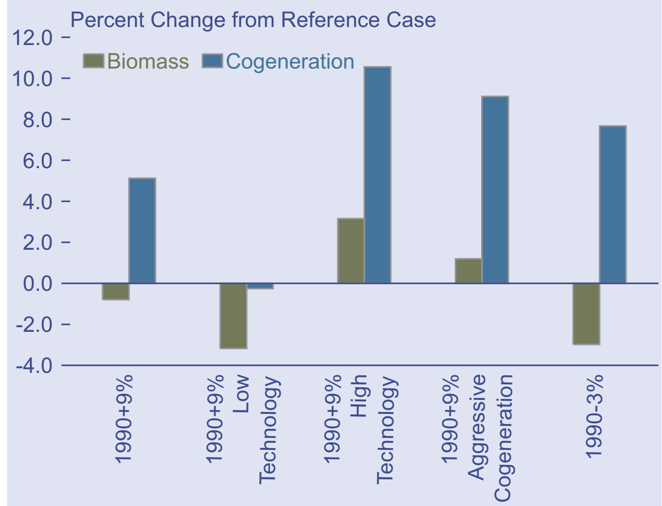
In the 1990+9% low technology case, industrial energy expenditures in 2010 are projected to be nearly double those in the 1990+9% carbon reduction case and $110 billion higher than those in the reference case. In the high technology sensitivity case, energy expenditures are projected to be only $23 billion higher than in the reference case, which has no carbon reductions, in 2010. The high technology case reduces, but does not eliminate, the impact of higher energy prices, producing $37 billion in savings attributable to the assumed technology advances (Figure 51).

Another sensitivity case for the 1990+9% carbon reduction case was implemented to examine the impacts of alternative assumptions about the use of cogeneration and biomass for electricity generation. These assumptions reflect the possibility that natural gas cogeneration and biomass could be used more extensively than projected in the other cases. Natural-gas-fired cogeneration is posited to be a function of two economic factors. One is demand for process steam, with higher demand leading to more cogeneration. (In the carbon reduction cases, industrial steam demand is reduced because the requirements for process steam fall when industrial output falls.) The other is the spread between electricity and natural gas prices, with a higher price difference leading to more gas-fired cogeneration. The assumption used here is that natural-gas-fired cogeneration is more responsive to increasing prices.

Industrial biomass consumption is dominated by activities in the pulp and paper industry, where biomass residue and pulping liquor are used to supply more than half the industry's energy requirements. Consumption of biomass residue and pulping liquor is a function of the industry's output. Consequently, biomass consumption tends to fall in the carbon reduction cases, because industrial output is projected to be lower. The 1990+9% aggressive cogeneration / biomass sensitivity case assumes that the reduction in biomass consumption will be attenuated by additional biomass recovery and utilization. Additional biomass recovery also leads to an increase in cogeneration from biomass, which further reduces the requirements for other fossil fuels.

The aggressive cogeneration / biomass case results in a 9-percent increase (20 billion kilowatthours) in the level of gas-fired cogeneration in 2010 relative to the reference case (Figure 52). This is smaller than the change seen in the high technology sensitivity case, because industrial output is lower in the aggressive cogeneration / biomass sensitivity than in the high technology case. (Industrial output is lower in the aggressive cogeneration case than in the high technology case, because the projected energy prices are higher in the aggressive cogeneration case.) Biomass consumption in 2010 is projected to be 1.2 percent (27 trillion Btu) higher in the aggressive cogeneration / biomass sensitivity case than in the reference case (Figure 52). As with cogeneration, this increase is slightly less than the change seen in the high technology sensitivity case, again because of the lower industrial output projected in the aggressive cogeneration / biomass case. Projected energy expenditures in the industrial sector in 2010 in this sensitivity case are $15 billion less than in the 1990+9% case. It should be noted that neither the cost nor the likelihood of achieving the assumed changes in the high technology or aggressive cogeneration / biomass sensitivity case has been evaluated. Instead, the experiments were an attempt to span the range of possible outcomes.

Figure 52. Natural-Gas-Fired Cogeneration and Biomass Consumption in the Industrial Sector in Alternative Carbon Reduction Cases, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, FREEZE09.D080798A, HITECH09.D080698A, BEHAVE09.D080498A, and FD03BLW.D080398B.

Industrial Composition

Because non-Annex I countries are not required to reduce emissions under the Kyoto Protocol, their energy prices are likely to be lower than those in the Annex I countries, including the United States. As a result, more energy-intensive industries could migrate from areas with high energy costs, and those that remain could lose markets to lower-cost foreign competition. Energy-intensive industries also may face reduced demand as consumers shift their consumption patterns to less energy-intensive goods and services. There are several counter arguments to this hypothesis: the relatively small share of energy expenditures in annual manufacturing expenditures makes the impact of differential energy prices relatively unimportant; energy prices are not important determinants of international trade or capital flows, which implies that U.S. energy-intensive industries are not likely to be seriously affected by an energy price disadvantage; and a large number of business opportunities related to climate change mitigation will become available both domestically and in non-Annex I countries. Needless to say, there are widely divergent points of view about the likelihood of significant industrial migration and the extent of adverse impacts on U.S. industry.[a] An analysis of the change in industrial composition, which would require an analysis of all the relative costs of manufacturing inputs, of which energy costs are only one, monetary issues, and international trade issues, is beyond the scope of this report.

One published study has attempted to evaluate the potential effects of differential changes in international energy prices on the U.S. industrial sector. The study was conducted by Argonne National Laboratory in a workshop format (see Argonne National Laboratory, *The Impact of High Energy Price Cases on Energy-Intensive Sectors: Perspectives from Industry Workshops* (July 1997)). Industry-specific discussion papers circulated to workshop participants contained analyses that examined impacts for each individual industry, assuming no price changes for other industries or markets. The industries affected and the percentage reductions in projected industrial output in the reference case were as follows: bulk chemicals, 28.5; aluminum, 13.7; pulp and paper, 10.2; steel, 30.5; and cement, 38.2.

A second study was conducted at EIA's request by Charles River Associates (CRA),[b] using a more general approach. Explicit linkages to international trade were a fundamental part of the modeling framework for the study, which was conducted under assumptions similar to those of the 1990+14% carbon reduction case in this analysis. The industries affected and the percentage reductions from reference case output projections were as follows: total chemicals, 3.9; nonferrous metals, 1.5; pulp and paper plus printing, 0.7; steel, 1.4; and nonmetallic minerals, 1.4. The percentage output reductions from the comparable NEMS case (1990+14%) are about double the CRA values: nonferrous metals, 4.4; pulp and paper plus printing, 2.0; steel, 3.1; and nonmetallic minerals, 3.5. The exception is total chemicals for which the NEMS results project a slightly smaller reduction of 3.5 percent. The projections from NEMS, which estimates only domestic output reductions, and from CRA, which treated both international capital flows and domestic output reductions, are significantly lower than those from the Argonne National Laboratory study.

In view of the above results, it is difficult to distinguish the effects of reduced output from those that could result from industrial migration abroad in response to differences in international energy prices. There are many analytical complexities in the assessment of potential effects of carbon reductions on industrial output. A complete analysis of the issue would require consideration of all input costs, including infrastructure and locational advantages, monetary issues, and trade issues. Significant additional research would be required to examine the differential impacts of climate change policies on the United States and other countries.

[a]The following authors provide a sample of the breadth of disagreement in this area: American Petroleum Institute, *Impacts of Market-Based Greenhouse Gas Emission Reduction Policies on U.S. Manufacturing Competitiveness*, January 1998; American Automobile Manufacturers Association, *Economic Implications of the Adoption of Limits on Carbon Emissions from Industrialized Countries*, November 1997; Argonne National Laboratory, *The Impact of High Energy Price Cases on Energy-Intensive Sectors: Perspectives from Industry Workshops*, July 1997; Matthewson, et al., *The Economic Implications for Canada and the United States of International Climate Change Policies*, 1997 Canadian Energy Research Institute Environment-Energy Modeling Forum, October 1997; Repetto, et al., *U.S. Competitiveness is Not at Risk in the Climate Negotiations*, (World Resources Institute, October 1997); and WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts*, 1998.

[b]Charles River Associates, *Report to the Energy Information Administration* (August 1998).

Transportation Demand

Background

In terms of primary energy use in 1996, transportation sector carbon emissions, which almost equaled industrial carbon emission levels, were the second highest among the end-use demand sectors. Nearly 33 percent of all carbon emissions and 78 percent of carbon emissions from petroleum consumption originate from the transportation sector. In the reference case, carbon emissions from transportation are projected to grow at an average annual rate of 1.9 percent to 2010, compared with 1.4 percent for the commercial sector and 1.2 percent for both the residential and industrial sectors. In addition, transportation is the only sector with increasing carbon emissions projected for the period from 2010 to 2020 in the carbon reduction cases. Therefore, if there are no specific initiatives to reduce carbon emissions in the transportation sector, especially beyond 2010, increasing pressure may have to be exerted in the other sectors in order to reach and then maintain 2010 carbon emissions targets beyond 2010.

Consumers select light-duty vehicles (cars, vans, pickup trucks, and sport utility vehicles) based on a number of attributes: size, horsepower, price, and cost of driving; weighting these attributes by their personal preferences. This analysis uses past experience to determine the weights that each of these attributes have in terms of consumer preferences for conventional vehicles. Technologies are represented by component (e.g., front wheel drive, electronic transmission type) with each technology component defined by a date of introduction, a cost, and a weight that indicates its impact on efficiency and horsepower. The vehicles are categorized by the 12 size classes for cars and light trucks defined by the Environmental Protection Agency and includes 2 conventional engine technologies, and 14 alternative fuel vehicle engine technologies. Technologies penetrate based on both their cost-effectiveness and by consumer preference based on past experience with similar technologies in the automotive industry. Consumers are assumed to consider only current energy prices when evaluating technologies. However, it is assumed that the automobile industry requires 3 years for minor technology makeovers and 5 years for major redesigns, estimating future fuel prices based on their rate of growth in the past 3 to 5 years. Therefore, manufacturers consider whether future fuel prices will enable their technologies to be cost-effective from a consumer standpoint.

Penetration of alternative-fuel vehicles is based on four consumer criteria—vehicle price, cost of driving per mile, vehicle range, and availability of refueling stations. Each of these attributes is weighted according to consumer surveys and expected changes over the forecast period as a result of technological improvements, larger scales of production, the availability and cost of fuel-saving technologies, and the availability of alternative-fuel refueling stations as more alternative-fuel vehicles penetrate the market. Production levels for alternative-fuel vehicles are constrained by the lead time to switch production to a particular technology and the availability of technologies in each size class.

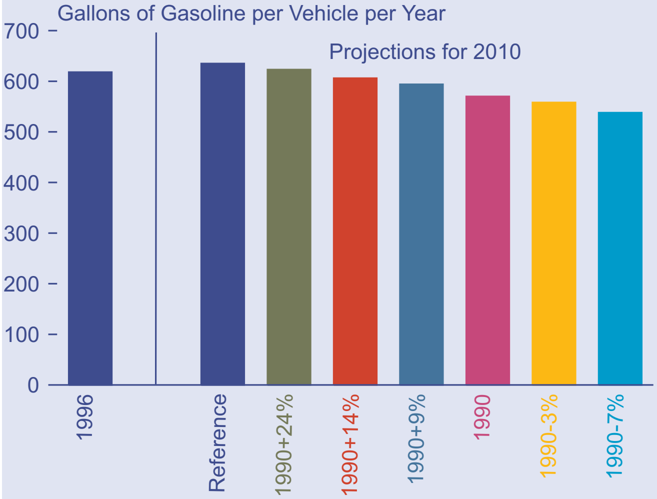
Depending on per capita income, fuel prices, and fuel economy, consumers may switch to either smaller size classes or smaller vehicles with lower horsepower requirements within a size class. The trend in vehicle sales toward or away from light trucks (vans, sport utility vehicles, and pickups) is determined by fuel prices. Vehicle travel is determined by the cost of driving per mile and per capita income. For flex-fuel or bi-fuel alternative-fuel vehicles, the percentage use of each fuel is based on the price differential between gasoline and the alternative fuel.

Responding to changes in fuel prices, gasoline has a 2-year demand elasticity of -0.25 and a 20-year elasticity of -0.45. In the long term, consumers are expected to alter their purchasing patterns and manufacturers to incorporate more fuel-saving technologies. Because fuel use for freight trucks and trains depends primarily on requirements for freight movement as a result of economic activity and the slow turnover of the stock, distillate fuel has lower 2-year and 20-year price elasticities, at -0.09 and -0.13, respectively. In addition to fuel prices, business and personal air travel also depend on gross domestic product (GDP) and per capita income, respectively, and have very slow rates of stock turnover. Jet fuel has 2-year and 20-year elasticities of -0.12 and -0.15.

Energy intensity in the transportation sector is defined as energy use (in terms of gallons of gasoline) per vehicle per year. In the reference case, transportation energy intensity in 2010 is projected to be about 635 gallons of gasoline per vehicle, or about 53 gallons per month (Figure 53). Energy intensity in the 1990+24% case is lower than in the reference case but only by 12 gallons of gasoline per car per month. In the 1990+9% case, the projected energy intensity in 2010 is almost 53 gallons lower—equivalent to 1 month's use of gasoline. In the 1990-3% and 1990-7% cases, the corresponding reductions in gasoline consumption in 2010 are equivalent to nearly 1.5 and 2 months of gasoline use, respectively.

In the absence of fuel price changes, transportation energy intensity will change in response to stock turnover, technology availability, and income effects (Table 10). Because 1998 prices are lower than those projected for 2010 in the reference case, vehicle-miles traveled would be higher and fuel efficiency lower than in the reference case if the 1998 price level continued. Constant 1998 fuel prices would slightly increase air

Figure 53. Light-Duty Vehicle Energy Intensity, 1996 and 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table 10. Projected Average Transportation Energy Intensities by Mode of Travel, 2010
(Million Btu per Vehicle per Year)

Travel Mode	1998 Average	Reference	Constant 1998 Prices
Light-Duty Vehicles . .	78.4	79.5	80.9
Freight Truck	699.5	787.7	787.7
Aircraft	486,100	517,100	521,900

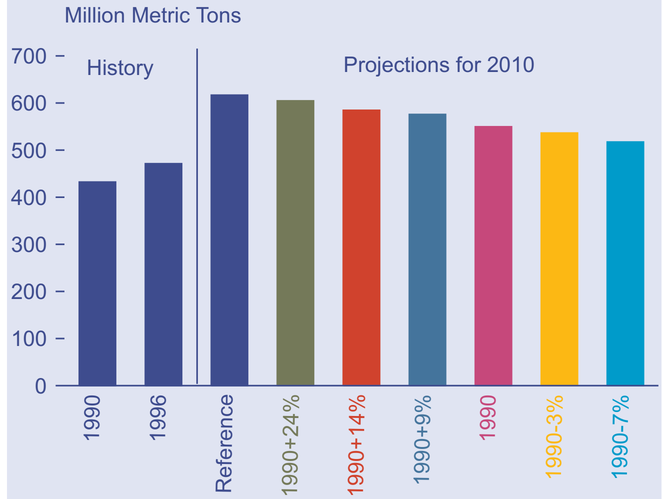
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

travel, but aircraft efficiency levels would not decline relative to those in the reference case. More air travel would necessitate higher aircraft stock levels in 2010, but the increase would be more than offset by higher levels of travel per plane. Freight truck fuel intensity would not change with constant prices, because freight travel is determined primarily by economic activity rather than fuel prices. The slightly lower fuel prices in the constant price case would not be enough to lower the fuel economy of freight trucks relative to their projected fuel economy in the reference case.

Carbon Reduction Cases

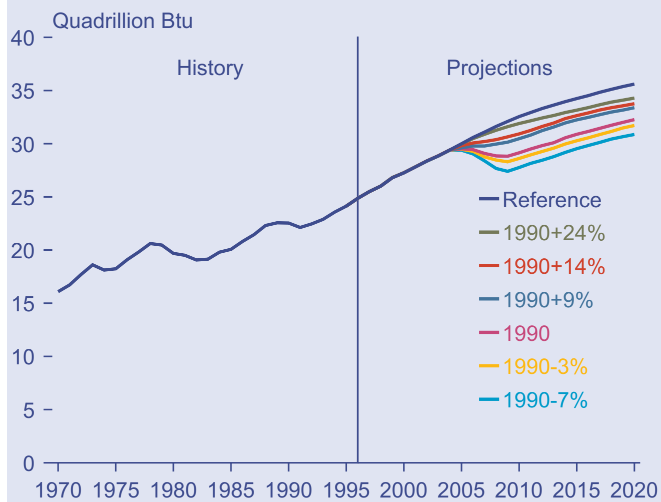
The transportation sector is the only sector that does not reach 1990 carbon emissions levels by 2010 in any of the carbon reduction cases (Figure 54). In the reference case, energy demand in the transportation sector is projected to exceed 1990 levels by approximately 10.7 quadrillion Btu in 2010, a 49-percent increase (Figure 55). The corresponding increases are 9.4 quadrillion Btu in the 1990+24% case, 8.6 quadrillion Btu in the 1990+9% case, and 6.6 quadrillion Btu in the 1990-3% case.

Figure 54. Carbon Emissions in the Transportation Sector, 1990, 1996, and 2010



Sources: **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 55. Fuel Consumption in the Transportation Sector, 1970-2020



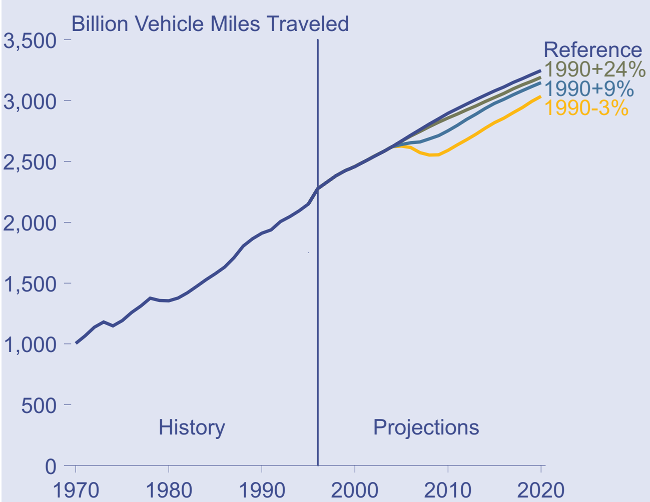
Sources: **History:** Energy Information Administration, *State Energy Data Report 1995*, DOE/EIA-0214(96) (Washington, DC, December 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Relative to the reference case, only 14 percent of the projected reduction in total energy demand for all sectors in 2010 occurs in the transportation sector in the 1990+24% case, 19 percent in the 1990+9% case, and 24 percent in the 1990-3% case. In the 1990-3% case, the reduction in carbon emissions from all sectors in 2010 is approximately 492 million metric tons, of which 18 percent comes from the transportation sector.

Light-Duty Vehicles

Travel Demand. Light-duty vehicle travel (cars, pickup trucks, vans, and sport utility vehicles) in 2010 is projected to be 1.3 percent lower than in the reference case in the 1990+24% case, 5.2 percent lower in the 1990+9% case, and 11.2 percent lower in the 1990-3% case (Figure 56). Declines in light-duty vehicle travel have been seen historically in 1973-1974 (2.7 percent) and 1979-1980 (1.6 percent). In the 1990+24% and 1990+9% cases, the levels of light-duty vehicle travel rise between 2005 and 2008, they are projected to decline by an average of 1.2 percent per year over the same period in the 1990-3% case (comparable to the rate of decline from 1979 to 1980). In 1973-1974 and 1979-1980, disposable per capita income was declining, at 0.7-percent and 0.3-percent annual rates, respectively. Those historical declines in income per capita, combined with rising fuel prices, further reduced vehicle travel. In contrast, from 2005 to 2008 income per capita is projected to rise at an average annual rate of 0.8 percent, more than twice the projected rate in the reference case, partially offsetting the reductions in travel that are expected to accompany higher fuel prices.

Figure 56. Light-Duty Vehicle Travel, 1970-2020



Sources: **History:** U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics*, various years, (Washington, DC). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Slowing growth in vehicle-miles traveled is projected even in the reference case, for several reasons. First, as the "baby boomers" age, they are expected to drive less (although they probably will drive more than previous generations of the same age group).[49] Second, as more women have entered the workforce over the past three decades, resulting in more two-income households, female drivers have logged more vehicle-miles of travel; however, that growth will eventually slow as the vehicle-miles traveled by women approaches that of men. Finally, consumers have been keeping their vehicles longer than in past decades, and older cars tend to be driven less than newer cars. A countervailing trend is the recent growth in purchases of light trucks, which are driven 4.7 percent more per year than cars. In the carbon reduction cases, a reversal of this trend back to car sales as a result of higher fuel prices is expected, leading to slower growth in vehicle-miles traveled.

After 2010, vehicle-miles of travel, total fuel use, and total carbon emissions for light-duty vehicles are projected to begin rising again in the 1990-3% case and to continue on an upward path through 2020, paralleling the trends in the reference, 1990+24%, and 1990+9% cases for the later years of the forecast. There are three reasons for the continued growth in vehicle-miles traveled after 2012. First, carbon prices are projected to decline in most cases after 2010. Second, lower demand for gasoline is projected to result in lower refining costs, lower world oil prices, and lower gasoline prices. Finally, increases in disposable income after 2012—particularly after 2015, when the U.S. average disposable income in the 1990+24%, 1990+9%, and 1990-3% cases is expected to exceed that projected in the reference case as the economy rebounds from the initial response to carbon reduction efforts—lead to more rapid increases in light-duty vehicle travel from 2012 through 2020.

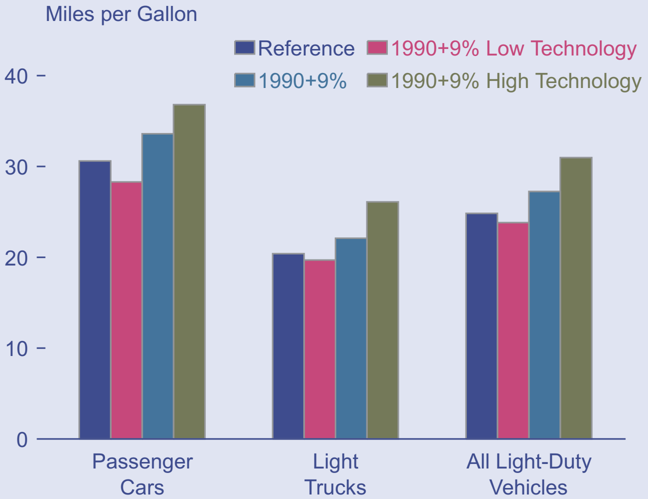
Increased telecommuting, which is assumed to reduce vehicle-miles traveled by 0.13 percent in 2000 according to the Climate Change Action Plan,[50] is also assumed in all the cases for this analysis, resulting in fuel savings of 21.6 trillion Btu in 2000. The 0.13-percent reduction is assumed to continue throughout the projections, so that as vehicle-miles traveled increase over time, the savings from telecommuting increase proportionately.

Fuel Efficiency. In the carbon reduction cases, the fuel economy of newly purchased light-duty vehicles in 2010 is expected to be higher than projected in the reference case. Higher fuel prices are expected to encourage the development of advanced fuel-saving technologies, as well as changes in consumer purchasing patterns. For example, average fuel efficiency for all new light-duty vehicles in 2010, projected to be just under 25 miles per gallon in the reference case, surpasses 27 miles per gallon in the 1990+9% case (Figure 57), and even higher levels might be achieved with more rapid advances in technology, as described in the discussion of sensitivity

[49] Federal Highway Administration, *National Personal Travel Survey: 1990 NPTS Databook*, Vol. I (Washington, DC, November 1993), p. 3-18.

[50] U.S. Department of Energy, Office of Policy, Planning, and Program Evaluation, *The Climate Change Action Plan: Technical Supplement* (Washington, DC, March 1994).

Figure 57. Projected New Car and Light Truck Fuel Economy, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

cases below. The projections of new vehicle fuel efficiency in the reference, 1990+24%, 1990+9%, and 1990-3% cases in 2010 are as follows: for cars, 30.6, 32.0, 33.6, and 35.6 miles per gallon; and for light trucks, 20.4, 21.2, 22.1, and 23.3 miles per gallon.

In the past, a 4.3-percent average annual increase in new car fuel efficiency was achieved by automobile manufacturers from 1976 to 1988. Thus, the projected increases of 0.9 percent per year from 1996 to 2010 in the 1990+24% case, 1.3 percent per year in the 1990+9% case, and 1.7 percent per year in the 1990-3% case appear to be possible. On the other hand, those historical improvement rates resulted from the introduction of fuel-saving technologies that involved radical changes in structural design and were relatively inexpensive to implement. For example, space and size reductions resulting from downsizing to front wheel drive designs actually reduced costs while also permitting the spatial redesign of engine compartments, but further downsizing and weight reductions may be difficult to achieve, because they could eliminate larger vehicles from the marketplace and, possibly, increase the safety concerns associated with smaller light-weight vehicles. Diminishing returns to scale have limited the potential for future fuel savings, because many of the least expensive options have already been implemented.

Light trucks have not achieved fuel efficiency improvements equivalent to those for automobiles, because consumers have sought higher horsepower for personal use (particularly in sport utility vehicles), hauling (pickup trucks), and commercial applications (standard vans). Historically, the highest average annual growth rate in fuel efficiency for new light trucks was 2.9 percent per year from 1976 to 1986. In contrast, light truck fuel economy is projected to grow by only 0.1 percent annually in the 1990+24% case, 0.4 percent annually in the 1990+9% case and 0.8 percent annually in the 1990-3% case between 2000 and 2010. Lower growth rates occur for light trucks in the carbon reduction cases than historically because of the difference described above regarding inexpensive and one time technological improvements.

Among the 55 fuel-saving technologies that are assumed to be available to manufacturers of light-duty vehicles in the reference and carbon reduction cases, the most significant market penetration is expected for drag reduction, continuously variable transmissions, electronic transmission controls, cylinder friction reduction technologies, advances in low-rolling-resistance tires, variable valve timing, and accessory control units (Table 11). Aerodynamic improvements (drag reduction) have already been implemented on many vehicles, but further market penetration may be possible, especially in the larger size classes. Continuously variable transmissions match the gear ratio in a continuous manner over the wide spectrum of gear ratios demanded by the engine, rather than having a discrete number of gears. Electronic transmission controls assist the transmission by matching more precisely the gear to be used with a given engine load. Cylinder friction reduction technologies, such as low-friction pistons and rings, lower the thermal and mechanical losses of the engine. Low-rolling-resistance tires limit energy losses from friction between tires and road surfaces. Variable valve timing improves the thermal efficiency of an engine by precisely timing when the ignition sparks within the cylinder. Electronic controls and electric motors for accessory drives on vehicles (cooling fan, water pump, alternator, power steering and windows) could improve fuel economy by reducing engine loads.

Changes in consumer purchasing patterns also are expected to contribute to the fuel economy improvements for light-duty vehicles in the carbon reduction cases. For that to happen, however, trends in consumer choices over the past decade would have to be reversed. With low fuel prices and high disposable income per capita, average fuel economy has been flat from 1990 to 1996. Consumer purchases have tended toward larger cars and light trucks, especially sport utility vehicles, and there has been a growing preference for light trucks over cars. Similarly, within each size class, consumers have tended to purchase cars and light trucks that are larger and have more horsepower.

In 1996, compact cars accounted for 45 percent of new automobile sales, an increase from 34 percent in 1990; however, the subcompact share of new car sales fell from a high of 26 percent in 1991 to 19 percent in 1996. Small pickup trucks, which captured 25 percent of the market for new light trucks in 1990, reached a low of

Table 11. Projected Penetration of Selected Technologies for Domestic Compact Cars, 2010
(Percent of New Sales)

Technology	Reference	1990+9%	1990+9% High Technology
Drag Reduction (I)	52	73	63
Drag Reduction (II)	14	19	17
Continuously Variable Transmission	48	54	49
Electronic Transmission Controls (I)	21	26	23
Electronic Transmission Controls (II)	22	28	24
Cylinder Friction Reduction (I)	46	65	56
Cylinder Friction Reduction (II)	7	9	8
Low-Rolling-Resistance Tires (I)	46	67	57
Low-Rolling-Resistance Tires (II)	22	30	26
Variable Valve Timing	79	82	52
Accessory Control Units (I)	24	33	28
Accessory Control Units (II)	21	27	24

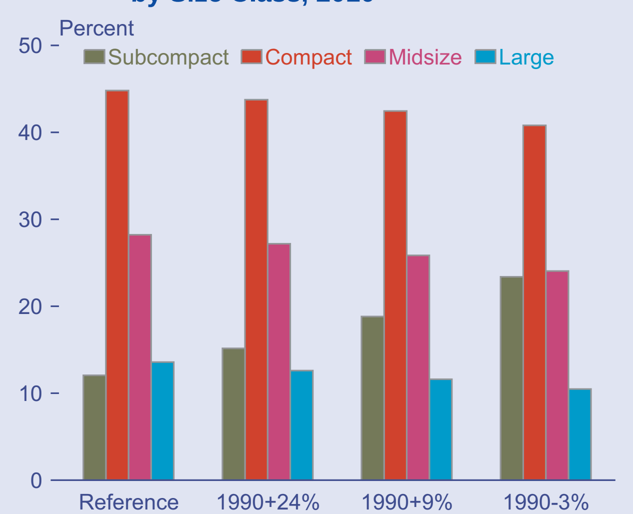
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and HITECH09.D080698A.

19 percent in 1996. Concurrently, standard and compact sport utility vehicles, which had only a 20-percent share of the light truck market in 1990, had a 45-percent share in 1996. The average fuel economy of small pickup trucks is 26.3 miles per gallon, as compared with 21.3 miles per gallon for small utility trucks and 18.1 miles per gallon for large sport utility vehicles, which are now growing in share at a much faster pace than even small utility trucks. Sales of large sport utility vehicles increased from 3.3 percent of all new light truck sales in 1991 to a high of 10.3 percent in 1996. In addition, sales of small vans, which currently have an average fuel economy rating of about 22.7 miles per gallon, are being displaced by sales of small and large sport utility vehicles. With a large supply of sport utility vehicles available to consumers and a lack of station wagons designed from sedan autos, which have a much higher fuel efficiency rating, the fuel economy options for new vehicle buyers are becoming limited.

With higher fuel prices in the carbon reduction cases in 2010 than in the reference case, it is projected that size class shares will return to near 1976 levels. The subcompact share of new car sales in 2010 is projected to be 15 percent in the 1990+24% case, 19 percent in the 1990+9% case, and 24 percent in the 1990-3% case, compared with 12 percent in the reference case (Figure 58). Similar trends are projected for all size classes in the carbon reduction cases, as consumers move their vehicle purchases down to lower size classes and sales of compact, mid-size, and large cars are reduced. Although shifting vehicle lines back to production of smaller cars would require major changes in production facilities, the lead time associated with those changes has narrowed from about 4 years to 2 years.

Since 1990, the growth in light trucks sales at the expense of car sales, and the growth in sales of standard and compact sport utility vehicles and minivans at the expense of station wagons has slowed the rate of improvement in efficiency for new light-duty vehicles. Light truck sales shares have grown from about 37 percent of all light-duty vehicle sales in 1990 to 43 percent in 1997, with a net loss on average of more than 8 miles per gallon between new cars and light trucks. In 2010, light trucks sales are projected to be 46.1 percent of light-duty vehicle sales in the 1990+24% case, 44.4 percent in the 1990+9% case, and 42.5 percent in the 1990-3% case, compared with 47 percent in the reference case. Reversing the trend back toward cars and away from truck purchases will not be costless, however. Vehicle manufacturers reap much higher profits from sales of light trucks than from car sales. In addition, consumers may have difficulty finding fuel-efficient vehicles suitable for larger families with the disappearance of many station wagons from the new car market.

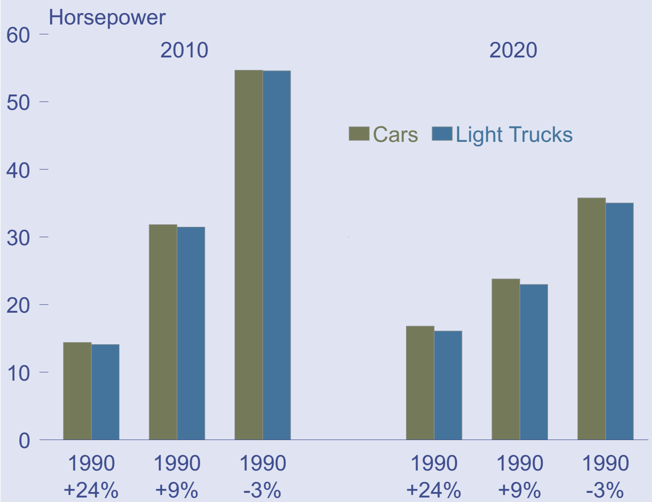
Figure 58. Projected Shares of Automobile Sales by Size Class, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Horsepower. Growth rates in new vehicle horsepower in the light-duty vehicle market are currently at their highest historical levels. From 1990 to 1997, new vehicle horsepower increased at annual rates of 3.2 percent for cars and 4.3 percent for light trucks. Between 1996 and 2010, horsepower for both cars and light trucks is projected to increase at an annual rate of 2.4 percent in the reference case, as a result of high per capita incomes and low fuel prices. The higher fuel prices in the carbon reduction cases are projected to lower the growth rate of horsepower for cars to 1.9 percent between 1996 to 2010 in the 1990+24% case, 1.2 percent in the 1990+9% case, and 0.3 percent in the 1990-3% case (Figure 59).

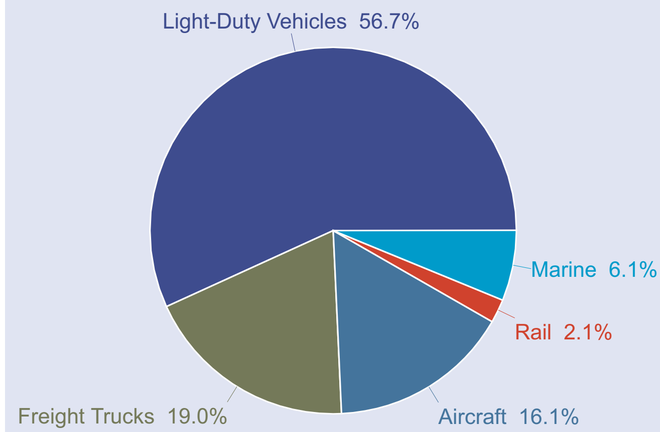
Figure 59. Projected Reductions From Reference Case Projections of Car and Light Truck Horsepower in the Carbon Reduction Cases, 2010 and 2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

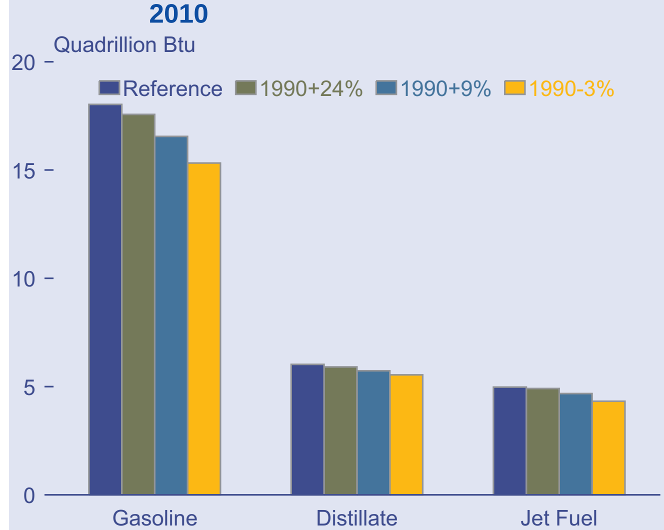
Fuel Consumption. Reductions in fuel use by light-duty vehicles (cars, pickup trucks, vans, and sport utility vehicles) are projected to account for more than two-thirds of the reduction in transportation energy consumption in 2010 in the carbon reduction cases relative to the reference case projections. In the reference case, light-duty vehicles are responsible for 57 percent of all transportation use in 2010 (Figure 60). The difference in gasoline consumption by light-duty vehicles (Figure 61) results from both a decline in vehicle-miles traveled and an increase in new car and light truck efficiency in response to higher gasoline prices and lower levels of disposable income. As fuel-saving technologies penetrate the light-duty vehicle market, higher fuel efficiencies lower the cost of driving per mile, which increases vehicle travel, offsetting some of the fuel savings.[51] The increase in fuel efficiency also reduced the demand for gasoline, leading to lower gasoline prices than would otherwise have occurred. Gasoline prices in real 1996 dollars in 2010 are projected to be 14 cents per gallon higher in the 1990+24% case than in the reference case, 30 cents per gallon higher in the 1990+9% case, and 55 cents per gallon higher in the 1990-3% case. Comparable increases in gasoline prices were last seen during the oil crisis of 1973-1974 (33 cents a gallon in 1996 dollars) and during the oil embargo of 1979-1980 (47 cents a gallon).

Figure 60. Projected Fuel Consumption in the Transportation Sector by Mode in the Reference Case, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

Figure 61. Projected Fuel Consumption in the Transportation Sector by Fuel Type, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

[51] This secondary effect has been estimated at about 10 to 12 percent. See L.A. Greening and D.L. Greene "Energy Use, Technical Efficiency, and the Rebound Effect: A Review of the Literature," draft report prepared for the Office of Policy Analysis and International Affairs, U.S. Department of Energy (Washington, DC, November 6, 1997).

Air Travel

Personal, business, and international air travel are expected to decline in response to higher jet fuel prices and higher ticket prices in the carbon reduction cases, as compared with the reference case, from 2005 through 2015. The projected levels of air travel in 2010 are 1.4 percent lower in the 1990+24% case than in the reference case, 7.4 percent lower in the 1990+9% case, and 16.0 percent lower in the 1990-3% case. Higher fuel prices in 2010 are projected to increase ticket prices by 5 percent, 13 percent, and 23 percent in the 1990+24% case, 1990+9% and 1990-3% cases, respectively, over the reference case prices. Lower merchandise exports (0.9 percent lower in the 1990+24% case, 2.5 percent in the 1990+9% case, and 4.9 percent in the 1990-3% case than in the reference case) have comparable effects on dedicated air freight travel.

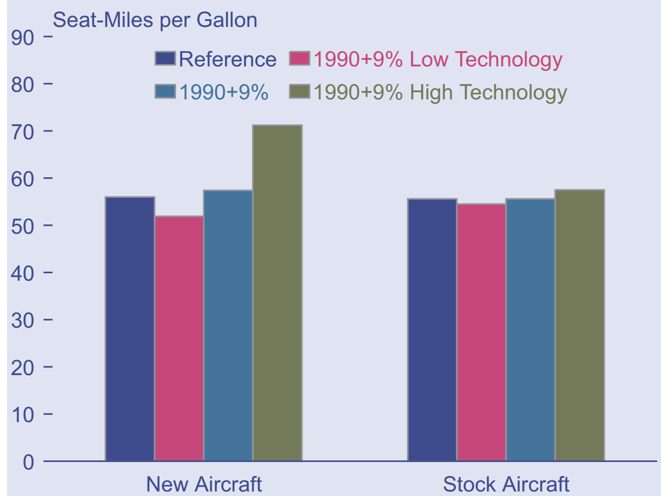
Between 2005 and 2008, air travel is projected to decline by 1.2 percent annually in the 1990-3% case as a result of a 19-percent average annual increase in jet fuel prices. In comparison, air travel declined by 2.2 percent from 1980 to 1981, when jet fuel prices increase by 49 percent. Similar to light-duty vehicles, differences in the responses to higher fuel prices between history and the carbon reduction cases can be explained by comparing growth rates in income levels. Income during 2005 to 2008 is expected to increase by 0.8 percent annually in the carbon reduction cases, however from 1980 to 1981 income was rising even faster at 2.3 percent per year, which mitigated the decline in air travel.

In 2010, the projected use of jet fuel is lower by 1.4 percent in the 1990+24% case than in the reference case, by 6.6 percent in the 1990+9% case, and by 14.2 percent in the 1990-3% case (Figure 61). Jet fuel prices are projected to be 15 cents per gallon higher than in the reference case in 2010 in the 1990+24% case, 34 cents per gallon higher in the 1990+9% case, and 63 cents per gallon higher in the 1990-3% case.

Only relatively minor changes in the average fuel efficiency of new aircraft are expected to result from the imposition of carbon reduction targets. For example, in the 1990+9% case, new aircraft fuel efficiency is projected to improve at an annual rate of just 0.9 percent between 1996 and 2010, compared with the 0.7-percent rate projected in the reference case. As a result, the average efficiencies projected for the entire U.S. stock of aircraft are nearly the same in the two cases (Figure 62).

Less air travel is expected in the carbon reduction cases than in the reference case, leading to slower rates of aircraft stock turnover, which in turn limit the penetration of new aircraft into the aircraft stock. Higher fuel prices and lower air travel in the carbon reduction cases lower the demand for wide-body aircraft, which have higher efficiencies in terms of seat-miles per gallon than do narrow-body aircraft. In addition, near-term aircraft technologies that can improve fuel efficiency are limited, and they are not expected to be cost-effective even in the 1990-3% case. Among the six advanced aircraft technologies available by 2010, only weight-reducing materials and ultra-high-bypass engines, which are currently in use, are expected to penetrate the market (Table 12); and only the ultra-high-bypass engine technology is projected to achieve significant penetration (more than 90 percent) by 2010, and then only in the 1990-3% case or the high technology sensitivity case described below.

Figure 62. Projected New and Stock Aircraft Fuel Efficiency, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

Table 12. Projected Penetration for Selected Advanced Technologies for Aircraft, 2010
(Percent of New Sales)

Technology	Reference	1990+9%	1990+9% High Technology
Ultra-High-Bypass Engines.	9	90	77
Weight-Reducing Materials.	85	85	96
Advanced Aerodynamics.	0	0	96
Thermodynamics	0	0	56

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and HITECH09.D080698A.

Freight Trucks, Rail, and Shipping

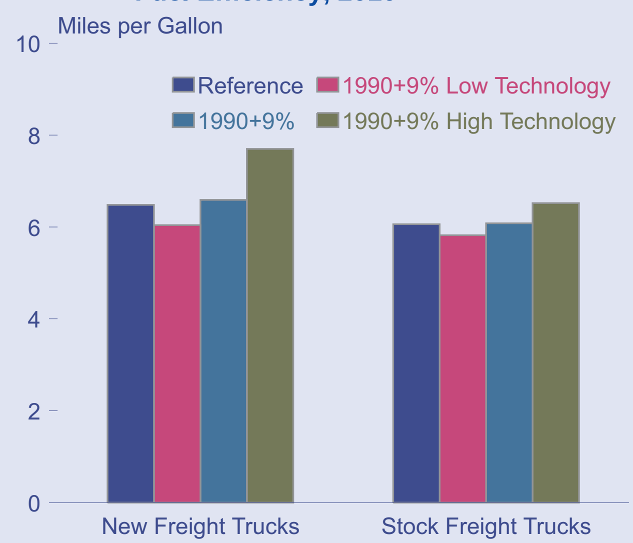
The projected demand for distillate fuel, used primarily for freight trucks and rail, is also lower in the carbon reduction cases than in the reference case in 2010—by 2 percent in the 1990+24% case, by 4.9 percent in the 1990+9% case, and by 8.3 percent in the 1990-3% case (see Figure 61). Distillate fuel prices are projected to be

15 cents per gallon higher in the 1990+24% case, 37 cents per gallon higher in the 1990+9% case and 68 cents higher in the 1990-3% case. These increases are larger than those projected for gasoline because of the higher carbon content of distillate fuel.

Higher fuel prices do not result in as much change in travel and efficiency for freight trucks and rail as they do for light-duty vehicles. Because of the slow turnover in the stock of freight trucks and rail and the high power requirements of the engines used to move freight, fuel savings are limited. The main source of reductions in distillate fuel use is the response to overall lower economic activity and demand for goods by 2010 in the carbon reduction cases, leading to lower freight travel for both trucks and rail. Lower demand for goods in the 1990+24%, 1990+9% and 1990-3% cases results in levels of freight truck travel that are 1.3 percent, 2.4 percent and 4.9 percent lower, respectively, in 2010 than projected in the reference case. Declines in coal consumption and production also lead to further cuts in rail travel as described below.

The potential for improvement in fuel economy for freight trucks is also limited. In the reference case, the fuel efficiency of new freight trucks is projected to increase by only 0.6 percent per year between 1996 and 2010. Even with higher distillate fuel prices in the 1990-3% case, the efficiency for new freight trucks improves at an annual rate of only 0.8 percent. As a result of the lower demand for goods and slower turnover in the stock of freight trucks projected in the 1990+9% case relative to the reference case, there is almost no difference in the projected average stock efficiencies for the two cases in 2010 (Figure 63).

Figure 63. Projected New and Stock Freight Truck Fuel Efficiency, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

The number of advanced technologies available for freight trucks is relatively small. Those with the greatest potential are advanced aerodynamics, the turbo-compound diesel engine, and the LE-55 heat engine, with expected marginal fuel efficiency improvements of approximately 25, 10, and 17 percent, respectively (Table 13). In all the carbon reduction cases, the advanced aerodynamics technology is projected to achieve the greatest efficiency improvements and highest penetration rates for both medium- and heavy-duty trucks. The turbo-compound diesel engine and the LE-55 heat engine do not penetrate the market until after 2010, except in the high technology sensitivity cases.

In percentage terms, the projections for rail and ship freight travel in 2010 show the sharpest reductions relative to the reference case in the carbon reduction cases. Rail freight travel is 9 percent, 23 percent, and 32 percent lower in 2010 in the 1990+24%, 1990+9%, and 1990-3% cases than in the reference case. Since more than 40 percent of rail travel is for coal transportation, the lower rail travel in the carbon reduction cases is primarily due to the projected reductions in coal production of 20 percent, 52 percent, and 71 percent in the 1990+24%, 1990+9%, and 1990-3% cases relative to the reference case. Domestic freight travel by ship is projected to be 3 percent, 6 percent, and 10 percent lower in the three cases than in the reference case. Domestic shipping is not expected to be affected as adversely by the decline in coal production as is rail traffic; however, with lower demand for goods and industrial production

Table 13. Projected Penetration of Selected Technologies for Freight Trucks, 2010
(Percent of New Sales)

Technology	Reference	1990+9%	1990+9% High Technology
Medium Trucks			
Improved Tires and Lubricants	0	0	0
Electronic Engine Controls	0	0	5
Advanced Drag Reduction	23	34	45
Turbo Compound Diesel	0	2	8
LE-55 Heat Engine	0	0	13
Heavy Trucks			
Improved Tires and Lubricants	0	3	98
Electronic Engine Controls	0	4	98
Advanced Drag Reduction	100	100	100
Turbo Compound Diesel	1	1	35
LE-55 Heat Engine	0	0	10

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and HITECH09.D080698A.

in the carbon reduction cases, domestic shipping is also projected to be lower.

Like freight truck and rail travel, shipping is affected more by the impacts of carbon prices on travel and shipping requirements than by the direct impacts of higher fuel costs. High-carbon residual fuel has the largest projected price increases of all the transportation fuels, with increments of 19 cents per gallon in the 1990+24% case, 46 cents in the 1990+9% case, and 84 cents—almost 100 percent—in the 1990-3% case relative to the prices projected for 2010 in the reference case.

Approximately 15 to 17 percent of the drop in total fuel consumption in 2010 in the carbon reduction cases is attributed to aircraft, 6 to 7 percent to freight trucks, 4 to 6 percent to rail engines, and 1 percent to marine engines. The relative energy consumption shares for the major transportation modes and fuels do not vary significantly across the cases (Table 14).

Table 14. Projected Fuel Consumption Shares in the Transportation Sector by Fuel and Travel Mode, 2010
(Percent of Total)

Projection	Reference	1990 +24%	1990 +9%	1990 -3%
Fuel				
Gasoline	58	58	57	56
Distillate	19	19	20	21
Jet Fuel	16	16	16	16
Residual	4	4	4	5
Alternative Fuels	3	3	3	3
Travel Mode				
Light-Duty Vehicles	57	56	56	55
Freight Trucks	17	19	20	20
Aircraft	16	16	16	16
Rail	2	2	2	2
Marine	6	6	6	7

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Both freight rail and domestic shipping efficiencies are projected to remain at reference case levels in the carbon reduction cases. Stock turnover will virtually cease, because rail ton-miles traveled are lower by 32 percent in 2010 in the 1990-3% case than in the reference case, and domestic shipping travel is 10 percent lower. Also, with the loss in revenue associated with the projected lower levels of travel, efficiency improvements will be difficult to achieve.

Alternative-Fuel Vehicles

According to consumer surveys, alternative-fuel vehicle sales are dependent on vehicle price, the cost of driving per mile, vehicle range, fuel availability, and commercial availability. In 2010, alternative-fuel vehicle sales as a percent of light-duty vehicle sales are projected to increase to 11.98 percent in the 1990+24% case, 12.07 percent in the 1990+9% case, and 12.10 percent in the 1990-3% case from 11.91 percent in the reference case. The projected market shares for alternative-fuel vehicles are higher in the carbon reduction cases primarily because higher fuel prices would encourage consumers to take advantage of the higher fuel efficiencies and lower costs of driving projected for some alternative-fuel vehicles relative to gasoline vehicles. In addition, as the fuel efficiency of alternative-fuel vehicles improves, their driving range will increase.

Although alternative-fuel vehicle sales increase in percentage terms relative to the reference case in 2010, the actual number of alternative-fuel vehicles sold is expected to be smaller in the carbon reduction cases as a result of projected declines in light-duty vehicle sales overall. In the reference case alternative-fuel vehicle sales are projected to be approximately 1.79 million vehicles in 2010, whereas sales range between 1.68 and 1.75 million vehicles in the 1990+24%, 1990+9%, 1990+9% , and 1990-3% cases. Similar results are projected for alternative-fuel consumption as a percentage of total transportation fuel use in 2010. Although the projected cost of driving per mile is lower for some alternative-fuel vehicles than for gasoline vehicles in some of the carbon reduction cases, it would still be more costly to drive an alternative-fuel vehicle than a gasoline vehicle. The purchase prices for most alternative-fuel vehicles still would be higher than those for conventional gasoline-powered vehicles, and additional driving costs would be incurred as the result of lower vehicle range and limited availability of fuel. Also, with higher projected fuel prices, vehicle-miles traveled are expected to be reduced for all vehicles, including those that use alternative fuels. Finally, the higher efficiencies of alternative-fuel vehicles would lower their total fuel consumption.

Sensitivity Cases

To examine the effects of technology improvements on energy use and prices, two sensitivity cases were analyzed for the transportation sector. The 1990+9% low technology sensitivity case was designed to hold average new vehicle fuel efficiencies at their 1998 levels throughout the forecast period. The implication is that stock turnover and travel reductions would have to compensate for the lack of fuel efficiency improvements in order to meet the carbon reduction targets. The 1990+9% high technology sensitivity case was designed to illustrate the effects of advanced fuel-saving technologies on transportation fuel efficiency, fuel consumption, and carbon emissions. This sensitivity case generally assumes that the costs of new technologies will be reduced, the marginal fuel efficiency benefits will be

Mass Transit and Carpooling

An issue for the transportation sector is whether the ratification of the Kyoto Protocol by the United States will lead to increased use of mass transit and carpooling. Automobile transportation is a major contributor to air pollution and greenhouse emissions, and a cutback in this area would be desirable. U.S. transportation patterns make this unlikely, however, in spite of the fact that the carbon reduction cases in this analysis project higher gasoline prices and lower levels of vehicle-miles traveled.

The United States consumes far more energy per capita for transportation than any other developed country, with U.S. passenger travel dominated by the automobile. In 1990, about 86 percent of passenger-miles were accounted for by automobiles, and mass transit accounted for less than 4 percent. The U.S. mass transit system includes buses, light rail, commuter rail, trolleys, subways, and an array of services such as van pools, subsidized taxis, dial-a-ride services, and shared minibus and van rides. Most cities of over 20,000 population have bus systems, and buses on established routes with set schedules account for over half of all public transit passenger trips. About 70 percent of all public transit trips in 1990, however, were in the 10 cities with rapid rail systems; 41 percent were in New York City and its suburbs.[a] More recent statistics show that, as of 1995, mass transit accounted for only 0.8 percent of total fuel consumption in the transportation sector.[b]

One reason for the low usage of mass transit in the United States and the concentration of use in major cities is urban development that has decreased the importance of historic central business districts (CBDs). Peak trips in general, and work trips in particular, have become diffuse in both origin and destination and thus not easily served by mass transit. In 1980 only 9 percent of the workers in urban areas and only 3 percent of workers living outside the central city were employed in the CBDs.[c] (In Europe, where population densities are much higher, access to the workplace is much easier.) Other factors that work against mass transit in the United States are a past history of low gasoline prices, rising income levels, increasing numbers of women in the workforce with needs to drop off and pick up children at child care facilities, a move toward less standardization of work hours, and premiums placed on personal independence and time saved by driving rather than making use of mass transit. The same factors affect the use of carpooling.

Available statistics support the contention that the lower levels of vehicle-miles traveled associated with the carbon reduction cases do not necessarily imply increased use of mass transit. According to the American Public Transit Association, all forms of mass transit in terms of passenger-miles decline during periods of high fuel prices.[d] Transit rail passenger-miles, which include light and heavy rail travel, declined by nearly 10 percent from 1973 to 1974 and by 5 percent from 1979 to 1981, even though real gasoline prices concurrently rose by 28 percent during both periods. Similar trends occurred in commuter rail, which experienced declines of almost 8 percent from 1980 to 1982. Between 1979 and 1982, transit bus passenger-miles declined by 7 percent and intercity bus travel by 1 percent, while real gasoline prices increased by 15 percent. A counter example is the period from 1973 to 1974, when transit bus use rose by 11 percent, and intercity bus passenger-miles increased by 5 percent. That period was unique, however, because gasoline was often either unavailable or required waits of up to several hours in gas station lines.

Carpooling trends, according to the U.S. Census Bureau, have declined from approximately 20 percent of the workforce in 1980 to just over 13 percent in 1990.[e] The National Personal Transportation Survey has reported similar trends in vehicle occupancy rates, which indicate that from 1977 through 1990, vehicle occupancy rates have declined in commuting to and from work, from 1.30 to 1.14 person-miles per vehicle mile.[f] These occupancy rates correspond to about one-third of total vehicle-miles traveled.

Because travelers do not take into account such externalities as reducing greenhouse gas emissions when making their transportation decisions, and past gasoline price increases do not seem to have had an impact, it is unlikely that mass transit and carpooling will increase in the United States without policy intervention factors such as higher gasoline taxes and urban and transportation planning that facilitates access to workplaces. There are differing opinions as to the role these factors could play in shaping travel patterns. If history, geography, income, and demographics are the primary determinants of travel patterns, policy may play only a minor role in changing energy use; but if instruments of public policy are primary travel determinants, then there is a large potential for policy to reduce energy use[g] and alter mass transit and carpooling patterns.

[a] U.S. Congress, Office of Technology Assessment, *Saving Energy in U.S. Transportation*, OTA-ETI-589 (Washington, DC, July 1994), pp. 5-6.

[b] S. Davis, *Transportation Energy Databook No. 17*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, August 1997), p. 2-12.

[c] U.S. Congress, Office of Technology Assessment, *Saving Energy in U.S. Transportation*, OTA-ETI-589 (Washington, DC, July 1994), pp. 5-6.

[d] American Public Transit Association, *1994-1995 Transit Fact Book* (Washington, DC, February 1995), pp. 106-107.

[e] S. Davis, *Transportation Energy Databook No. 17*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (data provided by the Journey-to-Work and Migration Statistics Branch, Population Division, U.S. Bureau of the Census) (Oak Ridge, TN: Oak Ridge National Laboratory, August 1997), p. 2-12.

[f] Federal Highway Administration, *National Personal Travel Survey: 1990 NPTS Databook*, Vol. II, Chapter 7 (Washington, DC, November 1993).

[g] U.S. Congress, Office of Technology Assessment, *Saving Energy in U.S. Transportation*, OTA-ETI-589 (Washington, DC, July 1994), pp. 5-6.

higher, and the advanced technologies will be commercially available at earlier dates than in the reference case or the carbon reduction cases.[52]

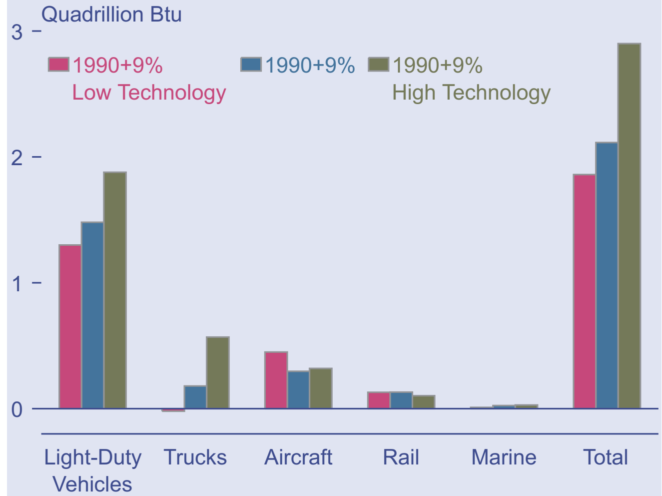
Higher projected carbon prices in the low technology sensitivity case lead to higher prices for all transportation fuels. In 2010, average fuel prices in the transportation sector are projected to be 14 percent higher in the 1990+9% low technology case than in the 1990+9% case. Gasoline prices are projected to be about 19 cents per gallon higher, jet fuel prices 21 cents per gallon higher, distillate fuel prices 22 cents per gallon higher, and residual fuel prices 26 cents per gallon higher.

Both fuel efficiency and travel are lower in the low technology case than in the 1990+9% case. Higher fuel prices would affect travel both directly and through their secondary impacts on the general levels of macroeconomic activity, disposable income, and freight movement. Of all travel modes, vehicle-miles traveled by light-duty vehicles are the most responsive to the higher fuel prices in the 1990+9% low technology case, with a 5.1-percent reduction from the projected level in the 1990+9% case in 2010. Air travel is reduced by a similar percentage, 5.5 percent, whereas smaller reductions are projected for freight, rail, and domestic shipping travel (0.8 percent, 3.1 percent, and 0.9 percent, respectively). Total projected fuel consumption in 2010 is higher in the low technology case than in the 1990+9% case, because fuel efficiency does not improve as rapidly.

With lower carbon prices and lower fuel prices in the 1990+9% high technology sensitivity case, more travel is expected than in the 1990+9% case. Despite the higher travel projection, however, more rapid improvements in new vehicle and stock fuel efficiencies result in lower fuel consumption in the high technology case, with higher fuel efficiencies outweighing the projected increases in vehicle-miles traveled that result from lower projected fuel prices. Average transportation fuel prices in 2010 are 9.6 percent lower in the 1990+9% high technology sensitivity case than in the 1990+9% case. Gasoline prices are projected to be 14 cents per gallon lower in 2010, jet fuel prices 13 cents per gallon lower, distillate fuel prices 14 cents per gallon lower, and residual fuel prices 16 cents per gallon lower.

Comparing across the travel modes, light-duty vehicles hold the greatest potential for reducing fuel consumption and carbon emissions with more rapid technology advances (Figure 64). Not only do light-duty vehicles

Figure 64. Projected Reductions From Reference Case Projections of Transportation Sector Fuel Consumption in High and Low Technology Sensitivity Cases, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

consume more fuel in total than the other vehicle types (more than 56 percent of all transportation fuel use in 1996), they also have the greatest potential for advanced technology penetration. In the 1990+9% high technology sensitivity case, light-duty vehicles are projected to account for 65 percent of the reduction in transportation fuel use relative to the 1990+9% case, compared with 20 percent for trucks, 11 percent for aircraft, 4 percent for rail, and 1 percent for marine.

Fuel-saving technologies for conventional light-duty vehicles in the high technology case are assumed to have approximately 50 percent lower marginal technology costs and 30 percent higher marginal fuel efficiency improvements than those for gasoline vehicles. All conventional technologies achieve lower sales penetration rates in the high technology case than in the 1990+9% case, due to lower fuel prices (Table 11); however, because the marginal fuel efficiencies are also higher than in the 1990+9% case, the total fuel efficiency improvement is larger in the high technology case.

With lower marginal costs and earlier introduction dates in the high technology sensitivity, most new aircraft technologies reach significantly higher penetration rates than in the 1990+9% case with reference technology (Table 12). The penetration rate for ultra-high-bypass

[52] High technology assumptions were derived from the following sources: light-duty vehicle conventional technology attributes from J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy*, American Council for an Energy-Efficient Economy (Washington, DC, November 1993); light-duty alternative fuel vehicle cost and performance attributes from U.S. Department of Energy, Office of Transportation Technologies, *Program Analysis Methodology: Final Report—Quality Metrics 98 Revised* (Washington, DC, April 1997); freight trucks from U.S. Department of Energy, Office of Transportation Technologies, *OHVT Technology Roadmap* (Washington, DC, October 1997), and conversations with Frank Stodolsky, Argonne National Laboratory, and Mr. Suski, American Trucking Association; air from conversations with Glenn M. Smith, National Aeronautics and Space Administration.

engines is lower in the high technology case, because they are partially displaced by advanced thermodynamic engines. Substantial fuel efficiency improvements result from the penetration of weight-reducing materials, advanced aerodynamics, and advanced thermodynamic engines, which can potentially achieve efficiency improvements of 15 percent, 18 percent, and 20 percent, respectively.

Fuel efficiency for new freight trucks rises by more than 1 mile per gallon by 2010 in the high technology case relative to the 1990+9% case, primarily because of the penetration of the turbo compound diesel, LE-55 heat engine, improved tires and lubricants, and electronic engine controls on heavy-duty trucks (Table 13). Both advanced engine technologies—the turbo compound diesel and LE-55 heat engine—are diesel technologies, which improve fuel economy by 10 percent and 23 percent, respectively.

The high technology case assumes that the U.S. Department of Energy Office of Transportation Technologies program goals[53] for alternative-fuel vehicle cost and performance improvements will be met. Generally these program goals include a reduction of 50 to 66 percent in the marginal price difference between comparable gasoline vehicles and electric or electric hybrid vehicles, and a 75-percent reduction in the difference for fuel cell vehicles. Fuel efficiency improvements are assumed to be 230 to 300 percent greater for electric and electric hybrid vehicles and 250 percent greater for fuel cell vehicles than for gasoline vehicles. These fuel efficiency improvements are also assumed to result in travel ranges that are 57 percent greater for electric hybrid vehicles and 20 percent greater for fuel cell vehicles than the range for similar sized gasoline vehicles. Total alternative-fuel vehicle sales in the 1990+9% high technology case in 2010 are projected to make up almost 19 percent of all light-duty vehicle sales, compared with just over 11 percent in both the reference and 1990+9% cases. The projected shares for different alternative-fuel vehicle types are shown in Table 15.

Table 15. Projected Alternative-Fuel Vehicle Shares of New Light-Duty Vehicle Sales by Type in the High Technology Cases, 2010
(Percent)

Vehicle Type	Sales Share
Flex-Fuel Methanol and Ethanol	9.1
Dedicated Methanol and Ethanol	2.1
Electric	1.2
Hybrid Electric/Gasoline	1.3
Hybrid Electric/Diesel	1.6
Bi-Fuel CNG and LPG	1.0
Dedicated CNG and LPG	2.5
Fuel Cell Gasoline	0.02
Fuel Cell Methanol	0.01
Diesel Direct Injection	2.1

CNG = compressed natural gas. LPG = liquefied petroleum gas (propane).

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

In order for alternative-fuel vehicles to displace large quantities of gasoline use, they must penetrate the market early enough to replace gasoline vehicles and then sustain high sales volumes. Displacement of gasoline may be limited, however, because the vast majority of the projected increase in alternative-fuel vehicle sales consists of alcohol flexible-fuel vehicles, which are expected to have only slightly higher fuel efficiencies than gasoline vehicles. They will also use only 15-percent blends of E85 and M85 and will more frequently be consuming gasoline than the alternative fuel.

For alternative-fuel vehicles to maintain a larger share of the vehicle market, they will need to have lower costs, higher performance, and earlier availability dates than projected in this analysis. Simultaneously, higher fuel prices will be needed to send market signals to both consumers and vehicle producers. The high technology case indicates both of these points: fuel-saving technology becomes available and is purchased in 2005, but its advantage is quickly offset by reductions in gasoline consumption, which lead to lower gasoline prices. Consequently, as fuel prices begin to decline after 2008, consumers tend to demand higher performance and larger vehicles, and manufacturers respond by designing and producing larger, more profitable models, such as sport utility vehicles.

[53] U.S. Department of Energy, Office of Transportation Technologies, *Program Analysis Methodology: Final Report—Quality Metrics 98* (Washington, DC, April 16, 1997).

4. Electricity Supply

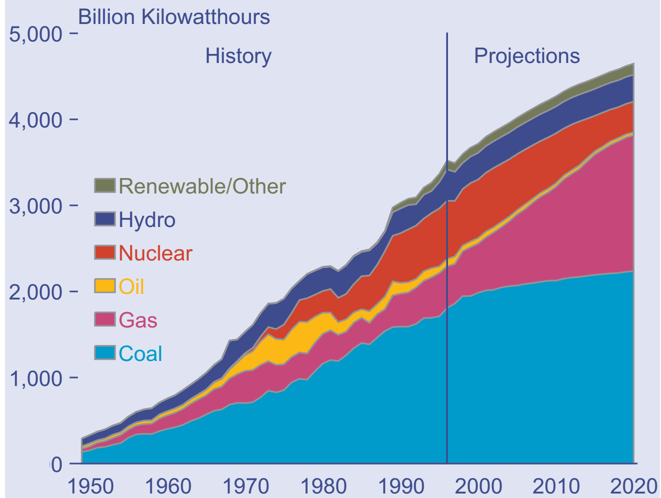
Introduction

This chapter discusses the electricity supply side options under various domestic carbon emissions reduction cases, particularly the 24-percent-above-1990 (1990+24%), 9-percent-above-1990 (1990+9%) and 3-percent-below-1990 (1990-3%) cases. The impacts on electricity sector fuel use, capacity expansion and retirement decisions, electricity prices, and carbon emissions are discussed. In addition, the results of sensitivity cases incorporating alternative assumptions about improvements in technology costs and performance, the potential role for new nuclear power plants, and reducing impacts on the coal industry are also discussed. The effects of demand-side decisions (i.e., consumer appliance choices and usage, as discussed in Chapter 3) that would reduce the demand for electricity are also considered.

During the approximately 100-year history of the electricity supply industry, the key fuels used to meet the ever-increasing demand for electricity have changed as new generating technologies have emerged and fuel prices varied (Figure 65). Beginning with small hydroelectric facilities just before the turn of the century, the industry then turned to fossil fuels. Among the fossil fuels, coal has almost always played a major role in U.S. electricity generation, and it remains the dominant fuel today. Oil and natural gas use has varied, depending on their respective prices. In fact, concerns about future oil and natural gas prices contributed to the emergence of nuclear power plants in the 1960s. In today's market, coal-fired power plants produce just over half of the electricity used in the United States, nuclear plants 19 percent, natural gas plants 14 percent, and hydroelectric plants about 10 percent. The remaining 7 percent comes from oil-fired plants and plants using other fuels such as municipal solid waste, wood, and geothermal and wind power.

In the reference case, which does not include the Kyoto Protocol, the power generation sector is expected to become more energy-efficient over the next 20 years as new, more efficient power plants are built. At the same time, however, dependence on fossil fuels, especially natural gas and coal, is expected to increase, leading to significant growth in power plant carbon emissions. Coal is expected to remain the dominant fuel as existing plants are used more intensively, but generation from natural gas is expected to increase rapidly, with gas-fired plants making up the vast majority of new capacity additions. Of the major non-carbon-based fuels, hydroelectric generation is expected to change very little, and nuclear generation is expected to decline as older, more costly plants are retired. Looked at another way, while the efficiency of the generation sector, expressed as the amount of energy in terms of British thermal units (Btu) needed to produce each kilowatthour of electricity, is expected to improve, increasing dependence on fossil fuels will lead to more rapid growth in electricity sector carbon emissions than in electricity sales (Figure 66). Without the improvement in efficiency, growth in fossil fuel use would match the growth in fossil-fired generation.

Figure 65. Electricity Generation by Fuel in the Reference Case, 1949-2020

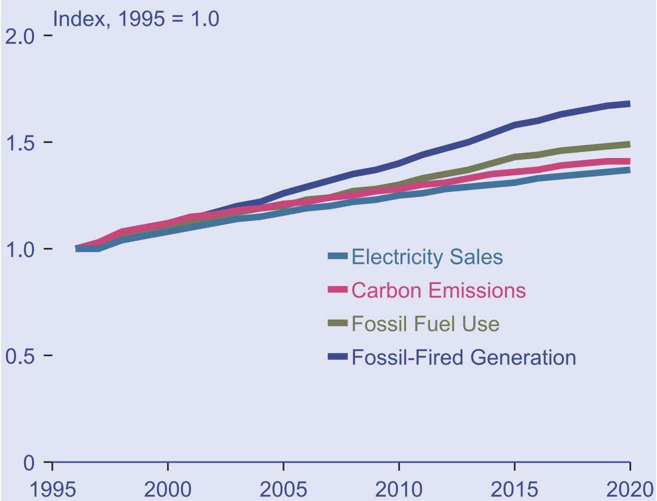


Note: Data on nonutility generation are not available for years before 1989, but it was small. In 1989, nonutility generation accounted for 6 percent of total U.S. electricity generation.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

Although the costs of non-carbon-based generating technologies have fallen, they still are not widely competitive with fossil fuel technologies. As a result, the most economical options available to electricity suppliers for meeting the demand for electricity over the next 20 years are existing coal plants and new natural gas plants. In 1995, the average operating cost of coal-fired power plants was 1.8 cents per kilowatthour. Only

Figure 66. Projections of Electricity Sales, Carbon Emissions, Fossil Fuel Use, and Fossil-Fired Generation, 1997-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

66 percent of their maximum potential output was needed, however, to meet the 1996 level of demand. Over the next 20 years, as the demand for electricity grows, the utilization of coal-fired plants is expected to approach 80 percent. For new capacity additions, the low capital costs and high operating efficiencies of natural-gas-fired combined-cycle plants make them the most economical choice for most uses.

Electricity suppliers have a variety of options available for reducing their carbon emissions. The degree to which each of the options is employed will depend on the level of reduction required and the resultant carbon price (i.e., the market value of a "carbon emissions permit") that evolves in the marketplace. Many of the options may require a significant financial incentive before they become economically attractive. Among the key carbon reduction options available to electricity suppliers are reducing the use of relatively carbon-intensive power plants (particularly coal-fired plants), increasing the use of less carbon-intensive technologies (mainly natural-gas-fired plants), the use of "carbon-free" technologies (i.e. wind, solar, biomass, geothermal, and nuclear), improving the operating efficiencies of existing plants, and investing in demand-side technologies that reduce electricity consumption.

In the short run, before a large number of new plants can be built, power suppliers will have to reduce carbon emissions by increasing the use of less carbon-intensive plants. For example, in today's market, most oil and natural gas steam plants are not used very intensively because of their relatively high operating costs. If carbon reduction efforts are made, however, their use is likely to increase, because they produce less carbon per kilowatthour than do coal-fired plants. In the longer run, power suppliers are more likely to turn to new, less carbon-intensive or carbon-free plants.

In this analysis, electricity producers are assumed to have 15 new generating technologies to choose from when new resources are needed, or when it is no longer economical to continue operating existing plants (Table 16). The lead times in the tables represent the time needed for site preparation and construction. Environmental licensing may take longer in some cases. The first-of-a-kind costs represent the cost of building a plant when the technology first becomes available, which tend to be relatively high until experience is gained with the technology. The *n*th-of-a-kind costs represent costs for technologies when they have matured. For technologies that are already considered mature, the two costs will be the same. Investors in the generation market are assumed to make their decisions by reviewing each technology's current and future capital, operations and maintenance, and fuel costs. Both current and expected future costs are considered, because generating assets require considerable investment and last many years. Therefore, developers are assumed to evaluate the costs of building and operating a plant for 30 years when making their decisions.[54] If the Kyoto Protocol is enacted, developers will also have to consider the relative level of carbon emissions from each technology, as well as the expected carbon prices. Depending on the carbon price, the economic decision could be tilted toward technologies that emit less carbon per unit of electricity produced.

Overall, because of the relatively wide variety of options available to them, electricity suppliers are expected to account for a disproportionately large share of projected carbon reductions. Nationally, to meet an emissions target 9 percent above 1990 levels, overall carbon emissions in 2010 would have to be reduced by 18 percent from their projected level in the reference case, which is 33 percent above 1990 levels. But in order to meet the target, emissions from the electricity sector in the 1990+9% case are reduced by 39 percent in 2010 relative to the reference case (Figure 67). The situation is similar in the 1990-3% case: electricity sector carbon emissions in 2010 are 54 percent lower than the reference case level. The reduction in carbon emissions is projected to be accomplished through a combination of fuel switching, improvements in end-use efficiency, and improvements in generator efficiency (Figure 68).

In the carbon reduction cases, carbon emissions in the electricity sector are projected to begin falling even before the enactment of the Kyoto Protocol, because power plant developers are assumed to consider future costs in their investment decisions. As the implementation date of the Kyoto Protocol approaches, it is assumed

[54] Capital costs are assumed to be recovered over the first 20 years of this period.

Table 16. Cost and Performance Characteristics of New Fossil, Renewable, and Nuclear Generating Technologies

Technology	Size (MW)	Lead Time (Years)	First Electricity Date	Overnight Capital Cost[a] (1996 Dollars per kWh) First-of-a-Kind	Overnight Capital Cost[a] (1996 Dollars per kWh) *n*th-of-a-Kind	Variable O&M (1996 Mills per kWh)	Fixed O&M (1996 Dollars per kW)	Heat Rate (Btu per kWh) First-of-a-kind	Heat Rate (Btu per kWh) *n*th-of-a-Kind	Carbon Emissions (Pounds per MWh)
Pulverized Coal (95% Scrubber)	400	4	2001	1,079	1,079	3.25	22.5	9,585	9,087	519
Advanced Coal (IGCC)	380	4	2001	1,833	1,206	1.87	24.2	8,470	7,308	417
Oil/Gas Stream (Conventional)	300	2	1998	991	991	0.5	30.0	9,500	9,500	296
Combined-Cycle (Conventional, F-Frame)	250	3	2000	440	440	2.0	15.0	8,030	7,000	250
Combined-Cycle (Advanced, G- & H-Frame)	400	3	2000	572	400	2.0	13.8	6,985	6,350	198
Combustion Turbine (Conventional)	160	2	1999	325	325	5.0	4.0	11,900	10,600	330
Combustion Turbine (Advanced Turbine System)	120	2	1999	458	320	5.0	5.7	9,700	8,000	249
Fuel Cell (Molten Carbonate)	10	2	2003	2,189	1,440	2.0	14.4	6,000	5,361	167
Nuclear (Evolutionary Advanced Reactor)	1,300	5	2010	2,356	1,550	0.4	55.0	10,400	10,400	0
Biomass	100	4	2005	2,243	1,476	5.2	43.0	8,911	8,224	0
Geothermal[b]	50	4	1996	NA	2,025	0.0	95.7	32,391	NA	0
Municipal Solid Waste[c]	30	1	1995	6,403	5,289	5.4	0.0	16,000	16,000	0
Solar Thermal[d]	100	3	2000	2,903	[e]1,910	0.0	46.0	NA	NA	0
Solar Photovoltaic	5	2	1997	4,556	[e]3,185	0.0	9.7	NA	NA	0
Wind	50	3	1997	1,235	965	0.0	25.6	NA	NA	0

[a]Overnight capital cost plus project contingencies.

[b]Because geothermal cost and performance parameters are specific for each of the 51 sites in the database, the value shown is an average for the capacity built in 2000.

[c]Because municipal solid waste does not compete with other technologies in the model, these values are used only in calculating the average costs of electricity.

[d]Solar thermal is assumed to operate economically only in Electricity Market Module regions 2, 5, and 10-13, that is, West of the Mississippi River, because of its requirement for significant direct, normal insulation.

[e]Capital costs for solar technologies are net of (reduced by) the 10 percent investment tax credit.

kW = kilowatt. kWh = kilowatthour. MW = megawatt. MWh = megawatthour. NA = not available. O&M = operations and maintenance costs.

Sources: Most values are derived by the Energy Information Administration, Office of Integrated Analysis and Forecasting from analysis of reports and discussions with various sources from industry, government, and the National Laboratories, with the following specific sources: **Solar Thermal**—California Energy Commission Memorandum, *Technology Characterization for ER94* (August 6, 1993). **Photovoltaic**—Electric Power Research Institute, *Technical Assessment Guide*, EPRI-TAG 1993. **Municipal Solid Waste**—EPRI-TAG 1993.

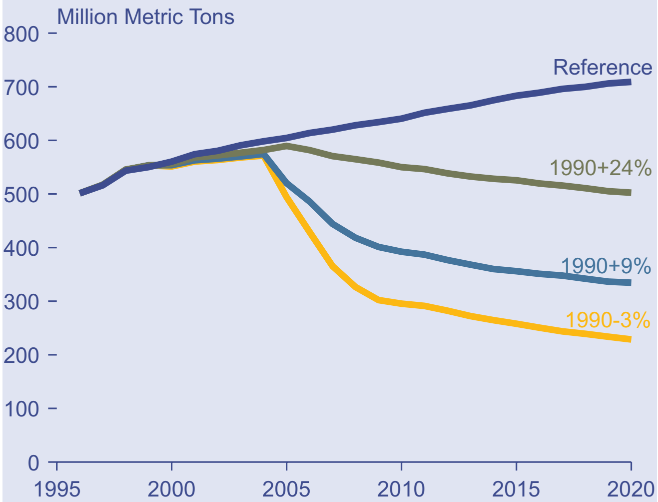
that developers will incorporate their expectations of carbon prices into their plans for new capacity additions, and that more lower-carbon generating capacity will be brought on line than would have been in the absence of the expected carbon reduction mandate.

Trends in Fuel Use and Generating Capacity

To reduce power plant carbon emissions in the 1990+9% case, the mix of fuels used to produce electricity is expected to change significantly from historical patterns (Figure 69). The change required is possible, but it will be challenging. For example, the shift required to stabilize carbon emissions 9 percent above 1990 levels is unprecedented historically. Even during the 1960s and 1970s, when nuclear generation grew rapidly, the change in fuel use patterns was not as dramatic as would be required in this case. In the 1990+24% case, the shift is less pronounced, but coal-fired generation still is projected to be 17 percent lower in 2010 and 40 percent lower in 2020 than in the reference case. Across the carbon reduction cases, the projections show a consistent shift away from coal to natural gas and renewables for electricity generation. In addition, nuclear generation remains near current levels, and the demand for electricity falls as the carbon reduction goal tightens (Figure 70).

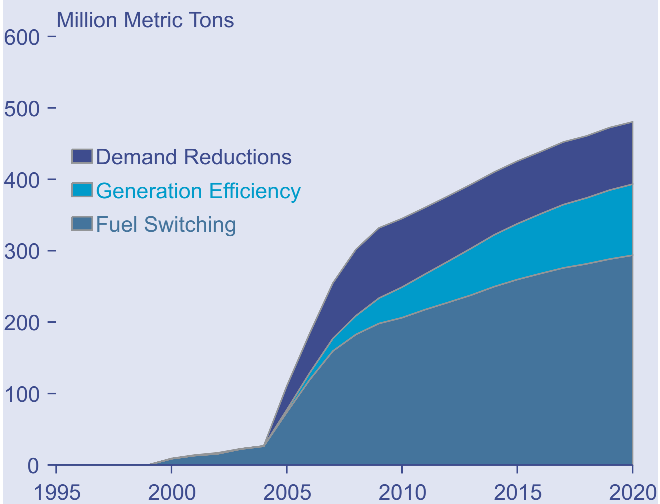
The shift away from coal-fired generation occurs because coal accounts for such a large share of power plant carbon emissions. In 1996, coal-fired power plants

Figure 67. Projections of Carbon Emissions From the Electricity Supply Sector, 1996-2020



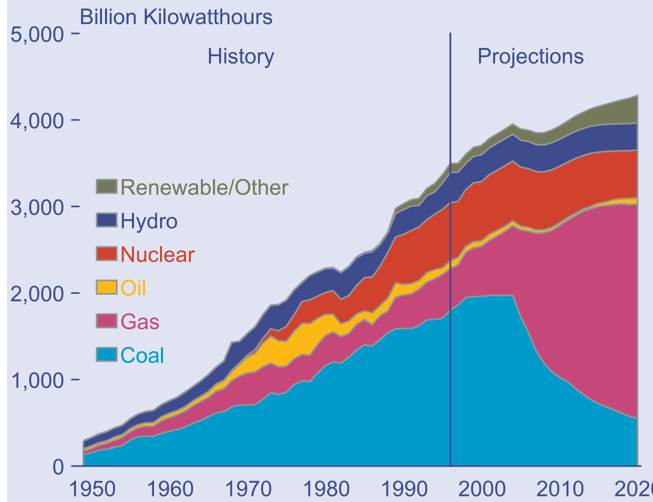
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 68. Projected Reductions in Carbon Emissions From the Electricity Supply Sector, 1990-3% Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

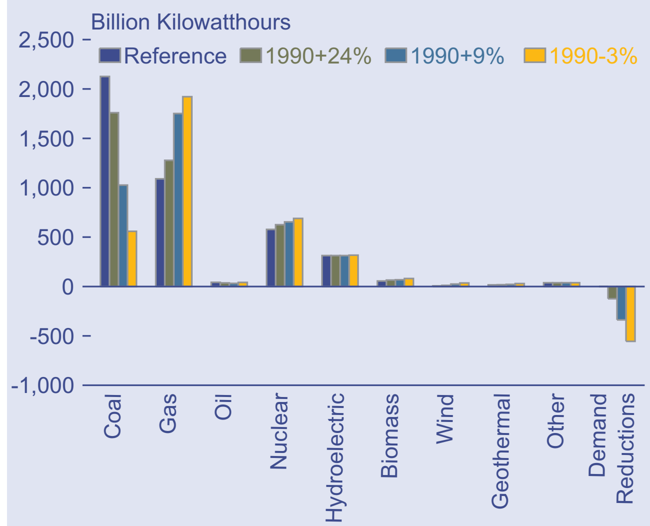
Figure 69. Electricity Generation by Fuel, 1990+9% Case, 1949-2020



Note: Data on nonutility generation are not available for years before 1989, but it was small. In 1989, nonutility generation accounted for 6 percent of total U.S. electricity generation.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD09ABV.D080398B.

Figure 70. Electricity Generation by Fuel, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

produced an estimated 92 percent of the carbon emissions in the power generation sector. In the reference case, that share is expected to be 86 percent in 2010; and in 2020, even though natural-gas-fired generation grows rapidly, coal plants still are expected to account for 81 percent of total carbon emissions from the electricity sector. Per unit of fuel consumed (Btu), coal plants emit nearly 80 percent more carbon than do natural gas plants, and the difference is even greater per megawatthour of electricity generated (Table 17). New natural gas combined-cycle plants are much more efficient than existing coal plants, requiring less than two thirds the amount of fuel (in Btu) to produce a kilowatthour of electricity. As a result, per megawatthour of electricity produced, existing coal plants release nearly 3 times as much carbon into the atmosphere as do the most efficient new natural gas plants.

Coal

Generation

In the carbon reduction cases, the projected decreases in coal-fired electricity generation are dramatic. In the 1990+24%, 1990+9%, and 1990-3% cases, coal-fired generation in 2010 is expected to be 18 percent, 53 percent, and 75 percent lower, respectively, than in the

Table 17. Carbon Emissions From Fossil Fuel Generating Technologies

Technology	Heat Rate (Btu per Kilowatthour)	Carbon Emissions	
		Pounds per Million Btu	Pounds per Megawatthour
Coal-Fired Technologies			
Existing Capacity	10,000	57	571
New Capacity Additions	9,087	57	519
Advanced Coal Technology	7,308	57	418
Natural-Gas-Fired Technologies			
Conventional Turbine	10,600	32	336
Advanced Turbine	8,000	32	253
Existing Gas Steam	10,300	32	326
Conventional Combined-Cycle	7,000	32	222
Advanced Combined-Cycle	6,350	32	201
Fuel Cell	5,361	32	170

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

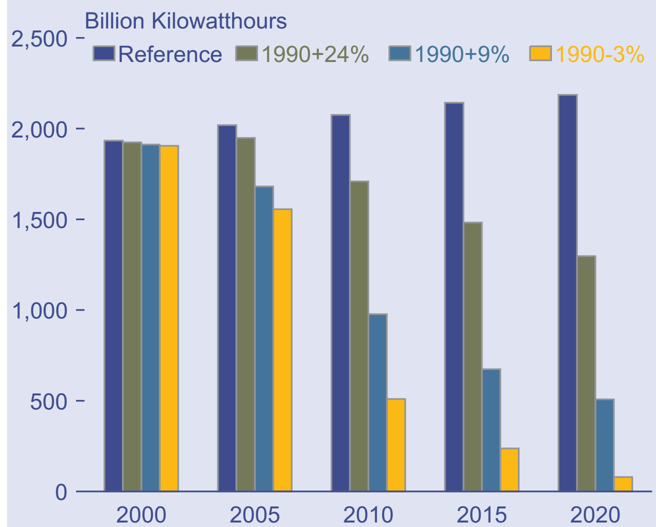
reference case (Figure 71). In 2020, the differences from the reference case are even larger: 41 percent in the 1990+24% case, 77 percent in the 1990+9% case, and over 96 percent in the 1990-3% case. In 1990-3% case, coal-fired generation is virtually eliminated. Coal plants simply are not very economical when carbon prices are high.

Such reductions in coal use would come at a cost. Although they are major carbon emitters, existing coal plants are very economical, and their operating costs have been falling (Figure 72). Under more stringent emissions reduction targets, however, with rising carbon prices, the economics of coal-fired generation would change (Table 18). For a power supplier deciding whether to continue operating an existing coal plant, build a new coal plant, build a new natural-gas-fired combined-cycle plant, or convert an existing coal-fired plant to natural gas, continued operation of the coal plant would be a clear winner in the absence of a carbon price. As the carbon price rises, however, the new natural gas plant looks more attractive. In the hypothetical example, assuming a 70-percent capacity factor for the four types of plant, it would make sense to shut the coal plant down and build a new natural gas plant at a carbon price of approximately $100 per metric ton of carbon.[55] Assuming a 30-percent capacity factor, the crossover point would be closer to $200 per metric ton of carbon. In this hypothetical example, the carbon prices that would induce power suppliers to retire existing coal plants are high, because the operating costs of most existing coal plants are low. In reality, the crossover point would vary from plant to plant.

Generating Capacity

In all the carbon reduction cases, significant amounts of coal capacity are expected to be retired (Figure 73). In general, the projected changes in the mix of generating

Figure 71. Projections of Coal-Fired Electricity Generation, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

capacity parallel the changes in fuel use. As the domestic carbon reduction requirement becomes more stringent, more coal capacity is retired and more natural gas and renewable plants are built (Figure 74). In the 1990+24% and 1990+9% cases, there is 3 percent and 10 percent less coal-fired capacity by 2010, and 13 percent and 36 percent less by 2020. Approximately two-thirds of the existing coal-fired capacity is projected to be retired by 2020 in the 1990-3% case. The net result is that the share of capacity accounted for by coal plants declines from around 40 percent in 1996 to just over 29 percent in 2010 and to slightly over 11 percent in 2020 in the 1990-3% case.

One possible effect of the projected coal plant retirements is that some of the plants may be shut down before their total investment costs are recovered. Such

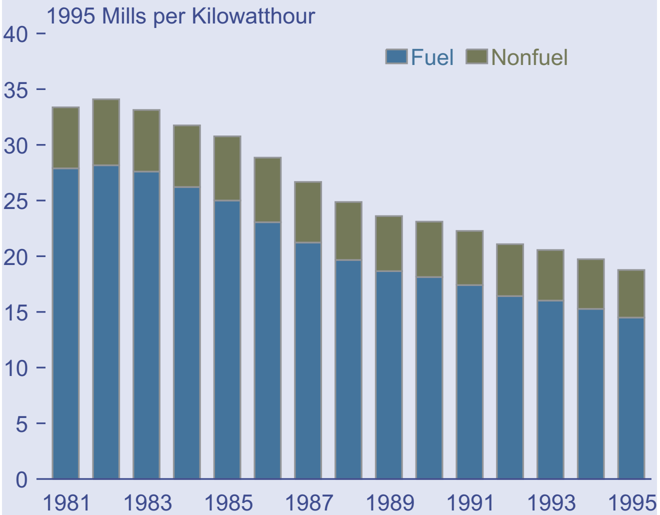
[55] In NEMS, the capacity factor for a particular plant type is determined by its operating costs. The values presented here are for illustration only.

Table 18. Hypothetical Examples of Levelized Plant Costs at Various Carbon Prices
(1996 Cents per Kilowatthour)

Plant Type	Carbon Price (1996 Dollars per Metric Ton)						
	0	50	100	150	200	250	300
70-Percent Capacity Factor							
Existing Coal-Fired	1.64	2.92	4.21	5.49	6.78	8.06	9.35
New Coal-Fired	3.67	4.91	6.16	7.40	8.65	9.89	11.14
New Gas-Fired Advanced Combined-Cycle	3.04	3.53	4.02	4.52	5.01	5.50	6.00
Coal-to-Gas Conversion	3.45	4.19	4.94	5.68	6.42	7.16	7.91
30-Percent Capacity Factor							
Existing Coal-Fired	1.92	3.21	4.49	5.78	7.06	8.35	9.63
New Coal-Fired	6.69	7.93	9.18	10.42	11.67	12.91	14.16
New Gas-Fired Advanced Combined-Cycle	4.23	4.72	5.22	5.71	6.21	6.70	7.19
Coal-to-Gas Conversion	3.90	4.64	5.38	6.12	6.87	7.61	8.35

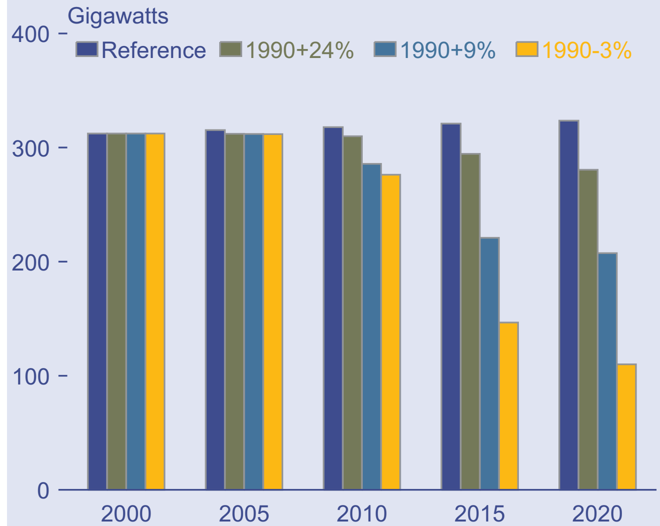
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 72. Operating Costs for Coal-Fired Electricity Generation Plants, 1981-1995



Source: Form FERC-1, "Annual Report of Major Electric Utilities, Licensees, and Other."

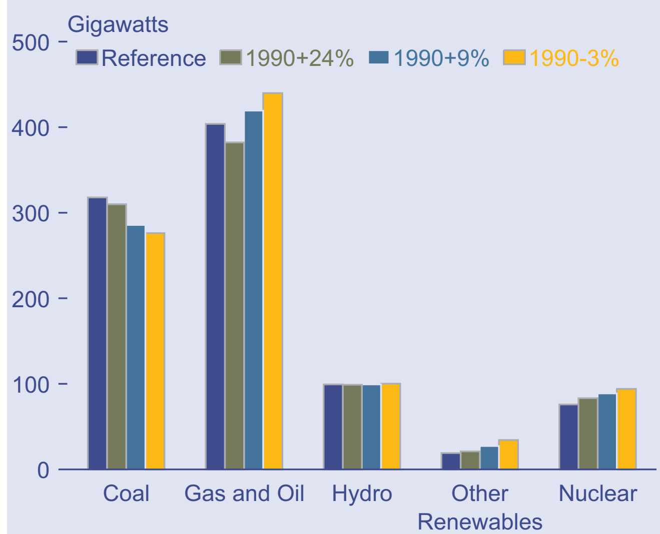
Figure 73. Projections of Coal-Fired Generating Capacity, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

unrecovered costs would be stranded. Most coal plants are fairly old, however, and their construction costs have already been recovered. On the other hand, some plant owners could suffer losses because plants they expected to be profitable might no longer be profitable when carbon prices are imposed.

Figure 74. Electricity Generation Capacity by Fuel, 2010



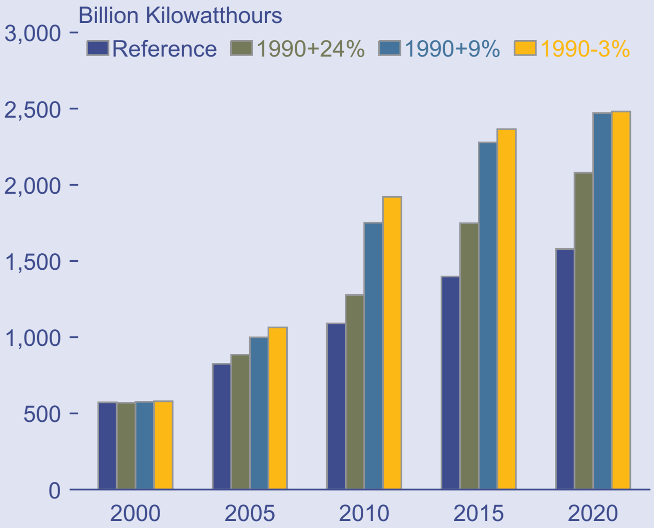
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Natural Gas

Generation

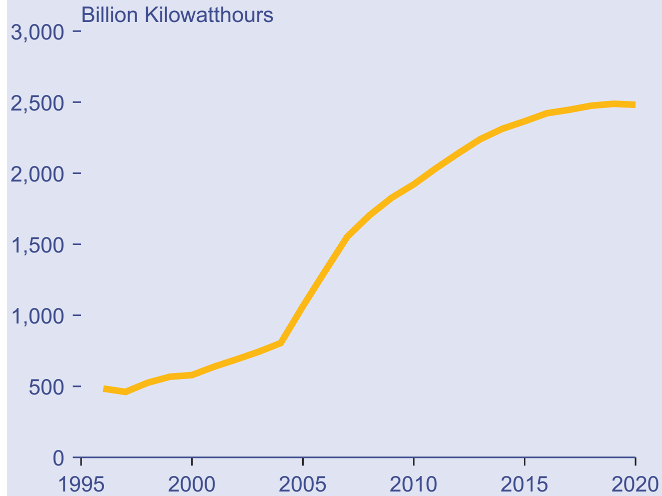
The story for natural gas generation is the opposite of that for coal (Figure 75). As the requirement to reduce carbon emissions tightens and the associated carbon price rises, natural-gas-fired generation becomes more economical than coal-fired generation. In 2010 and beyond, electricity generation from natural gas is between 17 percent and 76 percent higher in the carbon reduction cases than in the reference case projections. Overall, between 1996 and 2020, natural gas generation increases by almost 500 percent in the most stringent carbon reduction cases, and even in the 1990+24% case it

Figure 75. Projections of Natural-Gas-Fired Electricity Generation, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 76. Natural-Gas-Fired Electricity Generation, 1990-3% Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD03BLW.D080398B.

is more than 30 percent higher than in the reference case by 2020. Although it may be expensive to stop using low-cost coal plants, replacing them with efficient natural gas combined-cycle plants reduces carbon emissions per kilowatthour of electricity generated by nearly two-thirds.

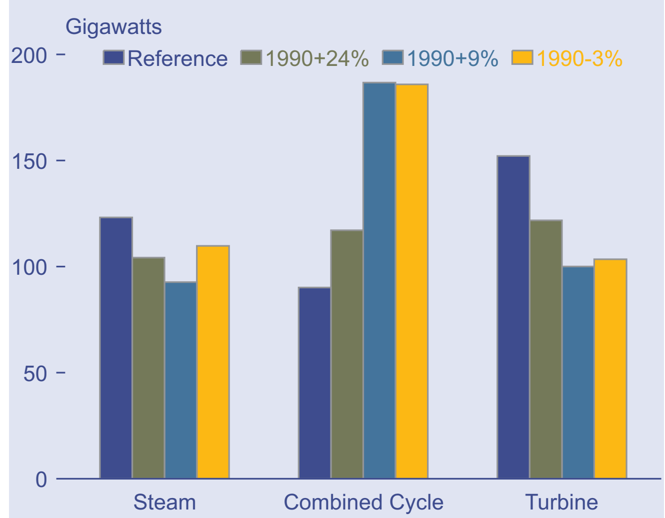
The rate of increase in natural-gas-fired generation varies over the 24-year projection period (Figure 76). When carbon emission limits are first imposed in 2005, there is rapid growth in natural gas generation, both because the rising carbon price makes existing natural gas plants more economical than existing coal plants and because new natural gas plants are added quickly. After the initial shift to natural gas, the growth in natural gas generation continues, but at a slower rate. In the later years of the projection, natural gas generation does not increase as rapidly, because carbon-free renewable technologies become economical as the demand for electricity grows and natural gas prices increase.

In the carbon reduction cases, power plant use of natural gas (excluding industrial cogeneration) is projected to rise from roughly 3 trillion cubic feet in 1996 to between 8 and 12 trillion cubic feet in 2010 and between 12 and 15 trillion cubic feet in 2020. The projected increase in demand for natural gas in the electricity sector contributes to higher gas prices overall. As a result, only small increases are projected for gas demand in other sectors for the less stringent cases. In the more stringent cases, gas demand in the other sectors (excluding industrial) actually declines. For example, in the 1990+9% case, electricity sector gas use in 2010 is 57 percent higher than projected in the reference case, but total gas consumption is only 10 percent higher (see Chapter 5 for a discussion of natural gas supply).

Generating Capacity

There is only a little variation in the projections of total natural-gas-fired generating capacity across the carbon reduction cases. On the other hand, there are differences in the types of natural gas plants projected to be built (Figure 77). In the more stringent carbon reduction cases, with higher carbon prices, the mix of natural gas plants shifts from relatively inefficient simple natural gas turbines and older steam plants to more efficient combined-cycle facilities. The trend toward more efficient gas-fired technologies would be even stronger in the 1990-3% case without the significant reduction in electricity demand that is projected relative to the reference case (see below, Figure 84).

Figure 77. Projections of Natural-Gas-Fired Electricity Generation Capacity, 2010



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

A critical question is whether new natural gas capacity can be built in sufficient quantity and in the right places to reduce carbon emissions to the levels required by the Kyoto Protocol. For example, in the 1990-3% case, the amount of capacity, mostly natural gas, projected to be built in some years far exceeds the amount of capacity built in any year since 1983. The average amount of generating capacity brought on line each year since 1983 has been around 10 gigawatts (33 typical plants).[56] The peak year was 1985, when just under 22 gigawatts of capacity was added. In the 1990-3% case, annual additions are projected to exceed 28 gigawatts (93 typical plants) in some years.

Some gas-fired plants are expected to be built to meet growth in demand, but most are likely to replace retiring coal plants. From 2008 to 2020, the projected additions of generating capacity in the 1990-3% case average 24 gigawatts annually, with just over 28 gigawatts in 2009. This level of construction is high but not unprecedented. It is actually less than the amount of capacity that was built annually during the 1970s, when the demand for electricity was growing at more than twice the rate projected in the reference case.

Given time and forewarning, the natural gas plant design and construction industry should be able to meet the challenge presented in the carbon reduction cases; however, the prices for new gas-fired facilities might rise above those used in this analysis. In addition, the situation could be exacerbated by the fact that many other countries may also be turning to natural gas in order to reduce their carbon emissions.

Not only will a large number of new natural gas plants have to be built, they will also have to be built in the right places. Today's electricity transmission system is constructed around major load and supply centers, connecting major cities to major power plants. The location of power plants is critical to the reliability of the electricity supply system. If, as expected, a large number of existing coal plants are retired to reduce carbon emissions, many of the new gas plants will have to be built at the locations of the coal plants they replace, in order to maintain the reliability of the system. (Biomass and wind plants must be built where their resources are available.) The alternative would be to reconfigure the transmission system to accommodate new plant locations,[57] an undertaking that might require additional investment.

One option for adding new natural-gas-fired capacity would be to modify existing coal-fired plants to burn natural gas instead of coal. This option, however, may not prove to be economical. Generally, there are two approaches for converting a coal plant to burn gas. The first is simply to modify the existing coal boiler so that it can be fired with natural gas. From a mechanical perspective this is not terribly difficult or expensive. The required plant modifications would be expected to cost \$70 to \$80 per kilowatt of capacity, mainly for new burners and gas handling equipment (compressors, metering station, distribution headers, etc.). In terms of performance, there would be a small loss of efficiency, 2 to 5 percent, if gas were burned in a boiler originally designed to burn coal.[58]

The main problem with this approach to plant conversion is the relative thermal inefficiency of existing coal plants. The majority of older coal plants consume between 10,000 and 10,500 Btu of fuel for each kilowatthour of electricity they produce,[59] as compared with 6,500 to 7,500 Btu of fuel input for each kilowatthour of electricity produced by a new gas-fired combined-cycle plant. Existing coal plants are economical because the fuel is inexpensive, not because they are thermally efficient.

As described above (see Table 18), in the absence of required carbon emissions reductions, existing coal-fired plants are the most economical option for electricity generation. Conversion of existing plants from coal to gas is not the most economical option if the plant is to be used at a high capacity factor. If the price of carbon emissions rises, however, continuing to run the existing coal plant becomes less economical. Assuming a 70-percent capacity factor and a carbon price of \$100 per metric ton, it would make sense to abandon the plant (not the site) and build a new gas-fired combined-cycle plant. At a lower capacity factor, the carbon price would have to be higher before the operational cost savings from the greater efficiency of a new combined-cycle plant would offset its higher capital costs (Table 18).

The second approach to using gas in an existing coal plant would be to "repower" it by converting it into a natural gas combined-cycle plant. This approach would result in higher plant efficiency, but it would also be much more expensive than the first approach. In a typical repowering, the coal handling system and the boiler are replaced with new combustion turbines and a heat

[56]Depending on the technology type, new power plants differ tremendously in size, from a few kilowatts for the smallest distributed photovoltaic technologies to 500,000 kilowatts (500 megawatts) or more for the largest new coal and nuclear technologies. Throughout this report, when a number of typical plants is provided, a 300-megawatt average plant size is used.

[57]See Energy Information Administration, "An Exploration of Network Modeling: The Case of NEPOOL," in *Issues in Midterm Analysis and Forecasting 1998*, DOE / EIA-0607(98) (Washington, DC, July 1998), for a discussion of the impact of plant location on reliability and pricing.

[58]Cost and performance impact estimates provided by Parsons Engineering.

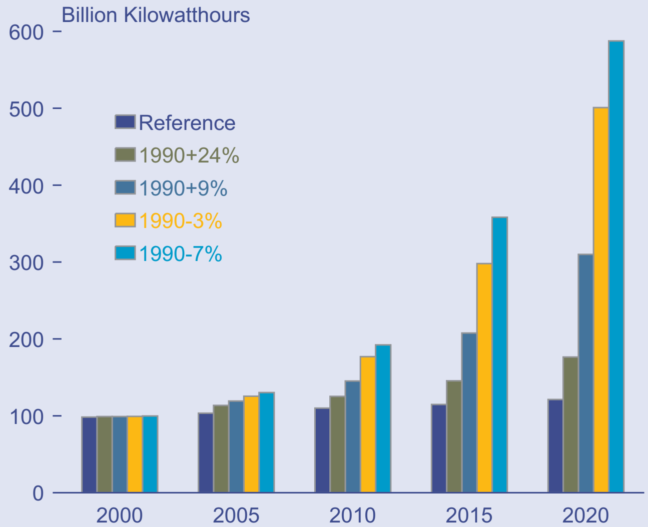
[59]Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

recovery boiler. The only significant part of the plant that is maintained is the original turbine generator. This approach can be attractive at some facilities, but it is not without problems. New combined-cycle plants are packaged systems. The turbines, heat recovery boiler, and turbine generator are designed to work smoothly together for optimal efficiency. Because many older coal-fired plants were custom designed and built, they do not always come in standard sizes or configurations or with standard operational parameters. If such facilities are to be repowered, additional work will be required to integrate the system components. Given that for a typical combined-cycle plant the steam turbine generator accounts for between 10 and 22 percent of the capital cost of the plant,[60] the additional work could easily drive the cost of repowering beyond what it would cost simply to replace the plant with a new, more efficient packaged combined-cycle plant.

Renewable Fuels

In the carbon reduction cases, U.S. electricity suppliers are expected to turn to renewable energy resources later in the projection period to meet the demand for electricity while reducing carbon emissions. Wind, biomass, geothermal, solar, and hydropower resources generally are thought to have less environmental impact than fossil fuels; they are domestically available; and in some instances they have begun to penetrate U.S. electricity markets. Significant growth in the use of nonhydroelectric renewable resources for electricity generation is expected to accompany efforts to reduce carbon emissions (Figure 78).

Figure 78. Projections of Nonhydroelectric Renewable Electricity Generation, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

The largest increases in renewable generation are expected after 2010 in the most stringent carbon reduction cases (Table 19). For this reason, the results of the 7-percent-below-1990 (1990-7%) case are also discussed in this section. Before 2010, nonhydroelectric renewable technologies generally are not competitive with new natural gas plants, but their costs are expected to fall over time. With higher carbon prices, these technologies can be expected to play a significant role in reducing carbon emissions. In the reference case little growth in generation from renewables is expected. In the carbon reduction cases, nonhydroelectric renewable generation is 1.1 to 1.7 times the reference case level in 2010 and 1.5 to 4.8 times the reference case level in 2020.

Because of the lack of market experience with renewable technologies other than hydropower, there is considerable uncertainty about the costs of developing them on the scale that would be needed for large carbon emission reductions. It is also unclear whether electric system reliability can be maintained if large quantities of wind or solar, which have intermittent output, are developed. Although some environmental objections have been raised against some renewables, including negative effects on animal life, destruction of habitat, and damage to scenery and recreation, these effects are small in comparison with the alternatives. While wind and biomass technologies are expected to be the most important renewable technologies used to reduce carbon emissions, others—including geothermal, conventional hydroelectric, and solar power plants—may also play a role (Table 19).

Wind

Among the nonhydroelectric renewable fuels, biomass and wind technologies are expected to make the most significant contributions to carbon emission reductions. Projected growth in the wind and biomass industries, together with the natural gas industry, would at least partially offset the impacts of declines in the coal industry. The biomass industry in the United States today is small, but it could see large growth. Similarly, the wind industry, estimated to employ 30,000 to 35,000 people worldwide in 1995, could increase several times over in the most stringent carbon reduction cases. In some regions, wind is projected to provide a significant share of electricity supply. However, the ability of wind resources to meet large-scale U.S. electric power needs reliably and cost-effectively is uncertain. Wind power is an intermittent technology, available only part of the time during a day or season. As a result, EIA assumes that the maximum contribution of wind power will be limited to 12 percent of any region's total annual generation requirements (excluding cogeneration) to avoid reliability problems that larger shares might cause.

[60] Electric Power Research Institute, *Technical Assessment Guide*. The steam turbine and auxiliary systems account for 10 percent of the plant. If the boiler can also be used, this figure rises to 22 percent.

Table 19. Projected U.S. Electricity Generation From Renewable Fuels
(Billion Kilowatthours)

Projection	2000	2010					2020				
	Reference	Reference	1990 +24%	1990 +9%	1990 -3%	1990 -7%	Reference	1990 +24%	1990 +9%	1990 -3%	1990 -7%
Electricity Generators											
Conventional Hydropower	310.3	313.0	313.0	313.0	317.4	321.9	313.2	313.1	313.1	317.7	322.4
Geothermal	17.2	16.8	18.0	21.7	29.9	30.4	19.9	25.1	33.4	47.2	53.3
Municipal Solid Waste	22.8	27.0	27.0	26.8	26.5	26.5	29.8	29.8	29.7	29.8	29.9
Wood and Other Biomass	8.2	8.7	17.6	21.0	34.7	36.4	8.7	22.5	83.1	244.4	305.1
Solar Thermal	0.9	1.2	1.2	1.2	1.2	1.2	1.5	1.5	1.5	1.5	1.5
Solar Photovoltaic	0.1	0.6	0.6	0.6	0.7	1.0	1.4	1.4	1.4	1.8	2.3
Wind	5.7	6.2	11.2	24.7	35.7	48.9	8.7	43.6	108.3	123.4	142.8
Subtotal	**365.2**	**373.5**	**388.6**	**409.0**	**446.1**	**466.2**	**383.2**	**437.0**	**570.5**	**765.9**	**857.2**
Cogenerators											
Municipal Solid Waste	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Biomass	41.2	47.3	47.4	46.9	45.9	45.6	48.9	50.2	50.2	50.4	50.5
Subtotal	**43.5**	**49.6**	**49.7**	**49.2**	**48.2**	**47.9**	**51.2**	**52.5**	**52.5**	**52.7**	**52.8**
Total Renewable Generation	**408.7**	**423.1**	**438.3**	**458.2**	**494.3**	**514.1**	**434.4**	**489.5**	**623.1**	**818.5**	**910.0**
Total Electricity Generation	**3,716.8**	**4,267.6**	**4,144.0**	**3,929.7**	**3,712.6**	**3,641.7**	**4,648.2**	**4,422.3**	**4,282.7**	**4,160.2**	**4,105.1**
Renewable Share of Generation (Percent)	11.0	9.9	10.6	11.7	13.3	14.1	9.3	11.1	14.5	19.7	22.2
Nonhydroelectric Renewable Share of Generation (Percent)	2.6	2.6	3.0	3.7	4.8	5.3	2.6	4.0	7.2	12.0	14.3

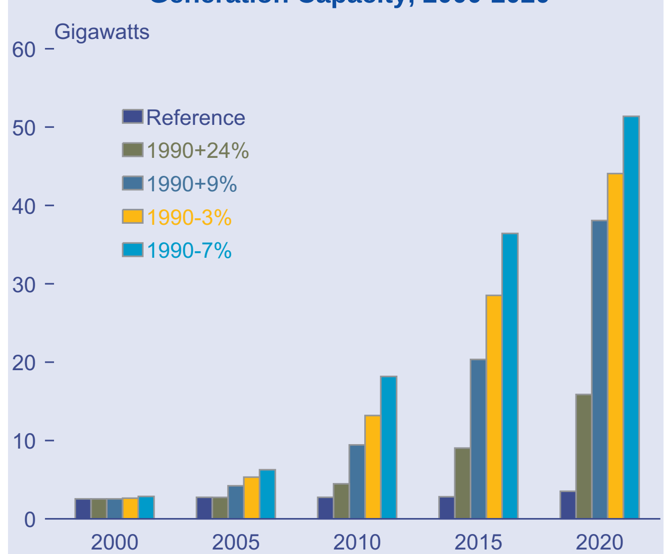
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

In the reference case, wind remains a minor contributor to both total renewable energy and total electricity supply through 2020 (Table 19), accounting for just 2 percent of generation from renewables and far less than 1 percent of total generation. In the carbon reduction cases, its contribution grows. In the 1990+9% case, generation from wind resources reaches 25 billion kilowatthours in 2010 and 108 billion kilowatthours in 2020, accounting for nearly 17 percent of renewable generation and 2.5 percent of all U.S. electric power. In the 1990-3% and 1990-7% cases, with greater carbon reduction requirements, U.S. reliance on wind power is expected to be higher, particularly after 2010. Generation from wind power reaches 36 billion kilowatthours by 2010 in the 1990-3% case and increases even more thereafter, reaching 123 billion kilowatthours in 2020. In the 1990-7% case it rises to 10 percent of renewable generation in 2010 and 16 percent (143 billion kilowatthours) in 2020, accounting for more than 3 percent of all electric power output.

In terms of generating capacity, wind accounts for more than 11 percent of all renewables capacity in 2010 in the 1990-3% case and 26 percent of all renewables capacity in 2020 in the 1990-7% case (Table 20). Again, however, wind-powered capacity remains a relatively small share of overall U.S. electricity generating capacity, in no case exceeding 6 percent of the total. Wind power is already entering some U.S. markets, and hundreds of megawatts of new wind capacity is expected to enter U.S. service before 2000. In the carbon reduction cases, wind power expands rapidly (Figure 79). The projection for wind capacity in 2005 in the 1990+9% case exceeds the reference case projection for 2020, and in 2020 it is more than 38 gigawatts. The wind capacity projections for 2020 are 44 gigawatts in the 1990-3% case and 51 gigawatts in the 1990-7% case—more than 14 times the reference case forecast.

The importance of wind power varies from region to region. Whereas wind capacity today is concentrated in

Figure 79. Projections of Wind-Powered Electricity Generation Capacity, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table 20. Projected U.S. Electricity Generation Capacity From Renewable Fuels
(Gigawatts)

Projection	2000 Reference	2010 Reference	2010 1990 +24%	2010 1990 +9%	2010 1990 -3%	2010 1990 -7%	2020 Reference	2020 1990 +24%	2020 1990 +9%	2020 1990 -3%	2020 1990 -7%
Electricity Generators											
Conventional Hydropower	79.39	79.78	79.78	79.80	80.74	81.84	79.78	79.79	79.80	80.78	81.92
Geothermal	3.02	2.80	2.98	3.51	4.68	4.75	3.02	3.77	4.95	6.94	7.81
Municipal Solid Waste	3.40	4.02	4.01	3.99	3.95	3.95	4.42	4.42	4.41	4.43	4.44
Wood and Other Biomass	1.64	1.76	1.80	2.70	4.93	5.32	1.76	2.74	11.95	35.27	43.99
Solar Thermal	0.36	0.44	0.44	0.44	0.44	0.44	0.54	0.54	0.54	0.54	0.54
Solar Photovoltaic	0.02	0.22	0.22	0.22	0.27	0.39	0.56	0.56	0.56	0.71	0.91
Wind	2.55	2.75	4.47	9.44	13.19	18.17	3.52	15.87	38.08	44.06	51.37
Subtotal	**90.39**	**91.77**	**93.71**	**100.10**	**108.20**	**114.85**	**93.60**	**107.68**	**140.29**	**172.72**	**190.97**
Cogenerators											
Municipal Solid Waste	0.44	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Biomass	6.08	6.70	6.68	6.60	6.48	6.44	6.84	6.96	6.93	6.93	6.94
Subtotal	**6.52**	**7.14**	**7.13**	**7.05**	**6.92**	**6.89**	**7.29**	**7.41**	**7.38**	**7.38**	**7.39**
Total Renewable Capacity	**97**	**99**	**101**	**107**	**115**	**122**	**101**	**115**	**148**	**180**	**198**
Total Electricity Capacity	**803**	**916**	**895**	**921**	**945**	**944**	**1,008**	**972**	**965**	**958**	**949**
Renewable Share of Capacity (Percent)	12.07	10.80	11.26	11.64	12.19	12.90	10.01	11.84	15.30	18.79	20.91
Nonhydroelectric Renewable Share of Capacity (Percent)	2.18	2.09	2.35	2.97	3.64	4.23	2.09	3.63	7.03	10.36	12.27

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

a few places—principally California, with smaller amounts in Texas and Minnesota—in the carbon reduction cases, wind power development is expected to occur in most regions west of the Mississippi River, as well as in New England. Wind plants do not penetrate heavily in most parts of the East and Southeast, where resources are limited. For example, in the 1990-3% case, more than 70 percent of all wind capacity in 2010 is projected to be in the West, with three-quarters of the remainder in the Upper Midwest. Still, wind power supplies only around 2 percent of generation in the Upper Midwest, the Northwest and California and nearly 10 percent in the Southwest in 2010 in the 1990-3% case. On the other hand, in the 1990-7% case, wind accounts for significant shares of total generation in 2020 in some regions.

Large-scale wind power development faces significant uncertainties with regard to reliability, technology costs, and resource development costs. Concerns about reliability center around the intermittent nature of wind. In some areas, winds are highly predictable and coincident with daily or seasonal electric power demands. By nature, however, winds are rarely steady, are in various degrees unpredictable (intermittent), and may occur at times of low demand. As a result, wind power requires the availability of other capacity to back it up. In addition, the variation in output from wind plants can stress distribution and transmission lines as well as other generating equipment. The upper limit on the amount of wind capacity that can be handled economically on a given system is unknown. Various studies suggest a very wide range of possibilities, but the highest value achieved for a single hour in the United States is 8 percent.

In Europe, wind power development has grown rapidly in recent years. In 1997, for example, Germany surpassed the United States in total wind capacity and became the first nation to exceed 2,000 megawatts of capacity. In Denmark, wind capacity exceeded 1,100 megawatts in 1997 and could approach 10 percent of the nation's electricity generation by 2005 if planned expansion occurs. In Spain total wind capacity exceeded 450 megawatts at the end of 1997. In all three nations, additional wind capacity additions are planned over the next 5 years.

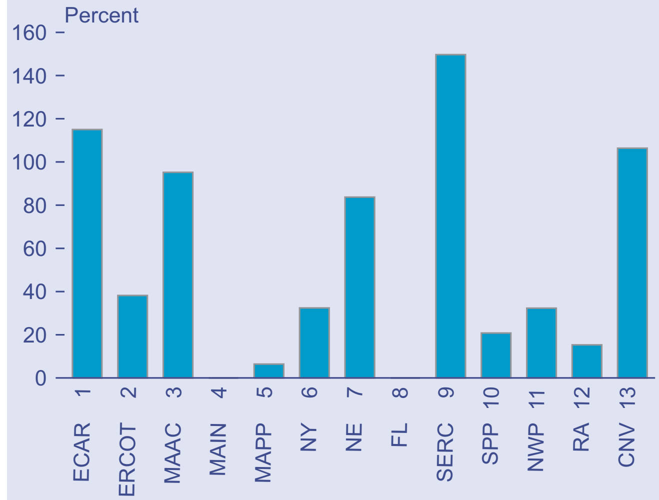
The rapid wind development in Europe is being encouraged by relatively high electricity prices and government subsidies. Under German law, wind power producers are reportedly paid the equivalent of 9 to 10 cents per kilowatthour (90 percent of the residential retail price). Prices paid to wind developers are reported to be up to 9 cents per kilowatthour in Denmark and about 8 cents per kilowatthour in Spain. Those prices are much higher than U.S. wholesale electricity prices, which typically are 2 to 4 cents per kilowatthour. Nevertheless, the European record suggests that power systems can support a larger share of wind than they have in the United States to date and that, if prices are high enough, capacity can be added fairly rapidly.[61]

A second issue is the considerable uncertainty surrounding the future cost of wind turbines. Installed capital costs for wind turbines and associated equipment have fallen over the past 20 years and are expected to continue falling, particularly if large numbers of turbines are built. The costs are near $1,000 per kilowatt of wind capacity today, and they are projected to be below $800 per kilowatt early in the 21st century and to approach $600 per kilowatt by 2020 in the most stringent carbon reduction cases. With no known manufacturing barriers to large increases in factory production capacity for wind turbines, the industry should be able to meet the production levels called for in the carbon reduction cases, given sufficient lead times. Of course, it is impossible to say with certainty that the projected cost declines will occur. This analysis does adjust for the cost effects of short-term bottlenecks in identifying sites, permitting projects, manufacturing equipment, and installing projects, but the actual effects of rapid large-scale expansion are not known.

While there appear to be large wind resources in many regions, the costs of developing some of the sites may be high. In general, wind power costs are expected to increase as the best natural resources are consumed and less-favored sites enter service. Lower quality sites—including those on steep, rocky, or sharply varied surfaces, those in more difficult environments (excessive cold, moisture, dirt, insects, or storms), and those with less useful winds (unpredictable, ill-timed, sharply varying, too fast)—could have much higher costs than more favorable sites. Moreover, in most regions only a portion of the total potential is likely to be economical. The possible stress on wind resources (and therefore costs) can be seen by comparing projections of wind capacity with EIA’s estimates of “economic” resources—identified as those available at capital costs no more than double the baseline projection (Figure 80). In the 1990-7% case, eight regions consume a third or more of “economic” wind resources, and three regions exceed that portion of supply, including California. In those regions, more expensive wind resources are developed in the most stringent carbon reduction cases. Little is known about the actual costs at these levels of resource use.[62]

The costs of transmission interconnections and of upgrading existing distribution and transmission networks are also expected to increase as the penetration of wind resources grows. As projects are developed at greater distances from existing lines, the costs of new interconnections will increase. In addition, the costs of upgrading existing local distribution networks, both to transmit the electricity generated from wind power and to offset the destabilizing local effects of varying power flows, will increase.

Figure 80. Projected Shares of Most Economical Wind Resources Developed by Region, 1990-7% Case, 1996-2020



Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD07BLW.D080398B.

Finally, market competition for land with good wind resources is also likely to increase the future costs of extensive wind power development. Other urban or agricultural uses may compete for some locations. Public opposition to wind project development on environmental, cultural, and recreational grounds may also grow as large numbers of wind facilities are built. Because excellent wind resources tend to occur in highly visible places, such as along ridges and other natural projections, preferred sites often serve other cultural, scenic, or religious purposes, and they may not be made available for wind power development. For example, it remains to be seen whether the development of 170 square miles in Texas (about 0.1 percent of the land area) for the wind capacity that would be needed to meet the 2020 projections in the 1990-7% case would be acceptable to the State’s inhabitants.

[61] American Wind Energy Association, *International Wind Energy Capacity Projections* (Washington, DC, April 1998).

[62] Only 6 percent of the estimated wind resources in region 5 (including Minnesota, Iowa, and the Dakotas) are used in the 1990-7% case; however, the remaining resources are not economically accessible to other regions.

Biomass

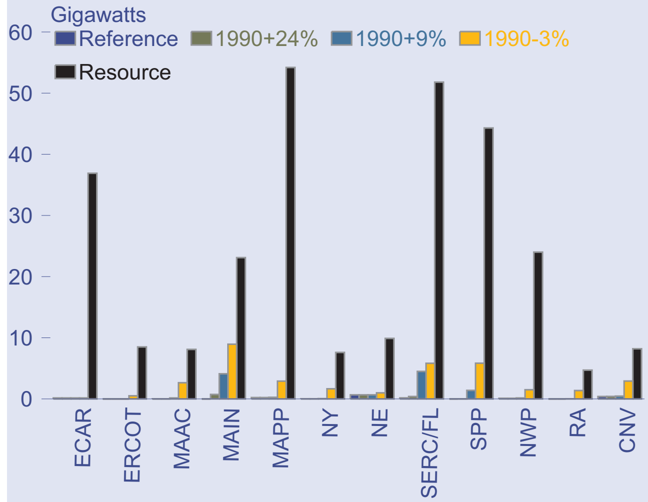
Unlike wind plants, which are intermittent, biomass plants operate continuously. Biomass currently is being used to supply energy for power generation and in the industrial, transportation, and residential sectors. The largest amount of biomass is used in the paper and lumber industries, where residue is burned to produce both electricity and steam (cogeneration). Biomass is also used to produce ethanol for fuel in the transportation sector, and wood is burned for residential heating.

Current biomass consumption in the electricity sector, excluding cogeneration, is limited to a few inefficient wood-burning generating units and a small amount of cofiring at coal plants. Newer technologies, primarily several types of gasification combined-cycle units, are in the demonstration phase in the United States and are expected to be commercially available by 2005. Such units would be somewhat more expensive than current technology, but they are expected to be more than twice as efficient. They can use a variety of fuel sources, such as wood and wood residues, several types of energy crops, and crop residues. Without a carbon price, these facilities currently are not competitive with new natural gas or coal plants. However, using biomass in the production of electricity produces no net carbon emissions. The carbon emitted during biomass combustion approximates the carbon sequestered during the growth of the trees or crops that are burned. As a result, it is an attractive option for complying with the Kyoto Protocol.

In the 1990+24% case, biomass generation increases only slightly from the levels projected in the reference case. In the 1990+9% case, however, biomass generation is projected to reach 68 billion kilowatthours—21 percent above the reference case projection—in 2010 and 133 billion kilowatthours—more than double the reference case projection—in 2020. In the 1990-3% case, biomass generation is projected to be 81 billion kilowatthours in 2010—44 percent above the reference case—and 295 billion kilowatthours—5.0 times the reference case—in 2020. And in the 1990-7% case, biomass generation exceeds the reference case projection by about 47 percent in 2010 and by 6.2 times in 2020. In each of these cases, biomass is allowed to contribute up to 5 percent of a coal plant's fuel input, but because coal plant usage declines rapidly as the carbon price increases, the contribution from cofiring is limited.

With biomass resources projected to play such a major role in meeting electricity needs in the carbon reduction cases, a critical question is whether the projected levels of reliance on biomass would be realistic. To answer that question, it is necessary to examine the components of the biomass resource. Biomass resources are diverse and potentially much larger than the amounts projected to be developed even in the most stringent carbon reduction cases in this analysis (Figure 81).

Figure 81. Estimated Biomass Resource Availability and Projected Generating Capacity in 2020 by Region



Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Biomass materials are derived from a variety of sources, including urban wood waste, mill residues, forest residue, agricultural residue, and energy crops grown specifically for combustion. Urban wood waste includes tree trimmings, construction and demolition debris, and discards such as crates and pallets. (Some of these materials are currently being used to make recycled products or as fuel, and the resource data used for this analysis exclude those quantities.) Mill residues are the sawdust and scrap from sawmills, pulp mills, and wood product facilities. Many mill residues are consumed on site, but some are accumulated in stockpiles or sent to landfills, often at a cost to the producer. Forest residues are, generally, material that is too low grade to be used for other products. They include branches, dead trees, unmarketable species, and cull trees from commercial forests. The alternative to its use as a fuel is to leave it in the forest. Agricultural residues include a wide variety of materials. The greatest quantities (and the only amounts included in this analysis) are from wheat straw and cornstalks. Only a small amount is currently used as fuel, most being left in the field. It is assumed here that only 40 percent of all agricultural residues would be available for use as fuel, with the rest continuing to be left in the field. What the above types of residues have in common is that they are very inexpensive at the source. On the other hand, the cost of gathering and delivering them to a power plant, compared with the cost of coal, usually makes them too expensive for use in electricity generation under current economic conditions.

Energy crops involve dedicated operations that would likely require long-term agreements between growers and conversion plant operators. The primary energy crops are willow, poplar, and switchgrass, each with distinct growing areas and conditions. Energy crops differ from residues in that it is the cost of growing them, not collection, that dominates their total costs.

Agricultural lands can be divided into croplands, pasturelands, and Conservation Reserve Program (CRP) acreage. The total U.S. agricultural land supply is approximately 960 million acres, of which about one-third is now used for field crops. In some instances, energy crops can be grown on poor quality land that has no other use. The amounts of agricultural land assumed to be available for energy crops in the resource data used for this analysis include all the CRP acreage, 20 percent of the cropland, and 10 percent of the pastureland. However, even in the cases that project the highest levels of biomass use, the total amount of land needed for energy crops would be about 10 to 12 million acres, which is in the range of the yearly fluctuations of U.S. cropland planted. Thus, the question of competition for land does not appear large. As fossil fuel prices rise in the more stringent carbon reduction cases, the value of biomass fuels would also rise, making energy crops more attractive economically.

There may be competition between the use of land for biomass energy crops and its use for tree planting to increase carbon sequestration. In terms of the amount of carbon sequestered or emissions avoided per acre of land used, displacing a new gas-fired plant with a biomass-fired plant would have about the same impact as planting trees. For example, the U.S. Environmental Protection Agency estimates that planting 1 acre of trees on marginal land would sequester 0.6 to 1.6 metric tons of carbon annually.[63] In comparison, if a new biomass power plant displaced a new gas-fired plant, an estimated 1.3 metric tons of carbon emissions would be avoided per acre of land used.[64] The comparison would not be as close if the generation displaced were from a coal-fired power plant, which would emit roughly 3 metric tons of carbon in producing the same amount of electricity that a biomass plant would generate from 1 acre of crops. The critical issue in the land use decision between tree planting and energy crops will be the relative economics of the two choices. If sequestration proves to be more economical, fewer biomass plants may be built than projected in this analysis. Instead of building a biomass plant, a developer could simply build a gas-fired plant and also grow enough trees to offset the carbon emissions from the plant.

It is assumed in this analysis that energy crops will not become economical until new integrated gasification combined-cycle (IGCC) plants are available in 2005 and after. The current technology for biomass plants, using stoker boilers, is inefficient and uneconomical. The newer IGCC technology is now being tested, and it is expected to be vastly superior to the current technology in terms of both efficiency and emissions. Most of the experience with the IGCC technology has been in Europe, particularly in Scandinavia. Sydkraft, the second-largest utility in Sweden, has been operating a 6-megawatt wood-fired IGCC plant in Varnami, Sweden, since 1994. Finland has a 30-megawatt unit operating on wood waste, as well as several smaller peat-fired gasification units with a combined capacity of 50 megawatts. There are several other demonstration plants that total about 5 megawatts of capacity worldwide. Future plans include 12 megawatts of capacity in Italy (Bioelettrica), 8 megawatts in the United Kingdom, and 32 megawatts in Brazil. In addition, a number of refineries are currently operating IGCC plants that burn petroleum coke.

In the United States, the most advanced IGCC project is operated by the Vermont Department of Public Works in cooperation with utilities in the State, the U.S. Department of Energy, the U.S. Environmental Protection Agency, and the U.S. Agency for International Development. The system, which gasifies waste wood and wood chips from a dedicated poplar tree farm, is just beginning operation, with a design capacity of 15 megawatts. The project is being used to demonstrate the economics of the technology. In addition, a privately owned 7.5-megawatt unit fueled with various wood, paper, and industrial wastes began operating in the Midwest in June 1998, and a 75-megawatt alfalfa-fired unit is planned for operation in 2001 in Minnesota.

As shown in Table 21, the potential resource base for biomass from all sources amounts to approximately 15 quadrillion Btu annually, roughly enough to meet 15 percent of today's U.S. energy needs if fully developed. Even in the most stringent carbon reduction case, however, only about 15 percent of the resource, about 2.3 quadrillion Btu, is projected to be used. The region that shows the greatest projected growth in biomass consumption is the Southeast, followed by the Midwest. The Southeast has ample supplies of both forests and cropland. In the Midwest, the land suitable for energy crops is vast, although energy demand there is low. The

[63]U.S. Environmental Protection Agency, *Climate Change Mitigation Strategies in the Forest and Agriculture Sectors* (Washington, DC, June 1995), p. ES-5.

[64]This estimate was derived from the following assumptions: biomass yield 6 tons per acre, biomass heat content 17,000,000 Btu per ton, biomass plant heat rate 8,000 Btu per kilowatthour, gas plant heat rate 7,000 Btu per kilowatthour, and natural gas carbon content 14,400 metric tons per trillion Btu.

region that comes closest to reaching a limit on available resources is Florida, which has high electricity demand and limited biomass resources. The West is the area that uses biomass the least, because land suitable for energy crops is limited, and other resources, including other renewables, are more plentiful.

Table 21. U.S. Biomass Resources

Biomass Resource	Quantity Available in 2020 (Quadrillion Btu)	Price Range (1996 Dollars per Million Btu)
Urban Wood Waste . . .	0.2	0 - 3
Mill Residues	0.8	1 - 4
Forest Residues.	6.5	3 - 4
Crop Residues	0.9	2 - 3
Energy Crops.	6.5	1 - 3
Total	**15.0**	—

Source: **Urban Wood Waste and Mill Residues:** Antares Group, Inc. **Forest and Crop Residues:** Oak Ridge National Laboratory. **Energy Crops:** Oak Ridge Energy Crop County Level Database (December 20, 1996).

Biomass Limitation. Because of concerns about the ability of the biomass energy business to develop as rapidly as would be required to meet the capacity and generation projections in the most stringent carbon reduction cases in this analysis, a special sensitivity case was analyzed, assuming that no new biomass capacity would be built. All other assumptions were same as those in the 1990-7% carbon reduction case. In the sensitivity case, the projected carbon price was approximately $39 per metric ton higher in 2020 than in the 1990-7% case, with smaller increments in 2010 and 2015.

Without additional biomass capacity, new natural gas capacity for electricity generation was projected to be about 43 gigawatts higher than in the 1990-7% case in 2020, making up 212 billion kilowatthours of the 295 billion kilowatthours of generation "lost" from biomass. Most of the remaining decrement was balanced out by lower demand resulting from higher projected electricity prices that stemmed from the higher carbon price. Natural gas prices at the wellhead were also projected to be higher in the biomass limitation sensitivity case, by about $0.13 per thousand cubic feet in 2020 as compared with the projected price in the 1990-7% case.

Geothermal

Although it is a more limited resource than biomass or wind, geothermal energy has the potential to contribute to the goal of carbon emission reductions. Only hydrothermal resources west of the Rocky Mountains are considered in this analysis. The technologies represented for new generating capacity are dual-flash and binary cycle plants, both of which are currently available. The existing dry-steam capacity at The Geysers is expected to decline as the resource continues to be depleted. Although few domestic orders for new geothermal plants are being placed, the U.S. geothermal industry remains viable because of activity with foreign projects, such as those in Indonesia and the Philippines. Under the Kyoto Protocol, the large U.S. resources, which are costly to develop because of their inaccessibility, could be brought within economic reach. Although little new capacity has been built in the United States in recent years, studies have estimated that more than 27 gigawatts of new capacity could be developed from currently identified resources and as much as 50 gigawatts when potential unidentified resources are included.[65]

In the reference case, geothermal electricity generation is projected to be 17 billion kilowatthours in 2010 and 20 billion kilowatthours in 2020. In the 1990+9% case, geothermal generation is projected to increase to 22 and 33 billion kilowatthours in those years, levels that are 29 percent and 68 percent, respectively, above the reference case projection. In the 1990-3% case, geothermal generation increases to 30 billion kilowatthours in 2010 and 47 billion kilowatthours in 2020. In the reference case, 280 megawatts of new capacity is added by 2010, more than 80 percent of which is built in the Northwest and the remainder in California. In the 1990-3% case, roughly 60 percent of the projected new capacity is built in the Northwest, 35 percent in California, and the remainder in the Southwest. These levels are within estimates of the potential for geothermal development by the California Energy Commission (CEC) and the Northwest Power Planning Council (NPPC). The CEC found more than 3 gigawatts of potential[66] and the NPCC nearly 4 gigawatts of potential in an optimistic case.[67]

Municipal Solid Waste

Electricity generation from municipal solid waste facilities is not expected to increase beyond the reference case levels of 29 billion kilowatthours in 2010 and 32 billion kilowatthours in 2020, regardless of the carbon reduction target assumed. The economics of these facilities are driven primarily by waste disposal costs (landfill tipping fees), rather than their energy production. After rising in the 1980s, tipping fees have stabilized, and they are not expected to increase significantly. Moreover, efforts to reduce carbon emissions could actually reduce the waste stream available for combustion because of greater emphasis on reusable products, reduced use of packaging materials, and recycling. In addition to their high cost, municipal solid waste facilities are expected to

[65]Energy Information Administration, *Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies*, DOE / EIA-0544 (Washington, DC, September 1991).

[66]California Energy Commission, *Technical Potential of Alternative Technologies* (December 2, 1991).

[67]Northwest Power Planning Council, *Northwest Power in Transition: Opportunities and Risk*, 96-5 (March 13, 1996).

be at a disadvantage in the electricity generation market because of the carbon emissions produced from the petroleum-based portion of the waste stream (primarily plastics), local resistance to their operation, and other environmental factors.

Solar

A variety of photovoltaic (PV) configurations serve U.S. electricity markets. Grid-connected PV can be (1) large central station units greater than 1 megawatt, (2) smaller distribution-level units less than 1 megawatt, and (3) individual end-user units, usually much less than 20 kilowatts. Off-grid PV always serves individual end uses—for remote buildings, pumps, signals and communications devices and for lighting—where the costs of grid interconnection are high. EIA forecasts include only grid-connected power.

PV is expected to grow steadily over the forecast period, as experience grows and costs decline. In general, increases in electricity prices should imply increasing opportunities for PV technologies. In the reference case, an increase in U.S. grid-connected PV is projected, from just over 10 megawatts in 1996 to 560 megawatts in 2020. No change from reference case levels is expected in the 1990+24% case. In the 1990-3% and 1990-7% cases, grid-connected PV capacity increases more rapidly, exceeding 700 and 900 megawatts by 2020, respectively.[68]

Off-grid PV applications, currently estimated to grow by less than 10 megawatts a year, should expand much more quickly if electricity prices rise, particularly if individual consumers shoulder the full costs of interconnection in locations that are difficult to serve. Furthermore, as costs decline, experience grows, and world demand increases, global markets for U.S. PV output—already absorbing nearly two-thirds of U.S. production—should also enjoy robust expansion. As a result, U.S. production of PV is likely to expand even more rapidly than domestic PV consumption.

Despite the optimistic outlook for PV in cases indicating increasing electricity prices—and despite expected large drops in PV costs—the technology is not expected to become a large component of U.S. electricity supply through 2020. In most instances, central station fossil, nuclear, and other renewable sources will remain far less costly than PV over the forecast period.

Even in the 1990-7% case, central station PV is expected to remain more expensive than alternatives through 2020 in all regions. In the most favorable areas, such as the Southwest, where central station PV costs are projected to decline to around 9 cents per kilowatthour after 2012, electricity generation costs for natural-gas-fired advanced combined-cycle plants are expected to be much lower, around 6 cents per kilowatthour including the carbon price, and to provide power more reliably and for a much greater proportion of the demand cycle. As a result, no new central station PV capacity is expected to be built on a cost-competitive basis.

Distributed PV units less than 1 megawatt are likely to succeed in small numbers in limited circumstances, and they are included, along with small end-user units, in EIA forecasts for grid-connected PV growth. Distributed PV may become competitive where the combination of excellent insolation, transmission or distribution line congestion, and unavailability of natural-gas-fired capacity make PV a cost-effective option. Such combinations, however, are expected to be infrequent.

As costs drop and experience grows, end-user sited PV may grow more rapidly, but it is not expected to become a general source of end-user electricity supply. More individual instances should occur in which delivered peak power can be cost-effectively supplied by grid-connected PV, such as where peak-time distribution line congestion and difficulty in siting new lines raise the costs of power from central station plants. Overall, however, PV is expected to remain costly for almost all applications that could use grid-connected power.

Smaller-scale PV units purchased by retail consumers are likely to cost even more than utility-scale PV. Moreover, grid-using PV consumers could incur some fixed costs of the transmission and distribution system to which they remain connected. And to the extent that utilities incur additional costs from the presence of end-user PV—such as for protecting lines and personnel from intermittent and unexpected electricity flows—users could incur additional costs. As a result, utilities may be unwilling to pay full retail rates for electricity purchases from end-user PV units.

Unlike PV, which uses solar energy to create electricity directly, solar thermal technologies—including trough, central receiver, and dish Stirling—convert solar energy to heat and then to electricity in generating units (usually turbines). The 360 megawatts of trough units built in California in the 1980s constitute almost all the solar thermal units operating today. No additional trough units are planned at this time. One central receiver unit, the 10-megawatt Solar II, is currently being tested. No commercial-scale central receiver units are in operation or planned. Dish-Stirling units are in relatively early testing stages, with only a few kilowatts operating.

Unless breakthroughs are forthcoming, solar thermal appears unlikely to make a notable contribution to U.S. electricity supply, even in the most demanding carbon

[68] Increases in PV capacity were determined exogenously to reflect small, distributed, and end-user applications. Central-station PV was allowed to compete with other central station generating technologies.

reduction cases. Solar thermal suffers a number of disadvantages. Cloud cover and humidity weaken the required (direct) solar radiation sufficiently to eliminate all but the drier Western regions from consideration, and where solar conditions are best the water volumes needed for steam production are in shortest supply. In addition, the technology currently has both high capital costs and limited availability. The facilities cannot operate many hours without storage, but adding energy storage fields to compensate for non-peak solar hours means significant additional capital costs. As a result, central station solar thermal generation is not expected to penetrate U.S. markets significantly before 2020.

Hydropower

Under currently expected circumstances, little additional hydroelectric power is likely to be available to meet U.S. carbon emission reduction targets. Conventional hydroelectricity is the major source of renewable electricity today, supplying about 80 percent of renewable generation and nearly 10 percent of all U.S. electric power in 1996. However, the combination of few additional sites, high capital costs, reduced Federal support, and changing national water-use priorities away from electricity and toward environmental improvements—including for fish, habitat preservation, and recreation—sharply limit the potential for expansion of U.S. hydropower capacity, whether or not carbon reduction measures are required.

In the reference case, U.S. conventional hydroelectric power stays virtually unchanged over the forecast period, annually providing about 313 billion kilowatthours. Because both overall electricity generation and use of other renewables increases, the hydropower shares of both renewable and total generation decline. In 2020, conventional hydropower is projected to provide about 72 percent of U.S. renewable electricity generation and less than 7 percent of total generation.

Increasing carbon reduction requirements are projected to increase reliance on other renewables but have little effect on hydropower. In the 1990+9% case, total renewable generation in 2020 is nearly 44 percent greater than in the reference case, but hydroelectricity remains unchanged. Despite much greater reliance on renewables in the 1990-3% and 1990-7% cases, U.S. conventional hydroelectric power increases only slightly. Even in the 1990-7% case, hydroelectric generation in 2020 is less than 3 percent above the reference case projection. The increases that are projected in this case are primarily from new units at existing dams rather than the addition of new dams. As a consequence, by 2020, conventional hydroelectric generation slips to second place, below biomass, providing about 35 percent of total renewable electricity generation.

Nuclear

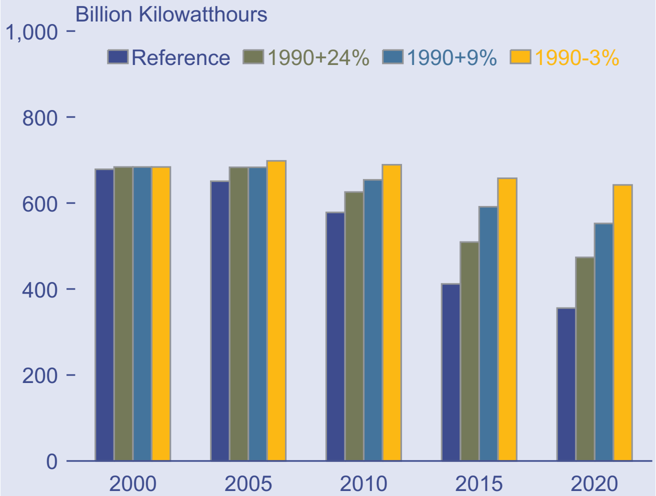
Nuclear generation is expected to be higher in the carbon reduction cases than in the reference case. In the reference case, more than half of the nuclear plants existing today are expected to be retired when their licenses expire. The economics of the retirement versus life extension decision will change, however, if significant reductions in carbon emissions are required.

To simulate this decision process, an approach was developed for evaluating the economic choice of continuing to operate a nuclear plant or retiring it and building a replacement plant. Essentially it was assumed that as nuclear plants age their components will eventually need to be replaced. At that point, the component replacement costs and the plant’s continuing operating costs can be compared to the costs of building and operating another type of generator. Because it is impossible to predict when component replacement costs will be incurred for a particular plant, it was assumed for the sake of simplicity that all nuclear plants would need refurbishment at 30 years and again at 40 years of life. The 30-year point represents the point at which many existing plants are expected to require turbine generator replacements, and the 40-year point represents the point at which plants will have to be prepared for continued operation after their 40-year operating licenses expire.

Even in the 1990+24% case, where the projected carbon price is much less than that in the 1990-3% case, it would be economical to incur the 30-year component replacement cost and continue operating most nuclear plants. For some plants, however, it would not be economical to continue operation after 40 years. With the higher carbon prices in the 1990-3% case, almost all existing nuclear plants would be maintained and continue their current electricity generation levels throughout the projection period (Figure 82). The difference in electricity generation projections between the reference and 1990-3% cases is greater for nuclear than for any other non-carbon-based fuel (see Figure 70). In the absence of that increment in nuclear generation, greater reliance on natural gas and nonhydroelectric renewables would result in even higher generating costs.

In the 1990-3% case, additional generation from nuclear plants operating beyond 40 years offsets approximately 30 to 40 million metric tons of carbon emissions—approximately equal to the difference between the carbon targets in the 1990-3% and 1990-7% cases. Thus, in the absence of the projected nuclear plant life extensions, projected electricity prices in 2010 in the 1990-3% case would be some 5 percent higher, equivalent to the 2010 price projection in the 1990-7% case.

Figure 82. Projections of Nuclear Electricity Generation, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

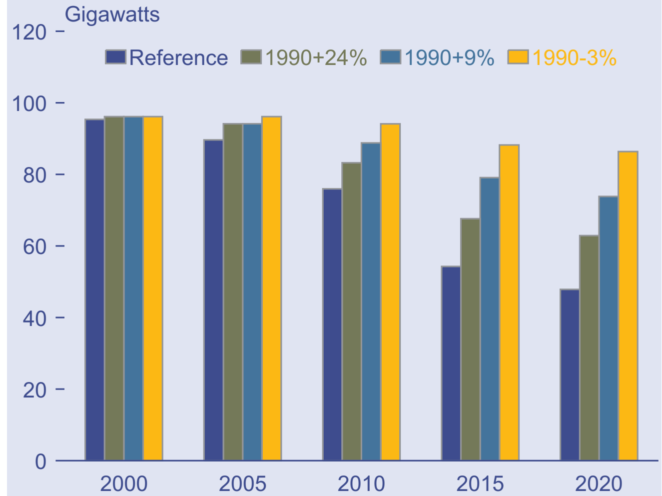
The higher projections for nuclear electricity generation in the carbon reduction cases would have implications for nuclear waste disposal. The projected impact is not significant through 2010, but in 2020 cumulative spent fuel discharges from nuclear units would be 6 percent and 9 percent higher than the reference case projection in the 1990+9% and 1990-3% cases, respectively. The spent fuel calculations assume that all spent fuel will be removed from a reactor when it is retired—a greater amount than would be discharged during a normal year of operation. Thus, even greater differences would be seen if spent fuel projections were calculated over the entire lifetime of all nuclear units.

Nuclear capacity varies significantly across the carbon reduction cases (Figure 83) not because new nuclear plants are built but because existing plants are maintained and life-extended. In the 1990+9% case, the carbon price makes it economical to maintain almost 75 percent of existing U.S. nuclear power capacity throughout the projection period, so that the projected capacity in 2020 is 26 gigawatts higher than in the reference case. With higher carbon prices in the 1990-3% case, it would be economical to keep 86 percent or more of the existing nuclear capacity—roughly 40 gigawatts more than in the reference case—operating through 2020.

Demand Reduction

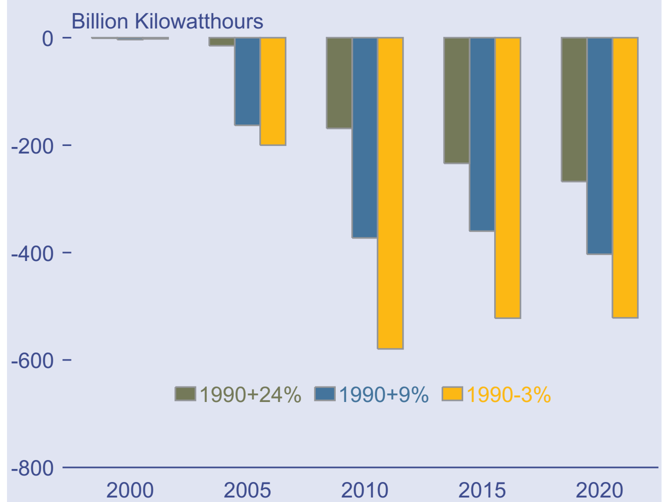
Electricity usage decisions by consumers, as discussed in Chapter 3, would also play a large role in reducing electricity sector carbon emissions (Figure 84). Even in the 1990+24% case, consumers would be expected to reduce their electricity consumption by 4 percent in 2010 and 6 percent in 2020 relative to the levels of consumption projected in the reference case. When a

Figure 83. Projections of Nuclear Electricity Generation Capacity, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 84. Projected Changes in Electricity Sales Relative to the Reference Case, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

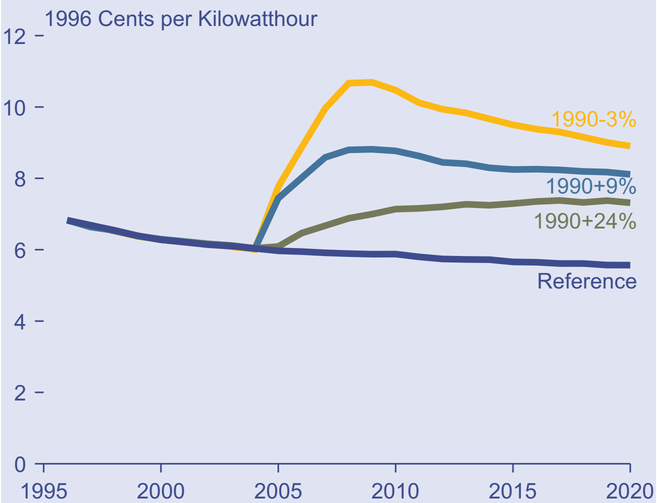
more stringent carbon reduction target is assumed in the 1990-3% case, consumer usage decisions are more important. In this case, lower demand for electricity accounts for a large share of the reduction in electricity sector carbon emissions.

Electricity Prices

While electricity suppliers do have options available for reducing their carbon emissions, it will take financial incentives to encourage them to implement them. In turn, this will have an impact on average electricity prices. In all the cases discussed in this analysis, with the exception of the competitive pricing cases described below, electricity prices are based on average costs in all regions except California, New York, and New England. It is assumed that competitive prices, based on marginal costs, will be phased in over time in those three regions.[69] In other words, the total costs of producing and delivering electricity to consumers are divided by the amount of electricity sold to calculate the average prices. In the carbon reduction cases, electricity production costs include the projected carbon prices. A discussion of competitive electricity markets is provided below.

In all the carbon reduction cases, projected electricity prices are higher than reference case prices beginning in 2005 as the carbon targets are phased in (Figure 85). The highest prices are projected between 2008 to 2012. In subsequent years, as new renewable plants become more economical and the financial incentives needed to ensure their development moderate, electricity prices are expected to decline. In 2009, average electricity prices in the 1990-3% case could be as much as 82 percent higher than in the reference case. The higher prices would lead to higher consumer bills. In 2010, residential consumers would pay $10, $23, and $36 more per month on average in the 1990+24%, 1990+9%, and 1990-3% cases, respectively, than the $70 average monthly bills projected in the reference case.

Figure 85. Projections of Electricity Prices, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Regionally, the price impact would be greatest in those regions where generation currently is dominated by coal-fired power plants. Particularly hard hit would be the midwestern ECAR and MAPP regions, where coal-fired generation accounts for 89 and 70 percent of total generation, respectively. In the 1990+9% case, efforts to reduce carbon emissions could lead to an increase of as much as 71 to 78 percent in the price of electricity in the two regions between 2008 and 2010 relative to the prices projected in the reference case. Nationally, prices in the 1990+9% case in 2008 are only 50 percent higher than in the reference case.

The impact on prices could be greater in a more competitive market. The results shown in Figure 85 are based on prices calculated as they have been in the regulated electricity market over the past 50 to 60 years.[70] This may not be appropriate in the near future. The U.S. electric industry is in the midst of a major change in its regulatory pricing structure. Historically, prices have been based on the average cost of producing and delivering electricity to the customer, but in a competitive market this will not be the case.

In a competitive market, prices will be based on the operating costs of the last plant needed to meet demand. On a typical hot summer day, generating plants are brought on line as the demand for electricity grows. Initially, the lowest cost plants (in terms of operating costs) are brought on line, but as consumer needs grow, more costly units are started. At any given time, the price for power will equal the cost of operating the highest cost unit supplying power—the “marginal unit.” The operating costs for a typical plant include fuel and operations and maintenance costs and, in a carbon reduction case, the carbon price. Because carbon prices would be included in the operating costs of the marginal plant, they would have a direct impact on the competitive price of electricity. In a regulatory pricing environment the effect of the carbon price would be smaller, because the operating costs for plants with lower carbon emissions would be averaged in with the costs for units with higher emissions.

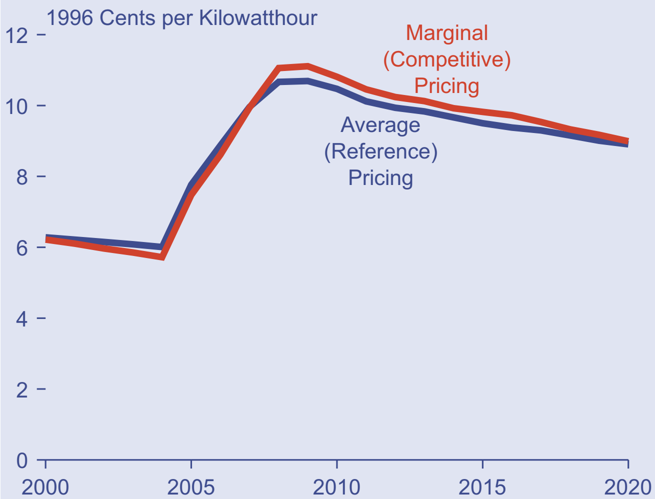
In this analysis, when higher carbon prices are projected, end-use electricity prices are higher under marginal cost (competitive) pricing than they would be under average cost (regulated) pricing (Figure 86). The effect of marginal cost pricing on electricity prices increases with the level of the carbon price. Because the effect is relatively minor in the less stringent carbon reduction cases, the 1990-3% case is examined. In this illustration, the higher prices in the early years under marginal cost pricing cause consumers to reduce their electricity use, resulting in lower generation requirements. Consequently, it is easier for suppliers to meet the carbon reduction goals, and the carbon price is lower than it would be under average cost pricing (Figure 87), although the competitive electricity price remains higher than the average electricity price.

[69] See Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), for a discussion of competitive pricing.

[70] In all cases the California, New York, and New England regions are treated as competitive.

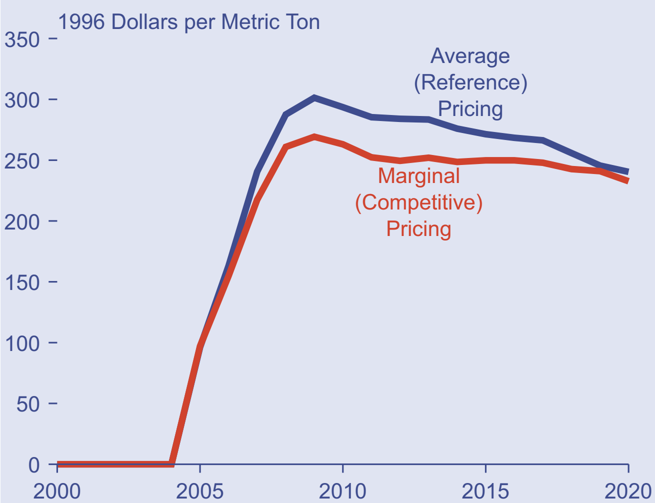
An easy way to see the impact of the carbon price is to look at the impact it has on the types of plants that will set the marginal price of power. A carbon permit system would change the plants that set the market price of electricity in a competitive pricing environment. In a carbon reduction case assuming competitive pricing, the order in which plants are used would differ from that in a corresponding reference case. The coal-fired plants that traditionally serve as baseload generators would be more expensive than the other fossil fuel plants or non-carbon-based technologies (renewables and nuclear) in the competitive pricing carbon reduction case. Therefore, they would be dispatched last and set the marginal price more often.

Figure 86. Projected Electricity Prices in Regulated and Competitive Electricity Markets, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD03BLW.D080398B and FD03COMP.D080698C.

Figure 87. Projected Carbon Prices in Regulated and Competitive Electricity Markets, 2000-2020

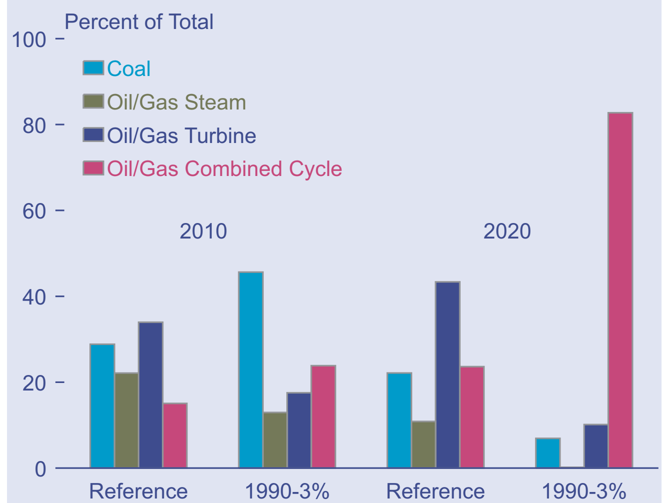


Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD03BLW.D080398B and FD03COMP.D080698C.

Figure 88 shows the fraction of time in which each technology would set the margin in a reference competitive case and in a 1990-3% competitive case. In 2010, even though total coal-fired generation is much lower in the 1990-3% case, the amount of time that coal units set the marginal price is greater than in the reference competitive case. In both cases, the marginal plant type shifts from generally older, existing plants (coal and other fossil steam) in 2010 to newer units (combined cycle and combustion turbine) in 2020. Because the carbon price would have a greater impact on plants with higher emissions, the carbon reduction case favors more efficient technologies. Thus, in 2020, the marginal price is most often based on the cost of a new combustion turbine in the reference case, but new combined-cycle units set the marginal price more frequently in the 1990-3% competitive case.

Changing electricity trade patterns are also expected to affect electricity prices. Although no new construction of interregional transmission lines is assumed in this analysis, changes in economy trades still occur. Economy trades take place whenever there is capacity available in a neighboring region that is cheaper than the cost of the marginal plant that would be needed in the home region. For example, in the reference competitive case, Region 1—the East Central Area Reliability Coordination Agreement—is a net exporter of power, because it has a large amount of coal capacity that can be operated inexpensively. In the 1990-3% competitive case, as a result of the carbon price, coal-fired capacity is more expensive to operate than other technologies. In this case, Region 1 becomes a net importer of electricity, finding generation from neighboring regions less expensive than electricity from its coal-fired units. Because the marginal cost of generation in a given region

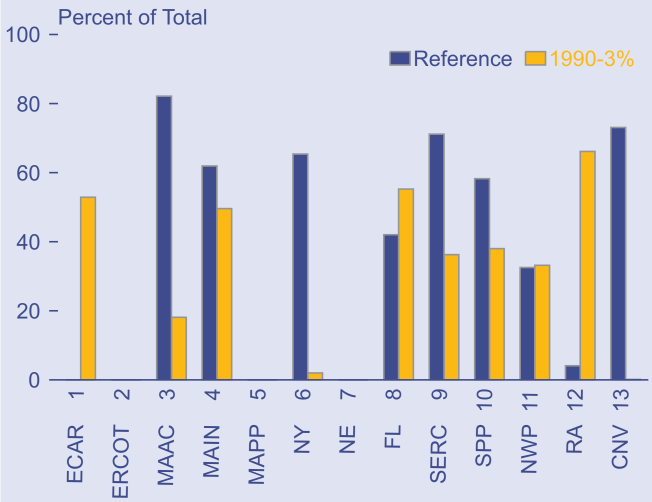
Figure 88. Projected Percentage of Time for Different Plant Types Setting National Marginal Electricity Prices, 2010 and 2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYCOMP.D080598A and FD03COMP.D080698C.

is the cost after economy trades are made, changes in trade patterns directly affect competitive prices. Figure 89 shows the fraction of time in which a trade is responsible for setting the marginal price in each region in 2020.

Figure 89. Projected Percentage of Time for Interregional Trade Setting Marginal Electricity Prices, 2020



Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYCOMP.D080598A and FD03COMP.D080698C.

Sensitivity Cases

Technological Progress

The development and market penetration of new technologies for consumer use (new air conditioners, furnaces, refrigerators, etc.) and for supplier use (new generation, transmission, and distribution equipment) will have a significant impact on the feasibility and costs of meeting the Kyoto Protocol targets in the U.S. electricity sector. All the carbon reduction cases in this analysis include substantial improvements in technology, mainly as a function of market penetration. For example, in the reference case the cost of new advanced combined-cycle plants declines from a starting point of $572 per kilowatt to $400 per kilowatt, a 30-percent improvement. In addition, the thermal efficiency of the same technology improves by roughly 10 percent. The situation is similar for wind plants, the cost of which falls from around $1,000 per kilowatt to under $750 per kilowatt. It is possible that further improvements might occur; however, it is impossible to predict to what degree a concerted effort to reduce carbon emissions might stimulate the development of new technologies or reduce the costs of existing ones.

As described in Chapter 2, to look at the potential impacts of technological innovation, development, and market penetration, a set of low (currently available) technology and high technology sensitivity cases were developed. In the 1990+9% low technology case, the new generating options available were limited to technologies available in 1998. In the 1990+9% high technology case, cost and performance characteristics were assumed to improve at rates consistent with those used in the high technology sensitivity cases in the *Annual Energy Outlook 1998*.

The performance and cost data used in the high technology cases are considered optimistic but not unreasonable. In addition, two new plant types, coal gasification with carbon sequestration and natural gas combined cycle with carbon sequestration were made available beginning in 2010 in the high technology case. The uncertainty involved in selecting aggressive cost and performance values for different technologies is considerable. Thus, the results of these sensitivity cases should not be viewed as indicating which technologies are most promising but, rather, as indicative of the extent to which technological innovation might lower the costs of meeting carbon emission reduction targets.

The key result of the high technology cases is that if new, more efficient, lower cost technologies evolve, the cost of meeting the Kyoto Protocol targets could be lowered significantly. The most important of the generating technologies appears to be the advanced natural gas combined cycle; however, as pointed out above, this is a product of the high technology assumptions, and it is impossible to say which technology might progress the most.

Figure 90 shows the average heat rate (number of Btu needed to generate each kilowatthour of electricity) for all natural-gas-fired generating plants. Even in the low technology case, the average heat rates for natural gas plants are expected to improve significantly. The improvement is greater in the 1990+9% case and even greater in the 1990+9% high technology case.

The effects of assuming lower and higher rates of technological progress on electricity prices in the carbon reduction cases are significant. For example, in 2010, projected electricity prices in the 1990+9% low technology case are more than 70 percent higher than those in the reference case (Figure 91). In the 1990+9% case and the 1990+9% high technology sensitivity case, they still are higher than in the reference case, but by only 49 and 36 percent, respectively. In 2020 the price difference remains quite high in the low technology case but is only 45 percent and 13 percent in the 1990+9% and

1990+9% high technology cases, respectively. Neither of the carbon sequestration technologies penetrates the market in the 1990+9% high technology case, because the projected carbon price is relatively low, and other high-technology options are more attractive.

Nuclear Power

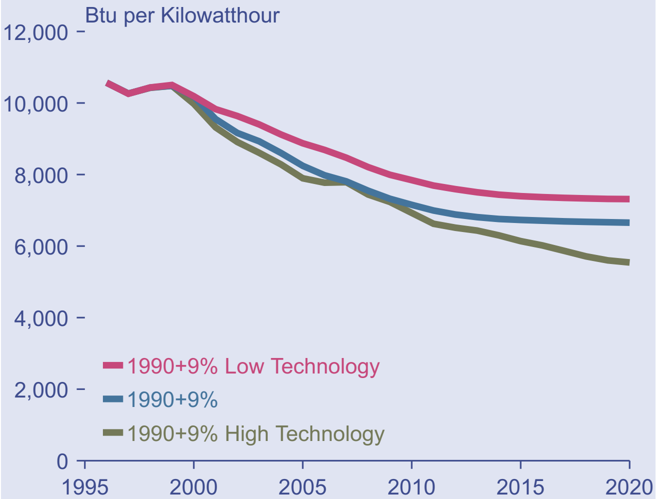
One carbon-free technology around which there is considerable uncertainty is new nuclear power plants. Currently nuclear power accounts for 20 percent of the power produced in the United States; however, no new nuclear power plants have been ordered since 1978, and the last one to come on line was Watts Bar 1 in 1996. In recent years, the overall performance of existing plants has improved dramatically (although several older units were retired before their 40-year operating licenses expired). In addition, manufacturers are now working on designs for a new generation of nuclear power plants, which are expected to be safer and less costly. As with any new technology the first few newly designed units are likely to be quite expensive, but costs should fall as manufacturers and regulators gain experience with them.

A special sensitivity case was used in this analysis to examine the possible impacts of new nuclear power plants on the carbon reduction cases. Because new nuclear plants are not economical in the 1990+9% case, this sensitivity was analyzed against the 1990-3% case. The 1990-3% nuclear sensitivity case assumes a carbon emissions target 3 percent below 1990 levels and new nuclear plant costs about 8 percent lower than the costs typically associated with the early units of new technologies, with rapidly declining costs as the new technology penetrates the market.

In the 1990-3% nuclear sensitivity case, about 40 gigawatts of new nuclear capacity is built, mostly in the later part of the projection period (Figure 92). With higher carbon prices and lower initial construction costs, the new plants are becoming competitive with other generating technologies. Nuclear electricity generation in the 1990-3% nuclear sensitivity case is only 9 billion kilowatthours higher than in the 1990-3% case in 2010 but is 248 billion kilowatthours higher in 2020.

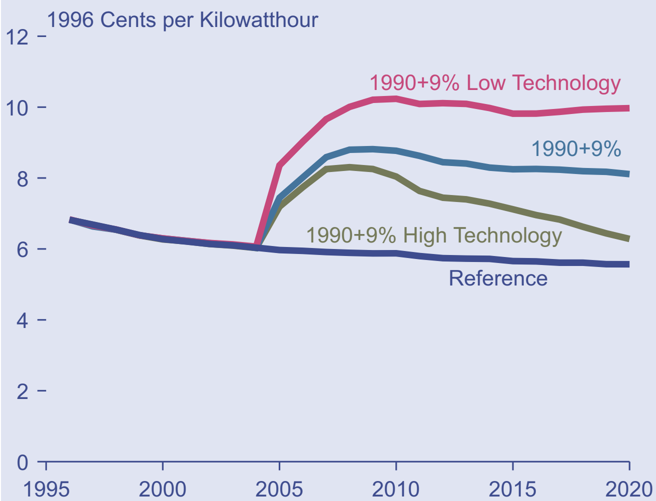
As discussed above, increases in nuclear capacity and generation will result in greater amounts of spent nuclear fuel discharged from nuclear generating units. The waste must ultimately be moved to a permanent storage facility. The 1990-3% nuclear sensitivity case results in a 15-percent increase in projected cumulative

Figure 90. Projections of Average Heat Rates for Natural-Gas-Fired Power Plants in High and Low Technology Cases, 1996-2020



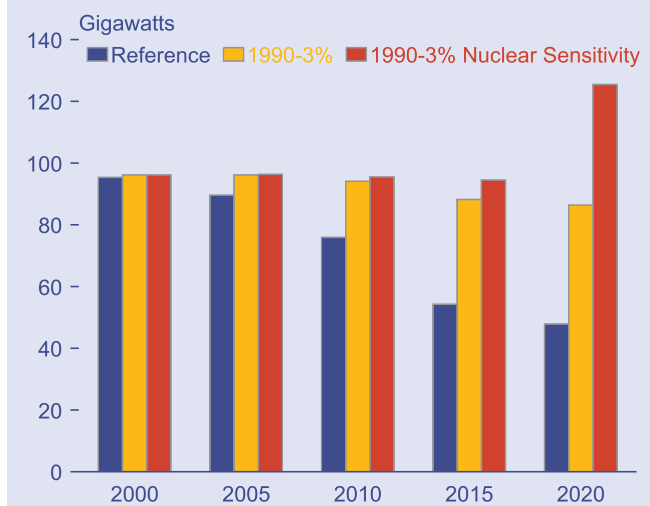
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

Figure 91. Projected Electricity Prices in High and Low Technology Cases, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

Figure 92. Projections of Nuclear Generating Capacity in the 1990-3% Nuclear Sensitivity Case, 2000-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD03BLW.D080398B, and NUKE03LC.D081298A.

spent fuel discharges by 2020, relative to the reference case.

The future of nuclear power in the United States is uncertain. Indeed, it may depend on the extent to which limits are set on carbon emissions in response to the Kyoto Protocol. The reference and carbon reduction cases in this analysis assume no new nuclear construction, for several reasons. One is concern about the future of nuclear waste disposal. The Nuclear Waste Policy Act of 1982 directed the U.S. Department of Energy (DOE) to begin accepting spent fuel for permanent disposal in 1998. As yet, however, no permanent waste storage site is available, and most of the waste is still being stored on-site by the utilities that operate nuclear power plants. The current schedule projects 2010 as the earliest that the proposed site at Yucca Mountain could begin accepting waste. Given the history of schedule slippage in the waste repository project, new investors may not commit to new nuclear power construction until they are certain that DOE will be prepared to handle the waste. In addition, public concerns about the safety of both plant operations and waste disposal will need to be addressed. The public's association of nuclear power with its weapons origin, along with highly publicized accidents at Three Mile Island and Chernobyl, have heightened safety concerns. Public opposition can cause delays in project approval, adding risk to investments in nuclear power.

Another uncertainty is the cost of new nuclear construction. If another nuclear reactor is built in the United States, it will be one of several new designs that have been approved by the U.S. Nuclear Regulatory Commission (NRC). Two evolutionary designs have received final approval from the NRC, and one "passively safe" design is still being reviewed. The nuclear industry hopes that creating relatively few, standardized designs will bring down construction costs and reduce the time needed to build future plants. However, past experience suggests that there will be considerable uncertainty until the first new units have actually been completed. No nuclear plant operating in the United States today was built at its initial estimated cost or schedule. Instead, all faced both cost overruns and delays in completion.

There is also uncertainty about the useful lifetimes of currently operating nuclear reactors. In recent years, a number of nuclear plants have been permanently shut down well before their license expiration dates, mainly because of the availability of more economical generation. Operating a nuclear unit for a full 40 years (the license life) will generally require additional capital expenditures over the last 10 to 15 years of the plant's life. Whether or not it is economical to incur such costs will depend on factors specific to each plant, such as location, other types of generation available, and fuel prices.

If limitations are placed on carbon emissions in the future, the relative costs of electricity generation could shift in favor of nuclear power. This analysis assumes that license renewal for nuclear plants will be considered, if economical, in all cases with restrictions on carbon emissions. Operators of nuclear power plants that are economical will renew the plant licenses, incurring the costs assumed to be necessary to prepare the plant for an additional 20 years of operation. In 1998, two utilities—Baltimore Gas & Electric and Duke Power—filed applications to renew the operating licenses of existing plants, the Calvert Cliffs units in Maryland and the Oconee plant in South Carolina. The approval process is likely to be lengthy for the first few plants, but as the NRC develops a standard review process, more utilities may consider license renewal a viable option.

Reducing the Impact on the Coal Industry

Coal is the most carbon-intensive fuel used for electricity production. The carbon emission rate for coal is 78 percent higher than that for natural gas, which has the lowest rate among the fossil fuels. Consequently, carbon reduction strategies are expected to affect coal more than other energy sources. Because of their heavy reliance on coal, electricity generators have historically produced more carbon than the other energy sectors. In 1996, more than one-third of U.S. carbon emissions resulted from electricity production.

Reductions in carbon emissions in the electricity sector are expected to occur primarily as a result of switching from coal to fuels with lower emission rates, such as natural gas and renewables. Initially, fuel switching occurs mostly by changing the utilization of existing capacity. That is, coal-fired plants are operated less frequently and gas-fired units are used more extensively. Later on, additional fuel switching results as new capacity is built to replace electricity from existing coal units.

Historically, electric utilities have accounted for most of the coal consumption in the United States. Therefore, fuel switching to reduce carbon would seriously affect the coal industry. In the 1990+9% case, utility coal use in 2020 is projected to be 78 percent lower than in the reference case. In the 1990-3% case, coal consumption for electricity production would be nearly eliminated in 2020. Absent significant changes in other sectors, continued use of coal in the electricity generation sector is not economical in the 1990+9% case. Substantially lower coal use would likely have dramatic impacts on mining employment, as fewer miners would be needed, and on the railroads, whose transportation of the coal used in power plants would decline dramatically.

(Continued on page 94)

Reducing the Impact on the Coal Industry (Continued)

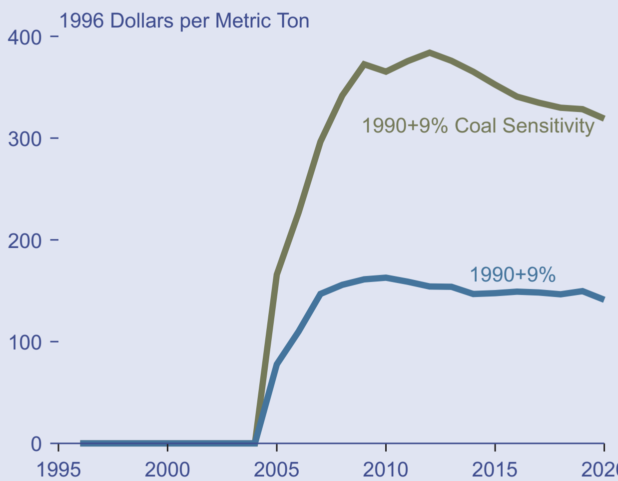
In the carbon reduction cases, the projected utilization rates for coal-fired generating capacity are much lower than the rates at which they have traditionally been operated. Many coal plants are designed as baseload capacity that operates almost continuously because they cannot be restarted quickly or efficiently. The low utilization rates in the carbon reduction cases are more typical of peaking or reserve capacity, which is run infrequently. It is unclear whether coal plants, particularly the larger units, can be operated either efficiently or economically in this manner.

For purposes of energy security, it may be advisable to maintain a broad portfolio of fuel options, including some coal. Coal is the largest domestic energy source and accounts for most of U.S. energy exports. In contrast, imports already represented over half of oil supplies in 1996, and imports are projected to make up more than 15 percent of natural gas supplies by 2020 in the reference case. Consequently, fuel switching from coal to gas would increase U.S. dependence on foreign energy sources. Renewable technologies, such as wind and biomass, are relatively new, and the projected capacity in the carbon reduction cases far exceeds existing capacity, particularly in the 1990-3% case.

With these issues in mind—the impacts on the coal and railroad industries, efficient operation of generating units, and energy security—a coal sensitivity case was prepared that maintained a share of the coal-fired electricity generation that would otherwise be lost. For the 1990+9% case, the carbon price for coal was adjusted, on a Btu basis, to be equivalent to that for natural gas. Because the utilization rates for coal-fired and gas-fired capacity are determined by the delivered prices and operating efficiencies for the respective fuels, the impact on coal in the sensitivity case was significantly reduced. Although coal use would still be lower because of reduced electricity demand and higher renewable capacity levels, utilization rates for coal units would more closely resemble current levels, because the adjustment effectively maintains the historical cost advantage of coal over natural gas.

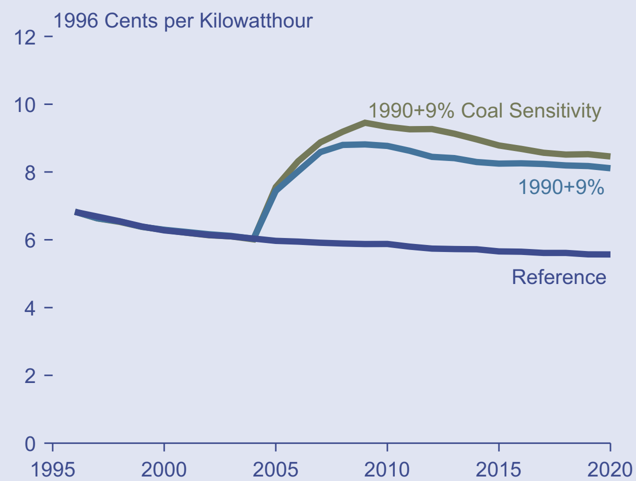
The key result of the 1990+9% coal sensitivity case is that subsidizing some portion of the coal industry would make it more difficult to reach carbon emission reduction targets, significantly raising both the carbon price and the price of electricity (see figures below). In the 1990+9% coal sensitivity case, the projected carbon price in 2010 is 124 percent higher than the carbon price in the 1990+9% case, and the price of electricity is 6 percent higher. (The impact on electricity prices is dampened by the reduced carbon price for coal users.) The impact on fossil fuel prices other than coal is also large. In 2020, the differences from the 1990+9% case are 126 and 5 percent, respectively. In contrast to the impact in the 1990+9% case, the reduction in coal use in the sensitivity case is significantly moderated. By 2020, the reduction in coal consumption by electricity producers would be only 41 percent relative to the reference case projection.

Projected Carbon Prices in the Coal Sensitivity Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B and HICOAL09.D080998B.

Projected Electricity Prices in the Coal Sensitivity Case, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and HICOAL09.D080998B.

5. Fossil Fuel Supply

The impacts on fossil fuel suppliers of policies to limit carbon emissions will depend on how much carbon is in each type of fuel: the more carbon in the fuel, the more severe the impact. If the Kyoto Protocol carbon emissions reduction targets were imposed, the U.S. coal and oil industries would see lower consumption and production than in the reference case, which does not incorporate the Protocol, whereas the natural gas industry would expand. Natural gas wins out over coal and oil in the carbon reduction cases used for this analysis, because its carbon content per British thermal unit (Btu) is only 55 percent of that for coal and 70 percent of that for oil. As a result of higher natural gas consumption and lower oil and coal consumption, carbon emissions from natural gas are projected to be higher in the carbon reduction cases, while emissions from oil and coal are lower.

Natural Gas Industry

Natural gas is a clean, economical, widely-available fuel used in more than 58 million homes and more than 60 percent of the manufacturing plants in the United States. Almost one-quarter of the energy consumed in the United States comes from natural gas. Most of the natural gas consumed in the United States is produced domestically from wells in the central part of the Nation. Gas is transported from the Central United States by pipelines throughout the country and becomes more expensive the farther it must be shipped. Yet natural gas is generally cheaper than oil products, though more expensive than coal on the basis of heating values.

In 1996 the combustion of natural gas produced 318 million metric tons of carbon emissions in the United States, about one-fifth of the U.S. total. The industrial sector was responsible for the biggest share of those emissions, about 45 percent, followed by residential, commercial, and electricity generation in order of magnitude. Twelve years from now, if no carbon reduction measures are put in place, emissions from natural gas combustion are expected to be about 100 million metric tons higher than they were in 1996. Even though the projected emissions are higher in 2010, the natural gas share of total emissions increases only slightly from 1996.

Natural gas consumption, production, imports, and prices are all expected to rise in the reference case. Natural gas consumption increases more rapidly than consumption of any other major fuel in the reference case from 1996 to 2010. Natural gas use increases in all sectors, but consumption by electricity generators more than doubles to take advantage of the high efficiencies of combined-cycle units and the low capital costs of combustion turbines. By 2010 the generating capability of combined-cycle plants increases more than sixfold, and the generating capability of combustion turbines more than doubles. More than four-fifths of the new consumption is supplied by increased domestic production. The remainder comes from increased imports, primarily from Canada.

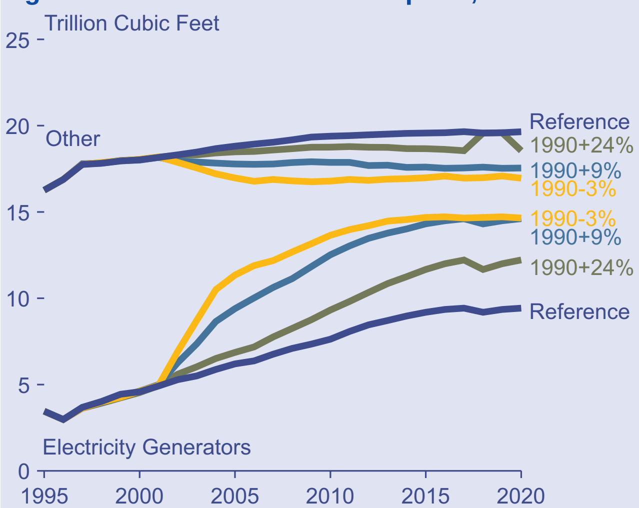
Two-thirds of the production increase between 1996 and 2010 is expected to come from onshore resources in the lower 48 States; the rest is expected to come from Alaska and lower 48 offshore resources. More production comes from onshore lower 48 resources, because roughly 75 percent of current proved reserves are located onshore, and continued technology improvements make development of the vast onshore unconventional resources more economical. Wellhead prices rise moderately in the reference case through 2010, reflecting increased consumption and its impact on resources, as each type of production progresses from larger, more profitable fields to smaller, less economical ones.

Policies designed to reduce carbon emissions would boost natural gas consumption, production, imports, and prices, principally because natural gas consumption would displace coal consumption in the electricity supply sector. In response, gas production and imports would increase, pushing up prices. In the 3-percent-below-1990 (1990-3%) case, for example, the natural gas share of the U.S. energy market is projected to increase from 24 percent in 1996 to 35 percent in 2010, compared with an increase of only 2 percentage points in the reference case. Following the imposition of a carbon price, higher prices for natural gas eventually would bring gas into competition with conservation (i.e., demand reduction) and renewable fuels, slowing the growth of gas consumption and prices.

Natural Gas Consumption

Natural gas plays a key role in the transition to lower carbon emissions, because it allows fuel users to consume the same number of Btu, while emitting less carbon. Thus, one strategy for fuel users seeking to quickly reduce coal use is to increase gas use. Natural gas consumption is expected to rise more rapidly in all the carbon reduction cases than in the reference case, driven by rising consumption in the electricity supply sector (Figure 93). Although electricity generators would produce less electricity in the carbon reduction cases than in the reference case, they would consume more natural gas, because relatively high-carbon coal would be replaced with relatively low-carbon natural gas. In the 9-percent-above-1990 (1990+9%) case, where the projected carbon price is relatively low, natural gas steadily replaces coal; but in the 1990-3% case, with a higher carbon price, renewable sources of generation begin to compete successfully with natural gas after 2010.

Figure 93. Natural Gas Consumption, 1996-2020



Note: Other uses are for residential, commercial, industrial, and transportation consumption.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

The projections for natural gas use in the residential, commercial, industrial, and transportation sectors are almost always lower in the carbon reduction cases than in the reference case, because those sectors have significantly less opportunity to switch from higher-carbon fuels to lower-carbon natural gas. In the residential and commercial sectors there is very little coal use, and most oil consumption occurs in areas where natural gas pipelines are limited. In the industrial sector, under the best circumstances, gas consumption can only hold its own in the carbon reduction cases, as some boilers switch from coal to gas. In the transportation sector gas has difficulty competing because of the limited range of compressed natural gas vehicles. As a result, consumption of natural gas in these sectors is reduced from the reference case levels because of higher natural gas prices, which lead to conservation and the penetration of more efficient technologies.

The pattern of total gas consumption differs in the carbon reduction cases, depending on the carbon price (Figure 93). Higher carbon prices, as in the 1990-3% case, lead to a quick surge in natural gas consumption when the carbon price takes effect in 2005 and gas gains an advantage over coal for electricity generation. Later in the forecast the increase in gas consumption in the 1990-3% case is moderated, as renewables on the supply side and energy efficiency gains on the demand side begin to cut into the natural gas market. Moderate carbon prices in the 1990+9% case result in a steadier rise in natural gas consumption, ultimately to higher levels in 2020 than those expected in the 1990-3% case, because natural gas prices are not high enough to induce significant levels of conservation or competition from renewables. Low carbon prices in the 24-percent-above-1990 (1990+24%) case lead to an even slower, 1.8 percent annual rise in consumption, from 1996 to 2020.

From 1950 to the late 1980s, electricity generators were third among the major users of natural gas, after industrial and residential users. In the late 1980s, they began to slip into fourth position, after commercial users, where they are today. When oil and coal prices were declining in the late 1980s, gas prices were fairly constant. As a result, oil and coal took a larger share of the growing electricity generation market while gas use remained flat. Gas consumption continued to grow in the commercial sector, however, eventually surpassing electricity sector consumption.

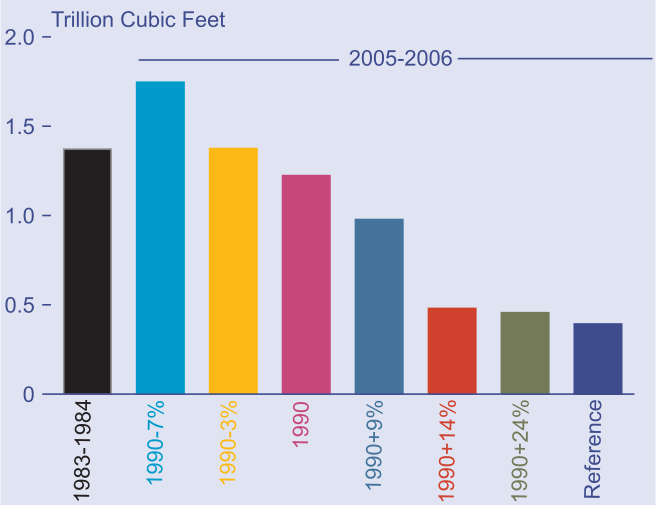
In the future, supply to electric generators is expected to become more important to the gas industry. In the reference, 1990+24%, and 14-percent-above-1990 (1990+14%) cases, electricity generators become the second largest consumers of natural gas, behind the industrial sector, by 2010. In the higher priced carbon reduction cases, they become the largest consumers of natural gas by 2010. Consumption of natural gas for electricity generation is projected to reach 12.2 trillion cubic feet in 2010 in the 1990-3% case, more than 5 trillion cubic feet higher than in the reference case and more than four times the 1996 level (Figure 93). Electricity generators can be expected to take a greater interest in natural gas pipeline capacity expansion by investing in some projects or by making long-term contracts. Pressure to merge gas and electricity companies could mount as the advantage of arbitraging the two markets becomes apparent. Electricity generators might also increase their direct ownership of natural gas resources or make long-term contracts with producers in efforts to reduce price volatility.

Natural Gas Production

In most of the carbon reduction cases examined here, natural gas production, in response to higher consumption and prices, is higher than it is in the reference case projections throughout the forecast period. Production patterns across the cases are similar to the consumption pattern: the 1990-3% case shows a sharper rise immediately after 2005, whereas the 1990+9% case shows a steadier but ultimately higher rise after 2011, and the 1990+24% case is slightly above the reference case. In 2010, production is projected to be 26.2 trillion cubic feet in the 1990-3% case, 25.9 trillion cubic feet in the 1990+9% case, and 24.1 trillion cubic feet in the 1990+24% case.

The imposition of carbon reduction targets in 2005 causes a sharp increase in natural gas production, due largely to increased consumption by electricity generators. The largest production increase is projected in the 7-percent-below-1990 (1990-7%) case (Figure 94), because competing coal prices rise faster than in any other case. The projected increase in natural gas production between 2005 and 2006 is 1.75 trillion cubic feet in the 1990-7% case, compared with only 0.39 trillion cubic feet in the reference case.

Figure 94. Increases in Natural Gas Production, 1983-1984 and 2005-2006



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Historically, the largest 1-year increase in gas production was 1.37 trillion cubic feet between 1983 and 1984 (Figure 94). However, in 1984 production was recovering to levels that already had been reached in 1982, and production in both 1983 and 1985 was down from the previous year. In contrast, the levels expected in 2005-2007—while not unlikely—have never before been reached. Increasing natural gas consumption during the initial phases of a carbon emissions reduction program may be the biggest challenge facing the oil and gas industry, and careful planning will be required.

Sufficient natural gas resources are available, however, and infrastructure can be made available, if the price is right.

All the carbon reduction cases would require more natural gas wells to be drilled to reach the expected higher production levels. In 1996 about 9,100 successful gas wells were drilled. In the reference case, some 12,000 are expected by 2010. The largest annual increase required in any of the carbon reduction cases is less than 700 wells. A 700-well increase could easily be handled by the drilling industry, considering that the number of successful gas wells increased by more than 2,000 from 1996 to 1997, when prices increased from $1.55 in 1995 to $2.23 in 1997. The stimulating effect of prices on drilling can also be seen in the 1990-3% case, which projects the highest number of gas wells in 2010, because gas wellhead prices are only a few cents below the 1990-7% case and oil wellhead prices are higher.

Although the number of available drilling rigs has been declining since 1982, price increases are a powerful incentive for increased drilling and the purchase of new drilling equipment. The number of available drilling rigs increased by almost 14 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms.[71] About 1,600 drilling rigs were available in the United States in 1996. To support the increased drilling in the carbon reduction cases, the number of available drilling rigs is also expected to rise, especially between 2005 and 2010, when 2-percent increases in rig construction are projected in some years. Given the historical response to rising prices, rig availability is unlikely to be a problem in the carbon reduction cases.

Increased drilling produces higher reserves in the carbon reduction cases than the reference case, but not until after 2010. Initially, increased consumption of natural gas depresses reserves in the carbon reduction cases, compared with the reference case projection, because production exceeds reserve additions. After 2010, however, natural gas reserves in the carbon reduction cases begin to exceed reserves in the reference case, pulled up by the higher prices. In all the cases, reserves peak late in the forecast and then begin to decline. The peak year for reserves is important, because a decline in reserves indicates that production is exceeding reserve additions. When that happens, wellhead prices tend to rise because of depletion effects. Reserves peak later in the higher carbon price cases, as higher wellhead prices sustain drilling and discoveries over a longer period. In the 1990-3% and 1990+9% cases, reserves peak in 2018, compared with 2013 in the reference case and 1990+24% case. The highest peak is projected in the 1990-7% case, at 195.5 trillion cubic feet of reserves in 2018. Projections

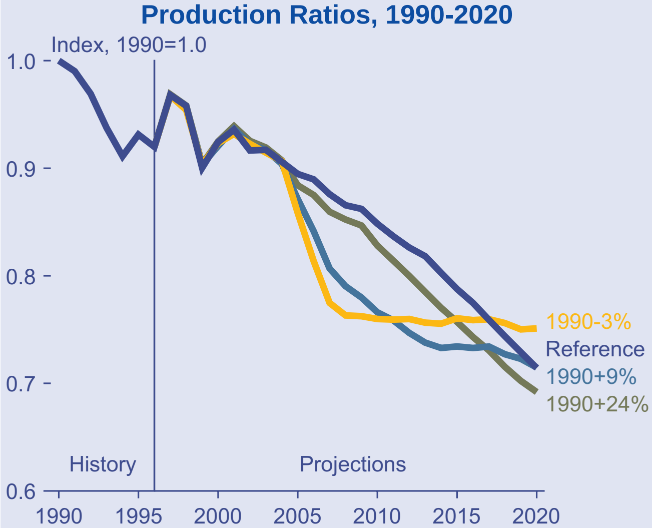
[71] T.A. Stokes and M.R. Rodriguez, "44th Annual Reed Rig Census," *World Oil* (October 1996).

of reserve levels depend on the assumed levels of natural gas resources and, as such, are highly uncertain, particularly in the offshore regions of the lower 48 States.

In general, increased reserves indicate that a mineral industry is well prepared to serve its customers; however, reserves must be placed in the context of production to gauge their real adequacy. Reserve-to-production (RP) ratios provide a measure of the adequacy of reserves. In this analysis, RP ratios generally are projected to fall faster in the carbon reduction cases than in the reference case, because production exceeds replacement of reserves (Figure 95). The path of RP ratios over the forecast is heavily influenced by the production path. When production increases steeply in the 1990-3% case the RP ratio drops steeply, whereas in the 1990+24% case the RP ratio drops more steadily to lower ultimate levels. In 1996, the RP ratio for natural gas was 8.3. In the reference case, it is projected to fall to 6.4 in 2020. In the 1990+24% case, the RP ratio in 2020 is slightly lower than in the reference case and is at the lowest level of any year in the forecast. In the 1990-3% and 1990+9% cases, the RP ratio in 2020 exceeds the reference case projection (Figure 95). Thus, when a higher carbon price is projected, the adequacy of natural gas reserves improves relative to that projected in the reference case, because higher gas prices are expected to lead to more reserve additions.

Most types of natural gas production are projected to be higher in the carbon reduction cases than in the reference case, with the exception of associated-dissolved (AD) and Alaskan gas. AD gas production is a function of oil production, which is expected to be lower in the carbon reduction cases than in the reference case (see the "Oil Production" section below). While

Figure 95. Index of Natural Gas Reserve-to-Production Ratios, 1990-2020



Sources: **History:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996*, DOE/EIA-0216(96) (Washington, DC, November 1997), and preceding reports. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

increasing in all cases, Alaska's production of natural gas is expected to be lower in the carbon reduction cases, because the market for Alaskan gas is limited mostly to the State. Electricity generators in Alaska are already more heavily dependent on natural gas than coal, and their opportunities to switch from coal to gas are limited. So, electricity generators reduce gas consumption. Although not included in this analysis, the market for Alaskan natural gas could grow through increased exportation of liquefied natural gas, manufacturing of liquids from natural gas (the Fischer-Tropsch process), increased industrial manufacturing, or methanol manufacturing.

Employment in the oil and gas industries generally has fallen in recent years, as oil production has declined and productivity has increased. According to the U.S. Bureau of Labor Statistics, employment in the oil and gas extraction industries declined from 400,000 employees in 1988 to 322,000 in 1996, a reduction of approximately 20 percent. Over the same period, total oil and gas production dropped from 34.9 quadrillion Btu to 33.0 quadrillion Btu, a reduction of only 5 percent. Rising productivity accelerated the decline in employment relative to the decline in production.

In the reference case, higher natural gas production is projected to more than offset lower oil production, leading to a total oil and gas production level of 38.6 quadrillion per year Btu by 2020. Although employment in the oil and gas industries is not included in the projections for this analysis, it is reasonable to expect that the increase in production would at least reduce the rate of decline in employment. In the 1990+9% case, total oil and gas production in 2020 is projected to be 2.1 quadrillion Btu (about 5 percent) higher than in the reference case, despite a reduction of 0.5 quadrillion Btu in oil production. Thus, the projection for the 1990+9% case implies that there would be more workers in the natural gas industry in 2020.

The patterns of U.S. natural gas production projected in the carbon reduction cases differ among the six onshore and three offshore producing regions, depending on consumption and available resources. In the largest producing regions, the Rocky Mountain and Gulf Coast onshore and Gulf Coast offshore, production rises throughout the forecast in the reference case, because significant amounts of resources are located in those regions, and technology improvements make more of the resources available for production in the projection period—particularly, unconventional resources and conventional resources at depths greater than 10,000 feet. In the three medium-sized onshore regions, production peaks during the forecast in the reference case and declines as production becomes more costly. In the two least productive regions, the West Coast and Pacific offshore, production generally falls throughout

Natural Gas Supply Issues

Uncertainty regarding estimates of the Nation's natural gas resources has always been an issue in projecting production. Although this study relies on resource estimates made by the U.S. Geological Survey (USGS) and Minerals Management Service (MMS), some uncertainty surrounds those estimates. Although many analysts believe that the USGS estimates are too high, an April 1998 study by the Gas Research Institute (GRI)[a] contends that the industry has "significantly underestimated" the growth potential of existing fields and should look to the Midcontinent, onshore Gulf Coast, East Texas, and San Juan Basin for reserve growth. GRI has increased its reserve estimates for those areas but maintains that assessing the actual amounts remains a difficult task. Uncertainty is a particular problem in the offshore area (which the industry hopes will provide significant supplies) because not much historical data is available for offshore production. Not all of the industry's original hopes may be realized, however. For example, the sub-salt area, which until recently was regarded as a promising supply source, is no longer considered to be as promising.

Another concern about supply availability is access to public land for drilling. Drilling moratoria have placed offshore areas in the eastern Gulf of Mexico, North Carolina, and California off limits, and drilling is limited in some areas of the West because of concern about emissions. Substantial resources in the Arctic National Wildlife Refuge (ANWR)[b] are also restricted from drilling, although the current inability to market natural gas from northern Alaska renders the accessibility issue moot.

In addition to concerns about supply availability, there is widespread speculation in the industry as to whether the level of production that would be needed to meet the hefty increases in demand projected in various carbon reduction scenarios could be achieved, given current worldwide shortages of offshore rigs and skilled personnel. Virtually every available offshore rig was in use throughout 1997, and capacity expansion has been limited by uncertainty surrounding the actual demand for new rigs. The lead time for construction of new rigs is 2 to 3 years, and costs range from $115 million for a 350-foot jack up to $325 million for a deepwater semisubmersible.[c] Considerable training is needed to develop a workforce, and many people are reluctant to enter the workforce because of its cyclical history and their consequent fear of future layoffs. In addition, there are concerns about the adequacy of the infrastructure to move gas from offshore drilling platforms to the shore.

To address these uncertainties, several studies are being undertaken. For example, former Secretary of Energy Federico Peña commissioned the National Petroleum Council (NPC) to undertake a study of whether the industry will be able to respond to meet projected demands,[d] and the Natural Gas Supply Association (NGSA) is working on a report that will analyze whether the industry can meet increased demand projections without increasing wellhead prices.[e]

Royalty issues are also of concern. The Assistant Secretary of the Interior for Land and Minerals Management, Robert L. Armstrong, raised the issue of a possible increase in the deepwater royalty rate to 16.67 percent from 12.5 percent after the current "royalty holiday." Although the proposal has not been supported by Congress, the uncertainty about royalty relief that stems from any talk about changes could place a damper on investment.

Despite the above concerns, considerable investment is being made in the industry. According to Arthur Andersen's 10th annual "U.S. Oil & Gas Industry Outlook Survey," executives of most U.S. exploration-and-production companies plan to increase spending in 1998.[f] As an example, Shell has recently announced plans to spend nearly $1 billion to develop three oil-and-gas fields in the deepwater Gulf of Mexico.[g]

Clearly, there are conflicting opinions throughout industry as to whether steep increases in production can be achieved in a timely fashion, even with significant increases in wellhead prices. In order for this to happen, the industry first needs to be confident that the demand will be there, so that the necessary investments in infrastructure, rigs, drilling, and manpower development can be made in time.

[a] *Assessment and Characterization of Lower-48 Oil and Gas Reserve Growth*, prepared by Energy and Environmental Analysis, Inc. for the Gas Research Institute (Chicago, IL, April 1998).

[b] ANWR resources are not included in this analysis.

[c] "Simmons: Offshore Rig Shortage Looms," *Oil and Gas Journal* (April 27, 1998), p. 24.

[d] "Producers Question Studies Showing Rising Gas Demand But Flat Prices," *Inside F.E.R.C.'s Gas Market Report* (May 15, 1998), p. 2.

[e] "Concerned About Prices, NGSA To Throw Shadow Over Rosy Supply Pictures," *Inside F.E.R.C* (May 11, 1998), p. 7.

[f] "E&P Companies Plan To Boost Spending Despite Variety of Concerns—Study," *Inside F.E.R.C.'s Gas Market Report* (December 26, 1997), p. 9.

[g] "Shell To Spend $1 Billion To Develop Three Gulf Deep-Water Discoveries," *Inside F.E.R.C.'s Gas Market Report* (April 3, 1998), p. 9.

the forecast, as a small resource base precludes significant responses to higher prices. Regional production in the carbon reduction cases is generally higher than in the reference case because prices are higher. In regions where production peaks during the forecast, production tends to peak sooner in the carbon reduction cases, because more gas is produced earlier.

Natural Gas Imports

Natural gas imports are projected to be higher in all the carbon reduction cases than in the reference case, as the industry works to meet rising demands for natural gas. In 2010, net natural gas imports are projected to be 4.7 trillion cubic feet in the reference case and up to 5.7 trillion cubic feet in the carbon reduction cases. Net imports are highest in the cases with high carbon prices, where imports surge as the carbon prices are imposed and remain at higher levels than those projected in the reference case. However, by the end of the forecast, the highest levels of net imports are expected in the 1990-3% case, rather than the 1990-7% case, because consumption is projected to be higher in the 1990-3% case.

In most of the carbon reduction cases, the majority of the higher imports come from Canada in 2010, but in the 1990-7% and 1990-3% cases at least half of the increase comes from Mexico. Even though Canada would be subject to its own carbon restrictions, it has a large enough resource base to increase both domestic consumption and exports. The Canadian Gas Potential Committee estimated in 1997 that the Western Canada Sedimentary Basin contained 263 trillion cubic feet of marketable gas.[72] In 2010 Natural Resources Canada projects Canadian natural gas consumption at 3.6 trillion cubic feet, up 600 billion cubic feet from 1995.[73] If carbon reduction targets were imposed, Canada's gas consumption would likely be higher. For example, if gas consumption in Canada were 10 percent higher in 2010 as a result of carbon restrictions, as projected for the United States in the most stringent carbon reduction cases, it would reach 4.2 trillion cubic feet in 2010. Even at that level, however, U.S. prices are expected to be high enough to continue the flow of imports from Canada.

In the carbon reduction cases, Mexico is a net exporter of natural gas to the United States in 2010, whereas it is a net importer in the reference case. Mexico begins to export gas to the United States in the carbon reduction cases in response to higher consumption and higher wellhead prices. Net imports of liquefied natural gas (LNG) reach one-third of a trillion cubic feet annually in all the carbon reduction cases but do so more quickly in the cases with higher projected carbon prices.

Natural Gas Pipelines

Interstate natural gas pipeline capacity additions would need to be higher in the carbon reduction cases than they are in the reference case projections, but they are expected to be manageable. In the reference case, cumulative additional natural gas pipeline capacity crossing the 12 regions used for this analysis are projected to increase to 52.5 trillion cubic feet of design capacity in 2010 from the 1996 capacity of 43.0 trillion cubic feet. The most significant increase is projected from 1998 to 2001, when capacity increases by 6.3 trillion cubic feet because of increasing consumption in the Midwest and Northeast not because of carbon reduction policies. During the 1998-2001 period, the Alliance pipeline is expected to come down to the Midwest from Canada, and the Maritimes / Northeast and Portland Natural Gas Transmission System pipelines are expected to come down from Sable Island in Canada to the northeastern United States. After 2001, pipeline capacity is projected to increase more gradually through 2010.

In the carbon reduction cases, the largest 1-year increase in pipeline capacity after 2001 is seen from 2011 to 2012 in the 1990+9% and 1990+14% cases, when capacity increases by 1.6 trillion cubic feet. The capacity increases in this period are primarily out of Texas, Louisiana, and Oklahoma, through the South, to the southern coastal States in response to growing consumption. The largest increase soon after imposition of the carbon price is from 2006 to 2007 in the 1990-3% case, when capacity is projected to increase by 1.4 trillion cubic feet. The increase is mainly from west to east, from the Texas-Oklahoma-Louisiana region to the Middle South.

Historically, the largest recent annual increase in pipeline capacity was 1.6 trillion cubic feet from 1991 to 1992, partly because of the construction of four major pipelines into California from the Mountain States (Kern River, Mohave, El Paso, and Transwestern) and two major pipelines out of Canada (Great Lakes into the Midwest and Iroquois into the New York / New England area). In view of the historical and expected near-term increases in capacity, capacity expansion is not likely to be a problem in any carbon reduction scenario, as long as pipeline requirements are known 2 to 3 years in advance.

Natural Gas Prices

Natural gas prices are higher in the carbon reduction cases than in the reference case, both at the wellhead and at the burner tip. At the wellhead, higher production to satisfy increased natural gas consumption, in the face of increasingly expensive resources, boosts prices. At the burner tip, adding carbon prices to resource costs could more than double some end-use prices.

In the reference case, lower 48 wellhead natural gas prices are projected to rise from $2.24 per thousand cubic feet in 1996 to $2.33 in 2010 in 1996 dollars (Figure 96). The 2010 wellhead prices are more than 40 cents per thousand cubic feet or 19 and 29 percent higher in the 1990-3% and 1990+9% cases, which project higher consumption and the use of increasingly expensive resources. The highest wellhead prices in 2010 are seen in the 1990-7% case at $3.03 per thousand cubic feet, where carbon prices are highest in 2010.

The pattern of natural gas wellhead prices is similar to the consumption and production patterns (see above). In the reference case, prices rise gradually, but in the carbon reduction cases prices rise quickly after a carbon

[72]Canadian Gas Potential Committee, *Natural Gas Potential in Canada* (Calgary: University of Calgary, 1997), Figure 1.2.
[73]Calculated from Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (Ottawa: Natural Resources Canada, 1997), Annex C.

price is imposed in 2005. In the cases with higher projected carbon prices, gas prices rise more quickly, then flatten out as energy conservation on the demand side and renewable energy production on the supply side slow the overall rate of growth in natural gas consumption. When moderate carbon prices are projected, gas prices rise more steadily but ultimately reach higher levels.

Natural Gas Pipeline Expansion

There are three ways of increasing pipeline capacity. The simplest and least expensive is to increase throughput by increasing compression at compressor stations. The second is through a process called "looping," in which parallel pipe is laid next to existing pipe to increase capacity along an existing route. The third, and most costly, is to build new pipe, usually entailing additional costs for land and / or right-of-way.

Two key criteria must be met in order for an expansion project even to be proposed: (1) the existence of demand must be shown, and (2) the project must be proven to be financially viable. Four steps are needed to bring a project to fruition: (1) an open season of 1 to 2 months during which bids for the proposed capacity are solicited and received, (2) a planning stage of 3 to 5 months, (3) filing with the Federal Energy Regulatory Commission (FERC) for approval, with an average time of 15 months (ranging from 5 to 18 months), and (4) an actual construction stage, which averages 6 to 9 months. Barring unforeseen delays, capacity can be added with a lead time of 2 to 3 years. Problems that can slow down the process include the filing of environmental impact statements and acquiring necessary approvals, and changes in market conditions (such as the changing market conditions that affected the Altamont project, which was approved in 1990 but still has not been constructed). FERC has seen a significant increase recently in the number of comments and protests received on proposed expansion projects. Another potential problem is competition between two pipelines for expansion to serve the same market, such as the recent competition to move supplies from Western Alberta, Canada, into the Midwest.

Greater increases in pipeline capacity than those projected in the carbon reduction cases are likely between now and 2000. More than 116 expansion projects have already been proposed. For the 71 projects for which preliminary estimates are available, the estimated total costs exceed $11 billion. In 2000 alone, $4.6 billion in expenditures is anticipated, as several major projects may be completed.[a] The added capacity is needed to provide access to new and expanding production areas, such as Canada and the deep offshore, and to accommodate shifts in demand patterns, such as new demands for natural gas to replace electricity generation capacity lost as a result of nuclear retirements.

Although there is speculation within the industry as to whether the needed expansions can occur, two factors support an optimistic outlook. The first is changes in FERC policy, which now leans more toward letting the pipelines assume more risk rather than requiring firm contracts to be in place before approving an expansion. This may work to speed up the approval process. The second is projected increases in natural gas demand, independent of the Kyoto Protocol. Demand growth is already anticipated to result from electric utility restructuring activities in a growing number of States, retirements of nuclear facilities, and measures included in the President's Climate Change Technology Initiative (a $6.3 billion initiative), which will proceed regardless of the fate of the Kyoto Protocol. If the anticipated increases in demand do materialize, they could provide the impetus for much of the capacity increase that would be needed in the event that the Kyoto Protocol is ratified.

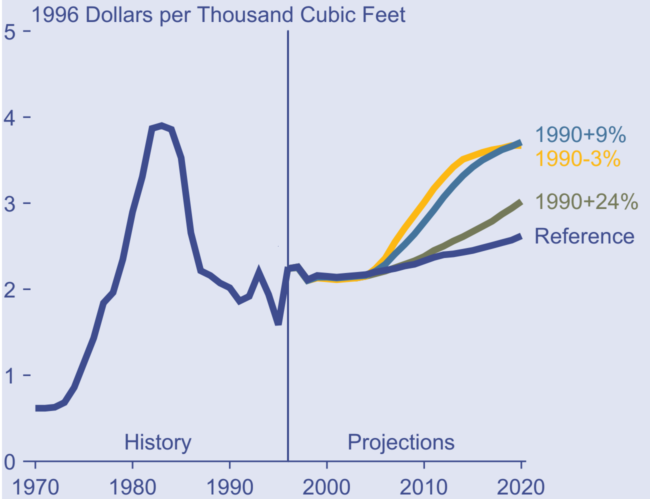
On the other hand, financial considerations are creating some uncertainty about the responsiveness of the pipeline industry. A major issue is whether the economic climate for investment will continue to be favorable. Pipeline owners are claiming that they currently face considerable risk because of increased competition and the threat of capacity turnback. While the Natural Gas Supply Association (NGSA) contends that the FERC's current policy for determining pipeline returns on equity is fair and properly accounts for the risk faced by the pipeline industry, the Interstate Natural Gas Association of America (INGAA) contends that the Commission's generic method artificially lowers allowed returns, and that rates should be calculated on a case-by-case basis. Pipeline executives contend that the 12- to 13-percent average rate of return for pipelines in 1996 was far lower than the 20-percent rate earned by most public companies.[b] In response to the industry's concerns, the FERC is currently evaluating possible changes in the method used to calculate pipeline returns. As even more risk is associated with the levels of expansion forecast in the carbon reduction cases, a key question is, "Who will assume the added risk—utilities that need the gas, other consumers willing to contract for gas, or the pipeline companies?"

Despite the obvious uncertainties, recent history shows that the industry can handle expansions of the same order of magnitude as those being projected as a result of the Kyoto Protocol. Changes in the pipeline industry between now and the time of the rapid capacity expansions that are expected to be needed to support electricity suppliers after the enactment of carbon reduction targets will be key to the industry's ability to respond. This is one of the issues that the upcoming NPC study commissioned by former Secretary of Energy Federico Peña will be addressing. Several other industry studies are underway to evaluate the industry's ability to respond, including an INGAA study that "will be looking at what needs to be done for the pipeline industry" to achieve a market of 30 trillion cubic feet by 2010.[c]

[a]Energy Information Administration, Office of Oil and Gas, *EIAGIS Natural Gas Geographic Information System Natural Gas Proposed Construction Database* (Washington, DC, preliminary as of April 1998).

[b]"NGSA: Return-on-Equity Fair Despite Protests by Pipelines," *Natural Gas Week* (March 9, 1998), p. 6.

Figure 96. Natural Gas Wellhead Prices, 1970-2020

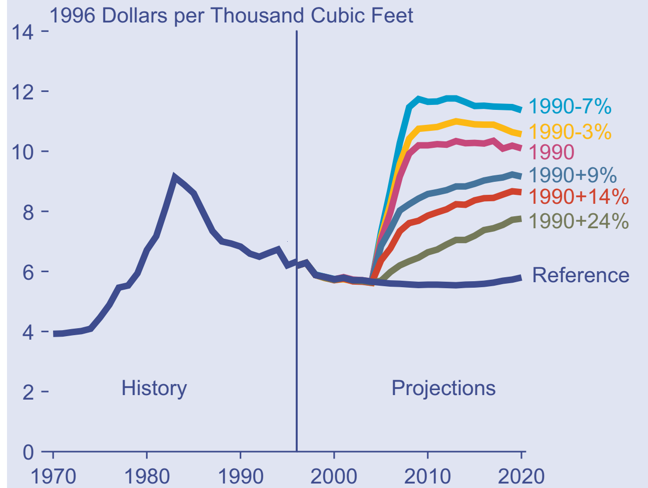


Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

On a regional basis, access to end-use markets heavily influences wellhead prices. Some of the lowest wellhead prices are seen in the Rocky Mountain region, where access to eastern markets is limited by pipeline constraints. This is balanced by wellhead prices in the two largest producing regions in this study, the Gulf Coast onshore and offshore, which have prices slightly above the national average in 1996. Wellhead prices are currently higher in the Northeast region than any other, where demand is significant and growing. Regional prices are generally higher in the carbon reduction cases, because of higher demand. Though more exaggerated, the pattern of growth across regions is much the same as in the reference case.

The projected end-use prices for natural gas in the carbon reduction cases are double the prices in the reference case at their peak in the most extreme cases. The main components of end-use prices are the wellhead price, the carbon price, and transmission and distribution margins. On a percentage basis, residential prices are the least affected by the imposition of carbon prices, and the prices to electricity generators are the most affected (the projected carbon price is almost the same for both sectors, but gas prices are significantly higher in the residential sector). In 1996, natural gas prices for end users in the residential sector, which has the largest number of end-use customers, were $6.37 per thousand cubic feet. In the 1990-3% case, residential prices are expected to peak in 2013 at $11.31 per thousand cubic feet (in 1996 dollars), compared with $5.71 in the reference case (Figure 97). The difference is almost entirely attributable to the carbon price, which adds $4.20 to residential gas prices in 2013. Wellhead prices and transmission margins are also projected to be higher, however, because of higher in total gas consumption even though residential consumption is

Figure 97. Delivered Natural Gas Prices in the Residential Sector, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

lower. In the residential sector, margins for distribution services are higher because fixed costs must be spread over a smaller consumption base. In the 1990-7% case, residential prices are projected to peak at $12.10 per thousand cubic feet in 2013, because this case has the highest carbon prices. End-use prices in the carbon reduction cases follow a pattern similar to the pattern of carbon prices.

The story is much the same for the electricity supply sector, where the most growth in consumption is expected, except that the projected difference between wellhead and end-use margins is much smaller (less than 10 cents per thousand cubic feet) in the 1990-3% case in 2010. The differences in margins is not as high as in the residential sector because higher electric generator consumption allows gas utilities to spread their fixed costs over a larger volume of gas. In 1996, delivered prices to electricity generators were $2.70 per thousand cubic feet. At their peak in 2014, prices in the 1990-3% case are projected to be $8.27 per thousand cubic feet, compared with $3.05 in the reference case. As in the residential sector, the higher the carbon price, the higher the end-use price.

End-use prices for natural gas are affected by their distance from the sources of supply. End-use prices in the Texas-Louisiana region are currently less than half of prices in New England, for example. Although New England currently has the highest average natural gas end-use prices, prices are expected to be highest in the Mid-Atlantic region in a few years, as new pipeline projects are completed into New England and as consumption for electric generation increases. Regional prices are generally higher in the carbon reduction cases than in the reference case, because of higher demand. They show much the same pattern of growth as in the reference case.

Oil Industry

Oil is a larger source of energy than natural gas. Nearly 40 percent of U.S. energy comes from oil, most of which is used to fuel our vehicles and industry. Gasoline and diesel oil fuel more than 200 million vehicles, one for every 1.3 people in the country. Almost half of our oil was imported by tanker ship from Venezuela, Mexico, Saudi Arabia, and other countries at a cost of more than $60 billion in 1996. The rest is produced domestically, mainly in Texas, Alaska, Louisiana, and California, and shipped by pipeline and tanker. With the exception of residual fuel oil, this easily moved, universally-available liquid tends to cost more per Btu than other forms of energy.

In 1996, oil combustion produced 621 million metric tons of carbon emissions in the United States, over two-fifths of the total and more than those produced from burning coal. The transportation sector was responsible for the major share of those emissions, almost three quarters, followed by industrial and residential emissions in order of magnitude. In 2010, if no carbon reduction measures are put in place, emissions from oil combustion are expected to be more than 130 million metric tons higher than they were in 1996, although their share of the total will be slightly lower.

U.S. oil consumption is expected to increase between 1996 and 2010 in the reference case, despite a projected decline in domestic oil production. Most of the growth is expected in the transportation sector, where oil consumption is projected to increase by almost 30 percent from 1996 to 2010. About half the increase comes from light-duty vehicle travel and more than 20 percent from increased air travel. Oil use in the industrial sector is projected to increase by about 15 percent between 1996 and 2010, with more than three-fifths of the increase coming in refining and petrochemical feedstocks. As a result of these increases, oil's share of the energy market will increase slightly over time.

While petroleum production from conventional sources in the lower 48 States and in Alaska is expected to fall between 1996 and 2010, enhanced oil recovery and offshore production are expected to increase, but not enough to prevent an overall decline. Net imports of crude oil and petroleum products are projected to rise to fill the gap between consumption and production. In the reference case, almost three-fifths of the U.S. oil supply in 2010 is projected to come from imports, with about three-fourths of total imports entering the country in the form of crude oil and the rest as finished or unfinished products. Gross refinery margins are projected to increase on the strength of increased refinery throughput and capacity expansion. End-use prices show little change in the reference case, as increases in world oil prices are balanced by assumed reductions in motor fuel taxes. Federal taxes on gasoline and diesel fuel are assumed to stay constant in real dollar terms, which would mean a decline in nominal terms.

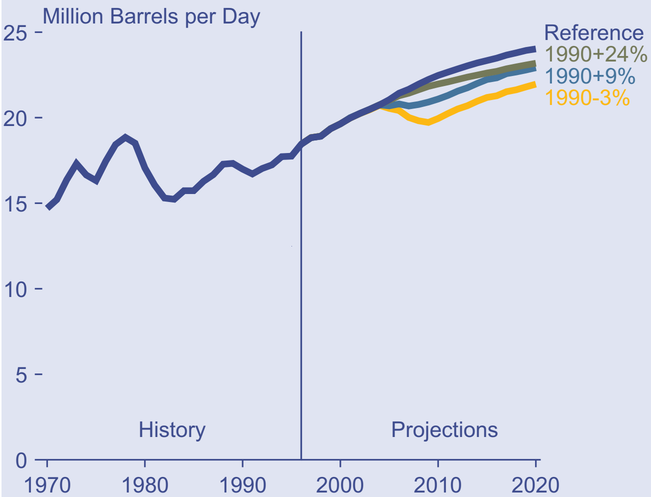
Policies aimed at reducing carbon emissions would lead to lower consumption, production, imports, and refinery margins for the U.S. oil industry. On the other hand, end-use prices and market share would be higher. Higher end-use prices—reflecting new carbon prices—would reduce consumption in the carbon reduction cases, lessening the need for domestic production and foreign imports. Refinery margins in those cases would be lower, because consumption of petroleum products and expansion of refinery capacity are projected to be lower than in the reference case. Despite the lower levels of oil consumption projected in the carbon reduction cases, oil's share of the energy market would be higher as a result of an even larger drop in coal use. For example, in the 1990-3% case, oil is projected to claim 41 percent of the domestic energy market in 2010 and coal just 7 percent, as compared with their respective 38-percent and 22-percent shares in 1996.

Oil Consumption

Oil consumption is expected to be lower in the carbon reduction cases than in the reference case (Figure 98), with most of the difference in the transportation sector. Current petroleum product consumption is at about the previous peak level of consumption reached 20 years ago. In the reference case, consumption rises from 18.5 million barrels per day in 1996 to 22.5 million barrels per day in 2010. In the carbon reduction cases, higher carbon prices overwhelm lower crude oil prices and lead to lower levels of oil consumption in 2010—22.0 million barrels per day in the 1990+24% case and 20.0 million barrels per day in the 1990-3% case. Consumption in the transportation sector is particularly affected. More than 65 percent of the difference between the reference and the carbon reduction cases in 2010 is in the transportation sector.

In the reference case, petroleum consumption rises throughout the forecast. Consumption also rises continually throughout the forecast in the carbon reduction case with the lowest projected carbon prices, the 1990+24% case. In the other cases, consumption declines during the 2005-2009 period after the carbon price is imposed. The higher the carbon price, the greater the decline in consumption. After 2009, consumption rises in all cases through the rest of the forecast, because highway and air travel increase while carbon prices change modestly.

Figure 98. Petroleum Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

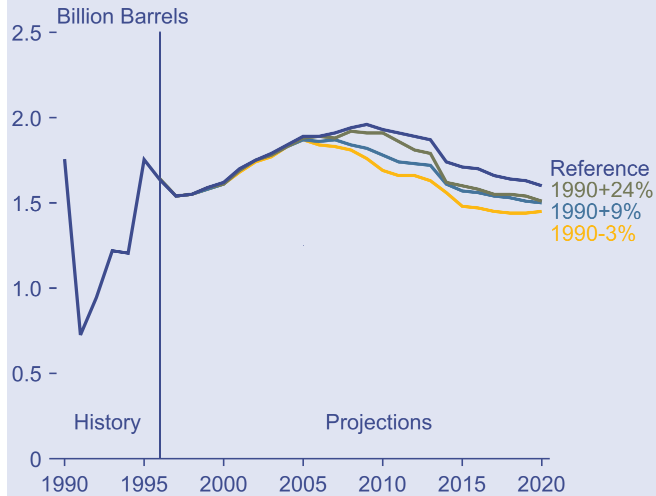
Oil use in the transportation sector is expected to absorb the largest share of the projected declines between 2005 and 2009, accounting for more than 85 percent of the total drop in oil consumption in the three most stringent carbon reduction cases, with smaller reductions in the residential, commercial, and industrial sectors. In the 1990-3% case, transportation consumption falls from 14.2 million barrels per day in 2004 to 13.5 million barrels per day in 2009, followed by a continuing increase to 15.0 million barrels per day in 2020. During the period of declining consumption, high carbon prices produce rapid increases in transportation fuel prices. After 2009, when consumption begins to rise, fuel prices in the transportation sector are generally level or declining, as the carbon prices decline.

Oil Production

U.S. oil production declines steadily throughout the forecast both in the reference case and in the carbon reduction cases, but lower consumption and diminishing oil reserves in the later years of the carbon reduction cases lead to larger production declines. In the reference case, crude oil production is projected to drop from 6.5 million barrels per day in 1996 to 5.9 million barrels per day in 2010, compared with 5.8 million barrels per day in the 1990+24% case and 5.7 million barrels in the 1990+9% and 1990-3% cases in 2010. The higher the carbon price, the lower is the crude oil price, the less is the buildup in reserves, and the lower is oil production, because the higher carbon prices overwhelm lower crude oil prices.

Domestic oil drilling activity rises steadily in the reference case and in the least stringent carbon reduction case. In the more stringent cases, drilling generally increases, but declines are projected in the middle years of the forecasts, when high carbon prices depress oil prices. The lowest levels of drilling activity are seen in the cases with the highest projected carbon prices, which result in the lowest wellhead prices.

Figure 99. Lower 48 Crude Oil Reserve Additions, 1990-2020



Sources: **History:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996*, DOE/EIA-0216(96) (Washington, DC, November 1997), and preceding reports. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

Despite the projections of increased oil drilling both in the reference case and in the carbon reduction cases, oil reserves are not expected to rise over the forecast period. Declining reserves are projected in all the cases, because reserve additions do not exceed production. For example, all the carbon reduction cases show reserve additions of only 1.9 billion barrels in 2005 (Figure 99), when production is projected to be about 2.2 billion barrels for the year. Thus, oil reserves decline. In the reference case, higher oil prices sustain enough drilling for annual reserve additions to peak at 2.0 billion barrels in 2009. In the more stringent carbon reduction cases, however, declining oil prices cause reserve additions to fall after 2005. The inability of the oil industry to replace reserves has less effect on oil prices than the inability to replace gas reserves has on gas prices, because oil prices are set in a world market, and because the RP ratios for oil are actually projected to rise.

Oil RP ratios, which are indicative of the industry's ability to sustain production, rise over the forecast both in the reference case and in the carbon reduction cases, as oil production falls more quickly than reserves. The RP ratio in the reference case rises from 7.1 in 1996 to 7.3 in 2010. RP ratios in the carbon reduction cases are slightly lower, because the low oil prices in the carbon reduction cases depress reserve additions more than production.

Most types of oil production are projected to be lower in the carbon reduction cases than in the reference case, and most of the lower production in the carbon reduction cases is in lower 48 onshore conventional and enhanced oil recovery production—the two types of production that are the most responsive to lower oil prices. In 2010, conventional onshore lower 48 oil production is 90,000 barrels per day lower in the 1990-3% case than in the reference case, 60,000 barrels per day lower in the 1990+9% case, and 20,000 barrels per day lower in the 1990+24% case. Enhanced oil recovery is 50,000 barrels per day lower in the 1990-3% case, 40,000 barrels per day lower in the 1990+9% case, and 10,000 barrels per day lower in the 1990+24% case.

Regionally, oil production is generally lower in the carbon reduction cases than in the reference case. It is significantly lower in the Southwest (western Texas and eastern New Mexico), in the Rocky Mountains, and in the offshore Gulf Coast, which are the largest producing regions. In the 1990-3% case, for example, the projected production in 2010 in each of these regions is 40,000 barrels per day less than projected in the reference case. In the Midcontinent region (Kansas, Oklahoma, and Arkansas), oil production is slightly higher in the more stringent carbon reduction cases than in the reference case, because increased drilling for gas in the carbon reduction cases leads to more oil discoveries and greater oil production; however, the peak difference is only about 10,000 barrels per day.

Regional crude oil prices are most affected by the quality of the crude oil. West Coast crude oil prices are generally lower than prices in the rest of the Nation because the density of West Coast crude oils is higher. Dense crude oils contain less of the higher-valued light products, like gasoline or diesel fuel, so their value is lower. Crude oil prices are lower in the carbon reduction cases, but the relationships among regional prices is the same as in the reference case.

Oil Imports

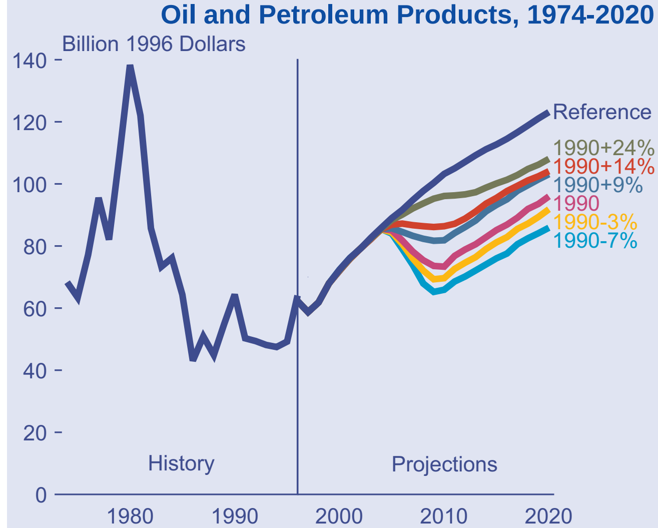
The projections for net imports of crude oil and petroleum products are lower in the carbon reduction cases than in the reference case, because oil consumption is projected to be lower, with domestic sources providing a greater share of the Nation's oil needs. As a share of total consumption, net oil imports reach 59 percent in 2010 in the reference and 1990+24% cases but only 54 percent in the 1990-3% case and 56 percent in the 1990+9% case. In all the cases, the projected import levels are above current levels, which are the highest yet recorded. The total value of net oil imports in 2010 is \$103 billion in the reference case but only \$96 billion in the 1990+24% case, \$82 billion in the 1990+9% case, and \$70 billion in the 1990-3% case (Figure 100). Both values are well below the 1980 peak of \$138 billion (in 1996 dollars). Even in 2020, the total projected expenditures for oil imports in the reference case are only \$123 billion.

Net crude oil imports rise steadily throughout the forecast in the reference case and in the 1990+24% and 1990+9% cases. In the 1990 stabilization, 1990-3%, and 1990-7% cases, however, net crude oil imports begin to fall when the carbon price is first imposed, bottoming out in 2009 before beginning to rise again. Imposition of relatively high carbon prices causes oil consumption—and imports—to fall temporarily in these cases.

Net petroleum product imports are affected more strongly than crude oil imports in the carbon reduction cases, because imported crude oil is generally more valuable to U.S. refiners than imported products inasmuch as profits are maximized only at high rates of refinery utilization. In the reference case, net product imports rise from 1.1 million barrels per day in 1996 to 3.1 million barrels per day in 2010. In comparison, the corresponding increases are only 70,000 barrels per day in the 1990-3% case, 760,000 barrels per day in the 1990+9% case, and 1.64 million barrels per day in the 1990+24% case. In the reference case and in the less stringent carbon reduction cases, net petroleum product imports exceed the historic 1973 peak of 2.8 million barrels per day at some time during the forecast, beginning as early as 2009 in the reference case, for example.

In the two most stringent reduction cases, unlike the other cases, product imports fall from 2004 through 2008 because of a decline in petroleum product consumption, and net product imports stay below the historic peak through 2020. In the 1990-7% case, net product imports remain below even their 2004 peak of 2 million barrels per day through 2020.

Figure 100. Net Expenditures for Imported Crude Oil and Petroleum Products, 1974-2020



Sources: **History:** Energy Information Administration, *Monthly Energy Review June 1998*, DOE/EIA-0035(98/06) (Washington, DC, June 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Petroleum Products

Consumption of almost all the individual petroleum products is projected to be lower in the carbon reduction cases than in the reference case, because higher prices lead to lower demand. Gasoline consumption in 2010 is 3 percent lower in the 1990+24% case than in the reference case, 8 percent lower in the 1990+9% case, and 15 percent lower in the 1990-3% case, in direct response to the projected carbon prices. Distillate, diesel, and jet fuel consumption levels are also lower. Residual fuel is the least affected, because it is projected to compete successfully with natural gas and coal in the industrial sector. The projected consumption of residual fuel in 2020 is actually higher in the 1990+9% case than in the reference case because of higher industrial demand.

In 2010, the projected product shares of total petroleum consumption are approximately the same in the reference, 1990+24%, 1990+9%, and 1990-3% cases: 43 percent for gasoline, 18 percent for distillate, 11 percent for jet fuel, 4 percent for residual fuel, and 24 percent all other products. The gasoline and jet fuel shares are slightly lower in the 1990-3% case, with slightly higher shares for the other, mostly heavier products. Purely on the basis of carbon content, consumption might be expected to move away from the heavier products, which have more carbon, and toward the lighter products; however, sector-by-sector tradeoffs with conservation and with other fuels are more critical to the shares. For example, residual fuel oil consumption in the industrial sector in 2010 is higher in the 1990-7% case than in the reference case, because the projected carbon price makes residual fuel less expensive than coal.

Ethanol

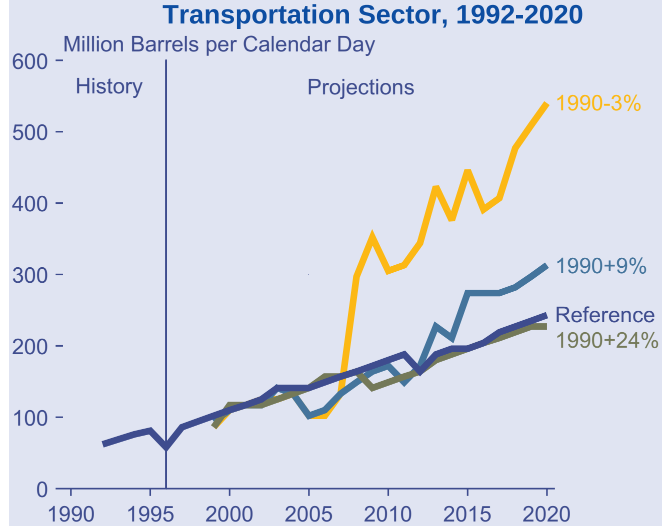
Ethanol consumption is generally expected to be higher in the carbon reduction cases than in the reference case (Figure 101). The United States consumed 80,000 barrels per day of ethanol in 1996 and is expected to consume 180,000 barrels per day in the reference case in 2010. Consumption is generally higher in the carbon reduction cases because of the growth in inexpensive cellulose-derived ethanol and because ethanol is exempt from the addition of a carbon price. However, ethanol consumption trends are quite complex because of changing legislation, production, and tax patterns.

In 1996 almost all ethanol consumed was blended directly into gasoline, but over the forecast period more ethanol is expected to be converted into an intermediate blending component or used in new types of alternative-fueled vehicles. At present ethanol is blended into gasoline as an "oxygenate" for reformulated and high oxygenated gasoline; up to 10 percent ethanol is also blended into traditional gasoline as a petroleum substitute. Oxygenates are used to reduce carbon monoxide emissions, as in oxygenated gasoline, or reduce the precursors of ozone pollution, as in reformulated gasoline. Besides ethanol, the other primary oxygenate is methyl tertiary butyl ether (MTBE). One gallon of ethanol contains approximately twice the amount of oxygen as one gallon of MTBE, but gasoline containing ethanol cannot be transported in pipelines because ethanol has an affinity for water, which limits its use as a blending component. From 1996 to 2010 ethanol for blending is expected to remain at about 80,000 barrels per day in the reference case. In the more stringent carbon reduction cases, ethanol for blending is expected to be significantly higher; in the less stringent cases, it is expected to be slightly lower, because ethanol is more economically attractive when the carbon price is higher.

Similar to the methanol oxygenate MTBE, ETBE (ethyl tertiary butyl ether), an ethanol oxygenate made from a combination of ethanol and isobutylene, is expected to become profitable in the next few years. The advantage of ETBE over straight ethanol is that it can easily be blended with gasoline and shipped by pipeline. In 2010 in the reference case, ethanol for ETBE production is 30,000 barrels per day. In the more stringent carbon reduction cases, ETBE production is expected to be slightly higher; in the less stringent cases, it is expected to be slightly lower, because ethanol is more economically attractive when the carbon price is higher.

To further complicate matters, over the next few years, flexible fuel vehicles are expected to begin burning a significant amount of 85 percent ethanol fuel (E85), as a result of legislative mandates under the Energy Policy

Figure 101. Consumption of Ethanol in the Transportation Sector, 1992-2020



Sources: **History:** Energy Information Administration, *Renewable Energy Annual 1997*, DOE/EIA-0603(97) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Act of 1992.[74] Around 2005, vehicles capable of burning only ethanol are projected to begin making a significant impact on the ethanol market, because they are expected to have one-third longer range and slightly higher gas mileage than flex-fuel vehicles. From 1996 to 2010, E85 consumption is expected to grow from less than 2,000 barrels per day to about 70,000 barrels per day in all cases, because E85 demand is expected to be driven primarily by legislative mandates. E85 demand is slightly higher in the less stringent carbon reduction cases, because the price of ethanol is attractive; demand is slightly lower in the more stringent carbon reduction cases because overall fuel demand is lower.

The sources of ethanol are also expected to change over time. At present ethanol is primarily derived from fermentation of corn. However, ethanol can also be made from cellulose biomass such as agricultural crop residuals, switchgrass, and other agricultural wood crops. In this analysis cellulose ethanol production was allowed to begin in 2001 at 1,300 barrels per day, based on current construction plans. From 2006 forward, capacity for cellulose-based ethanol is allowed to grow annually at 10,000 barrels per day for the reference case and 16,000 barrels per day for the carbon reduction cases.

Ethanol produced from non-fossil fuels receives a Federal tax credit of 54 cents per gallon. This is equivalent to 5.4 cents per gallon on gasoline blended with 10 percent ethanol. (The credit is prorated for blends of less than 10 percent and applies to the ethanol used to make ETBE.) The tax exemption is scheduled to decline to 51 cents a gallon from 2000 to 2007 and is allowed to remain at 51 cents through the rest of the forecast. Because this tax credit is in nominal dollars, inflation eats away about half its value in real terms by 2020. In the carbon reduction cases, a carbon price is not added to ethanol or the ethanol part of ETBE, because ethanol is produced with a non-fossil-fuel feedstock. Any carbon emitted from burning ethanol is assumed to be recovered when new crops are planted. To prevent ethanol from receiving both a tax credit and an advantage from not suffering an added carbon price, ethanol is allowed to receive the greater of the two; in some cases from 2005 to 2007 the tax credit is greater.

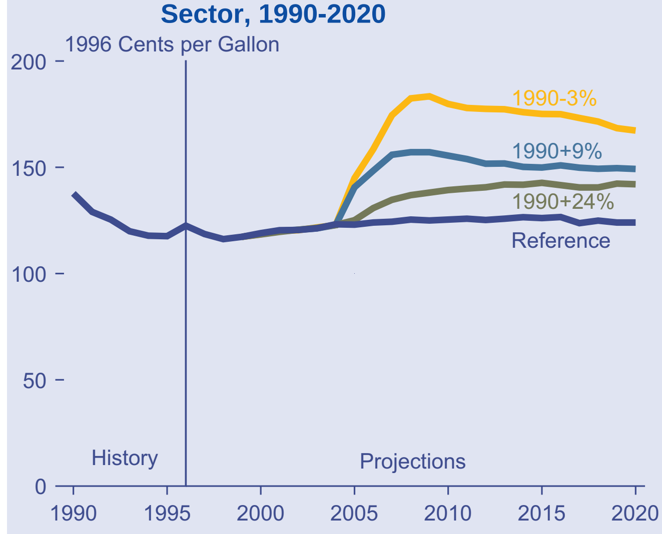
In the carbon reduction cases, ethanol consumption in some years is lower than in the reference case (Figure 101), because the carbon price causes the cost of corn-based ethanol to increase and not enough inexpensive cellulose-based ethanol is yet available. One of the costs of corn production is diesel fuel. When the cost of diesel fuel goes up because of the added carbon price in 2005, the cost of ethanol rises. Higher ethanol prices make MTBE more attractive than ethanol as an oxygenate. In addition, declining oil prices and lower oil demand work to slow increases in the price of MTBE, which is usually made entirely from fossil fuels. Significant quantities of cellulose-based ethanol do not become available until after 2005. Significant new demand for ethanol does not appear until after 2010, when the absence of an added carbon price in ethanol makes ethanol much more attractive as a feedstock for gasoline production. (Appendix A has additional information on the ethanol supply assumptions.)

Petroleum Product Prices

The projected prices of petroleum products in the carbon reduction cases are substantially higher than those in the reference case projections. For example, in 2010 the transportation sector gasoline price is 54 cents a gallon higher in the 1990-3% case than in the reference case (Figure 102). Gasoline prices are higher in cases with higher carbon prices and lower in cases with lower carbon prices, and the prices of other petroleum products follow the same pattern. The primary components of petroleum product prices are the crude oil price, refinery processing, Federal and State taxes, carbon prices, and distribution costs.

In effect, carbon prices cause greater increases in the prices of fuels that have higher carbon contents. In the 1990+24% case, the carbon price in 2010 adds 21 cents per gallon to the price of residual fuel oil but only 9 cents per gallon to the price of liquefied petroleum gas; the corresponding price increases projected for gasoline, jet fuel, and distillate fuel oil are 16, 17, and 19 cents per gallon.

Figure 102. Gasoline Prices in the Transportation Sector, 1990-2020



Sources: **History:** 1990-1995: Energy Information Administration (EIA), *Petroleum Marketing Annual 1995*, web site www.eia.doe.gov/oil-gas/pmal/pmaframe.html (May 30, 1997). 1996: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

[74] Public Law 102-486, Oct. 24, 1996, Title III, Section 303; Title V, Sections 501 and 507.

World oil prices and demand-side effects moderate to some extent the higher prices resulting from the carbon price. Higher product prices lead to reduction in demand in all the carbon reduction cases, which reduces world oil prices. Thus, the world oil price and demand effects combine to relieve some of the pressure on product prices that results from carbon prices (Table 22). The only product with a positive demand-side effect in the carbon reduction cases relative to the reference case is E85 in the 1990-3% and 1990-7% cases (Table 22). Demand for ethanol grows more rapidly in the cases with higher projected carbon prices, because there is no carbon price added to ethanol-based products. (Because ethanol is made from renewable plant material, carbon emitted from burning ethanol is assumed to be re-covered when new crops are planted.) In 2010, the projected demand for ethanol is 70 percent higher in the 1990-3% case than in the reference case. With the projected growth of demand for ethanol in the 1990-3% case, increasing supplies of inexpensive biomass-based ethanol are made available, reducing projected price increases in 2010.

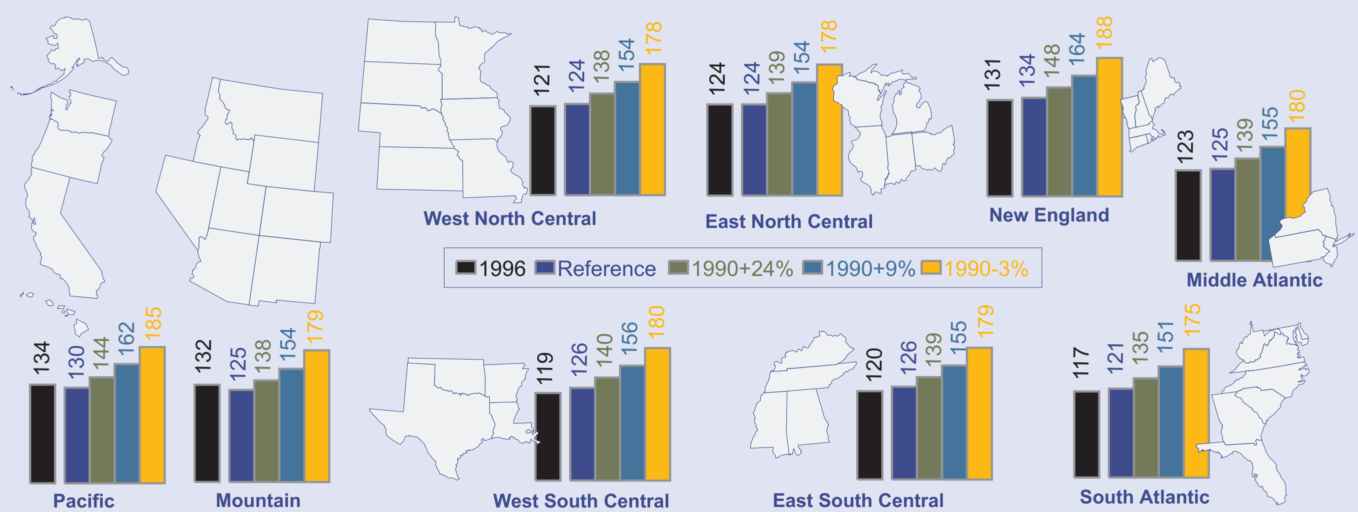
Regional petroleum product prices in the carbon re-duction cases reflect many of the same market patterns that exist today. In general, the Northeast and Pacific regions continue to have the highest priced petroleum products in the reference case and the carbon reduction cases (Figure 103). Prices in these regions remain relatively high because State tax rates are higher and supplies are limited. Limited refining capacity in the Northeast region increases reliance on imports and supplies brought in from other regions. In contrast, the Pacific region is isolated from outside sources of supply by geography and by environmental restrictions. Geographically separated from the rest of the Nation by the Rocky Mountains, California must rely heavily on its own refinery production. In addition, the State of California has the most restrictive environmental regulations on gasoline and diesel in the country, which

Table 22. Components of Differential Petroleum Product Prices Relative to the Reference Case, 2010
(1996 Dollars per Gallon)

Fuel	1990+24%			1990+9%			1990-3%		
	Demand Reduction	Carbon Price	Total	Demand Reduction	Carbon Price	Total	Demand Reduction	Carbon Price	Total
Gasoline	-0.02	0.16	0.14	-0.08	0.38	0.30	-0.15	0.69	0.54
Distillate	-0.04	0.19	0.15	-0.05	0.42	0.37	-0.13	0.81	0.68
Jet Fuel.	-0.02	0.17	0.15	-0.07	0.41	0.34	-0.13	0.76	0.63
Residual Fuel	-0.02	0.21	0.19	-0.04	0.50	0.46	-0.08	0.93	0.85
LPG	-0.02	0.09	0.07	-0.08	0.23	0.15	-0.13	0.42	0.29
E85	-0.02	0.03	0.01	-0.08	0.05	-0.03	0.07	0.11	0.18
World Oil Price	-0.02	—	—	-0.05	—	—	-0.07	—	—

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 103. Retail Gasoline Prices by Region, Average of All Grades, 1996 and 2010
(1996 Cents per Gallon)



Sources: **1996:** Energy Information Administration, Form EIA-782A, "Refiners'/Gas Operators' Monthly Petroleum Product Sales Report," and Form EIA-782B, "Resellers'/Retailers' Monthly Petroleum Product Sales Report," and volume-weighted taxes estimated by the Office of Integrated Analysis and Forecasting. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

result in additional processing costs and further limit California's sources of supply.

Refinery Industry

Like all energy-intensive U.S. industries, the refinery industry would be adversely affected by policies aimed at reducing the consumption of carbon-based fuels. U.S. refiners would bear the burden of reducing refinery emissions of greenhouse gases, and at the same time demand for their primary products would decline.

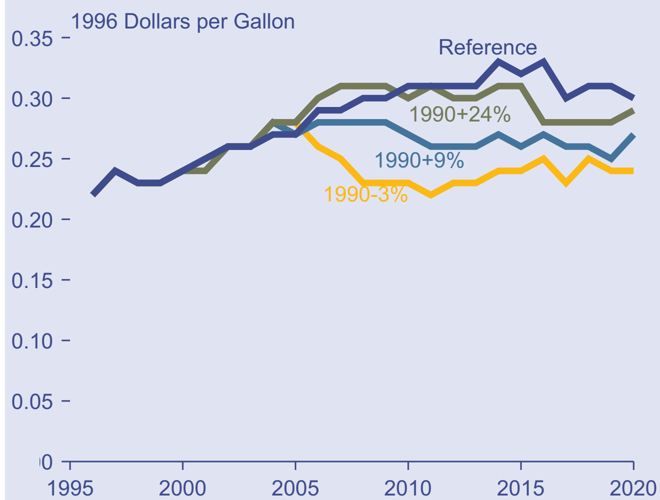
Lower demand for petroleum products is expected to slow the growth of the U.S. refinery industry. In the reference case, the combined distillation capacity of U.S. refineries is projected to be 16.9 million barrels per day in 2010, with a utilization rate of 95 percent. In comparison, in the 1990+24% and 1990-3% cases, the projections for distillation capacity in 2010 are 16.8 and 16.5 million barrels per day, respectively, with utilization rates of 95 and 93 percent. From 2010 to 2020, distillation capacity grows in the carbon reduction cases in response to increasing petroleum consumption. U.S. refiners are not expected to recover all the investments in new capacity made before 2003 in the 1990-3% case, because consumption drops off between 2005 and 2015. Thus, utilization drops off particularly in 2009 in the 1990-3% case. Reduced utilization rates and product consumption may have an adverse impact on smaller or less competitive refineries that cannot develop ways to increase product margins or market share. In the 1990+9% and 1990+24% cases, utilization remains close to 95 percent throughout the forecast, and investment continues to be recovered.

Refinery fuel consumption in the carbon reduction cases drops in direct response to declines in product consumption and crude oil input. Total petroleum consumption at refineries in 2010 is projected to be 143 and 310 trillion Btu lower in the 1990+9% and 1990-3% cases than in the reference case. By 2020, however, compared to the reference case, total petroleum consumption at refineries is higher in the 1990+9% case because residual fuel oil replaces natural gas and is lower in the 1990-3% case because total consumption is lower.

Consumption of natural gas at refineries in the carbon reduction cases drops off after 2010, because gas is projected to be more expensive than petroleum. The higher price for natural gas causes petroleum fuel consumption to rise. Late in the forecast LPG and residual fuel consumed at refineries are higher in the more severe carbon reduction cases than in the reference case, because still gas production and consumption are lower as a result of lower crude inputs to refineries, and because higher natural gas prices result from the higher demand for natural gas. Refinery processing gain also follows the petroleum product consumption and domestic refinery production of products, with processing gains 4 percent and 11 percent lower in the 1990+24% and 1990-3% cases, respectively, than in the reference case in 2010.

Petroleum product margins (wholesale price minus crude costs), which indicate the amount of revenue received by refineries per gallon, are lower in the carbon reduction cases than in the reference case, in response to lower product consumption (Figure 104). In the 1990+24% case, margins for gasoline, distillate, diesel, and jet fuel in 2010 are 4 to 11 percent lower than in the reference case, and in the 1990-3% case they are 26 to 30 percent lower. Between 2010 and 2020 the margins for gasoline, distillate, and diesel remain about the same, and those for jet fuel increase slightly in the carbon reduction cases, because of shifts in demand.

Figure 104. Projected Wholesale Gasoline Margins, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Refinery revenues also follow the product consumption and product margins losses. Total projected refinery revenues in the 1990+24% and 1990-3% cases are 5 and 24 percent lower in 2010 than they are in the reference case, and revenues per barrel of product supplied are 3 and 14 percent lower. Total revenue losses associated with the projected drop in world oil prices are 4 percent and 14 percent in the 1990+24% and 1990-3% cases, respectively, in 2010.

The projections of lower product margins, total revenues, and revenues per barrel of product supplied indicate that the U.S. refinery industry could face severe constraints on profits and shareholder returns. Competitive pressures could force petroleum marketers to lower prices while maintaining or improving product quality in order grow market share. U.S. refineries may also face competition from refiners in foreign countries that are not parties to the Kyoto Protocol.

Coal

Background

Coal provides the largest fuel share, nearly 31 percent, of U.S. domestic energy production. Electric utilities and independent power producers generate more than 55 percent of all electricity via coal-fired technology and account for approximately 89 percent of domestic coal consumption. Steam coal is also consumed in the industrial sector to produce process heat, steam, and synthetic gas and to cogenerate electricity, and metallurgical coal is used to make coke for the iron and steel industry. With more than 90 million tons[75] of steam and metallurgical coal shipped in 1996, coal is the only net energy fuel export for the United States. In the reference case, coal production and domestic consumption (expressed in tons) are projected to increase at rates of 1.1 and 0.9 percent per year, respectively, and coal exports are projected to increase somewhat more rapidly at a rate of 1.5 percent annually through 2020, primarily reflecting the continued growth of steam coal consumption for electricity generation in both domestic and overseas markets.

The proposed limitations on carbon emissions will have a significant negative impact on the coal industry. In the carbon reduction cases analyzed here, the advantages of the low carbon content of natural gas and the zero net carbon emissions that are associated with renewables offset the relatively low fuel cost of coal for use in electricity generation. Thus, coal markets are projected to be severely affected, in terms of both overall sales and supply patterns, as the need to reduce carbon emissions results in significant shifts away from coal consumption to natural gas, renewable energy, efficiency improvements in the demand sectors, and—in some cases—nuclear energy (see Chapter 4 for a discussion of fuel switching and changes in electricity generating capacity).

Carbon Emission Considerations

Coal, oil, and natural gas respond differently to restrictions on carbon emissions. Of the three, coal is most affected for reasons that relate to the nature of its markets and its chemical structure. Electricity generation markets, by far the largest market for coal, are increasingly competitive and cost-conscious as restructuring initiatives by States have increasing influence on fuel purchase strategies. Fossil fuels derive their energy content primarily from oxidation of their carbon and hydrogen contents. A fee based on carbon emissions from burning fossil fuels (i.e., a carbon price) naturally falls most heavily on coal, because coal derives a higher percentage of its energy content from the oxidation of carbon than do oil and natural gas.

Coal is heterogeneous in terms of both its energy content and carbon content. Subbituminous coal derives a higher proportion of its energy from carbon than does bituminous coal; thus, production in the large low-sulfur coalfields of the Northern Great Plains (Wyoming and Montana) would be more affected by carbon emissions restrictions than would bituminous coalfields such as those in Colorado and Utah, the Appalachian States, and the Interior region. Lignite, which is produced primarily in Texas, North Dakota, and Louisiana, has more carbon content than subbituminous coal, and its production would be more severely affected than that of bituminous or subbituminous coal in the carbon reduction cases, in the absence of any offsetting factors such as close proximity to customers.

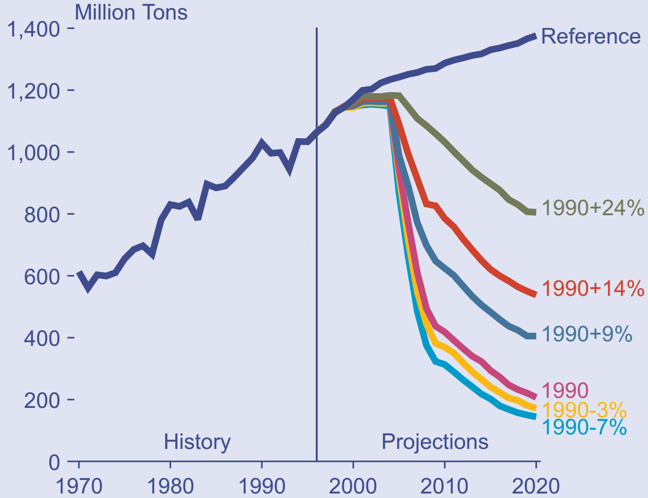
Other factors that would affect the regional impacts of carbon emission restrictions on different coalfields stem from differences in mining and transportation costs. Subbituminous coal production in the southern Powder River Basin of Wyoming had an average mine price of $6.41 per ton in 1996, as compared with bituminous mine prices of $26.68 per ton in Appalachia, $21.43 in the Interior, and $21.61 in the western States. However, there is only a limited market for subbituminous coal in the regions where it is mined. This coal has achieved national importance in the past two decades because of its low sulfur content and mining costs, giving it the ability to bear transportation costs of $20.00 per ton or more while retaining economic competitiveness in markets on the Atlantic, Pacific, Great Lakes, and Gulf coasts, up to 2,000 miles from its origin. A carbon price would create a double penalty for such coal, first by penalizing the coal for its inherent high ratio of carbon to energy content, second by penalizing the carbon content in the transportation fuels that are required to bring it to market. Thus, carbon emissions restrictions would most heavily penalize those coals most dependent on transportation to reach their markets.

Coal Production

In the reference case, U.S. coal production climbs to 1,287 million tons in 2010 and 1,376 million tons in 2020 (Figure 105). In the carbon reduction cases, U.S. coal production begins a slow decline early in the next decade, accelerates rapidly downward through 2010, and then continues to drop slowly through 2020. Coal production in the 1990+24% case is 20 percent lower by 2010, at 1,032 million tons, in the 1990+9% case is 52 percent lower than reference case levels by 2010, at 624 million tons, and 71 percent lower in the 1990-3% case at

[75]In this section, physical quantities of coal are expressed in short tons, a unit of weight equal to 2,000 pounds. Carbon emissions are reported in metric tons, a unit of weight equal to 2,204.6 pounds.

Figure 105. U.S. Coal Production, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

369 million tons. By 2020, coal production in the 1990+24% case is 805 million tons and in the 1990+9% case is 405 million tons, and production in the 1990-3% case drops to a mere 172 million tons.

The projected declines in coal production result primarily from sharp cutbacks in the use of steam coal for electricity generation. Additional declines in production occur from reductions in the use of coal for boiler fuel within the industrial sector, as a result of fuel switching to natural gas. In 2010, coal consumption by electricity generators in the 1990+24% case is 20 percent lower than in the reference case, in the 1990+9% case is 57 percent lower, and in the 1990-3% case it is 79 percent lower. Lower consumption results from a reduction (via retirements) of in-place coal capacity, as well as lower dispatch rates for coal-fired generation because the coal capacity that remains available is used less intensively. In 2010, coal-burning capability in the electricity supply sector drops from 308 gigawatts in the reference case to 300 gigawatts (a 3-percent decline) in the 1990+24% case, 276 gigawatts (a 10-percent decline) in the 1990+9% case, and 266 gigawatts (a 13-percent decline) in the 1990-3% case. Utilization of existing coal capacity drops from 77 percent in the reference case to 65 percent in the 1990+24% case, to 40 percent in the 1990+9% case, and to 22 percent in the 1990-3% case.

In 2020, coal consumption by electricity generators is projected to be 630 million tons in the 1990+24% case, with coal-fired generating capacity at 271 gigawatts and utilization at 55 percent, and only 235 million tons in the 1990+9% case, with coal capacity at 198 gigawatts and utilization at 29 percent. In the 1990-3% case, increased retirements of coal-fired plants result in coal capacity of 100 gigawatts (approximately one-third of reference case levels), coal consumption for electricity generation of 33 million tons, and a very low utilization rate of 9 percent. Operating and maintenance costs per unit of electricity generated will increase for coal plants that are run at low utilization because of thermal fatigue and the inefficiencies of starting and stopping units that were designed for baseload operation.

The expected reductions in coal exports and industrial uses in the carbon reduction cases are somewhat less severe than those in the electricity supply sector, because not all coal-importing countries will be subject to strict carbon caps, and because certain industrial consumers have less flexibility (because of plant configuration or fuel availability) to switch to lower carbon-emitting fuels. As a result, coal production from regions such as Central Appalachia that now serve this set of customers declines somewhat less severely than that from regions such as the Powder River Basin that have the heaviest dependence on electricity producers. Coal export projections are discussed later in this section.

Regional Coal Production Patterns

Reductions in coal consumption are expected to occur in all regions and consuming sectors, but they will be of different magnitudes and affect different coal types. As a result, regional production patterns in the carbon reduction cases will shift differentially across regions relative to the reference case, rather than on a basis that is strictly proportional to national levels of coal consumption. In the electricity generation sector, each reduction in overall coal generation will make it easier to achieve the Clean Air Act Amendments sulfur dioxide (SO_2) target of 9 million tons of SO_2, and in the more severe carbon reduction cases, prices for the SO_2 allowances will be driven to zero. There will be upward pressure on coal transportation rates, as a result of higher prices (from carbon prices) on the diesel fuel used for rail, barge, and truck transportation. At the same time, lower quantities of coal shipments could place downward pressure on transportation rates. The strong shift to greater use of low-sulfur coal, particularly that mined in the West, in the reference case will cease and reverse in consuming regions where local mid- and high-sulfur coal can be delivered at a lower cost than western coal.

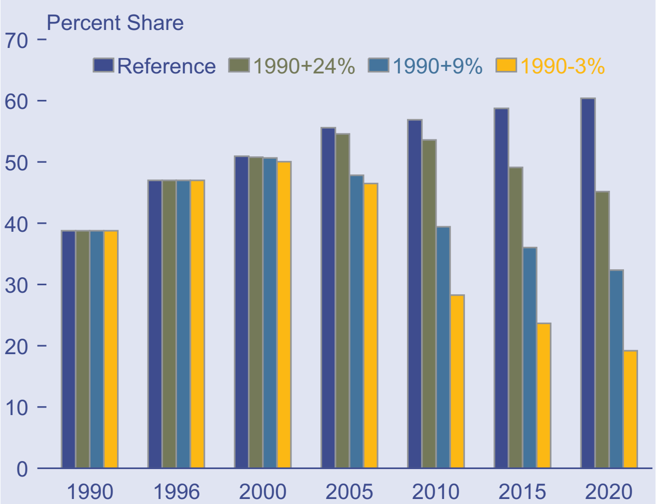
The slower decline in coal consumption in the industrial, metallurgical coal, and export sectors in the carbon reduction cases will translate into relatively less severe production cuts in regions that currently supply these markets than the reductions in those regions that depend more heavily on electricity generators. Nevertheless, there will be intensified intraregional competition to serve these important, albeit declining markets, and some interregional shifts in production occur in the forecast as regional demands shift.

In the reference case, the western share of total U.S. coal production increases from 47 percent in 1996 to 57 percent in 2010, as a result of its lower cost and the growing requirements for low-sulfur coal under the Clean Air Act Amendments (Figure 106). In contrast, the western share in the carbon reduction cases decreases to 54 percent in the 1990+24% case, to 39 percent in the 1990+9% case, and to 28 percent in the 1990-3% case in 2010. Approximately 75 percent of the 179 million ton reduction in western coal production in the 1990+24% case, 486 million ton reduction in the 1990+9% case, and the 628 million ton reduction in the 1990-3% case is borne by subbituminous surface mines in the Powder River Basin. The low-sulfur coal from these surface mines is used almost exclusively for electricity generation and must be transported over relatively long distances to reach many of the markets that are projected to expand in the reference case.

As overall demand falls, eastern minemouth prices are reduced, and there is less economic incentive to transport western coal. Western coal becomes less competitive in electricity generation markets as transportation fuel costs increase, and its potential to expand into most industrial and export applications is limited by its lower heat content and other physical characteristics, such as moisture content and handling problems.

By 2020, western coal production has dropped by an additional 189 million tons from 2010 levels in the 1990+24% case, 115 million tons in the 1990+9% case, and by 71 million tons in the 1990-3% case, with western production shares reaching 45, 32, and 19 percent, respectively. In these cases, the limited coal that is produced in the West is generally sold in markets close to the point of production.

Figure 106. Western Share of U.S. Coal Production, 1990-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Coal Prices

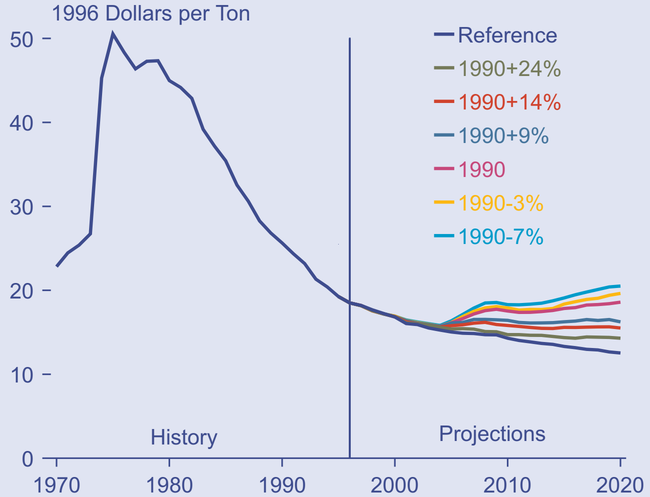
Because coal is heterogeneous in terms of heat content, sulfur level, and other physical properties, trends in national average prices are affected substantially by the relative shares of the various coal types produced and sold and by the units in which prices are reported. For example, coal from the Powder River Basin is generally the lowest-priced coal per ton on a minemouth basis; however, because Powder River Basin coal has roughly two-thirds the heat content of bituminous coal, its cost advantage is somewhat less on a Btu basis and may be nonexistent when delivered to more distant markets.

In general, to the extent that market share shifts away from Powder River Basin coal, which has a low minemouth price, to higher-priced bituminous coal, the national average minemouth price will increase. Similarly, the greater the share represented by metallurgical coal and by premium grades of coal for export use, the higher will be the share-weighted average price. This compositional effect offsets the reduction in minemouth prices at the regional level that is likely to occur because of intraregional competition and the lower production quantities that occur when carbon restrictions take effect. The regional productivity improvements projected in the reference case are assumed to occur at the same rates in all the carbon reduction cases given the same rate of technological progress. However, if the level of investment in new capital equipment is severely constrained, there could be adverse impacts on productivity.

In 2010, real minemouth prices are projected to decrease to $14.29 per ton in the reference case but increase to $14.72 in the 1990+24% case, to $16.42 in the 1990+9% case, and to $17.90 in the 1990-3% case (Figure 107). Minemouth prices in individual regions generally decline in all cases, but the national average minemouth price increases in the carbon reduction cases because of the shift in quantity shares to higher grade and higher priced coal and away from coal with a lower minemouth price, such as that from the Powder River Basin. In some instances, however, even the regional weighted average price for a given coal rank will increase relative to the reference case, if a greater share of coal is being shipped to export or metallurgical markets that demand premium-grade (and therefore higher priced) coals. The pattern of higher national average prices in the carbon reduction cases is accentuated by the projections for 2020, when prices increase from the reference case value of $12.53 to $14.29 in the 1990+24% case, to $16.24 in the 1990+9% case, and to $19.63 in the 1990-3% case.

Delivered prices for coal, as projected in this report, reflect the sum of the minemouth price, transportation cost (in dollars per ton), and the carbon price associated with meeting a carbon reduction target. The carbon price dominates the effects on delivered prices in the

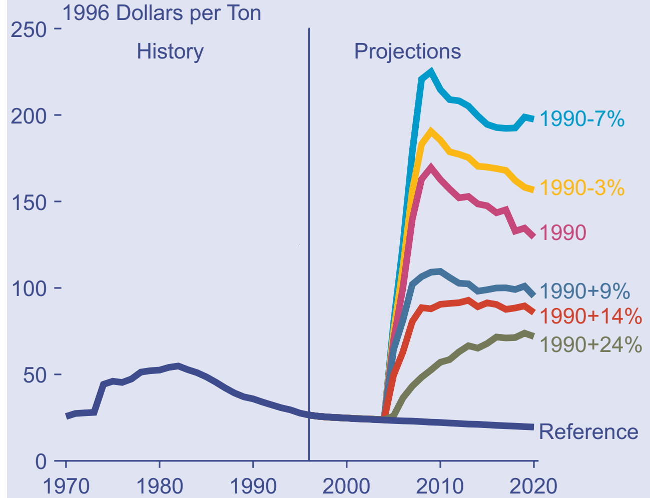
Figure 107. Average U.S. Minemouth Coal Prices, 1970-2020



Note: Carbon prices are added to the delivered price of coal, not to the minemouth price.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 108. Coal Prices to Electricity Generators, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

carbon reduction cases. In 2010, the carbon fee adds $1.73 per million Btu to the delivered price of coal to electricity generators in the 1990+24% case, $4.18 per million Btu in the 1990+9% case, and $7.51 per million Btu in the 1990-3% case. In 2020, the carbon price component drops to $2.55, $3.62, and $6.14 per million Btu, respectively because the carbon price for all fuels is lower in 2020.

In 2010, the national average delivered price of coal to electricity generators increases from $22.20 per ton in the reference case to $57.03 in the 1990+24% case, $109.56 in the 1990+9% case, and $185.47 in the 1990-3% case (Figure 108). In 2020, the delivered price to electricity generators rises from $19.56 in the reference case, to $71.95 in the 1990+24% case, to $95.33 in the 1990+9% case, and to $156.60 in the 1990-3% case.

Coal Industry Employment and Productivity

Between 1978 and 1996, the number of miners employed in the U.S. coal industry fell by 5.8 percent a year, declining from 246,000 to 83,000. The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.7 percent over the same period. An additional factor was increased output from large surface mines in the Powder River Basin, which require much less labor per ton of output than mines located in the Interior and Appalachian regions. The Powder River Basin share of total U.S. coal production increased from 13 percent in 1978 to 30 percent in 1996.

In the reference case, productivity improvements are assumed to continue but to decline in magnitude over the forecast period. On a national basis, labor productivity increases at an average rate of 2.3 percent a year over the whole forecast. The annual rate of increase slows, however, from 5.8 percent in 1996 to approximately 1.6 percent per year from 2010 to 2020. With improvements continuing over the forecast period, further declines in employment of 1.3 and 1.1 percent per year are projected from 1996 through 2010 and from 2010 through 2020, respectively. In absolute terms, coal mine employment declines from 83,000 in 1996 to 69,000 in 2010 and to 62,000 in 2020.

Regionally, labor productivity in the carbon reduction cases is assumed to improve at the same rates as in the reference case.[76] As a result, lower levels of production in the carbon reduction cases in all supply regions, relative to the reference case, result in lower employment levels in all regions. Table 23 shows projections of coal mining jobs in 2010 by region for the reference case and the carbon reduction cases. In the 1990+24% case, coal mine employment declines at a rate of 2.5 percent a year between 1996 and 2010, falling from 83,000 in 1996 to 58,000 in 2010 (Figure 109). In the 1990+9% case, employment declines at a more rapid rate of 4.6 percent a year to 2010, resulting in employment of only 43,000 miners in 2010. In the 1990-3% case, coal mine employment declines at a rate of 7.2 percent a year between 1996 and 2010, reaching 29,000 in 2010.

Production and employment are positively correlated. In 2010, the projected levels of coal production in the

[76] Higher or lower rates of productivity growth could occur in the carbon reduction cases depending on the skill level and motivation of the labor force in a rapidly contracting job market and the rate at which new capital equipment and technology are adopted.

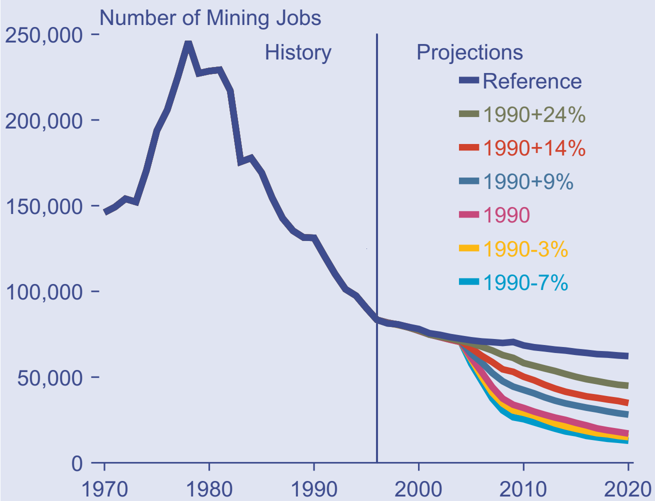
Table 23. Projected Number of Coal Mining Jobs by Region, 2010

Region	1996	Reference	1990+24%	1990+14%	1990+9%	1990	1990-3%	1990-7%
Appalachia[a]	60,001	49,477	41,617	37,340	32,386	26,034	24,307	21,654
Interior[b]	13,477	8,043	7,801	7,617	6,257	4,315	3,484	2,663
Powder River Basin[c]	4,159	5,013	3,827	2,490	1,829	1,015	844	673
Other West[d]	5,825	5,693	4,785	2,859	2,254	1,034	941	895
U.S. Total	**83,462**	**68,519**	**58,223**	**50,224**	**42,531**	**32,053**	**29,187**	**25,486**

[a]PA, OH, MD, WV, VA, and KY (east).
[b]IL, IN, KY (west), IA, MO, KS, AR, OK, TX, and LA.
[c]WY, MT, and ND.
[d]CO, UT, NM, AZ, AK, and WA.

Source: **History:** Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-584(96) (Washington, DC, November 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW.D080398B.

Figure 109. Coal Mine Employment, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559, (Washington, DC, November 1992) and EIA, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

1990+24% and 1990-3% cases are 20 percent and 75 percent lower, respectively, than in the reference case. In comparison, employment in the 1990+24% case is only 15 percent lower in 2010 than in the reference case and employment in the 1990-3% case in 2010 is only 57 percent below the reference case. The projected declines in employment are smaller than the declines in production because of the relatively greater losses in output projected from mines in the Northern Great Plains, which require less labor per unit of output than mines in other coal-producing regions.

Table 24 provides an indication of the importance of coal industry jobs in the top coal-producing States. The table shows that the wages associated with coal mining exceeded 2 percent of all wages paid in 1996 in West Virginia, Kentucky, and Wyoming. In West Virginia and Wyoming, they accounted for more than 5 percent of all wages paid. The fact that coal mining wages are higher than average wages in these States is shown by the fact that coal industry jobs account for a greater share of total wages than their share of total employment. In West Virginia, the coal industry employs 3.2 percent of all workers in the State but accounts for 6.5 percent of all wages paid. In Wyoming, coal industry workers account for only 2.2 percent of all jobs but earn 5.3 percent of all wages. Similarly, in Kentucky, the coal industry provides 1.2 percent of all jobs but 2.1 percent of all wages. Table 24 also shows that while the potential for direct losses of coal-related wages and employment is concentrated in the 10 States listed, it is much more strongly concentrated in West Virginia, Kentucky, Wyoming, and perhaps Pennsylvania (depending on whether the absolute amount of wages and employment at stake is counted, or the relative proportion of the State's total wages and employment).

In addition to the substantial contraction of the U.S. coal industry projected in the carbon reduction cases, the U.S. rail industry, which derives considerable revenues from coal shipments, also stands to be greatly affected (see box).

U.S. Coal Exports

U.S. coal producers exported 90 million tons of coal in 1996. Of that amount, 59 percent represented shipments of coking coal for use at integrated steel plants worldwide, and 41 percent was steam coal, used primarily for electricity generation and for the production of process steam and direct heat for industrial applications. In 1997, U.S. coal exports fell by 7 million tons, reversing the upward trend of the previous 2 years. The decline was mostly in steam coal exports, as a result of weak international coal prices and strong competition from other coal-exporting countries.

In the reference case, U.S. coal exports are projected to increase from 90 million tons in 1996 to 113 million tons in 2010. All the increase reflects expected growth in steam coal exports, with exports of metallurgical coal projected to decline slightly. In the reference case, world metallurgical coal trade remains relatively constant, although regionally there is a slight shift away from markets in Europe and Japan to Brazil and the

Table 24. Coal Industry Wages and Employment, 1996

State	Wages		Employment[a]	
	Million 1996 Dollars	Percent of State Total	Number of Jobs	Percent of State Total
West Virginia	1,041	6.53	21,033	3.17
Kentucky	815	2.06	19,372	1.20
Wyoming	258	5.29	4,706	2.20
Pennsylvania	512	0.34	11,214	0.22
Illinois	347	0.20	6,136	0.11
Virginia	290	0.03	7,039	0.02
Alabama	332	0.74	6,552	0.04
Ohio	172	0.12	3,889	0.01
Texas	149	0.65	2,861	<0.01
Montana	49	0.66	933	0.03
Subtotal	3,965	0.42	83,375	0.03
United States	**4,691**	**0.17**	**97,649**	**0.08**

[a]Relative to Form EIA-7A, “Coal Production Report,” which focuses on workers directly involved in the production and preparation of coal, the data presented in this table include coverage of corporate officials, executives, clerical workers, and other office workers. Data from Form EIA-7A indicate that 83,462 miners were employed in the U.S. coal industry in 1996.

Source: U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, “Covered Employment and Wages.”

developing countries in Asia. World steam coal trade is projected to increase by 45 percent between 1996 and 2010, rising from 305 million tons to 441 million tons. The U.S. share of total world coal trade is projected to remain constant at about 18 percent.

In the reference case, Japan’s remaining two coal mines are assumed to be closed shortly after 2000. Currently these mines have a combined annual production capacity of about 3.5 million tons, representing less than 3 percent of Japan’s total coal consumption. In 1996, coal consumption in Japan amounted to 144 million tons—82 million tons of steam coal (including 9.5 million tons of coal for pulverized coal injection at blast furnaces) and 62 million tons of coking coal.

In the carbon reduction cases, two alternative coal trade scenarios were developed. In a severe carbon reduction case (1990-3%), carbon emissions in Western Europe were assumed to be 8 percent below their 1990 level by 2010 consistent with the limits for the European Union that were specified in the Kyoto Protocol. Similarly, carbon emissions in Japan were assumed to be 6 percent below their 1990 level by 2010. Coal was assumed to play a proportionately greater role than oil or natural gas in meeting these emission reductions, because it has a higher carbon content (on a Btu basis) and the opportunities to substitute for petroleum products in the transportation sector are limited. In Western Europe, both domestic coal production and imports were assumed to decline by approximately 50 percent, but in Japan coal imports had to account for the total reduction in coal consumption.

In Europe, steam coal imports from all sources are reduced from 156 million tons in the reference case in 2010 to 47 million tons in the 1990-3% case. Only steam coal imports to the industrialized Annex I countries in Europe are reduced. Steam coal imports to Japan, the only Annex I country in Asia, are reduced from 99 million tons in the reference case in 2010 to 56 million tons in the 1990-3% case. Because other fuels are not easily substituted for coal coke at steel plants, coking coal imports are not adjusted downward.

Steam coal imports to Japan are reduced by a relatively smaller amount than are imports to Europe, primarily because Japan has limited access to alternative sources of energy such as natural gas and renewable fuels. In addition to reduced use of coal, other strategies that Japan may pursue to meet its carbon reduction targets include purchasing surplus emission allowances from other signatory countries and pursuing an accelerated nuclear program.[77]

U.S. coal exports to Europe and Asia in 2010 are projected to be lower by 27 and 7 million tons, respectively, in the 1990-3% case (and all other carbon reduction cases where U.S. carbon emissions are held at or below the 1990 level in 2010) than in the reference case. In these cases, U.S. coal exports are projected to decline to 76 million tons in 2010.

In the moderate cases, 1990+24% and 1990+9%, developed to evaluate the potential impacts of less severe reductions in carbon emissions, Western European coal consumption and imports were assumed to decline by a smaller amount than in the severe case discussed above,

[77]In June 1998, a panel headed by then Prime Minister Ryutaro Hashimoto urged the government to construct an additional 20 new nuclear plants over the next 12 years, with the goal of increasing Japan’s nuclear generation by more than 50 percent between 1997 and 2010. EIA’s *International Energy Outlook* (*IEO98*) high nuclear case projects an increase of 12.4 gigawatts (29 percent) in Japan’s nuclear generating capacity over the same period. The *IEO98* reference case projects an increase of only 5.2 gigawatts (12 percent) between 1996 and 2010.

reflecting the lower emission target. Japanese coal consumption and imports were also assumed to decline by a smaller amount as in the severe case. In Europe, projected steam coal imports from all sources are reduced from 156 million tons in the reference case in 2010 to 96 million tons in the 1990+9% case. Only steam coal imports to the industrialized Annex I countries in Europe are reduced.

U.S. coal exports to Europe and Asia in 2010 are projected to be lower by 17 and 4 million tons, respectively, in the 1990+24% and 1990+9% cases (and in all other carbon reduction cases where U.S. carbon emissions are above the 1990 level in 2010) than in the reference case. In these cases, U.S. coal exports of 89 million tons are projected for 2010, as compared with 113 million tons in the reference case.

Impacts on the Rail Industry

In 1996, 705 million of the 1,064 million tons of coal produced in the United States (66 percent) was transported to consumers partly or entirely by rail. Coal freight provided Class I railroads with $7.7 billion, 23 percent of all revenue earned. Coal freight car loadings and ton-miles tend to be dominated by a handful of railroads. For the major coal-hauling railroads, coal represented 39 percent of all car loadings during 1996.[a] Available data from the Federal Railroad Administration that summarize railroads' reported return on investment and the extent of their dependence on coal freight revenues are shown in the table below.

Because the carbon reduction cases analyzed here project heavier losses in coal production for western than for eastern coalfields, and because much of the production from western coalfields is shipped long distances into midwestern and eastern markets to satisfy demand for low-sulfur fuel, it is likely that the burden of reduced coal transportation revenues would fall most heavily on railroads in the West—particularly on the Burlington-Northern and Union Pacific systems, which now include the St. Louis Southwestern, the Chicago & Northwestern, the Denver & Rio Grande Western, the Southern Pacific, and the Atchison, Topeka & Santa Fe railroads.

Progressively deregulated since the Staggers Rail Act of 1986, railroads have made substantial progress in improving productivity and reducing real costs by investing in new and more powerful locomotives, improved maintenance of main-line rights of way, and more efficient use of labor. A major contribution to achieving the joint goals of lower costs and maintenance of service has been made through a number of mergers over the past decade. Mergers have resulted in the emergence of four major railroad companies—two in the East (CSX and Norfolk-Southern) and two in the West (Burlington Northern - Santa Fe and Union Pacific - Southern Pacific). The recent merger between Union Pacific and Southern Pacific was followed by a period of service problems (particularly in Texas, but also affecting rail shipments throughout the Union Pacific - Southern Pacific system) that have not yet been entirely resolved. As a result of these service issues, there has been controversy surrounding the policies of the Surface Transportation Board as it has sought to balance the needs of railroad shippers and

Revenue Adequacy and Relative Dependence on Coal Revenue by Railroad, 1989-1995

Railroad	1989		1991		1993		1995	
	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment
Eastern District								
Conrail	15.4	2.6	16.8	NM	14.2	6.5	15.9	6.8
CSX	34.4	6.1	35.3	NM	29.9	0.1	29.8	6.5
Florida East Coast	1.1	10.3	1.0	2.2	NA	NA	NA	NA
Grand Trunk Western	8.1	1.9	9.4	NM	8.2	NM	7.9	NM
Illinois Central	16.0	11.2	15.2	15.2	12.7	14.7	13.9	17.2
Norfolk Southern	36.1	11.9	37.0	6.0	32.9	12.1	30.9	12.1
Western District								
Atchison Topeka & Santa Fe	7.7	NM	8.9	6.5	8.7	1.9	7.3	5.3
Burlington Northern	33.0	12.5	33.5	NM	31.9	9.4	32.7	6.3
Chicago & Northwestern	12.4	8.2	14.1	7.1	13.5	10.3	15.5	NA
Kansas City Southern	33.7	10.7	31.9	9.3	29.9	9.0	19.7	7.9
Soo Line	11.3	NM	12.8	4.0	9.2	NM	3.8	NM
Southern Pacific	2.2	1.8	2.4	NM	3.2	3.5	9.4	1.3
St. Louis Southwestern	2.6	1.8	2.2	NM	3.2	3.5	9.4	1.3
Union Pacific	16.1	10.4	17.5	1.7	16.8	11.1	19.0	11.7

NM = negative returns on investment are described only as "not meaningful" in the source.
NA = not available, usually because the railroad has ceased to operate as an independent entity.
Source: Federal Railroad Administration.

(Continued on page 117)

Impacts on the Rail Industry (Continued)

the continued profitability of the Union Pacific, and of the Nation's major railroads in general. Even if these issues are successfully resolved over the next few years, the adoption of carbon emissions restrictions would inevitably result in a reduction in domestic coal traffic handled by the railroads.

As suggested by the results of the carbon reduction cases, the reductions in coal traffic range from moderate to severe, depending on the case. In all cases, western coal, particularly subbituminous coal from the Powder River Basin, would be most severely restricted, because of its dependence on long-distance rail transportation to reach its markets in locations up to 2,000 miles away and its high ratio of carbon to energy content. As shown in the table, the Burlington Northern and Union Pacific systems have a fairly high dependence on coal freight revenue; therefore, the loss of revenue associated with carbon reduction measures could create significant financial problems for those firms. Lignite production in Texas, Louisiana, and North Dakota would also be severely reduced by carbon emissions restrictions, but the effect on rail revenues would be minor. Because of its inherently low heat content, lignite is predominantly consumed at or close to the place of mining.

Although the projected losses of coal production in the individual carbon reduction cases are proportionately and absolutely less for Appalachian coalfields than for the Powder River Basin, the two eastern rail systems (CSX and Norfolk Southern) are also highly dependent on coal revenue. In the more severe carbon reduction cases, Appalachian coal production could be reduced by one-third to one-half, with potentially serious financial consequences for these carriers.

[a]Association of American Railroads, Freight Commodity Statistics.

6. Assessment of Economic Impacts

Objectives of the Macroeconomic Analysis

Because energy resources are used to produce most goods and services, higher energy prices can affect the economy's production potential. Since the energy crisis of the 1970s, economic research has led to a better understanding of the potential adverse economic consequences of rising real energy costs, in terms of both long-run equilibrium costs and short-run adjustment costs. Long-run equilibrium costs are associated with reducing reliance on energy in favor of other factors of production—including labor and capital, which become relatively cheaper as energy costs rise. Short-run adjustment costs, or business cycle costs, can arise when price increases disrupt capital or employment markets. Long-run costs are considered unavoidable. Short-run costs might be avoidable if price changes can be accurately anticipated or if appropriate compensatory monetary and fiscal policies can be implemented.

This chapter assesses possible impacts on the economy associated with attaining the alternative carbon mitigation targets presented earlier in this report, focusing on three target cases—the 3-percent-below-1990 (1990-3%), the 9-percent-above-1990 (1990+9%), and the 24-percent-above-1990 (1990+24%) cases—and comparing them with a reference case that does not include the Kyoto Protocol. In evaluating these alternative targets, three key questions are posed:

- What would be the unavoidable minimum impact on the economy?
- With rising energy prices and inflation, what cyclical reactions could the economy face, and how would the Federal Reserve Board implement accommodating monetary policy?
- What would be the impact of fiscal policy on economic output and inflation?

EIA used the Data Resources, Inc. (DRI) model of the U.S. economy to assess these issues.[78] The DRI model is a representation of the U.S. economy with detailed output, price, and financial sectors incorporating both long-term and short-term properties. In the DRI model, the concept of *potential* GDP reflects the trajectory of the long-term growth potential of the economy at full employment, while *actual* GDP is a measure of the transition effects as the economy adjusts to its long-run path. Energy end-use demands and prices for fuels are the key energy inputs to the DRI model.[79] In addition, for this analysis, assumptions were made about the domestic flow of funds that would result from a U.S. system of carbon permits sold by the Federal Government, and about the international flow of funds that would result from international trading of permits. These assumptions were based on the results of the energy market analyses described in the preceding chapters of this report.

This chapter first presents a discussion of the U.S. permit system and the potential role of international trading of permits. A summary of the macroeconomic effects is presented next, focusing on the definition and measurement of *potential GDP*, *actual GDP*, and the *value of the purchased international permits* as key elements. The chapter then discusses in detail two topics. The first addresses the unavoidable loss to the economy that would result from a reduction in available energy resources. The unavoidable loss has two components: the loss in potential GDP and the value of the purchased international permits. The chapter concludes with a discussion of the possible transitional impacts on the aggregate economy that might occur as energy prices increase in response to carbon emission constraints. The critical roles of monetary and fiscal policy are highlighted. Two fiscal policies are considered as alternative methods of returning carbon permit revenues to the economy: through a lump sum personal income tax rebate and through a social security tax rebate that would pass funds back to both employers and employees.

[78]The version of the model used is US97A95.

[79]This macroeconomic analysis of the costs of implementing the Kyoto Protocol is limited to the consideration of investment costs that are comparable in magnitude to those in the reference case, as well as direct fuel costs. No consideration is given to the potential incremental costs of investment in technology and infrastructure that would be necessary in each of the specific cases analyzed. Business investments above reference case levels may be required to reduce energy costs in response to increasing energy prices.

The U.S. Permit System and International Trading of Permits

Two key features shape the discussion in this chapter—first, the characterization of the carbon permit trading system as an auction run by the Federal Government; and second, the international trading of carbon permits. Both of these issues have important implications for the assessment of the potential macroeconomic impacts of carbon mitigation policies.

The U.S. Permit System

When a system is developed for the trading of carbon permits within the United States, a number of initial decisions must be made: How many permits will be available? Will they be freely allocated or sold by competitive auction? If they are allocated, how will the initial allocations be made? If they are sold, what will be done with the revenues? How many permits will be bought in international markets? If the permits are traded in a free market, holders of permits who can reduce carbon emissions at a cost below the permit price will sell their permits, and those with higher costs of reduction will buy permits, resulting in a transfer of funds between private parties. If the permits are sold by competitive auction, there will be a transfer of funds from emitters of carbon to the Federal treasury.

This analysis makes the explicit assumption that carbon permits will be sold in a competitive auction run by the Federal Government.[80] To illustrate the importance of recycling the funds back to the economy, two fiscal policy approaches are considered: first, returning collected revenues to consumer through personal income tax rebates and, second, lowering the social security tax rate as it applies to both employers and employees. The two policies are meant only to be representative of a set of possible fiscal policies that might accompany an initial carbon mitigation policy.

International Trading of Permits

In the energy market assessments described earlier in this report, the projected carbon prices reflect the price the United States would be willing to pay to achieve a given emissions reduction target. The more stringent the carbon target, the higher the carbon price. The energy market analysis in this report does not address the international implications of achieving a particular target at the projected carbon price. In the absence of modeling international trade of emissions permits, the energy market assessment makes no link between the U.S. carbon price and the international market-clearing price of permits, or the price at which other countries would be willing to offer permits for sale in the United States.

The macroeconomic analysis in this chapter departs from the above interpretation in order to facilitate an evaluation of the role of the purchase of permits in an international market. The analysis first assumes that the U.S. State Department's assessment of the accounting of carbon-absorbing sinks and offsets from reductions in other greenhouse gases will reduce the binding U.S. emissions target to 3 percent below the 1990 level of emissions. Then, if the United States is to meet a target that is less stringent, the difference in emissions is assumed to be made up through the purchase of permits on the international market. Moreover, the United States is assumed to purchase international permits at *the marginal abatement cost in the United States*. Thus, the domestic carbon price would be the same as the international permit price under the alternative targets considered. If unrestricted international trading among Annex I countries is allowed, the international carbon price could fall below the levels projected here for domestic permits. If this were to occur, to achieve equilibrium in an unconstrained market for carbon permits, the domestic carbon price would fall to the international carbon price.

The above assumptions imply that different international supplies of permits would be available in the alternative cases considered. This is an important simplifying assumption, and the value placed on the overseas transfer of funds to purchase international permits is subject to considerable uncertainty. However, this element must be considered a key factor in performing any assessment of the impacts on the economy, and therefore it is explicitly factored into the analysis. Table 25 shows the assumed carbon reductions, carbon prices, and number and value of carbon emission permits purchased on the international market in the 1990-3%, 1990+9%, and 1990+24% cases.

Summary of Macroeconomic Impacts

In the long run, higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and

[80] A permit auction system is identical to a carbon tax as long as the marginal abatement reduction cost is known with certainty by the Federal Government. If the target reduction is specified, as in this analysis, then there is one true price, which represents the marginal cost of abatement, and this also becomes the appropriate tax rate. In the face of uncertainty, however, the actual tax rate applied may over- or undershoot the carbon reduction target. Auctioning of the permits by the Federal Government is evaluated in this report. The costs of administering the program are not considered. To investigate a system of allocated permits would require an energy and macroeconomic modeling structure with a highly detailed sectoral breakout beyond those represented in the NEMS and DRI models. For a comparison of emissions taxes and marketable permit systems, see R. Perman, Y. Ma, and J. McGilvray, *Natural Resources and Environmental Economics* (New York, NY: Longman Publishing, 1996), pp. 231-233.)

Table 25. Energy Market Assumptions for the Macroeconomic Analysis of Three Carbon Reduction Cases, Average Annual Values, 2008 through 2012

Analysis Case	Binding Carbon Emissions Reduction Target (Million Metric Tons)	Average U.S. Carbon Emissions Reductions (Million Metric Tons)	U.S. Purchases of International Permits (Million Metric Tons)	Carbon Price		Value of Purchased International Permits (Billion 1992 Dollars)
				1996 Dollars per Metric Ton	1992 Dollars per Metric Ton	
1990-3%	485	485	0	290	263	0
1990+9%	485	325	160	159	144	23
1990+24%	485	122	363	65	59	21

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher-cost energy, this gradual reduction in energy use would tend to lower the productivity of other factors in the production process. The derivation of the long-run equilibrium path of the economy can be characterized as representing the “potential” output of the economy when all resources—labor, capital, and energy—are fully employed. As such, potential gross domestic product (GDP) in the DRI model is equivalent to the full employment concept calculated in a number of other models that focus on long-run growth while abstracting from business cycle behavior.[81]

The ultimate impacts of carbon mitigation policies on the economy will be determined by complex interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. As such, cyclical impacts on the economy are bound to be characterized by uncertainty, possibly significant. Raising energy prices and, as a result, downstream prices in the rest of the economy could introduce cyclical behavior in the economy, resulting in employment and output losses in the short run. The measurement of losses in actual output for the economy, or actual GDP, incorporates the transitional cost to the aggregate economy as it adjusts to its long-run path. Resources may be less than fully employed, and the economy may move in a cyclical fashion as the initial cause of the disturbance—the increase in energy prices—plays out over time.

The possible impacts on the economy are summarized in Table 26, which shows average changes from the reference case projections over the period from 2008 through 2012 in the three carbon reduction analysis cases.[82] The *loss of potential GDP* measures the loss in productive capacity of the economy directly attributable to the reduction in energy resources available to the economy. It represents part of the long-run, unavoidable impact on the economy. The *macroeconomic adjustment cost* reflects frictions in the economy that may result from the higher prices of the carbon mitigation policy. It recognizes the possibility that cyclical adjustments may occur in the short run. The *loss in actual GDP* for the economy is the sum of the loss in potential and the adjustment cost. The *purchase of international permits* represents a claim on the productive capacity of domestic U.S. resources. Essentially, as funds flow abroad, other countries have an increased claim on U.S. goods and services. The *total cost to the economy* is represented by the loss in actual GDP plus the purchase of international permits (Figure 110). These costs need to be put in perspective relative to the size of the economy, which is projected to average $9,425 billion between 2008 and 2012 in the reference case.

Another way to view the macroeconomic effects is by looking at the effects of the carbon reduction cases on the growth rate of the economy, both during the period of implementation and during the early part of the commitment period, from 2005 through 2010, and then over the entire period from 2005 through 2020 (Figures 111 and 112). In all instances, the economy continues to grow, but growth is slower than projected in the reference case. In the reference case, potential and actual GDP grow at 2.0 percent per year from 2005 through 2010. In the 1990+9% case, the growth rate in potential GDP slows to 1.9 percent per year, and the growth rate in actual GDP slows to 1.6 percent per year when the

[81] In the DRI model, the aggregate production function (the potential GDP equation) uses the following concepts as important variables: energy, labor, capital stocks of equipment and structures, and research and development expenditures. The aggregate supply is estimated by a Cobb-Douglas production function that combines factor input growth and improvements in total factor productivity. Factor input equals a weighted average of energy, labor, fixed capital (outside the energy-producing sector), and public infrastructure. Factor supplies for the non-energy sector are defined by estimates of the full-employment labor force, the full-employment capital net of pollution abatement equipment, domestic energy consumption, and the stock of infrastructure. Total factor productivity depends on the stock of research and development capital and a technological change trend.

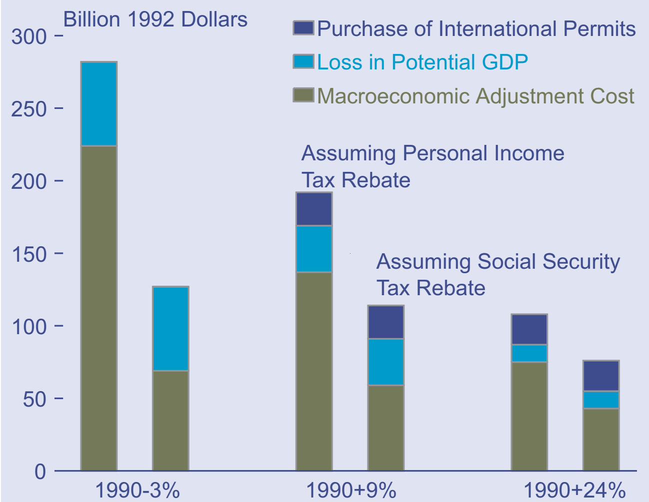
[82] The output measures presented in this chapter are expressed in constant 1992 chain-weighted dollars. The DRI macroeconomic model uses National Income and Products Accounts (NIPA) as an estimating framework. Expressing these output measures in 1992 dollars maintains consistency with the NIPA framework and facilitates comparison with results from other macroeconomic models. For the purposes of recycling the funds, collections and rebates are expressed in nominal dollars, to be consistent with the Federal Government’s tax accounting system.

Table 26. Macroeconomic Impacts in Three Carbon Reduction Cases, Average Annual Values, 2008-2012
(Billion 1992 Dollars)

Analysis Case	Loss in Potential GDP	Macroeconomic Adjustment Cost	Loss in Actual GDP	Purchases of International Permits	Total Cost to the Economy
1990-3%					
Personal Income Tax Rebate.	58	225	283	0	**283**
Social Security Tax Rebate	58	70	128	0	**128**
1990+9%					
Personal Income Tax Rebate.	32	137	169	23	**192**
Social Security Tax Rebate	32	59	91	23	**114**
1990+24%					
Personal Income Tax Rebate.	12	76	88	21	**109**
Social Security Tax Rebate	12	44	56	21	**77**

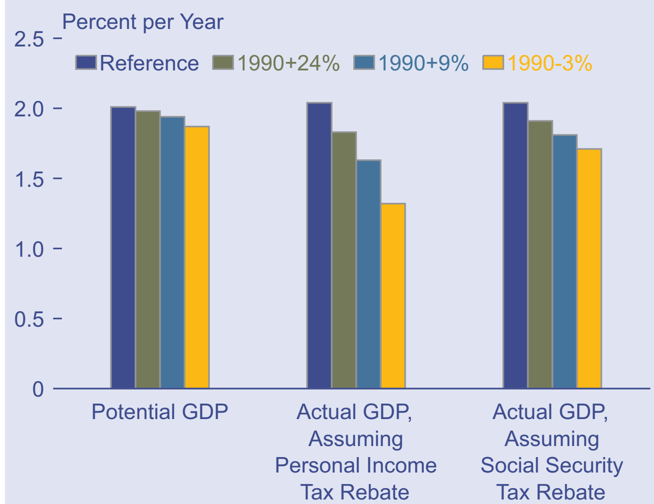
Note: Loss in potential GDP plus the macroeconomic adjustment costs equals the loss in actual GDP. The actual GDP loss plus purchases of international permits equals the total cost to the economy.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 110. Projected Annual Costs of Carbon Reductions to the U.S. Economy, 2008-2012



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 111. Projected Annual Growth Rates in Potential and Actual GDP, 2005-2010

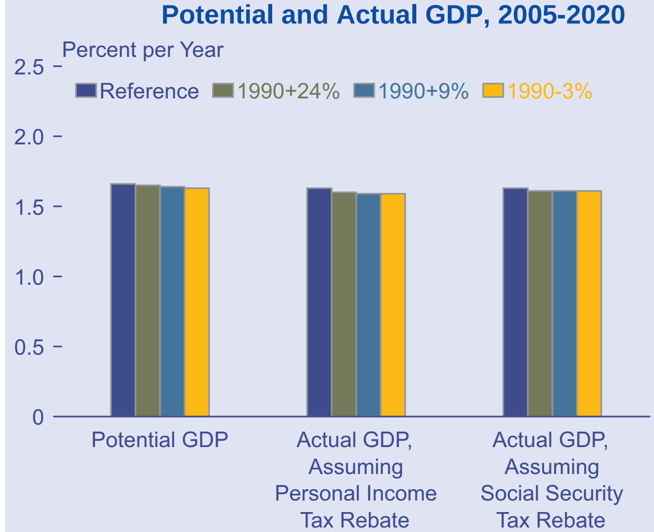


Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

personal income tax rebate is assumed or 1.8 percent per year when the social security tax rebate is assumed. However, through 2020, with the economy rebounding back to the reference case path, there is no appreciable change in the projected long-term growth rate. The results for the 1990+24% and 1990-3% cases are similar.

Aggregate impacts on the economy, as measured by actual GDP, are shown in Table 27 in terms of losses in actual GDP per capita. In the 1990+9% case, the loss in potential GDP per capita is $106; however, the loss in actual GDP for in the 1990+9% case is $567 assuming the personal income tax rebate and $305 assuming the social security tax rebate. Again, the lower value (loss in potential GDP) represents part of the unavoidable loss per person, and the higher values (loss in actual GDP) reflect the highly uncertain, but significant, impacts that individuals could experience as the result of frictions

Figure 112. Projected Annual Growth Rates in Potential and Actual GDP, 2005-2020



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Table 27. Projected Losses in Potential and Actual GDP per Capita, Average Annual Values, 2008-2012 (1992 Dollars per Person)

Analysis Case	Loss in Potential GDP per Capita	Loss in Actual GDP per Capita, Personal Income Tax Rebate	Loss in Actual GDP per Capita, Social Security Tax Rebate
1990-3%	193	947	428
1990+9%	106	567	305
1990+24	40	294	187

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

within the economy. Again, to provide scale, actual GDP per capita averages $31,528 in the reference case from 2008 through 2012.

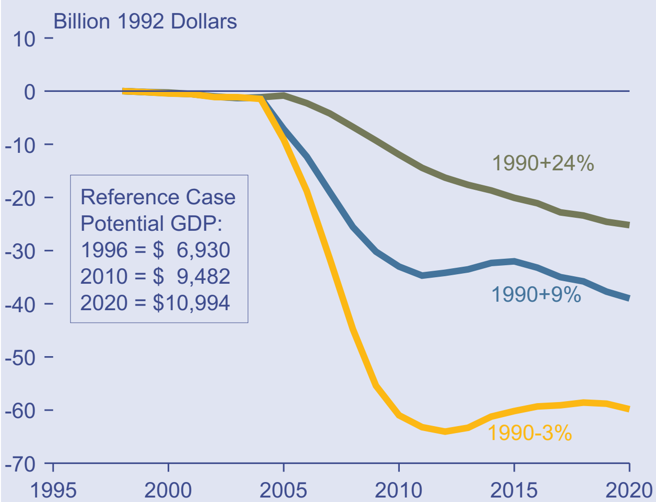
Estimating The Unavoidable Impact on the Economy

Figure 113 shows the losses in the potential economic output, as measured by potential GDP, for the three carbon reduction cases. The shapes of the three trajectories mirror the carbon price trajectories. In the 1990-3% case, potential GDP declines relative to the reference case from 2005 through 2008, reaching a maximum loss of $64 billion (in 1992 dollars) in 2012 and then leveling off at just under $60 billion a year through 2020. In the 1990+9% case, the loss in potential GDP declines to $35 billion by 2011 and reaches $39 billion in 2020. In the 1990+24% case, with steadily increasing carbon prices, potential GDP declines relative to the reference case projections throughout the period and is $26 billion lower than the reference case levels in 2020.

These three potential GDP trajectories represent a valuation of the possible loss in output in the economy in the absence of any cyclical influences brought on by price changes. As shown in Table 25, the three cases considered in this chapter reduce U.S. carbon emissions by 122, 325, and 485 million metric tons a year on average between 2008 and 2012. Figure 114 shows the relationship between the projections of carbon emission reductions and carbon prices. When the carbon reduction target is more stringent, the carbon price is higher; and for the most stringent targets, the projected carbon prices are disproportionately higher than those in the less stringent cases (i.e., the relationship is nonlinear). This curve can be used to measure losses to the aggregate economy by calculating the integral under the curve up to the level of the specified target case. Results for the 1990-3%, 1990+9%, and 1990+24% cases are shown in Table 28.

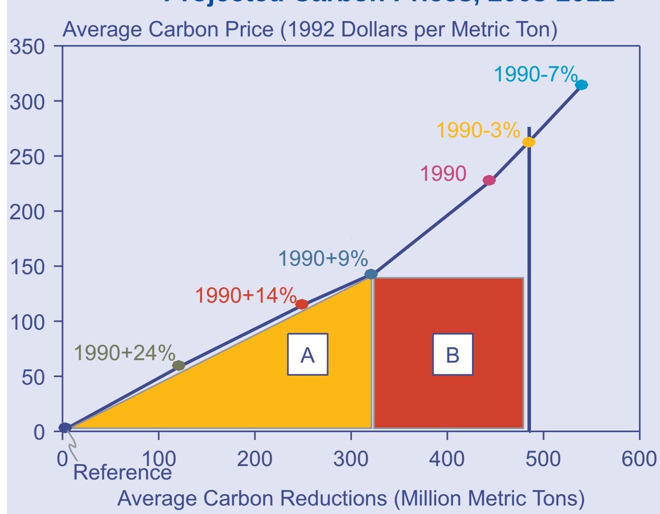
The 1990+9% case results in an average reduction in carbon emissions of 325 million metric tons per year during the period from 2008 to 2012. The average carbon price projected for the same period is $144 per metric ton (in 1992 dollars) (Table 25). The triangular area under the curve in Figure 114, labeled A, represents the value of the carbon reduction to the economy—i.e., the value of reduction in economic output that would result from higher energy prices. In the 1990+9% case, the economic loss projected by the NEMS model totals $25 billion (Table 28). In comparison, the loss in potential GDP

Figure 113. Projected Dollar Losses in Potential GDP Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 114. Average Carbon Reductions and Projected Carbon Prices, 2008-2012



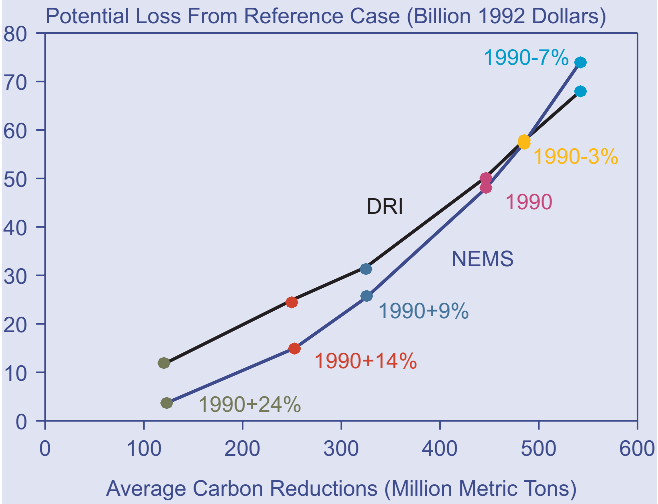
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table 28. Average Projected Annual Losses in Economic Output, 2008-2012

Analysis Case	Value of Lost Output: NEMS Valuation (Billion 1992 Dollars)	Value of Lost Output: DRI Potential GDP Loss (Billion 1992 Dollars)	U.S. Purchase of International Permits (Billion 1992 Dollars)
1990-3%	57	58	0
1990+9%	25	32	23
1990+24%	4	12	21

Sources: Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B, and simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 115. Comparison of Average U.S. Economic Losses Projected by the NEMS and DRI Models, 2008-2012



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

calculated by the DRI model over the same period is $32 billion. As a first approximation, this value closely matches the estimate of the value of the lost output calculated independently using the energy model results (Figure 115).

The curve shown in Figure 114 can also be used to estimate the international value of traded permits. The carbon prices calculated in the NEMS model can be characterized as the particular penalties that the United States would be willing to pay to achieve a given carbon mitigation target. For example, in the 1990+9% case, U.S. carbon emission reductions average 325 million metric tons per year during the period 2008 to 2012. The difference between that reduction and the binding target of 485 million metric tons under the Kyoto Protocol (as reflected by the 1990-3% case) is assumed to be made up through purchases of international permits abroad. The value of those purchases is shown as the rectangle B under the curve in Figure 114. For the 1990+9% case, this represents a transfer of $23 billion dollars (1992 dollars) to purchase permits abroad. For the 1990+24% case, the transfer is $21 billion (Table 25). Even though more permits are purchased abroad, the purchases occur in the context of greater permit availability in the 1990+24% case, and the international price at which they are bought is projected to be dramatically lower, as shown in Table 25.

Focusing on the last two columns of Table 28 highlights the role of international permit trading. Potential GDP is a measure of the level of the output of the economy, but as the last column indicates, there now is a cost to the economy reflected in the transfer of funds abroad to buy permits. Although the direct cost to the U.S. economy in terms of lost potential GDP as a result of lower energy consumption would be less in the 1990+24% and 1990+9% cases than in the 1990-3% case, there would be additional losses of output available to the U.S. economy in those cases. Funds transferred abroad for purchases of international carbon emissions permits would, in effect, reduce the amount of potential GDP available for domestic use.

Energy Prices and the Role of Monetary and Fiscal Policy

This following analysis focuses on the possible transitional impacts on the aggregate economy that would result from efforts to reduce U.S. carbon emissions. The measurement of *actual* output for the economy, or actual GDP, is the key concept used in the examination of changes in the aggregate economy as it adjusts to its long-run path. In addition to internal frictions caused by wage-price interactions and capital stock obsolescence, losses in domestic income may occur as funds are transferred out of the United States to purchase international carbon permits. Resources may be less than fully employed, and the economy will move in a cyclical fashion as the initial cause of the disturbance—the increase in energy prices—plays out over time. Shifts in the sectoral composition of the economy would also accompany the adjustment process.

Here, a single fiscal policy is assumed to accompany the carbon mitigation policy—the revenues collected from the domestic permit auction are returned to consumers through personal income tax rebates. This is a stylized analysis in that it represents only one of a wide range of possible combinations of monetary and fiscal responses.

Impacts of Higher Energy Prices on the Economy

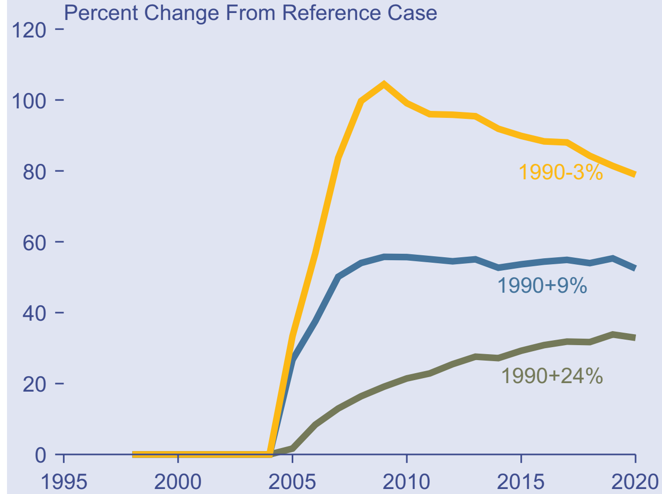
As a direct consequence of the carbon price, aggregate energy prices in the U.S. economy are expected to rise. One way to measure this effect is to look at the percentage change in the *level* of prices in the economy. One measure that can be used is the calculated wholesale price index for fuel and power (Figure 116). In the 1990-3% case, aggregate energy prices are projected to double by 2010 and then decline to 79 percent above reference case price levels in 2020. In the 1990+9% case, energy prices are 56 percent higher than the reference case projection in 2010 and remain more than 50 percent above the reference case over the rest of the forecast period. Prices in the 1990+24% case are 22 percent higher than the reference case in 2010 and continue to rise to 33 percent in 2020.

These changes can also be expressed as rates of change. In the reference case, overall energy prices rise by 3.9 percent per year between 2005 and 2010; however, in the 1990+9% case, aggregate energy prices rise at a rate of 13.5 percent per year, a difference of 9.6 percentage points. The 1990-3% case shows a more dramatic rise, at 19.2 percent per year, and the 1990+24% case shows a rise of 8.0 percent per year. Over the longer run, measured between 2005 and 2020, the rise in energy prices is less dramatic, with the reference case growth at 4.2 percent per year and the 1990+9% case at 7.2 percent per year, a difference of 3.0 percentage points. For the 2005-2020 period, the 1990-3% case shows energy prices rising by 8.3 percent and the 1990+24% case by 6.2 percent per year.

The projected energy price increases would also affect downstream prices for all goods and services in the economy. An intermediate measure is the producer price index (Figure 117), which reflects price impacts on intermediate goods and services. The projected increase in producer prices relative to the reference case in 2010 is 16 percent in the 1990-3% case, 9 percent in the 1990+9% case, and 4 percent in the 1990+24% case. By 2020, the prices in the three carbon reduction case begin to converge, as the differences in projected carbon prices narrow.

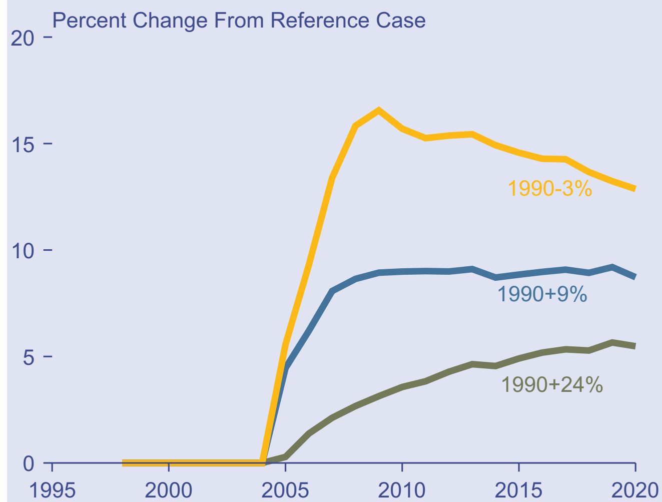
Final prices for goods and services in 2009, as shown by the consumer price index (CPI) series (Figure 118), are more than 6.6 percent higher in the 1990-3% case than in the reference case, 3.7 percent higher in the 1990+9% case, and 1.4 percent higher in the 1990+24% case. Again, by 2020, the differences narrow considerably. In the reference case the CPI rises by 3.6 percent per year between 2005 and 2010, but in the 1990+9% case, it rises at a rate of 4.3 percent per year, a difference of 0.7 percentage points. The 1990-3% case shows a more dramatic rise, at 4.8 percent per year, and the annual

Figure 116. Projected Changes in Wholesale Price Index for Fuel and Power Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 117. Projected Changes in Producer Price Index Relative to the Reference Case, 1998-2020

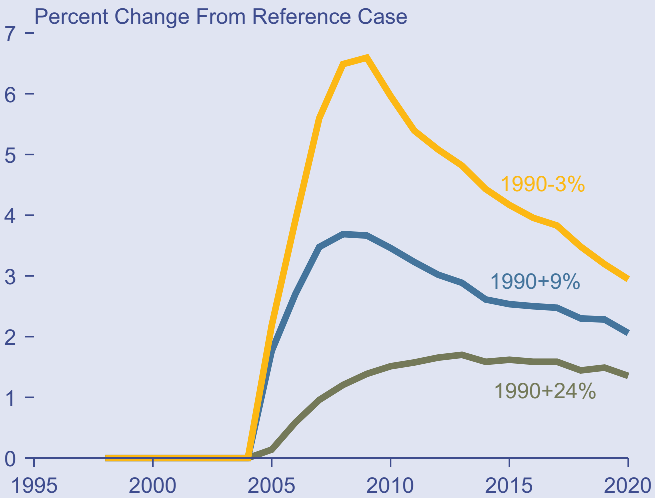


Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

increase in the 1990+24% case is 3.9 percent. In the long term, between 2005 and 2020, the increase in the aggregate price for all goods and services is less dramatic: 3.8 percent per year in the reference case and 3.9 percent per year in the 1990+9% case, a difference of only 0.1 percentage points. Over the same period, the 1990-3% case projects a 4.0-percent annual increase in the CPI and the 1990+24% case a 3.9-percent annual increase.

One aspect of the CPI is particularly noteworthy. The CPI measures the prices that consumers face, regardless

Figure 118. Projected Changes in Consumer Price Index Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

of the country of origin of the product. Import prices, to the extent that they do not rise at the rate of domestic prices because non-Annex I countries do not face carbon constraints, would dampen the price effects as lower priced imports found their way into U.S. markets.

These figures suggest the following rule of thumb for the year 2010. Each 10-percent increase in the level of aggregate prices for energy may lead to a 1.5-percent increase in producer prices and a 0.7-percent increase in consumer prices.

Revenues Flows With International Permit Purchases

The process of auctioning emissions permits would raise large sums of money. If permits were purchased from other countries, as is assumed in both the 1990+9% and 1990+24% cases, there would actually be two revenue flows—domestic and international. The carbon permit revenues remaining within U.S. borders for each case are calculated as the carbon permit price for that case times the level of carbon emissions in the 1990-3% case. Thus, the number of carbon permits purchased domestically remains constant; only the price at which they are available varies across cases. Permits are assumed to be purchased abroad in order for U.S. carbon emissions to continue above the 1990-3% level. Therefore, the international revenue flow equals the difference between actual emissions in the 1990+9% (or 1990+24%) case and those in the 1990-3% case, times the carbon permit price in the 1990+9% (or 1990+24%) case.

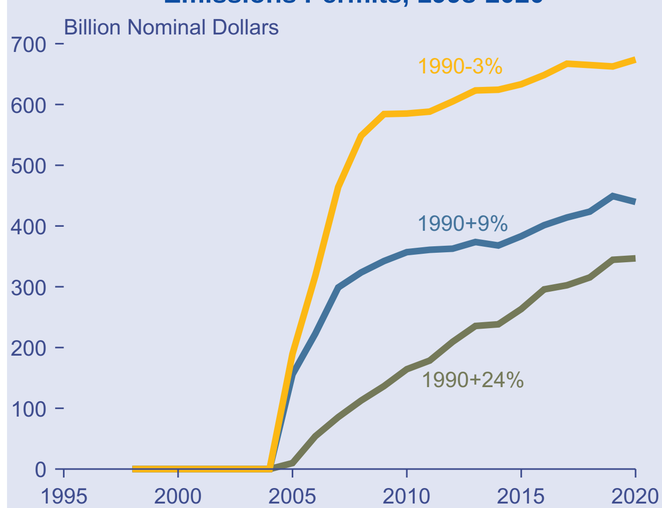
In the 1990-3% case the United States attains the binding target level, and all the funds collected are kept within U.S. borders. The revenue collected in 2010 is projected to total $585 billion nominal dollars, calculated as the level of carbon emissions (1,305 million metric tons) times the carbon permit price ($266 in 1992 dollars), adjusted to nominal dollars. In contrast, in the 1990+9% case, U.S. emissions are reduced to 1,467 million metric tons, or 162 million metric tons short of the binding target. The domestic portion of the collected revenues is equal to the binding target value of 1,305 million metric tons times the new, lower carbon permit price of $148 per metric ton in 1992 dollars. The remaining 162 million metric tons must be offset by permits purchased abroad, again valued at $148 per metric ton. Figure 119 shows total U.S. expenditures for carbon permits in the three carbon reduction cases, and Figure 120 shows the projected split between domestic and international flows for the years 2010 and 2020.

The total projected payments for carbon permits become substantially lower as the carbon reduction target moves from 1990-3% to 1990+9% to 1990+24%. And, although the flow of funds overseas represents an increasing *proportion* of the total collected funds from the 1990+9% case to the 1990+24% case, the actual level of the transfers is relatively stable. Under the domestic-only program of the 1990-3% case, the revenue from permits is assumed to be returned to U.S. households through income tax rebates. In the 1990+9% and 1990+24% cases, only the domestic portion of the funds would be recycled back to consumers. The international flow of carbon permit revenue is considered an increase in the purchase of imported services.

Dynamics of Adjustment in an Economy With Frictions

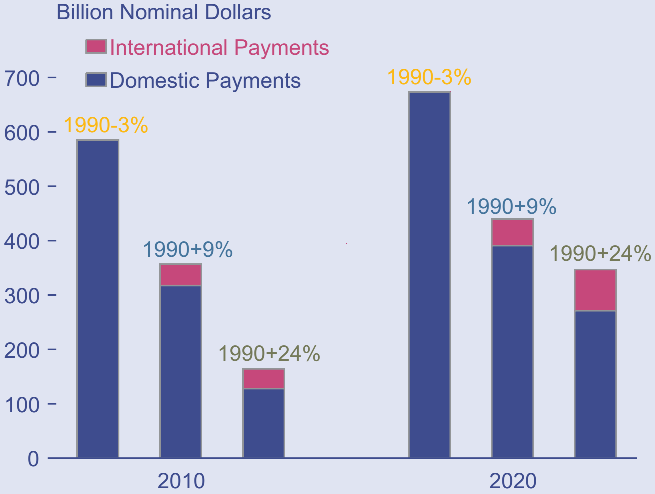
The ultimate impacts of carbon mitigation policies on the economy will be determined by complex

Figure 119. Total Projected U.S. Payments for Domestic and International Carbon Emissions Permits, 1998-2020



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 120. Projected Destinations of Funds Paid for Carbon Emissions Permits, 2010 and 2020



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. As such, any discussion of possible cyclical impacts on the economy is bound to be characterized by uncertainty and controversy. It should be recognized, however, that the process of raising the price of energy and downstream prices in the rest of the economy by the magnitudes shown in Figure 116, 117, and 118 could introduce cyclical behavior in the economy resulting in employment and output losses beyond those associated with the projected impacts on potential GDP.

The introduction of carbon emission limits would affect both consumers and businesses. Households would be faced with higher prices for energy and the need to adjust spending patterns. Nominal energy expenditures would rise, taking a larger share of the family budget for goods and service consumption and leaving less for savings. Higher prices for energy would cause consumers to try to reduce spending not only on energy, but on other goods as well. Thus, changes in energy prices would tend to disrupt both saving and spending streams.

Energy services also represent a key input in the production of goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the nominal prices of all intermediate goods and final goods and services in the economy, with widespread impacts on spending across many markets. The ultimate effect will depend on opportunities for substitution away from higher-cost energy to other goods and services and the effectiveness of compensatory fiscal and monetary policy.

The transitional adjustment of the economy can be captured by calculations of the actual GDP of the economy. The impacts on actual GDP represent a measure of the loss of output from the economy, recognizing that adjustments are not frictionless and that all resources may not be fully employed in the near term. The output of the economy as reflected by actual GDP can cycle around the measure of potential GDP.

The Role of Monetary Policy

Monetary policy can moderate or intensify the ultimate impacts on the economy; however, trying to predict the response of monetary authorities to large increases in energy prices is a difficult task. The emphasis on controlling inflation relative to concerns about rising unemployment has changed over the past 20 years, and using history as a guide does not remove the large amount of uncertainty about the response of monetary authorities. In addition, the types of financial instruments available have become more numerous and more interdependent, and the task of monitoring the Nation’s money supply has become more complex.

The monetary authorities could concentrate on increased inflation resulting from higher energy prices and choose not to increase the money supply in order to moderate the resulting inflation. In this instance, output and employment losses would be larger than they would if the money supply were expanded when energy prices increased. Another option would be to allow the money supply to increase in order to remove the unemployment impacts while allowing substantial additional price inflation. This analysis uses neither extreme of these assumptions about the response of the Federal Reserve. The discussion that follows represents a middle path that the Federal Reserve might follow.

In the setting that has been described—returning funds in the form of personal income tax rebates—higher prices in the economy would place upward pressure on interest rates. The Federal Reserve Board would then seek to balance the consequences of higher energy prices on the economy with possible adverse effects on output and employment. The Federal Reserve would respond to changes in inflation and unemployment brought on by the initial carbon mitigation policy by making adjustments to influence the Federal funds rate.[83] The adjustments would be designed to moderate the possible impacts on both inflation and unemployment, and to return the economy toward its long-run growth path. The characterization of monetary policy reactions to inflation and unemployment used in these simulations is based on a DRI reaction function that has been estimated to reflect the historical relationship between the

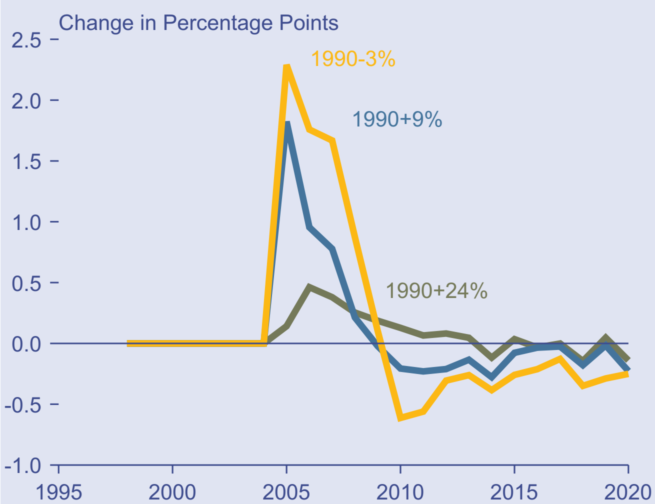
[83] The Federal funds rate is the rate charged by a depository institution on an overnight sale of Federal funds to another depository institution. This rate influences the trend in behavior for other interest rates in the economy.

Federal funds rate and changes in inflation and unemployment. As such, the reaction function is a reflection of how the Federal Reserve may react to changes in the economy caused by the carbon price, based on past behavior.

If the rate of inflation increases, but unemployment does not increase, the Federal Reserve may choose to let the nominal interest rate rise in an attempt to cut the rise in inflation. However, if this is accompanied by an increase in the unemployment rate, the Federal Reserve may consider a cut in the rate to stimulate economic expansion and the demand for labor. In essence, there is a balancing game between the two factors—inflation and unemployment—as the initial originating policy initiative has uneven impacts on the two over time. Figures 121, 122, and 123 show the interrelationship between the projected inflation rate, unemployment rate, and Federal funds rate in the 1990+24%, 1990+9%, and 1990-3% cases. This assessment combines the monetary policy formulation described above with a fiscal policy that returns collected carbon permit revenues back to consumers. An alternative combination of fiscal and monetary policy is considered later in this section.

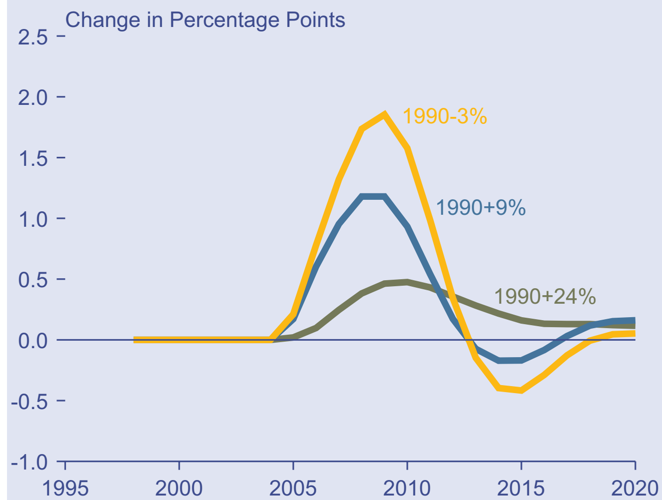
Focusing first on the 1990+9% case, the inflation rate jumps from 3.3 percent per year to 5.1 percent per year, a difference of 1.8 percentage points in 2005, the first year of the energy price rise, and continues to remain high for the first 4 years of the carbon reduction program. In the same 4-year period, the unemployment rate first responds slowly and then accelerates to a peak in 2009 that is more than a full percentage point above the reference case unemployment rate, rising from 5.6 percent in the reference case to 6.8 percent in the 1990+9% case. The key point here is that the responses of inflation and unemployment are not symmetric over time. There is a lag between the two effects with output and employment effects lagging behind price effects. Prices rise in the economy in response to the initial energy price increase and then to secondary price effects as the costs of intermediate goods and services rise. Business, in response to rising prices and lower aggregate demand, absorbs the near-term output loss but eventually reduces its use of labor. The lag from initial price effects to ultimate output and employment losses can be a year or so.

Figure 121. Projected Changes in U.S. Inflation Rate Relative to the Reference Case, 1998-2020



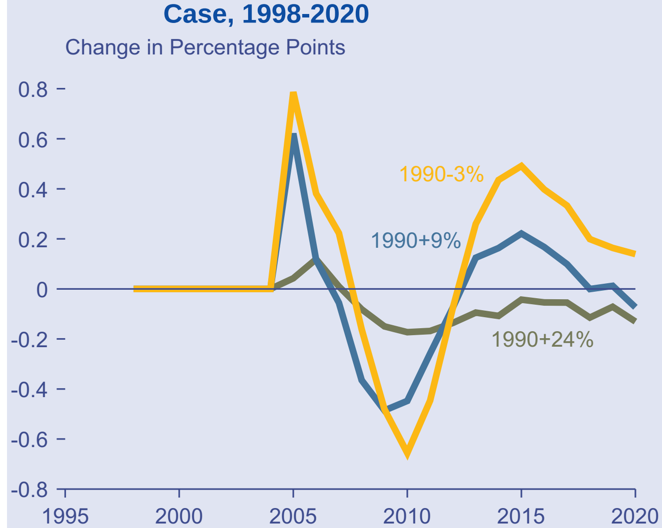
Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 122. Projected Changes in U.S. Unemployment Rate Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 123. Projected Changes in U.S. Federal Funds Rate Relative to the Reference Case, 1998-2020



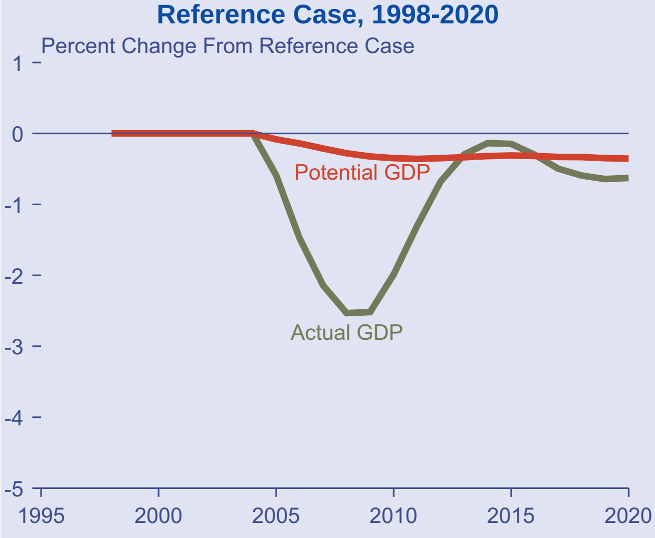
Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

As a result of the differential effects projected for inflation and unemployment during the years from 2005 to 2008, the Federal Reserve is assumed to allow a modest rise in the Federal funds rate in the short term, when concern over inflation outweighs concern over GDP losses and unemployment. After the initial rise in energy prices, with the carbon price actually projected to fall after 2009, the inflation rate reverts to that projected in the reference case; however, aggregate output is still depressed, and unemployment in the economy remains above the reference case value. During this period, the Federal Reserve reacts by reducing the Federal funds rate, in order to combat the loss in output and employment in the economy. After 10 years, by 2015, both inflation and unemployment have returned to at or about reference case levels. The Federal Reserve again allows interest rates to rise to bring the economy back to its long-run growth path.

Impacts on Actual Output and Consumption

In the 1990+9% case, potential GDP is projected to decline smoothly over time, leveling off to a steady-state value of approximately 0.35-percent loss in output for the economy (Figure 124). In contrast, actual GDP is buffeted about as the economy adjusts to the significant price pressures brought on by higher energy prices, losing approximately 2.5 percent in real output by 2009. The loss in actual output can also be described in terms of the impacts on the growth rate for actual GDP. Between 2005 and 2010, actual GDP is projected to grow by 2.0 percent per year in the reference case. In the 1990+9% case, the growth rate slows to 1.6 percent per year, reducing growth in the economy over the same period by 0.4 percentage points.

Figure 124. Projected Changes in Potential and Actual U.S. Gross Domestic Product in the 1990+9% Case Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

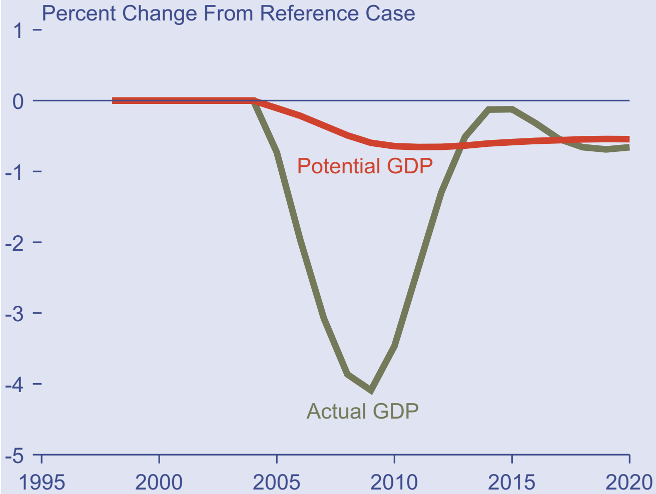
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

After 2010, although the economy is still below the reference case, actual GDP begins to cycle in response to energy prices. The economy cycles for two fundamental reasons. First, output effects lag price effects in the economy as consumers and businesses adjust to the price changes. Also, in the case considered, the rise in energy prices levels off dramatically by 2010, and inflation rates are actually lower than in the reference case, as shown in Figure 121. The interesting property of the two output concepts, actual and potential, is that they begin to converge by 2015, 10 years after the beginning of the initial impacts on the economy. By 2020 they have merged into a steady-state path. This suggests that while the economy may very well be on a long-run path that could yield a loss to the economy of about 0.3 percent if its potential output, there is the possibility that near-term impacts may be larger as the economy adjusts to its long-run trajectory.

The projected impacts on actual GDP in the 1990-3% case peak at a loss of 4.1 percent in 2009, but again rebound back toward and merge with the ultimate potential GDP impact measure of 0.55 percent (Figure 125). The growth rate between 2005 and 2010 slows to 1.3 percent per year, a reduction of 0.7 percentage points from the reference case growth rate of 2.0 percent. In the 1990+24% case, actual GDP shows a peak loss of 1.0 percent relative to the reference case in 2010, with no significant impact on the growth rate, then begins to return to its long-run potential GDP path. In this case, however, because the carbon price is still rising, the economy continues to show a slight divergence between actual and potential GDP in 2020, although the gap is significantly narrowed (Figure 126).

Beyond the aggregate impact on GDP, a significant change in the composition of final demand is projected in the carbon reduction cases (Table 29). In the 1990+9% case, consumption in 2009 is projected to be 1.9 percent lower than projected in the reference case (Figure 127). Returning the carbon permit revenues to households through personal income tax rebates moderates the impacts on disposable income in the economy, which, in turn moderates the adverse impact on purchases of consumer goods and services, and therefore the impact on the aggregate economy measured by actual GDP. Investment is more severely affected, with rising interest rates and a general loss in demand in the economy projected in the years immediately after the imposition of the carbon price (Figure 128). In 2007, investment in the 1990+9% case is projected to be 5.9 percent below the reference case projection. After 2008, with lower interest rates, the economy begins to rebound as investment expands rapidly. By 2013, investment is above the reference case by 3.2 percent and is leading the recovery.

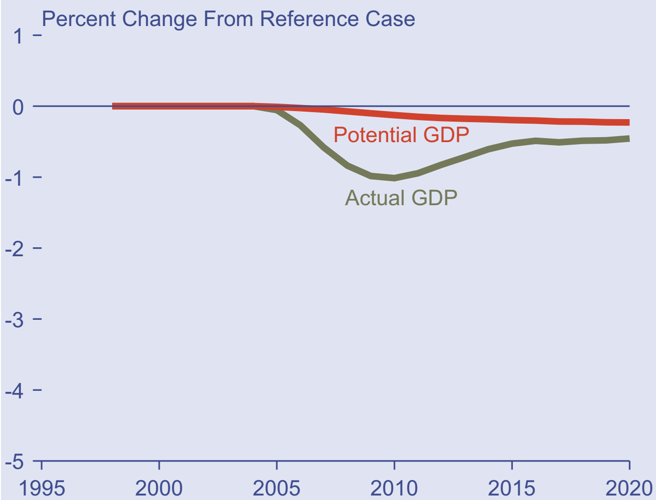
Figure 125. Projected Changes in Potential and Actual U.S. Gross Domestic Product in the 1990-3% Case Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

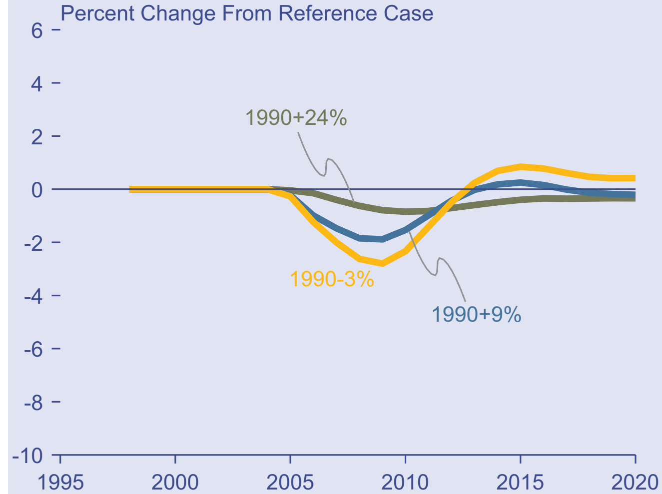
Figure 126. Projected Changes in Potential and Actual U.S. Gross Domestic Product in the 1990+24% Case Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

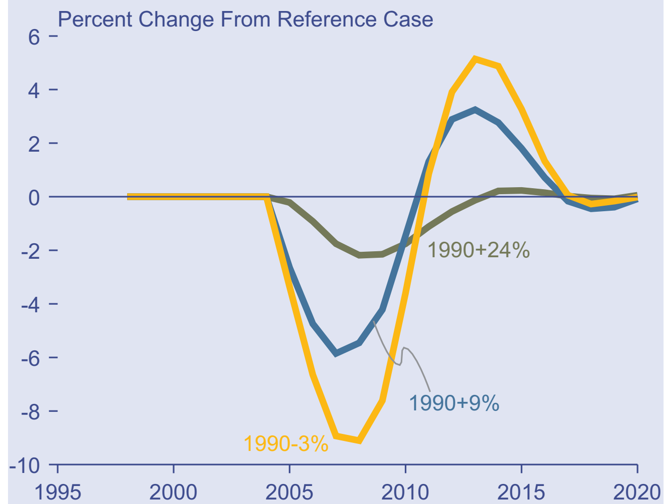
Figure 127. Projected Changes in Real Consumption in the U.S. Economy Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 128. Projected Changes in Real Investment in the U.S. Economy Relative to the Reference Case, 1998-2020



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

The 1990-3% case shows a pattern of adjustment similar to that projected in the 1990+9% case, except that the reaction in terms of both consumption and investment is more extreme, given the higher carbon price. Consumption reaches its lowest point in the year 2009 at 2.8 percent below the reference case. Thereafter, consumption returns to the reference case level in 2013 and by 2015 is 0.8 percent above the reference case level. Investment is more volatile, falling to 9.1 percent below reference case levels by 2008. Again, with interest rates declining relative to the reference case after 2010, investment recovers rapidly and by 2013 is 5.1 percent above the reference case.

The 1990+24% case reflects a much smoother path for both consumption and investment. Consumption remains below the reference case throughout the period, but with a maximum loss of only 0.8 percent in 2010. The impact on investment, likewise, is more moderate than in the 1990-3% and 1990+9% cases, falling to 2.2 percent

Table 29. Projected Economic Impacts of Carbon Reduction Cases Assuming Personal Income Tax Rebate (Changes From Reference Case)

Analysis Case	2010	2015	2020
1990-3%			
Collections (Billion Nominal Dollars)	585	633	674
Wholesale Price Index for Fuel and Power (Percent Change)	99.1	89.9	78.9
Producer Price Index (Percent Change)	15.7	14.6	12.9
Consumer Price Index (Percent Change)	6.0	4.2	2.9
Unemployment Rate (Difference in Rate)	1.6	-0.4	0.1
Federal Funds Rate (Difference in Rate)	-0.7	0.5	0.1
Potential GDP (Percent Change)	-1.2	-0.8	-0.6
Real GDP (Percent Change)	-3.5	-0.1	-0.7
Real GDP (Billion 1992 Chain-Weighted Dollars)	-327	-12	-72
Consumption (Percent Change)	-2.3	0.8	0.4
Investment (Percent Change)	-3.6	3.3	-0.0
Industrial Output (Percent Change)	-5.8	-2.5	-3.6
1990+9%			
Collections (Billion Nominal Dollars)	317	340	391
Wholesale Price Index for Fuel and Power (Percent Change)	55.7	53.7	52.5
Producer Price Index (Percent Change)	9.0	8.8	8.7
Consumer Price Index (Percent Change)	3.5	2.5	2.1
Unemployment Rate (Difference in Rate)	0.9	-0.2	0.2
Federal Funds Rate (Difference in Rate)	-0.4	0.2	-0.1
Potential GDP (Percent Change)	-0.7	-0.4	-0.4
Real GDP (Percent Change)	-2.0	-0.1	-0.6
Real GDP (Billion 1992 Chain-Weighted Dollars)	-187	-15	-68
Consumption (Percent Change)	-1.5	0.2	-0.2
Investment (Percent Change)	-1.5	1.8	-0.1
Industrial Output (Percent Change)	-3.0	-1.6	-3.1
1990+24%			
Collections (Billion Nominal Dollars)	128	206	271
Wholesale Price Index for Fuel and Power (Percent Change)	21.5	29.3	32.9
Producer Price Index (Percent Change)	3.6	4.9	5.5
Consumer Price Index (Percent Change)	1.5	1.6	1.4
Unemployment Rate (Difference in Rate)	0.5	0.2	0.1
Federal Funds Rate (Difference in Rate)	-0.2	-0.0	-0.1
Potential GDP (Percent Change)	-0.2	-0.3	-0.3
Real GDP (Percent Change)	-1.0	-0.5	-0.5
Real GDP (Billion 1992 Chain-Weighted Dollars)	-96	-54	-49
Consumption (Percent Change)	-0.8	-0.4	-0.3
Investment (Percent Change)	-1.8	0.2	0.1
Industrial Output (Percent Change)	-1.3	-1.3	-2.0

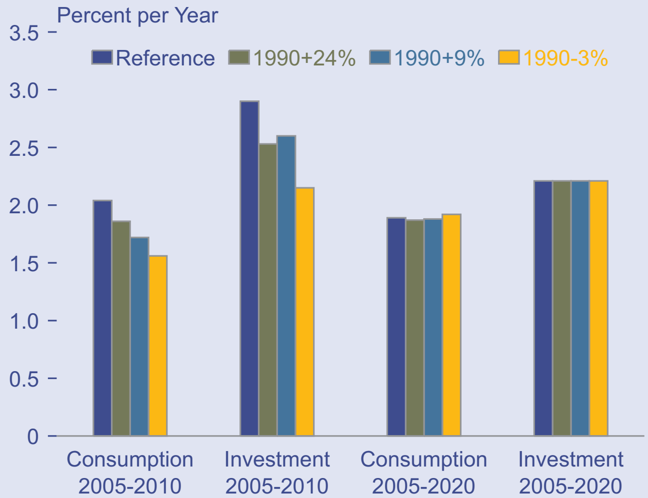
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

below the reference case in 2008. Thereafter, investment returns to the reference case level and essentially remains at that position for the remainder of the forecast period.

Figure 129 shows the projected impacts on consumption and investment in terms of growth rates between 2005 and 2010 and between 2005 and 2020. Between 2005 and 2010, consumption growth rates fall from 2.0 percent per year in the reference case to 1.9 percent in the 1990+24% case, 1.7 percent in the 1990+9% case, and 1.6 percent in the 1990-3% case. Investment shows a similar, but more pronounced profile, with growth declining from 2.9 percent per year in the reference case to 2.5 percent, 2.6 percent, and 2.2 percent in the respective carbon reduction cases. Slight variations in the order of the impacts—the 1990+24% case at 2.5 percent and the 1990+9% case at 2.6 percent—can be explained by the highly cyclical effects on investment, as shown in Figure 128. In the long run, as indicated by the projected growth rates between 2005 and 2020, growth in both consumption and investment returns to the reference case rates.

These results indicate that, as a result of higher energy prices, the economy may absorb a near-term loss in output in response to higher inflation and a rise in the unemployment rate. However, with appropriate action

Figure 129. Consumption and Investment Growth Rates



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

on the part of the monetary authorities, these impacts could be mitigated, and in the long-term the economy could rebound.

The Role of Fiscal Policy

This analysis assumes that revenues from carbon permits would be collected by the Federal Government, which would have a number of alternatives with regard to their disposition. The producers of carbon-intensive fuels could keep the permit revenues; or the Government could either use the revenues to reduce the national debt, return them to businesses through reductions in corporate income tax rates or increased business tax credits, return them to consumers through personal income tax rebates, or return them to both consumers and businesses through social security tax rebates. Each method of using the collected permit revenue is plausible, and each method would have a different economic impact.

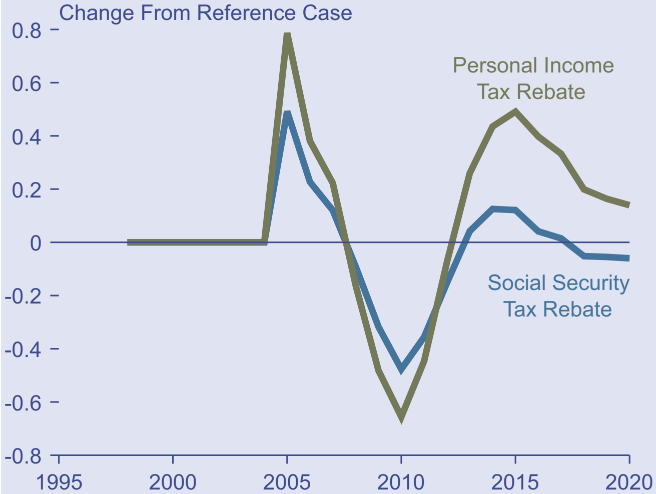
Returning the funds to consumers through personal income tax rebates or returning them to consumers and businesses through social security tax rebates would work to ameliorate the short-term impacts on the economy by bolstering disposable income. Alternative fiscal policies, such as having the Federal Government use the funds to lower the Federal debt level, or a corporate income tax rebate, probably would result in larger near-term impacts, because disposable income and therefore consumption would fall by greater amounts. Conversely, policies that serve to shift the economy away from consumption toward investment may have greater long-term benefits in terms of expansion of the aggregate capital stock.

All the projections discussed so far in this chapter have assumed a policy of returning carbon permit revenues to households through personal income tax rebates, using a lump sum transfer.[84] To highlight the potential significance of an alternative fiscal regime this chapter next reviews the potential effects of a rebate of social security taxes that passes funds back to both employees and employers in equal amounts. The analysis of a hypothetical rebate of the social security tax is meant only to be descriptive of a tax measure that could have the effect of reducing price pressures in the economy by lowering business costs, while also accomplishing a partial compensation to consumers for the higher energy bills they would face. The two policies considered in this analysis—the personal income tax rebate and the social security tax rebate—are only meant to be representative of a set of possible fiscal policies that might accompany an initial carbon mitigation policy.

The fundamental difference between the two policies is in their treatment of business. On the employer side, the reduction in employer contributions to the social security system would lower costs to the firm and, thereby, moderate the near-term price consequences to the economy. Since it is the price effect that produces the predominately negative effect on the economy, any steps to reduce inflationary pressures would serve to moderate adverse impacts on the economy. The smaller impact on aggregate prices would also moderate the monetary policy reaction, as shown in Figures 130, 131, and 132. In all the carbon reduction cases, the reaction of the Federal funds rate to the economic effects of higher energy prices would be less pronounced than projected under the assumption of a personal income tax reduction. Similarly, the social security tax option would moderate the potential impact on actual GDP in the carbon reduction cases (Figure 133), largely because of the cost-cutting aspects of lowering of the employer portion of the tax. Similar moderating effects would be seen for consumption (Figure 134) and investment (Figure 135). Under both policies, the economy would eventually revert to a long-run path consistent with the path of potential output.

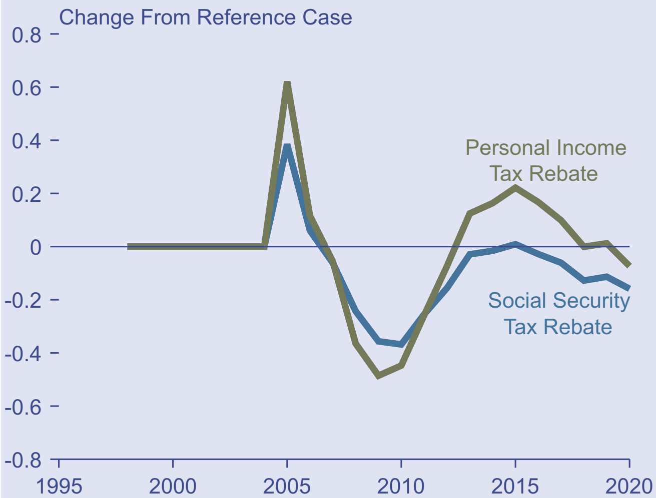
[84] In the DRI model for personal taxes only, a lump sum transfer produces the same effects as a cut in the personal income tax rate.

Figure 130. Projected Changes in U.S. Federal Funds Rate in the 1990-3% Case Relative to the Reference Case Under Different Fiscal Policies, 1998-2020



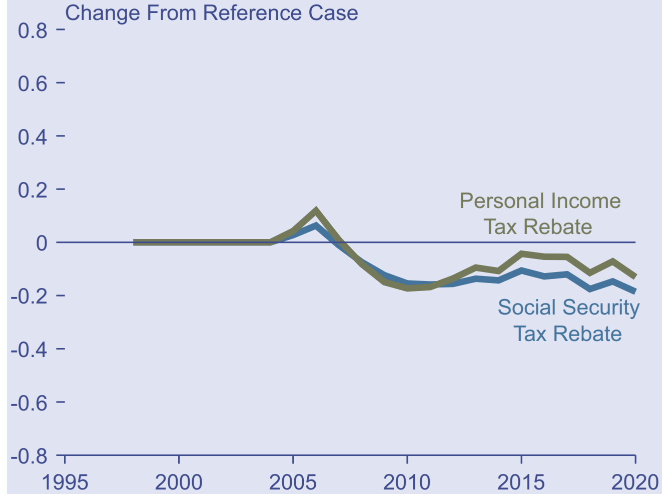
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 131. Projected Changes in U.S. Federal Funds Rate in the 1990+9% Case Relative to the Reference Case Under Different Fiscal Policies, 1998-2020



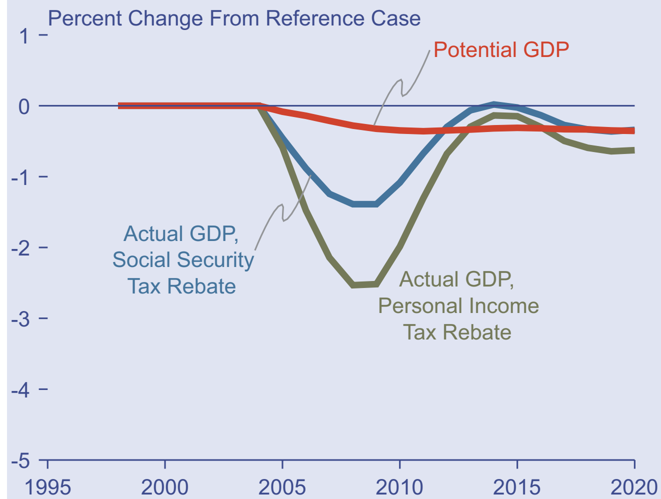
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 132. Projected Changes in U.S. Federal Funds Rate in the 1990+24% Case Relative to the Reference Case Under Different Fiscal Policies, 1998-2020



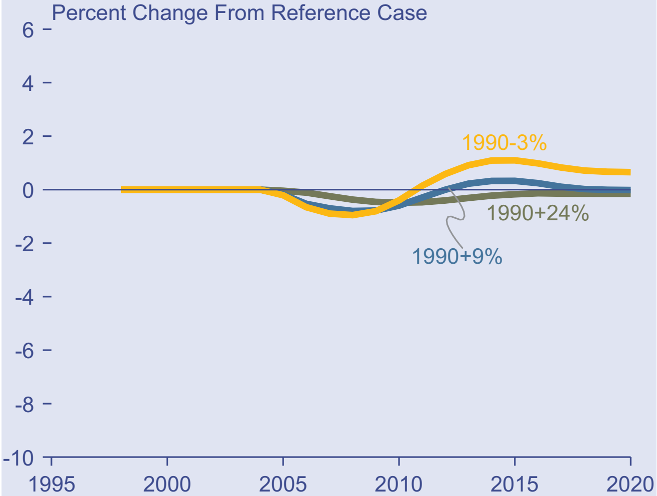
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 133. Projected Changes in Potential and Actual U.S. Gross Domestic Product in the 1990+9% Case Relative to the Reference Case Under Different Fiscal Policies, 1998-2020



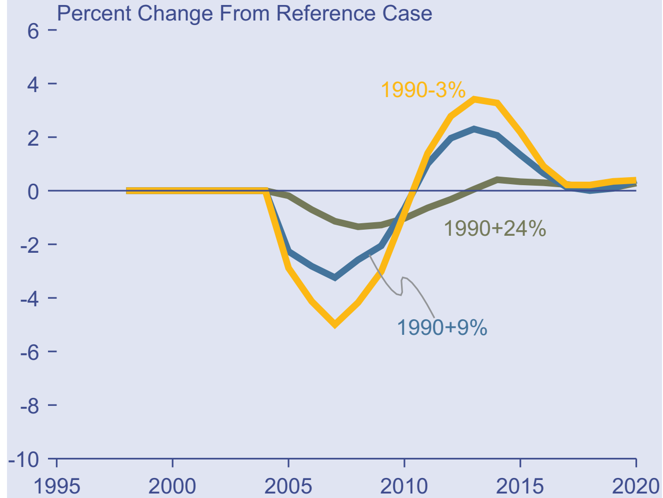
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 134. Projected Changes in Real Consumption in the U.S. Economy Relative to the Reference Case, 1998-2020, Assuming a Social Security Tax Rebate



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 135. Projected Changes in Real Investment in the U.S. Economy Relative to the Reference Case, 1998-2020, Assuming a Social Security Tax Rebate



Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Energy Investment

This macroeconomic analysis of the costs of the Kyoto Protocol includes the direct fuel costs and only those investment costs that are comparable in magnitude with those in the reference case. Business investments above reference case levels may be required to reduce energy costs in response to increasing energy prices. The potential incremental costs of investment in technology and infrastructure that may be necessary to obtain the emissions reductions specified in each of the cases analyzed are not included, either because they are not available or, in cases where they are available, because there is no direct mapping to the National Income and Product Accounts.

Full investment costs would include: (1) fuel and equipment costs, including the cost of capital and the cost of premature obsolescence; (2) research and development costs; (3) infrastructure costs, including equipment maintenance, supply, and distribution; (4) regulatory monitoring and enforcement costs; (5) the costs for manufacturers to retool prematurely; and (6) the costs of lost investment opportunities. This macroeconomic analysis, like all others, does not include all of these investment costs. The premature obsolescence of capital—when a firm is forced to retire equipment before the end of its physical or economic life—is typically ignored or assumed to be costless, because estimates of the amount of capital retired early are difficult to make. Estimates of the full cost of developing new technologies, particularly the associated research and development costs, are generally unavailable. In addition, certain new technologies may require a considerable amount of additional investment in infrastructure in order to be widely adopted. For example, widespread adoption of carbon-free vehicles (such as hydrogen fuel cell automobiles) may require substantial investment to guarantee consumers that hydrogen refueling stations are conveniently located and that the development of hydrogen stations does not present safety risks. Estimates of these costs are difficult to obtain and are at best uncertain.

In NEMS, capital costs are included for newly constructed technologies in the electricity generation sector, for major appliances and technologies in the residential and commercial sectors, for new vehicles in the transportation sector,[a] and for new natural gas pipelines and new oil refineries. The investment costs in buildings include new equipment costs but do not include costs attributable to improving the energy efficiency of structures, such as insulation and thermal windows. For generators, the investment costs include additional expenditures on both equipment and structures required for generation, transmission, and distribution of electricity. The NEMS representations of investment costs for generators probably are the most detailed estimates available from any energy modeling system; however, the financial accounting categories available from the electricity sector do not map directly into the National Income and Product Accounts included in macroeconomic models. The mapping difficulties are even greater for the end-use sectors. Reconciling and meaningfully incorporating investment information from energy models into macroeconomic models is a research area that still needs to be studied. As a result, this analysis includes only the direct cost of fuels when evaluating the macroeconomic impacts of the Kyoto Protocol.

[a]While infrastructure costs are not directly included for the transportation model, the rate at which infrastructure can expand is included in the adoption of new alternative-fuel vehicles.

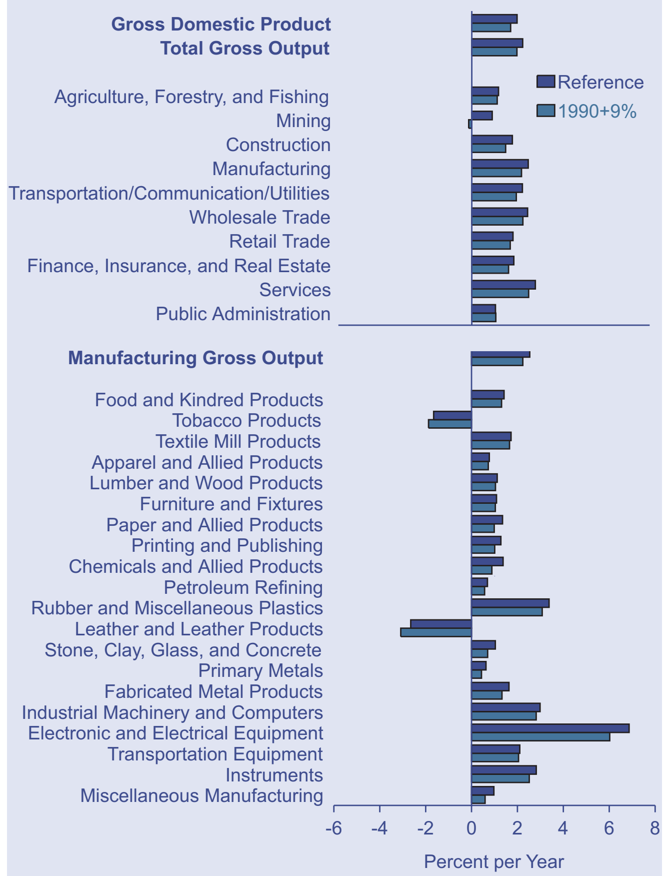
Sectoral Impacts

Regardless of the effects of carbon mitigation policies on the ultimate level of the aggregate economy, there are likely to be impacts on the configuration of the sectoral output of the economy. This section describes one possible set of outcomes. While the results are very uncertain, they indicate the potential for differential impacts among industries, primarily as the result of four key factors:

- First, the direct impact of higher energy prices is a reduction in energy demand, particularly for coal with its high carbon content. The consequences are reductions in output from the mining sector and from all services connected to the production and distribution of coal.
- Second, higher energy prices disproportionately increase the cost of production for energy-intensive industries. As energy price increases are passed along by industry through higher prices for their products, consumers will tend to substitute away from the relatively expensive energy-intensive products to less energy-intensive products and services. The consequences are reductions in gross output from the energy-intensive sectors of the economy, principally, chemicals and allied products; stone, clay, glass, and concrete; and primary metals.
- Third, the changing composition of macroeconomic final demand will alter the composition of sectoral output. In the cases considered here, all the carbon permit revenues are assumed to be returned to consumers through personal income tax rebates, moderating the projected impacts on disposable income. Consequently, in percentage terms, consumer spending falls by less than GDP, while investment falls by more. This change in the composition of final demand decreases the output from consumer-related sectors, such as services and retail trade, by less than the average drop for all economic output, while decreasing the output from the construction and manufacturing sectors by more than the average.
- Finally, because the carbon emissions restrictions are placed only on Annex I countries, industries with high levels of imports, particularly those with imports from non-Annex I countries, will see larger reductions in domestic output than industries with low import penetration. If imports are already competitive, increasing the cost of production for the domestic industry and not for non-Annex I importers will tend to increase imports, leading to a drop in domestic output. For this reason, output from manufacturing sectors such as leather and leather products, electronic and other electrical equipment, and miscellaneous manufacturing will fall by more than the output for the manufacturing sector as a whole.

It is difficult, *a priori*, to predict the degree and rate of change of such effects. Figure 136 shows the disaggregated impacts of restricting carbon emissions in the 1990+9% case. The upper part of the graph shows the projected growth rates for GDP, total gross output, and sectoral gross output for the major SIC divisions between 2005 and 2010. The GDP and total gross output growth rates provide an economy-wide frame of reference against which the sectoral growth rates can be compared. The lower part of the graph shows the growth rates for total manufacturing gross output and sectoral gross output by 2-digit SIC breakdown between 2005 and 2010, with the growth rate for total manufacturing gross output as a reference. Figures 137 and 138 show the results for the 1990-3% and 1990+24% cases, respectively.

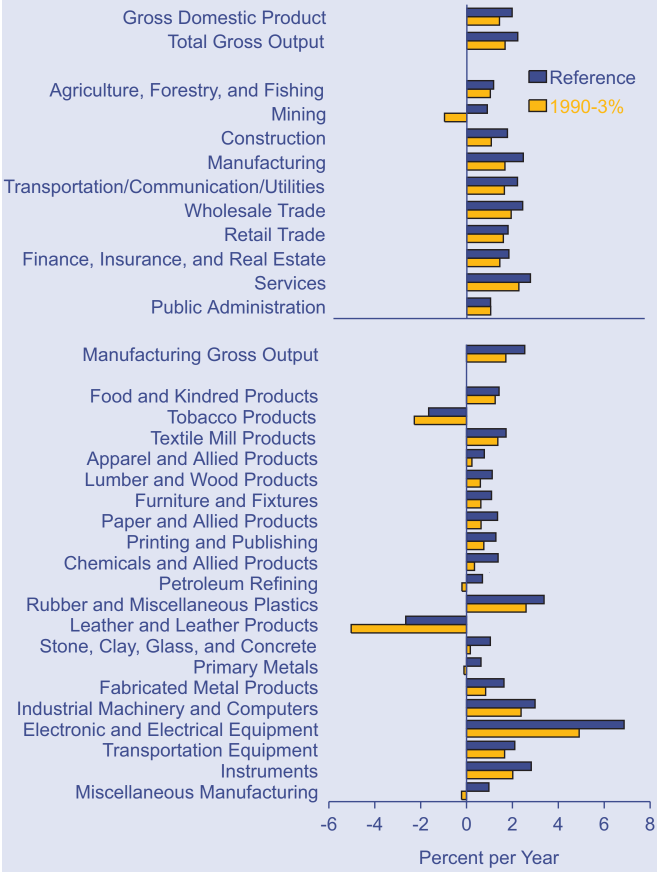
Figure 136. Projected Sectoral Growth Rates in Real Economic Output in the 1990+9% Case, 2005-2010



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

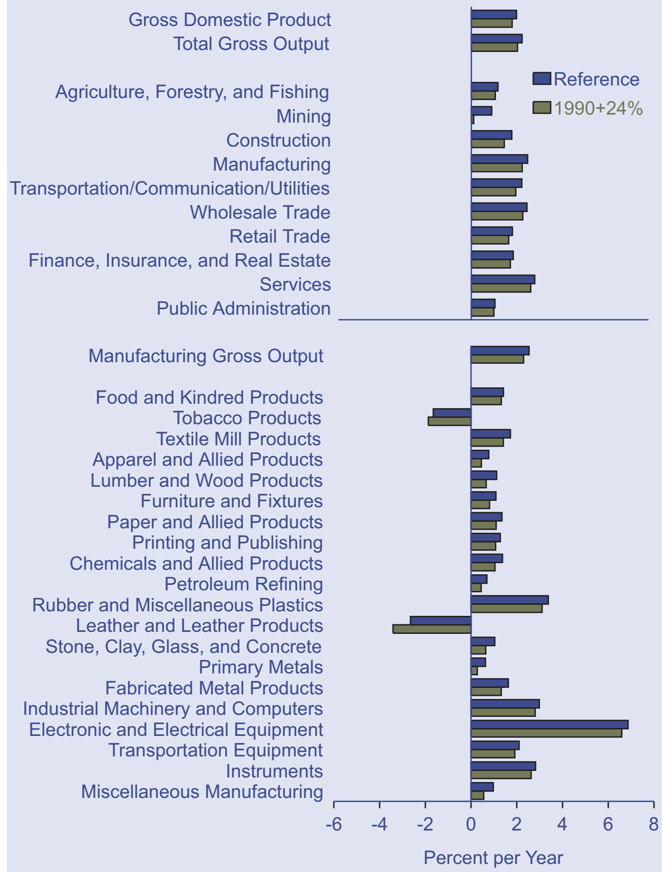
Figure 137. Projected Sectoral Growth Rates in Real Economic Output in the 1990-3% Case, 2005-2010



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 138. Projected Sectoral Growth Rates in Real Economic Output in the 1990+24% Case, 2005-2010



Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.

Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

7. Comparing Cost Estimates for the Kyoto Protocol

Introduction

This chapter provides a comparison of recent publicly available estimates of the costs of achieving the Kyoto Protocol carbon reduction targets in the United States for the period 2008 to 2020. The projections are compared for the years 2010 and 2020, when the information is available, for the following projection sources: the Energy Information Administration (EIA) using the National Energy Modeling System (NEMS), WEFA,[85] Charles River Associates (CRA) using the Multi-Regional Trade model (MRT),[86] the Pacific Northwest National Laboratory (PNNL) using the Second Generation Model (SGM),[87] the Massachusetts Institute of Technology (MIT) using the Emissions Prediction and Policy Analysis Model (EPPA),[88] Electric Power Research Institute (EPRI) using the MERGE model[89] and Data Resources, Inc. (DRI).[90] Differences between studies are related, to the extent possible, to the features of the modeling systems used (e.g., level of aggregation, level of geographic coverage), important assumptions employed, and the particular points of view embodied in the models.[91]

Two cases were solicited for analyses from each group: a 7-percent-below-1990 (1990-7%) case in which the United States is assumed to reduce carbon emissions to 1990-7% levels for the period 2008-2020 without the benefit of sinks, offsets, international carbon permit trading, or the Clean Development Mechanism (CDM); and a best estimate of the impact on U.S. energy markets if sinks, offsets, and Annex I emissions trading were allowed, but not global trading or CDM.

Differences in the cost estimates for meeting the Kyoto Protocol targets can be related to important differences in assumptions about (1) economic growth in the reference cases without the Kyoto Protocol, (2) the status of the resources available (e.g., resource base, world oil prices, and the slate of technologies available to the marketplace), (3) the sensitivity of energy demand to price changes, (4) the degree of foresight that decisionmakers have in the marketplace, (5) the structure and function of the economy (e.g., how quickly the economy can shift to less energy-intensive industries when the price of energy relative to capital and materials increases), (6) the degree and speed of substitution for factors of production (capital, labor, energy, and materials) when their relative prices change, and (7) the representation of technology (i.e., representation of vintaged energy equipment and the penetration of new technologies).

Summary of Comparisons

Because the information available varies considerably, a detailed comparison among the sources is virtually impossible. Therefore, a comparison of common variables is provided in this section, with an explanation for the differences between the sources. Comparisons are provided for three of the cases analyzed in this report: the 1990-7% case and two cases—9 percent above 1990 (1990+9%) and 14 percent above 1990 (1990+14%)—that are comparable in some respects to the Annex I trading case. The variables compared are carbon price, change in actual gross domestic product (GDP) from the respective reference case in each study,

85 WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts* (Eddystone, PA, 1998).

86 Both the CRA and WEFA studies have been supported to some extent by industry groups, including the American Petroleum Institute.

87 J.A. Edmonds et al., *Modeling Future Greenhouse Gas Emissions: The Second Generation Model Description* (Washington, DC: Pacific Northwest National Laboratory, September 1992). Runs using PNNL's SGM model formed the basis for the testimony provided by Dr. Janet Yellen, chairman of the Council of Economic Advisers, on March 4, 1998, before the House Commerce Committee, Energy and Power Subcommittee.

88 H.D. Jacoby, R. Eckhaus, A.D. Ellerman, et al. "CO_2 Emission Limits: Economic Adjustments and the Distribution of Burdens," *Energy Journal*, Vol. 18, No. 3 (1997), pp. 31-58. MIT's analysis is part of a much larger integrated assessment methodology funded by the Office of Energy Research, U.S. Department of Energy.

89 A.S. Manne and R.G. Richels, "On Stabilizing CO_2 Concentrations—Cost Effective Emissions Reduction Strategies," *Energy and Environmental Assessment*, Vol. 2 (1997), pp. 251-265. EPRI's work is self-funded and is part of the research agenda of electric utilities.

90 Standard and Poors DRI, *The Impact of Meeting the Kyoto Protocol on Energy Markets and the Economy* (July 1998).

91 Information used in this chapter was contributed by Dr. Montgomery and Dr. Bernstein of Charles River Associates, Dr. Richels of the Electric Power Research Institute, Dr. Edmonds of Pacific Northwest National Laboratory, and Professor Jacoby of MIT.

actual and potential GDP loss, expenditures for purchases of carbon emission permits, change in carbon intensity from the respective reference case, and change in fossil fuel consumption. Tables 30 and 31 provide comparisons of the results for 2010 and 2020. Further details are provided in Appendix C.

For the WEFA study, comparisons are provided only with the 1990-7% case. For DRI comparisons are provided only for a trading case (Case 2). WEFA does not believe that sinks, offsets, or trading will be agreed upon and implemented before the target period of 2008 to 2012, nor by 2020. As noted earlier in the report, EIA does not have the capability to analyze international trading and thus is unable to provide a most likely estimate of the impacts of the international trading provisions of the Kyoto Protocol, or of sinks and offsets, on the level of the energy-related carbon reductions required to meet the 1990-7% reduction in greenhouse gases. EIA's 1990+9% and 1990+14% cases are used in Table 31, because the carbon emissions levels of those cases were most closely aligned with the other studies presented.

Some of the major factors that result in differences in the projected carbon prices and costs to achieve the 1990-7% carbon reduction level are:

- **Relative differences in reference GDP and carbon emissions growth rates through 2020.** For example, if the GDP or carbon emissions growth rate in a given reference case is lower than that in EIA's reference case, a smaller carbon reduction will be needed, and it will generally be easier to achieve the emissions target. If the reference GDP growth or carbon emissions growth is higher than in EIA's reference case, the carbon price and GDP impacts relative to those projected by EIA in this study will generally be higher. Most of the major differences among the analyses are attributable to differences in the reference case projections.

- **Differences in assumptions about the potential for economical life extension or refurbishment of existing nuclear power plants beyond their normal licensing period.** If, for example, no existing nuclear plants were retired by 2020, about 40 million metric tons of carbon emissions would be avoided from the combustion of fossil fuel used in plants to replace them.

- **The amount of knowledge about future events assumed for decisionmakers.** For example, models that assume that decisionmakers have perfect knowledge about future prices, demands, or policies could underestimate compliance costs, because all future events would be anticipated with certainty and responded to at minimum cost. Analyses that assume that all decisionmakers are myopic will tend to overstate transition costs.

- **The amount of lead time decisionmakers are assumed to have to adjust to the Kyoto Protocol.** For example, if a model starts to begin the adjustment process in 1985, 1990 or 1995, it could underestimate the costs of complying with the Kyoto Protocol, because it has more time to adjust. Models that wait until the last moment to begin the adjustments could overstate adjustment costs.

- **The level of aggregation in the model for technologies and goods.** A model that deals only with aggregate products such as oil, gas, or coal without the benefit of an explicit technology representation may not capture important variables that can significantly affect energy efficiency and intensity or the changing mix of industries that may result from compliance efforts.

- **The amount of focus on the transition process and the associated costs.** For example, a model that assumes that all capital and labor can be immediately switched from one use to another cannot capture the short-term or medium-term impacts of complying with the Kyoto Protocol, because those costs are not reflected in the model.

- **The assumed speed and extent of changes that consumers can make in energy consumption or demand for energy services in response to changing prices (price elasticities of demand).** Higher assumed elasticities make it easier to achieve the carbon target through demand reductions. Lower elasticities make it more difficult.

Among the studies compared in Table 30, the projected carbon prices in 2010 fall into three groups. MIT, EPRI, CRA, and WEFA project prices in the range of $265 (WEFA) to $295 (CRA) per metric ton of carbon. PNNL projects carbon prices of about $221 per metric ton. EIA projects carbon prices of $348 per metric ton.

In the PNNL study, assumptions about consumer price responsiveness (demand elasticities and capital / energy substitution elasticities) are consistent with a long-term time frame where everything is changeable.[92,93] Applying the long-term elasticities to the short-term andmid-term period can overstate the ease and willingness with which consumers change their equipment or reduce their consumption in response to price increases.[94]

Further contributing to the low carbon price projection is the amount of lead time consumers have to respond, as well as differences in the reference case economic growth rates. The PNNL and EIA reference case GDP projections are very similar. However, PNNL's end-use representation does not explicitly represent technologies, and PNNL's assumed consumer responsiveness to prices (prompting lower energy service demand) and interfuel substitution potential appear to be substantially higher in the medium term (through 2010) than the implicit elasticities in EIA's explicit representation of technologies and consumer choices. The PNNL model begins solving in 1985 in 5-year increments. The PNNL reference case is calibrated to *AEO98*. In the PNNL policy runs, the carbon policy was phased in over a 10-year period beginning in 2000. Consequently, policy adjustments begin in 2001, consumers and producers begin to anticipate the Kyoto Protocol in that year, making the appropriate adjustments. In the PNNL analysis, electricity demand grows by 0.4 percent annually in the reference case between 2010 and 2020. This is a significant departure from the annual growth rate of more than 2 percent in recent years. Most electricity demand projections have annual growth in excess of 0.9 percent between 2010 and 2020, as compared with PNNL's 0.4 percent.[95] Offsetting these factors are factors that tend to overstate cost. For example, in the PNNL analysis, primary renewable use for generation changes only slightly from the reference case in 2020, even with a carbon price of $286 per metric ton.

The group of models projecting costs between $265 per metric ton and $295 per metric ton in 2010 for the 1990-7% case include transitional processes and costs—either in the macroeconomy or in the energy system—through a detailed representation of the cost, performance, and market adoption of technologies.[96] This group includes the CRA model. Through 2010, CRA projects that, in the reference case, U.S. GDP will grow by $270 billion more than projected in most of the other studies compared. The higher growth rate of GDP normally makes the reduction in emissions harder and more costly to the U.S. economy.

If differences in the reference cases were the only factor accounting for the different estimates of the costs of complying with the Kyoto Protocol, then CRA's costs would exceed EIA's and WEFA's in 2010; however, large econometric models of the U.S. economy like those of WEFA and DRI tend to focus on the transitional process, including the method of recycling any carbon fees that may be collected by the Federal Government, and unemployment that may be increased as a result of policy implementation. The WEFA, EIA, and DRI analyses assume that labor can be dislocated, whereas most other analyses assume full employment[97] despite the sudden reduction of energy resources. More aggregated world analyses, including the CRA, PNNL, EPRI, and MIT studies, omit such details, because the inclusion of global regional coverage and trade flows requires simplifications (some important) in the detail with which each region is represented. Model aggregation tends to underestimate the macroeconomic costs; on the other hand, a lack of global coverage (as in the EIA, DRI, and WEFA models) may overstate transition costs, particularly if international trading is implemented efficiently. Also, fossil fuel consumption in 2010 in the CRA analysis is about 6 quadrillion British thermal units (Btu) less than in the EIA reference case, with virtually identical carbon emissions levels, suggesting an accounting difference in emissions coefficients.

92 The PNNL study uses a dynamic-recursive, computable general equilibrium (CGE) model with neoclassical elements. A model is a "general equilibrium" model if it represents all parts of the economy, both energy and non-energy, and all markets clear (supply equals demand at the prices determined). The model is "computable" if a computer is used to solve for the equilibrium; it is "dynamic" if it keeps track of variables over time. A model is "neoclassical" if the model structure assumes that (1) its economic agents have perfect foresight and knowledge of all past, present, and future events, (2) there is perfect and instantaneous ability of capital and labor to move between uses and sectors, and (3) such transitions are costless and instantaneous.

93 The PNNL model (SGM) can be run with either perfect or imperfect foresight. Labor and new capital move freely.

94 A carbon price of $221 per metric ton in 2010 would increase the delivered electricity price by 49 to 69 percent and reduce electricity consumption by 22 percent relative to PNNL's reference case. This implies that, on average, consumers will reduce consumption of electricity by 3.2 to 4.5 percent for every 10-percent increase in the price of electricity. In 2020, a carbon price of $286 per metric ton translates to an electricity price increase of 59 to 66 percent, resulting in a 28-percent reduction in electricity consumption. This implies that consumption will decline by about 4.2 to 4.7 percent for every 10-percent increase in price. (The estimated electricity price changes were derived from comparable EIA cases.)

95 For example, WEFA's annual electricity growth rate is 1.7 percent and EIA's is 0.9 percent.

96 The WEFA, CRA, MIT, and DRI models are econometric, general equilibrium, macroeconomic models. WEFA and DRI model the United States, CRA and MIT model the world.

97 The full employment assumption means that the unemployment rate is unchanged from reference case levels.

Table 30. Comparison of Results for Reducing Carbon Emissions to 7 Percent Below 1990 Levels Without Trading, Sinks, Offsets, or Clean Development Mechanism

Projection	MIT	EPRI[a]	CRA	EIA	PNNL	WEFA
2010						
Carbon Price (1996 Dollars per Metric Ton)	**266**	**280**	**295**	**348**	**221**	**265**
Change in Actual Gross Domestic Product From Reference Projection						
Percent	-1.5[b]	-1.0	-2.1	-4.2	NA	-3.2
Billion 1996 Dollars	-156	-102	-227	-437	NA	-332
Loss in Potential Gross Domestic Product Relative to Reference Projection (Billion 1996 Dollars)	NA	73	82	79 to 94[c]	65	60
Change in Carbon Intensity (Percent)	NA	-27.9	-32	-26	-31	-24.5
Change in Fossil Fuel Consumption (Percent)	NA	-19.3 to -23.9[d]	-30.3	-22.1	-24.5	-20.9
2020						
Carbon Price (1996 Dollars per Metric Ton)	**147**	**251**	**316**	**305**	**286**	**360**
Change in Actual Gross Domestic Product From Reference Projection						
Percent	-1.5[b]	-0.96	-2.4	-0.8	NA	-2.0
Billion 1996 Dollars	-156	-120	-311	-91	NA	-257
Loss in Potential Gross Domestic Product Relative to Reference Projection (Billion 1996 Dollars)	NA	81	111	75 to 103[c]	109	130
Change in Carbon Intensity (Percent)	NA	-32.2	-31.0	-38.9	-36.9	-35.9
Change in Fossil Fuel Consumption (Percent)	NA	-24.0 to -32.3[e]	-35.1	-25.7	-29.6	-28.4

[a]EPRI allows 50 million metric tons for sinks in this case.

[b]The percentage represents MIT's upper bound estimate, including some macroeconomic adjustment costs. MIT provided a range from -0.5 to -1.5 percent for change in GDP, to be interpreted as minimum and maximum losses to the economy. For the purposes of this chapter, the lowest range is the irreducible economic loss. Because GDP was not provided for the MIT reference case, the reader may assume a central value for GDP of $9,400 billion in 2010 and $10,900 in 2020 (1992 dollars). Consequently, the range of losses is $52 billion to $156 billion in 2010 (1996 dollars).

[c]The losses in potential GDP for EIA shown in Tables 30 and 31 use two different concepts, which give slightly different results. One uses the computation of potential GDP that is derived from the DRI model as described in Chapter 6 of this report. The second uses the approximation method under the carbon reduction versus carbon price curve, also discussed in Chapter 6. The two calculations produce nearly identical results for the 1990-3% case. For the 1990-7% case, the DRI calculation produces a smaller estimate of potential GDP losses. For all other cases, the DRI calculation produces a higher estimate of potential GDP losses. Because the projections from analyses other than EIA's were calculated using the approximation method related to the carbon reduction versus carbon price curve, estimates from both the DRI and approximation methods are provided for the EIA study.

[d]Only total primary energy was provided. Fossil fuel consumption was derived by subtracting an estimate for nuclear energy and renewable energy ranging from 13 to 17 quadrillion Btu from total primary energy for 2010.

[e]Only total primary energy was provided. Fossil fuel consumption was derived by subtracting an estimate for nuclear energy and renewable energy of 12 to 20 quadrillion Btu from total primary energy for 2020.

NA = not available.

Sources: **EIA:** National Energy Modeling System, run FD07BLW.D080398B. **WEFA:** WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts* (Eddystone, PA, 1998). **PNNL:** E-mail of data from PNNL with explanation of GDP effect received from Ronald Sands of PNNL on August 26, 1998. **CRA:** Paul M. Bernstein, Charles River Associates, e-mail communications, August 24, 1998. **EPRI:** E-mail provided by R. Richels of EPRI on July 6, 1998. **MIT:** Facsimile dated July 10, 1998, from Prof. Henry Jacoby, MIT, Cambridge Massachusetts.

Table 31. Comparison of Results for Reducing Carbon Emissions to 7 Percent Below 1990 Levels With Annex I Trading, Sinks, and Offsets

Projection	MIT	EPRI[a]	CRA	DRI Case 2	EIA[b] 1990+9%	EIA[b] 1990+14%	PNNL
2010							
Carbon Price (1996 Dollars per Metric Ton)	**175**	**114**	**109**	**110**	**163**	**129**	**100**
Change in Actual Gross Domestic Product From Reference Projection							
Percent	-1.5	-0.5	-1.3	-1.1	-2.0	-1.7	NA
Billion 1996 Dollars	NA	-56	-133	-118	-207	-177	NA
Loss in Potential Gross Domestic Product Relative to Reference Projection (Billion 1996 Dollars)	NA	17	15	16	27 to 36	17 to 29	38
Irreducible Losses (Billion 1996 Dollars)	NA	43	46	32	53 to 62	47 to 59	55
Expenditures on Annex I Trading (Billion 1996 Dollars)	NA	-26	-31	-16	-26	-30	-17
Purchased Emissions Credits (Million Metric Tons)[c]	NA	229	288	147	161	229	171
Change in Carbon Intensity (Percent)	NA	-15.7	-15.8	-15.8	-15.8	-12.9	NA
Change in Fossil Fuel Consumption (Percent)	NA	-13.2	-14.6	-11.7	-12.7	-10.3	-16.8
2020							
Carbon Price (1996 Dollars per Metric Ton)	**119**	**188**	**175**	**131**	**141**	**123**	**142**
Change in Actual Gross Domestic Product From Reference Projection							
Percent	-1.5	-0.96	-1.7	-0.3	-0.6	-0.5	NA
Billion 1996 Dollars	NA	-120	-226	-41	-76	-63	NA
Loss in Potential Gross Domestic Product Relative to Reference Projection (Billion 1996 Dollars)	NA	44	42	31	33 to 43	24 to 35	71
Irreducible Losses (Billion 1996 Dollars)	NA	73	82	46	56 to 66	52 to 63	102
Expenditures on Annex I Trading (Billion 1996 Dollars)	NA	-33	-40	-15	-23	-28	-31
Purchased Emissions Credits (Million Metric Tons)[c]	NA	177	228	111	161	229	219
Change in Carbon Intensity (Percent)	NA	-22.8	-18.8	-23.5	-22.2	-20.1	NA
Change in Fossil Fuel Consumption (Percent)	NA	-18.7	-23.3	-19.3	-16.2	-14.2	-20.6

[a]EPRI allows some contribution from the CDM.

[b]The 1990+9% and 1990+14% cases are shown for comparison only, because the carbon emissions levels projected in these cases are near those of the other studies shown.

[c]For EIA and EPRI, purchased carbon emissions credits equal the difference between the emissions target and 1,306 million metric tons (3 percent below the 1990 carbon emissions level).

NA = not available.

Sources: **EIA:** National Energy Modeling System, runs FD09ABV.D080398B and FD14ABV.D080398B. **CRA:** Paul M. Bernstein, Charles River Associates, e-mail communications, August 24, 1998. **EPRI:** E-mail provided by R. Richels of EPRI on July 6, 1998. **DRI:** Standard and Poors DRI, *The Impact of Meeting the Kyoto Protocol on Energy Markets and the Economy* (July 1998). **MIT:** Facsimile dated July 10, 1998, from Prof. Henry Jacoby, MIT, Cambridge Massachusetts. **PNNL:** Ronald Sands, PNNL, e-mail communication, August 26, 1998.

Because of the aggregation of sectors and outputs in the CRA analysis, CRA's analytical approach is likely to underestimate the costs of the Kyoto Protocol.[98] In the CRA reference case GDP grows rapidly from 2010 to 2020, making it more difficult to comply with the Kyoto Protocol in the 1990-7% case. Hence, the carbon price is projected to rise to $316 per metric ton in 2020.

WEFA projects reference case GDP that is about 1.3 percent lower than EIA's in 2010 but then rises above EIA's by about $670 billion, or about 6 percent, by 2020. The difference in the carbon prices in 2010 between the two studies ($265 per metric ton for WEFA and $348 per metric ton for EIA) is largely attributable to (1) a lower reference case GDP and lower emissions in the WEFA study, so that smaller reductions are needed to comply with the 1990-7% target, and (2) differences in the mix of fuels used in the reference case to generate electricity. WEFA's analysis projects less coal and more gas use for electricity generation than EIA's analysis, with basically the same electricity demands in 2010.

In 2020, the WEFA carbon price rises to about $360 per metric ton—about $55 per metric ton higher than the EIA carbon price for the same case. The reason for this difference is based on three factors. Differences in the reference case GDP growth rates (WEFA's GDP grows much faster than EIA's from 2010 to 2020) lead to the need for higher fuel prices in the WEFA projection to comply with the 1990-7% case. WEFA assumes that nuclear life extensions would not be economical or feasible, whereas EIA allows economical nuclear refurbishments. WEFA projects that renewables cannot contribute significantly to electricity generation: renewable use for generation increases by only 11 percent in 2020 relative to the baseline, even with a carbon price of $360 per metric ton, whereas EIA projects a 115-percent increase in the use of renewables for electricity generation in the 1990-7% case relative to the EIA reference case.

The EPRI analysis begins to react to the Kyoto Protocol in 1990, resulting in lower carbon prices and GDP losses than in the EIA analysis for 2010.[99] Further, since the model does not have end-use technology detail, the rate of autonomous energy efficiency improvement is assumed as a policy lever and is based on the analyst's judgement or on calibration with other midterm, technology-rich models.

The pattern of carbon prices in the MIT study is similar to that in the EIA and EPRI studies. In the MIT analysis, decisionmakers do not see future prices or the impending Kyoto Protocol. In addition, capital stock is vintaged—i.e., once capital is invested in equipment, that capital is sunk and the technology's efficiency and use cannot change during its survival period.

Carbon prices in 2020 for the 1990-7% case are more evenly distributed among the studies, ranging between $147 per metric ton for MIT to about $360 per metric ton for WEFA. The declining carbon prices in the EPRI and EIA studies result from the projected increasing penetration of carbon-free or low-carbon generation technologies, coupled with greater selection of more efficient technologies that become economical with higher end-use fuel prices. MIT's carbon price in 2020, $147 per metric ton, is the lowest because this study implicitly has greater optimism than EIA and EPRI that the economy will produce and adopt low-carbon or carbon-free technologies by 2020.

As already mentioned, the lead time that decisionmakers have to anticipate the Kyoto Protocol and the assumed responsiveness of consumers and equipment (demand elasticities and fuel substitution elasticities) can significantly affect the projections of how costly and difficult the transition will be. Most of the studies compared, with the exception of WEFA and EIA, allow the transitions to begin as early as 1990 or 1995.[100] Since starting earlier allows consumers and producers to react earlier, the economy has more time to adjust to the Kyoto Protocol. This may result in an underestimation of the carbon prices and the midterm actual GDP losses to the economy that will be required to achieve the 1990-7% case.

The CRA, WEFA, and PNNL studies exhibit a rising trend in the carbon prices required over time to maintain the 1990-7% emissions target, because technological improvements do not occur quickly enough relative to demand growth. The technology-rich studies reach their peak carbon price in the early part of the compliance period, followed by a flat or declining carbon price to 2020 as more efficient technologies are adopted. The relatively high energy prices make higher-efficiency and higher-cost equipment more competitive in the early part of the compliance period and give rise to normal learning through manufacturing experience, which

[98] The CRA model uses perfect foresight for investment behavior, which may also contribute to underestimating the costs. It assumes that products (like gas and coal) are not perfect substitutes and capital is not perfectly malleable. Further, the demand for energy is only moderately responsive to price changes, compared to the PNNL model. CRA develops its model parameters using the GTAP database from Purdue University and the International Energy Agency (IEA) database.

[99] EPRI's MERGE model is an Aggregate Optimization Model and has perfect foresight. The EPRI model is being rebenchmarked to start in 2000 and should result in higher carbon prices and higher GDP losses in 2010 than are shown in their current analysis.

[100] For PNNL, since the model begins solving in 1985, policy instruments could be introduced as early as 1990. For this study, PNNL reports that the policy instruments for the Kyoto Protocol were phased in beginning in 2001.

helps to reduce equipment costs in the later part of the compliance period.

The other major area of disagreement among the projections is the impact on actual GDP. In 2010, actual GDP losses relative to each reference case range from -1.0 percent (EPRI) at the low end to about 4.2 percent (EIA) at the high end. Some economists have noted that the total GDP impact on the U.S. economy of regulatory programs such as the Kyoto Protocol are large, and that the true costs typically exceed direct costs by a factor of two to four, particularly in the few years following implementation.[101] CRA projects a 2.1-percent loss in GDP in 2010 and a 2.4-percent loss in GDP in 2020. This contrasts with the EIA projection of a 4.2-percent loss in GDP in 2010 and a 0.8-percent loss in 2020, a trend returning to the reference case GDP. The EIA projected recovery trend is due to declining real prices after 2012, whereas increasing GDP losses for CRA are due to continued increasing delivered energy prices throughout the projection period and the relative high GDP level in the reference case from which the reductions must be made.

Most of the reasons for the differences in carbon prices also contribute to the differences in GDP losses. For example, perfect foresight and long lead times allow the economy to adjust at minimum cost as in the PNNL, EPRI, and CRA models. In the WEFA analysis, lower GDP growth in the early period allows for lower carbon prices and smaller GDP losses relative to the EIA study. CRA's lower carbon price and smaller GDP losses are attributable to four factors: (1) the lack of representation of a revenue recycling mechanism, (2) the high level of aggregation of the U.S. energy-economy, (3) the length of the adjustment period, and (4) the incorporation of international trade flows.

The GDP losses portrayed in the analyses are not based on the same definitions. EIA, DRI, and WEFA report losses in potential GDP[102] and full macroeconomic adjustment costs. CRA and EPRI report losses to potential GDP plus some but not all of the macroeconomic adjustment costs, because the level of aggregation used to represent the U.S. macroeconomy does not permit a full representation of the macroeconomic adjustment costs. PNNL reports only the direct cost of meeting the required commitment level, i.e., losses in potential GDP. The loss in potential GDP can be estimated for all the studies except MIT and can be combined with payments for international permits to develop “irreducible” losses to the economy arising from compliance with the Kyoto Protocol for each of the two cases (no trading and Annex I trading).[103] Estimates of irreducible losses to GDP in the 1990-7% case in 2010 are remarkably close, ranging from $60 billion for WEFA to about $94 billion for EIA (in 1996 dollars). The range of irreducible losses in 2020 is $75 billion for EIA to $130 billion for WEFA. WEFA projects the largest potential loss in 2020 because it has the highest carbon prices and its reference case projection of GDP in 2020 is one of the two highest.

The GDP comparisons imply that there is a great deal of uncertainty about the actual economic losses that could result from adherence to the Kyoto Protocol, with actual economic losses rising to as high as 4.2 percent of reference case GDP in 2010—particularly for analyses that use highly disaggregated representations of the U.S. economy (EIA and WEFA). The difference between actual losses and potential GDP losses represents macroeconomic adjustment costs, which are viewed by economists as *theoretically* reducible by optimal fiscal and monetary policies. This may be another factor leading to the wide variation in estimates of macroeconomic adjustment costs. Nevertheless, there is considerable agreement on the level of the potential GDP losses.

All the studies are in close agreement on the change in carbon intensity that must occur relative to each reference case. Reductions in carbon intensities are between 24 percent and 29 percent in 2010 and between 32 percent and 39 percent in 2020.

[101] Jorgenson and Wilcoxen, “Impact of Environmental Legislation on U.S. Economic Growth and Capital Costs,” in *U.S. Environmental Policy and Economic Growth: How Do We Fare?* (Washington, DC: American Council on Capital Formation, 1992); “Reducing U.S. Carbon Emissions: An Econometric General Equilibrium Assessment,” *Resource and Energy Economics*, Vol. 15 (1993), pp. 7-25; and P.M. Bernstein and W.D. Montgomery, “How Much Could Kyoto Really Cost? A Reconstruction and Reconciliation of Administration Estimates” (Charles River Associates, 1998).

[102] The curve shown in Figure 114 in Chapter 6 of this report summarizes the relationship between the level of control and the marginal cost of that level of control. Hence, at each increment of control, the marginal cost is by definition equal to the economic resources that must be forgone in order to achieve the increment in control. It follows, therefore, that the sum of the marginal costs must equal the total cost of the controls that would be internalized in markets. This is the integral of the area under the curve, shown as area A in Figure 114. Conceptually, this is essentially the same effect that is measured by the unavoidable cost in the reduction of potential GDP in the macroeconomic models. As shown in Figure 115, this measure of the unavoidable costs using the results of the NEMS model is nearly identical to the similar estimate from the DRI macroeconomic model.

[103] Furthermore, for the balance of total emissions needed to meet the Kyoto targets, permits would be purchased on the international market. If the marginal cost of control in the United States and the international prices of permits are in equilibrium, then the area B in Figure 114 will represent the total payments for permits, and the sum of the two parts will represent the irreducible losses to the economy under that trading regime to meet the Kyoto requirements.

Comparisons of Annex I Trading Cases

Only five analyses—MIT, EPRI, CRA, PNNL, and DRI—provided simulations of the impacts of sinks, offsets and Annex I trading. DRI's Case 2 is compared with the other Annex I trading cases because carbon permits purchased abroad are closest, falling in the range of 147 to 288 million metric tons.[104] Two EIA cases—1990+9% and 1990+14%—are compared with those studies in Table 31, because both of these cases yield carbon emissions in the range of the other studies. Internationally purchased carbon credits in 2020 fall in the range of 111 to 229 million metric tons for all these analyses. EIA's carbon prices in the 1990+9% case is $163 per metric ton[105] in 2010 and $141 per metric ton in 2020. The EIA carbon price in the 1990+14% case is $129 per metric ton in 2010 and $123 per metric ton in 2020. MIT provided only carbon prices and a range of GDP losses; thus, further comparisons are not possible.

EIA's purchased carbon credits in 2010 (229 million metric tons) in the 1990+14% case are closest to the projected international purchased credits by EPRI and CRA (229 and 288 million metric tons, respectively). The carbon price projected in these cases ranges from $109 per metric ton for CRA to $129 per metric ton for EIA, a statistically insignificant variation. While there is considerable agreement on the carbon price and credit purchases in these analyses, actual GDP losses projected in EIA's 1990+14% case are more than 200 percent higher than the actual GDP losses projected by EPRI and more than 33 percent higher than CRA's. It is also about 50 percent higher than DRI's.

In the Annex I trading cases, only the DRI and EIA analyses consider how the domestic funds will be recycled back to the economy. EIA assumed that the revenues from domestic sales of carbon emission permits would be recycled back to consumers through a personal income tax rebate, as described in Chapter 6,[106] and DRI assumes a return of funds to business. The DRI choice of returning the carbon revenues to business provides a significant boost to business investment in the economy, which implies higher business profits and lower real incomes for consumers in the medium term. According to the DRI analysis, returning carbon revenues to business ultimately would accelerate recovery and lead to stronger economic growth in the longer term than would recycling the carbon revenues to consumers. The impacts of the two recycling mechanisms account for most of the differences in macroeconomic results between the EIA and DRI analyses.

The DRI approach also phases in the carbon policy over a 10-year period (an approach necessitated by the structure of the DRI energy model), whereas EIA phases in the policy over a 3-year period. This factor adds to the difference between the EIA and DRI analyses of macroeconomic costs. In the DRI study, the 10-year phase-in and the assumption that consumers will anticipate and respond to the Kyoto Protocol early results in a smoother economic transition and tends to give a lower carbon price than analyses with shorter phase-in periods like EIA's.

The estimates of unavoidable (irreducible) losses—income losses that cannot be recovered—for the U.S. economy range from $32 billion (DRI Case 2) to about $62 billion (EIA) in 2010. There are many frictions that can increase costs above the irreducible minimum. These include business cycles, international trade and capital constraints, regulation, use of imperfect instruments instead of auction permits, coal subsidies, CAFE standards, exemptions, efficiency losses from taxation, etc.[107] Various Federal Reserve and Federal Government policies might mitigate actual GDP losses. There is considerable uncertainty regarding all the above actions.

The EPRI analysis, because of its perfect foresight and optimizing framework, yields actual GDP losses that are closest to its estimated unavoidable losses. CRA estimates actual GDP losses that are almost 3 times its unavoidable losses in 2010, and estimated actual GDP losses in 2010 for the DRI and EIA 1990+14% cases are 3 to 4 times the unavoidable losses. Because DRI's and EIA's actual GDP losses are based on a detailed macroeconomic model that has limited foresight, focuses on the transitional process rather than the steady-state condition of the economy, their projected GDP losses are expected to be the largest and perhaps more appropriate in the mid term (through 2010). WEFA and EIA incorporate revenue recycling, while DRI redirects the revenues through higher profits to business.

[104]Standard and Poors DRI recently analyzed three cases for the UMWA-BCOA LMPCP Fund. Case 1 assumed that 8 percent of the necessary carbon reduction in 2010 would be accomplished from sinks and offsets, 15 percent from trading, and 77 percent domestically. Case 2 assumed that sinks and offsets would account for 12 percent of the required reduction from baseline in 2010, 30 percent would be purchased from abroad, and 58 percent would be accomplished domestically. Case 3 assumes that sinks and offsets would generate 16 percent of the required reductions from baseline, 55 percent of the reduction would be purchased from abroad, and 29 percent of the reduction to be accomplished within domestic energy markets. Given that the DRI baseline for 1990 carbon emissions is 1,336 million metric tons, the domestic target for Case 1 in 2010 (1,354 million metric tons) is about 1 percent above 1990 levels, Case 2 (1,452 million metric tons) is about 9 percent above 1990 levels, and Case 3 (1,593 million metric tons) is about 19 percent above 1990 levels.

[105]For simplicity and ease of exposition, it is assumed in this chapter that the carbon price, the price at the margin that the United States is willing to pay to reduce carbon emissions, equals the internationally traded permit price.

[106]In Chapter 6, EIA also considers a social security tax rebate.

[107]Tom Tietenberg, *Environmental and Natural Resource Economics*, Third Edition (Harper Collins Publishers, 1992).

The DRI and EIA analyses share the same DRI macroeconomic model; however, they differ in the way they represent the energy market. DRI uses a largely econometric approach, with some technology components to simulate equipment turnover. Responses of energy demand to energy prices are approximated through demand elasticities. Elasticity estimates can vary dramatically and are a major factor in determining results.

Because DRI and EIA share the same macroeconomic model, the reference case[108] estimates of macroeconomic variables are nearly identical for 2010. The differences in the reference case energy projections are primarily due to differences in fuel prices. By 2020, the differences between the DRI and EIA macroeconomic projections widen as differences in fuel prices widen.

The EIA 1990+9% case reduces more emissions domestically (325 million metric tons) than the 1990+14% case at an average carbon price of $159 per metric ton (peaking at $163 per metric ton) for the 2008-2012 period. The unavoidable losses to the U.S. economy for 2010 are estimated to be slightly ($3 to $6 billion) more than in the 1990+14% case. The actual GDP losses are more than 3.5 times the unavoidable losses in the EIA cases.

The carbon price in the two EIA cases and the MIT trading case declines from 2010 to 2020, unlike the carbon prices in the EPRI, CRA, and DRI analyses that increase over the decade. Most of the reasons for these differences have already been described in the 1990-7% comparison case and will not be repeated here. However, one noteworthy difference remains—the availability and cost of Annex I carbon permits and international trade. In the EPRI model, inexpensive permits are presumed to be available from Russia in the early part of the Kyoto Protocol implementation period but are assumed not to be available in the later part of the period. The elimination of the easy Russian permits makes it harder for the United States to meet its commitments in 2020 through Annex I trading and raises the carbon permit price by 65 percent relative to 2010. The reason for the 60-percent increase in 2020 in the CRA carbon price is related to the differences in the representation of advanced technologies, the level of aggregation of the CRA model as previously discussed, and the absence of easy carbon permits from Russia.

The Administration's estimate of the costs of implementing the Kyoto Protocol[109] has been developed, in part, by using the PNNL model. The Administration's analysis does not provide sufficient data to be included in Tables 30 and 31; however, the Administration asserts in Table 4 of the analysis (page 52) that under Annex I trading, the carbon price would be reduced by 72 percent and the resource cost would be decreased by 57 percent relative to a case in which all carbon reductions are achieved domestically. Using Tables 4 and 5 on pages 52 and 53 of the Administration's report on the Kyoto Protocol, the carbon price for the 1990-7% case can be calculated to be $192 per metric ton (in 1996 dollars), and the irreducible economic losses can calculated to be $60 billion. When Annex I trading is assumed, the Administration projects that carbon prices would be reduced to $54 per metric ton, with $26 billion dollars of irreducible losses.[110] The relatively lower GDP growth rate from 1995 to 2010 in the Administration's reference case analysis—2.1 percent annually, compared with 2.3 percent in the *AEO98* reference case, is a major factor that results in a lower carbon price and lower economic costs needed to achieve a carbon target.

Based on Tables 30 and 31, the following can be summarized:

- There is no clear consensus on how effective Annex I trading will be in reducing carbon prices and the costs to the United States. WEFA believes that Annex I trading will not be effective at all because of

[108] Other reference case differences that influence the Kyoto analysis include: (1) The DRI reference case projects 3.1 quadrillion Btu lower primary energy consumption and 1.8 quadrillion Btu lower fossil fuel consumption in 2010 than does EIA. By 2020, the differences grow to 4.2 quadrillion Btu of primary energy and 2.4 quadrillion Btu of fossil fuel consumption. Associated carbon emissions are also lower. Consequently, it should be less costly for the economy to achieve the same carbon target (1,452 million metric tons) in the DRI analysis than in the EIA analysis (1,461 million metric tons in 1990+9% case), as Table 31 confirms. (2) The DRI reference case projects higher world oil prices, higher delivered coal prices, and lower gas prices than the EIA reference case and greater coal, lower gas, and lower oil consumption than the EIA reference case for 2010 and 2020. The differences in the mix of fuel consumption are related to the differences in fuel prices in the cases. Because the delivered price that consumers react to is the sum of the fuel costs plus the carbon price, when oil and coal prices are higher (without the carbon price), the additional carbon price required to achieve the same delivered coal and petroleum product prices will be lower. Higher reference case prices imply lower required carbon prices to induce an energy demand or mix change. Lower carbon prices usually result in lower economic losses.

[109] *The Kyoto Protocol and the President's Policies To Address Climate Change: Administration Economic Analysis* (Washington, DC, July 1998).

[110] According to Table 5, page 53, of the Administration's report, Annex I trading with participation by key developing countries would result in a permit price of $23 per metric ton and irreducible losses of $12 billion. Table 4 on page 52 of the report indicates that the permit price in that case would be reduced by 88 percent and the resource cost would be reduced by 80 percent relative to a "domestic only" case. This means that 12 percent of the carbon price for the domestic only case would be $23, and thus the carbon price in the domestic only case would equal $192 per metric ton. Similarly, 20 percent of the domestic only resource cost would be $12 billion, meaning that the domestic only resource cost would be $60 billion. Using the percentages for Annex I trading in Table 4, the carbon price and the irreducible losses can also be derived for the Annex I trading case.

political and implementation difficulties. Others, like CRA, EPRI, and PNNL, suggest that carbon prices in 2010 can be reduced by about 60 percent.

- All the studies project irreducible losses to the economy that are small (less than 1 percent of GDP in 2010 and 2020) in absolute magnitude—between $32 billion and $62 billion in 2010 and between $46 billion and $102 billion in 2020. The wider differences in 2020 reflect the different perspectives on production losses to the economy associated with forced reductions in fossil fuel energy use.

- With Annex I trading, estimated actual GDP losses relative to each reference case range from 0.5 percent to about 2 percent.

- If the United States is required to achieve stabilization at the 1990-7% levels, the estimate of carbon prices required for stabilization in 2010 range from a low of $221 per metric ton to $348 per metric ton, with the vast majority in the $265 to $295 per metric ton range. Actual GDP losses are projected to range from 1.0 percent to 4.2 percent. However, since all the studies except EIA's and DRI's assume early U.S. action (before 1998) to limit carbon emissions, their estimates of carbon prices and GDP estimates are likely to be low.

The “Five-Lab Study”

Five U.S. Department of Energy Laboratories were asked in the winter of 1996-97 (before the Kyoto conference) to develop technology-oriented strategies for reducing U.S. carbon emissions to 1990 levels by 2010.[111] To represent the potential impact of new technology strategies on carbon emissions, the study assumes increased performance and lower costs for new technologies, new government policies that promote their adoption into the market, and a greater propensity by consumers to buy them than they have shown in the past. In addition, the Five-Lab Study assumes the lower economic growth (and lower carbon emissions) in the *Annual Energy Outlook 1997* than the EIA analysis described in this report.

The principal components of the Five-Lab Study focus on the adoption of energy-efficient technologies under the assumption of a $25 and $50 per metric ton domestic carbon price; an aggressive research and development (R&D) program; and aggressive but unspecified new policies to facilitate adoption of energy-efficient technologies. The analysis was produced using a series of independent end-use sector models that were manually coupled to an electricity market model that assumes a deregulated electricity market.[112] Thus, feedback between energy markets and the rest of the economy were not captured. Consequently, the individual sector solutions may be inconsistent with each other and most likely do not represent a market equilibrium.

The Five-Lab Study is not directly comparable with any of the analyses compared above, because it was not prepared using an integrated modeling framework that simultaneously balances the energy demand for equipment and consumption made by consumers in all segments of the economy with the supply and prices of fuels and economic growth. Therefore, simple comparisons between the Five-Lab Study and EIA's analysis can be misleading.

Given all the above qualifications, three comparisons are made between the Five-Lab Study and the EIA analysis (Tables 32 and 33). The Five-Lab Study is compared in terms of (1) the EIA case that comes closest to achieving a carbon price of $50 per metric ton in 2010 (the 1990+24% case), (2) the EIA case that comes closest to reducing carbon emissions by about the same amount relative to its baseline (the 1990+9% case), and (3) the EIA case that focuses on advanced technologies (the 1990+9% high technology sensitivity case). By design, none of the Five-Lab Study scenarios results in carbon emissions that are below 1990 levels, because they were targeted to achieving stabilization at 1990 levels.

The Five-Lab Study defines three scenarios: (1) an efficiency case, (2) a high efficiency / low carbon case with a $25 per metric ton carbon price (25 HE/LC), and (3) a high efficiency / low carbon case with a $50 per metric ton carbon price (50 HE/LC). The efficiency case assumes better technology and improved cost competitiveness as compared to the business-as-usual case,

[111] Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low Carbon Technologies by 2010 and Beyond* (Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, National Renewable Energy Laboratory, and Argonne National Laboratory, September 1997).

[112] For the buildings sector (residential and commercial), a spreadsheet model was used for the Five-Lab Study, and it was calibrated to yield the results of the *Annual Energy Outlook 1997 (AEO97)* for a business-as-usual case. For the industrial sector, the Long-Term Industrial Energy Forecasting model was used, and it was calibrated to the *AEO97* results for the business-as-usual case. For the transportation sector, the transportation model of the National Energy Modeling System (NEMS) was used, and the *AEO97* baseline was modified based on the judgment of analysts at Oak Ridge National Laboratory to develop the business-as-usual case. For the electricity sector, a new model was developed by Oak Ridge National Laboratory, which assumed a deregulated electricity industry.

Table 32. Comparison of Energy Consumption, Gross Domestic Product, and Energy Intensity Results for EIA and Five-Lab Study Analyses

Projection	1990	1996	2010					
			Five-Lab Study		EIA			
			Business as Usual	50 HE/LC	Reference	1990+24%	1990+9%	1990+9% High Technology
Energy Use by Sector (Quadrillion Btu)								
Buildings	29.8	34.3	36.0	32.0	38.6	36.1	32.2	33.3
Industrial	31.4	34.6	37.4	33.6	40.0	38.5	36.9	34.6
Transportation	22.7	24.9	32.3	27.8	32.6	31.9	30.5	29.8
Total	83.9	93.8	105.7	93.4	111.2	106.5	99.6	97.7
Gross Domestic Product								
Billion 1992 Chain-Weighted Dollars	6,139	6,928	9,185	9,185	9,429	9,333	9,241	9,277[a]
Change From Reference Projection (Percent)	—	—	—	0.0	—	-1.0	-2.0	-1.65
Energy Intensity								
Thousand Btu per Dollar of GDP	13.67	13.54	11.51	10.17	11.79	11.42	10.78	10.54[a]
Annual Percent Change, 1996-2010	—	—	-1.2	-2.0	-1.0	-1.25	-1.65	-1.78

[a]The GDP and intensity values are approximations derived without using the full DRI model.

— = not applicable.

Sources: **Five-Lab Study**—Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low Carbon Technologies by 2010 and Beyond* (Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, National Renewable Energy Laboratory, and Argonne National Laboratory, September 1997), Table 1.1. **EIA**—National Energy Modeling System, runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and HITECH09.D080498B.

Table 33. Comparison of Carbon Emissions Results for EIA and Five-Lab Study Analyses (Million Metric Tons)

Projection	1990	1996	2010					
			Five-Lab Study		EIA			
			Business as Usual	50 HE/LC	Reference	1990+24%	1990+9%	1990+9% High Technology
Carbon Emissions by Sector[a]								
Buildings	457	516	571	509	615	545	424	462
Industrial	454	476	548	455	559	519	462	437
Transportation	434	471	616	513	617	605	576	562
Total	1,346	1,463	1,735	1,340	1,791	1,668	1,462	1,461
Electricity Generation[b]	477	517	636	500 (-136)[c]	657	567	409	446
Change From Reference Emissions	—	—	—	395	—	127	342	342
Carbon Price (1996 Dollars per Metric Ton)	—	—	—	50	—	67	163	121

[a]Carbon emissions in each sector include a share of the carbon emitted from electricity generation.

[b]In the EIA cases, carbon emissions reduced from electricity generation are accounted for in the end-use sectors.

[c]For the 50 HE/LC case, 136 million metric tons saved in electricity generation must be subtracted from the emissions in the end-use sectors, which do not incorporate the saved emissions for generation.

— = not applicable.

Sources: **Five-Lab Study**—Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low Carbon Technologies by 2010 and Beyond* (Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, National Renewable Energy Laboratory, and Argonne National Laboratory, September 1997), Table 1.2. **EIA**—National Energy Modeling System, runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and HITECH09.D080498B.

as a result of additional government spending on R&D and new, unspecified government programs and policies encouraging adoption of energy-efficient technologies. The HE/LC cases assume even more aggressive government spending, policies, and programs with regard to development and deployment of energy-efficient and low-carbon technologies. These cases assume that government policies and programs will be phased in gradually beginning in 2000 and implemented by 2010, with a carbon price that begins in 2000 and rises until 2010. The two HE/LC cases differ only in the carbon prices assumed, one reaching $25 per metric ton in 2010 and the other $50 per metric ton. The Five-Lab Study focuses on the $50 per metric ton case because that analysis finds that carbon emissions can be stabilized at 1990 levels by 2010. This case is equivalent to 5 percent above 1990 levels when adjusted for the carbon emission and economic baseline used in the EIA analysis.

Comparison of EIA Cases With the Five-Lab Study 50 HE/LC Case

The principal factors that explain differences between the EIA cases and the Five-Lab Study results include (1) lower reference case economic growth (1.9 percent annually for the Five-Lab study versus 2.2 percent annually for EIA) and carbon emissions growth (70 million metric tons lower in 2010) than the EIA reference case; (2) a more aggressive menu of technologies in the 50 HE/LC case than in either the 1990+24% case or the 1990+9% case, due to the assumption of aggressive R&D; (3) a more aggressive consumer response—assumed through changes to their purchase behavior for energy-efficient equipment and changes to energy conservation—than has been seen historically, as the result of new, unspecified government policies; and (4) a non-integrated analysis, in which the feedback between markets is not captured and some double counting of benefits is probable.

As illustrated below, differences in the reference GDP and carbon emission growth rates can have an enormous impact on the difficulty or ease of achieving target carbon emissions, the carbon prices needed to achieve a carbon emissions target, and the emissions reductions achieved.

Comparison With the EIA 1990+24% Case: This comparison is made because the carbon prices are similar in the two cases ($60 per metric ton for EIA and $50 per metric ton for the Five-Lab Study.) At $67 per metric ton, EIA projects carbon emissions will be reduced by 123 million metric tons (7 percent relative to the reference case) in 2010. The Five-Lab Study projects a carbon emissions reduction of 395 million metric tons (23 percent) from its baseline in 2010 at the carbon price of $50 per metric ton. EIA projects a GDP loss of about $14 billion in 2010 and an annual 1.25-percent rate of decline in energy intensity from 1996 to 2010. The Five-Lab Study estimates no GDP losses and an annual energy intensity decline rate of 2.0 percent. Although the EIA cases assume a dynamically changing menu of technologies, the differences in energy intensity result from the assumed penetration of even more efficient technologies in the Five-Lab Study due to the more aggressive technology assumptions and consumer behavior.

Comparison With the EIA 1990+9% Case: The EIA 1990+9% case reaches a carbon target of 1,467 million metric tons—about 325 million metric tons below EIA's reference case—in 2010. The Five-Lab Study 50 HE/LC case reduces carbon emissions by 396 million metric tons below the business-as-usual case. If the two studies had used EIA's reference levels of emissions in 2010, then 1,416 million metric tons would have been the adjusted carbon emissions in the Five-Lab Study 50 HE/LC case. Nevertheless, the carbon price required in the EIA 1990+9% case is about $163 per metric ton, compared with $50 per metric ton in the Five-Lab Study. The combination of more advanced technologies and consumer behavior, coupled with a lower reference case economy and carbon emissions, allows the Five-Lab Study to achieve comparable carbon emission reductions at a much lower carbon price.

GDP losses are estimated to be close to zero in the Five-Lab Study. GDP losses in the EIA 1990+9% case are estimated to be about 2.0 percent relative to the EIA reference case. GDP in the EIA 1990+9% case in 2010 is about $80 billion above that in the Five-Lab Study' business-as-usual case. Consequently, a significant portion of the difference in the carbon prices required to achieve the respective carbon emission targets can be explained by differences in reference GDP and carbon emission levels.

Comparison With the EIA 1990+9% High Technology Case: In the 1990+9% high technology case, EIA's projected energy intensity reduction rate approaches 1.8 percent annually and requires a carbon price of $110 per metric ton. The technological progress assumed is roughly similar to that in the Five-Lab Study, but EIA's consumer decisionmaking remains unchanged. The annual rate of change in energy intensity, due primarily to technological change, in the 50 HE/LC for 1996-2010 is about 2 percent per year, a rate that is historically unprecedented for any 14-year period when energy prices are relatively stable, illustrating the study's more aggressive assumptions about cost-effective technology and consumer behavior. Some of the assumptions of the Five-Lab Study that explain the major differences from the EIA results presented in this report are discussed below.

Differences in Assumptions

The following list identifies representative differences between the major assumptions between the EIA reference case—a minor modification of the *Annual Energy Outlook 1998* (*AEO98*) reference case—and those used for the Five-Lab Study. The EIA reference case assumes that current policies continue unchanged for the entire forecast period and that technology continues to evolve as represented by EIA's assessment of the best engineering estimates of their cost and performance during the forecast period. The Five-Lab Study is based on the assumption that technological advances are supported by various new governmental policies; therefore, it is expected that penetration rates of new energy-efficient technologies will generally be higher in the Five-Lab Study.

Buildings Sector Assumptions

Technological Optimism and Adoption: The EIA reference case technology menu for the buildings sector improves over time in terms of both costs and efficiencies, including future technologies that are unavailable today. Market penetration is determined by economics and observed consumer behavior. For the commercial sector, available technologies are selected on the basis of annualized life-cycle costs and specified replacement equipment behavior rules (e.g., same fuel or no constraints). For the residential sector, technologies are selected on the basis of first cost and first-year operating cost, using observed market discount rates. The EIA reference case and carbon reduction cases use a distribution of implicit discount rates developed from observed consumer behavior, ranging from 15 percent to more than 200 percent in real terms; energy-efficient investments must earn returns greater than these discount rates in order to be adopted by consumers.

The Five-Lab Study 50 HE/LC case includes implementation of most of the cost-effective efficiency improvements, using a life-cycle cost calculation based on a 7-percent real discount rate for both the residential and commercial sectors. By assumption, in the Five-Lab Study 50 HE/LC case, 65 percent of the cost-effective potential is achieved. The 7-percent discount rate implies that consumers on average are willing to wait about 15 years to get their payback on the incremental investments required to acquire more energy-efficient equipment. Currently, residential and commercial consumers tend to have payback periods of 6 months to 5 years, and residential homeowners tend to move about every 7 years. Further, the assumption that 65 percent of all equipment that is cost-effective at a 7-percent discount rate is purchased assumes that dramatic changes will occur in consumer behavior as a result of government policy. Because the EIA cases assume no new government policies, these Five-Lab Study assumptions make a dramatic difference in the efficiency of equipment purchased in the buildings sector and in the carbon price required to achieve a specified carbon target.

Miscellaneous Electricity Growth: In the EIA cases, miscellaneous electricity use in the buildings sector, measured in primary terms, grows at 2.8 percent per year from 1997 to 2010. In the Five-Lab Study, buildings sector miscellaneous electricity growth is 0.9 percent per year from 1997 to 2010 in the HE/LC cases. The difference is significant because it means that electricity demand is lower in the Five-Lab Study HE/LC cases than in the EIA cases, requiring a lower carbon price in the Five-Lab Study to achieve the target.

Transportation Sector Assumptions

Light-Duty Vehicle Cost and Performance: The EIA reference case achieves a new car efficiency of 30.6 miles per gallon by 2010. In EIA's 1990+24% case, with a carbon price of $67 per metric ton, new car efficiency increases to about 32.0 miles per gallon in 2010. In comparison, new car efficiencies reach 50.2 miles per gallon in the Five-Lab Study HE/LC cases. The Five-Lab Study achieves the higher efficiency by reaching 73-percent diesel penetration, 11-percent electric hybrid penetration, and a small penetration of fuel cell vehicles by 2010. The Five-Lab Study higher efficiencies and penetration rates were achieved through a variety of assumptions: (1) a major breakthrough of diesel NO_x catalysts was assumed; (2) the characteristics of advanced diesel vehicles (vehicle price, vehicle range, fuel availability, commercial availability, etc.) were assumed to be the same as those of gasoline vehicles and to be accepted by consumers; (3) the incremental costs of advanced vehicles were assumed to be substantially lower than those in the EIA cases; and (4) with a price increase of 12.5 cents per gallon, consumers were assumed to prefer vehicles with much lower horsepower in the Five-Lab Study in 2010 (182 horsepower) than projected in the EIA cases (258 horsepower).

Industrial Sector Assumptions

Model Methodology and Calibration: For the Five-Lab Study, the Long-Term Industrial Energy Forecasting (LIEF) model was calibrated to yield *AEO97* results for the business-as-usual case. Variations from the business-as-usual case involved changing two major assumptions in the LIEF model. For the HE/LC cases, the capital recovery factor (the implicit discount rate used to evaluate investment alternatives) was reduced from 33 percent to 15 percent, and the market penetration factor (the rate at which cost-effective investments are undertaken) was doubled from 3 percent to 6 percent. Both assumptions accelerate adoption of advanced technologies in the Five-Lab Study.

Additional Assumptions: The HE/LC cases in the Five-Lab Study included additional reductions of 31 million metric tons of carbon-equivalent greenhouse gas emissions, based on results that were not part of the LIEF modeling exercise. The additional reductions included 14 to 24 million metric tons from advanced turbine systems and 12 to 16 million metric tons of biomass and black liquor gasification, cement clinker replacement, and aluminum technologies. The cement clinker replacement and advanced aluminum production cells were assumed to reduce emissions by 1 to 2 million metric tons and 3.5 million metric tons of carbon equivalent, respectively, by 2010. These technologies were not included in the EIA cases.

Electricity Sector Assumptions

Electricity Competition: In each of the Five-Lab Study cases, greenhouse gas emission reductions in the utility sector result from lower electricity demand in the end-use sectors, the assumed deregulation of the electric power industry, an assumed carbon permit trading price of $50 per metric ton, and utility supply-side assumptions for fossil, nuclear, and renewable technologies. The Five-Lab Study assumes competitive prices in 2010 in all regions. The competitive pricing assumption tends to raise the price of electricity relative to the regulated cost-of-service price when a carbon price is applied to the carbon content of the fuels. The EIA reference case assumes competitive prices in 2010 in only three regions—New York, California, and New England.

Electricity Demand Growth: In the EIA reference case, electricity demand is expected to grow by 1.6 percent per year from 1996 to 2010. In the EIA carbon reduction cases, electricity demand initially falls in response to higher electricity prices and then recovers as more efficient units are constructed and brought on line to displace uneconomical units. In the Five-Lab Study 50 HE/LC case, electricity demand is assumed to grow by just 0.2 percent per year. In 2010, total electricity demand in the 50 HE/LC case is 17 percent lower than in the EIA reference case.[113] The lower electricity demand growth in the Five-Lab Study results from its estimates of efficiency improvements in the end-use sectors and lower growth for new electricity uses.

Coal Retirements: The EIA reference case determines when and if any generation plants should be retired based on economics. In the Five-Lab Study, external assumptions are used in the business-as-usual and HE/LC cases to determine whether coal plants should be retired and whether coal units should be co-fired with biomass. In the 50 HE/LC case, 75 gigawatts of coal-fired capacity was assumed to be retired by 2010. In the EIA 1990+24% case, only 2.5 gigawatts of coal capacity and about 30 gigawatts of oil and gas steam were economically retired by 2010. In the EIA analysis, a carbon price of $50 per metric ton is insufficient to cause large-scale retirements of coal plants and replacement by natural-gas-fired advanced combined-cycle plants.

An Integrated Estimate of the Five-Lab Study

The U.S. Environmental Protection Agency, Office of Atmospheric Programs, contracted with Lawrence Berkeley Laboratory to modify the *AEO98* version of the National Energy Modeling System to analyze the technology and policy assumptions of the Five-Lab Study within an integrated accounting system.[114] Substantial modifications were made to the NEMS to model the variations of the Five-Lab Study. For example, the NEMS demand models were used as an accounting tool to represent the aggressive research and development program that facilitates adoption of energy-efficient technologies in the Five-Lab Study. Major assumptions regarding the retirement of fossil fuel units were implemented manually in the NEMS electricity module to make room for advanced, low-carbon technologies. The NEMS integrated framework was retained so that interactions between the supply and demand sectors could be consistently represented.

The EPA/LBNL study analyzes two of the Five-Lab Study cases: a high efficiency/low carbon case with a carbon price of $23 per metric ton and a high efficiency/low carbon case with a carbon price of $50 per metric ton. All the technology and behavioral assumptions in the Five-Lab Study, with a few exceptions listed below, were adopted by the EPA/LBNL study. A scenario approach was used to determine the impact of each major group of assumptions.

The major exceptions included: (1) the hurdle rates assumed in the residential and commercial sectors were reduced from the *AEO98* baseline to 15 and 18 percent, respectively, instead of 7 percent in the Five-Lab study—roughly matching energy consumption in the HE/LC cases in the Five-Lab Study; (2) 16 gigawatts of coal-fired capacity and 100 gigawatts of oil- and gas-fired steam were retired by 2008, whereas the Five-Lab Study retired about 75 gigawatts of older coal plants and repowered an additional 45 gigawatts of coal plants as combined-cycle units; (3) cogeneration capacity was increased between 2000 and 2010 by 35 gigawatts instead of the 42 to 51-gigawatt capacity increase assumed in the 50 HE/LC case of the Five-Lab Study; (4) wind received an extension of the renewable tax credit of 1.5 cents per kilowatthour rather than assuming the penetration of wind in the Five-Lab Study; and (5)power plant efficiencies were not improved relative to the baseline, unlike the Five-Lab Study.

The EPA/LBNL preliminary results indicate that, when all the efficiency and capacity improvements, fossil generation retirements, other technology enhancements, electricity demand reductions, and behavioral assumptions are used simultaneously with a carbon price of $50 per metric ton, carbon emissions can be reduced in 2010 to 1,491 million metric tons (11 percent above 1990) and 1,461 million metric tons (9 percent above 1990) in 2020. Energy intensity declines by a projected annual rate of 1.9 percent in this case. In

[113] Total electricity demand in 2010 in the 50 HE/LC case is projected to be 9.7 percent lower than in the 1990+9% case and 4.5 percent lower than in the 1990+24% case.

[114] J.G. Koomey, R.C. Richey, S. Laitner, A.H. Sanstad, R.J. Markel, and C. Marnay, *Technology and Greenhouse Gas Emissions: an Integrated Scenario Analysis Using the LBNL-NEMS Model*, LBNL-42054 (Lawrence, CA: Lawrence Berkeley Laboratory, Energy Analysis Department, September 1998).

comparison, the EIA 1990+9% high technology case yields the equivalent carbon emissions with an energy intensity decline rate of -1.78 percent and a carbon price of $110 per metric ton but without the additional behavioral assumptions used in the EPA/LBNL analysis.

Appendix A

Modifications to the Reference Case

At the request of the House Science Committee, this analysis of the Kyoto Protocol is based upon the assumptions and methodology of the *Annual Energy Outlook 1998* (*AEO98*).[114] Although the reference case in this report is similar to the reference case from *AEO98*, there are some small differences. Modifications were made in order to permit additional flexibility in the National Energy Modeling System (NEMS) in response to higher energy prices or to include certain analyses previously done offline directly within the modeling framework. In addition, some assumptions were modified to reflect more recent assessments of technological improvements and costs. This appendix describes (1) those changes in assumptions and methodologies that cause a change to the reference case of *AEO98*, and (2) other model changes that were implemented in preparing the carbon reduction cases.

Modifications to the Reference Case

Industrial

In *AEO98*, coke imports were incorrectly reported. In 2020, the reference case forecast for coke imports is 260 trillion Btu compared with 82 trillion Btu reported in *AEO98*.

Due to a revision in the methodology for representing the non-energy-intensive industries, the reference case forecast for electricity consumption in 2020 is 220 trillion Btu, or 4.7 percent, less than in *AEO98*. The modification results in an improved representation of the non-energy-intensive industries.

Electricity Generation

Electricity sales are lower by 1.6 percent, or 68 billion kilowatthours, in 2020 compared with *AEO98*, primarily due to the revision in industrial demand noted above.

The ratio of peak load to base load was recalibrated to recent data, resulting in lower projections of peak demands and reducing capacity requirements in the early years of the forecast. This modification reduced the projection of turbine builds by almost 55 gigawatts in the pre-2000 period and by almost 34 gigawatts by 2020, compared with *AEO98*.

In *AEO98*, generating plant retirements were developed offline to the model based on an analysis of when high-cost units would become uneconomic. Retirement decisions for fossil units and pumped storage are now developed internal to the model based on two criteria. First, fossil units that are candidates for retirement must have going-forward costs greater than the total costs of building a replacement over the forecast years for capacity planning. Second, such units must have short-run costs greater than revenues in the year it is scheduled for retirement. This impacts all fossil-fired units. In the revised reference case, only 5 gigawatts of coal units retire from 1996 through 2020 compared to 29 gigawatts in *AEO98*. Total oil and gas retirements from 1996 through 2020 are 13 gigawatts lower than in *AEO98*, with the reduction in retirements most pronounced around 2005.

Nuclear retirements were also based on an offline analysis in *AEO98*. The retirement decision is now made internal to the model. After 30 years, if the going-forward cost of the unit (including all capital expenditures necessary to continue operation) is greater than that of the full levelized cost of a replacement unit, the unit is retired. This represents the point in time when many plants need to replace their turbine generators. This modification results in about 1 gigawatt of additional nuclear retirements by 2020 relative to *AEO98*.

Oil and Gas

Lower 48 natural gas reserves are lower in the revised reference case than in the *AEO98* reference case, resulting in lower levels of domestic production and slightly higher prices. For this analysis, the initial finding rates, success rates, and the assumed level of technically recoverable resources in the shallow waters of the Gulf of Mexico were revised. The initial finding and success rates were updated using new drilling data published by EIA and resulted in significantly lower natural gas reserve additions from conventional sources. The resources for the shallow waters of the Gulf of Mexico were made consistent with the technically recoverable resource levels estimated by the Minerals Management Service. This change also lowers the overall level of reserves, particularly in the later part of the projection period. Both of these changes put upward pressure on prices.

Cellulose-derived ethanol was added for this analysis, based on updated information about this source of ethanol. This supply represents ethanol derived from cellulose biomass such as agricultural crop residuals, switch gas, and other agricultural wood crops, supplementing the corn-derived ethanol supply curves. Capital and operating cost estimates for the cellulose ethanol production were obtained from the Office of Energy Efficiency and Renewable Energy and decline by 20 percent linearly throughout the forecast for all cases except the high technology sensitivities, for which the costs decline by 50 percent. Consumption of ethanol for gasoline blending and E85 production is higher in the revised reference case than in *AEO98* due to higher demands for E85 and the availability of attractively-priced cellulose-based ethanol. The additional availability of cellulose-

[114] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

based ethanol reverses the downward trend in the blending of ethanol in gasoline in *AEO98*. Additional blending of ethanol in gasoline rises above the levels in *AEO98* starting in 2005 and maintains this level, even though the subsidy for ethanol is declining through 2020. The additional availability of cellulose-based ethanol also reduces prices in the latter half of the forecast period.

Canadian natural gas pipeline capacity additions were assumed to be higher in the revised reference case, particularly in the near term, given updated information on proposed pipelines. This change resulted in a higher forecast for Canadian imports and a somewhat lower domestic natural gas production forecast, even with relatively consistent consumption levels. As a result, through the latter half of the forecast, the import prices in the revised reference case exceed the national average wellhead price by a greater margin than in the *AEO98* reference case.

The forecasts for total domestic natural gas pipeline and storage capacity builds are lower in the revised reference case, mainly in the later and earlier years of the forecast, respectively. This is primarily because anticipated consumption growth was tightened in the capacity planning model. Previously, the model planned for more consumption than was realized. This change also contributed to a somewhat lower use of pipeline fuel.

Additional Model Changes

Macroeconomic Activity

- The previous methodology was a response surface representation of the Standard and Poor’s Data Resources, Inc. (DRI) Macroecnomic Model of the U.S. Economy. This was replaced with a nonparametric estimation technique known as kernel regression. The kernel regression model mimics DRI results by comparing inputs from NEMS to databases of inputs and outputs from DRI model simulations of different policy and implementation strategies. The inputs include tax collections and energy prices and quantities. The outputs are 99 macroeconomic variables used in NEMS.
- As part of the analysis underlying the Kyoto service report, EIA requested that DRI examine its Federal Reserve reaction function estimated in the 1997 version of the model, which was the model used in generating *AEO98*. The DRI model used by EIA in this service report changed the structural form of the Federal Reserve reaction function to incorporate a longer-term view of the tradeoff between inflation and unemployment changes.

Residential

- Short-term price elasticity was increased from -0.15 to -0.25 to reflect increased willingness by consumers to reduce energy services in the face of dramatically higher prices, for example, adjusting thermostats, turning off lights when leaving the room, etc. Also, a price elasticity was included for more end uses, such as water heating and clothes drying.
- The unit energy consumption values were adjusted for personal computers, color televisions, and furnace fans to reflect more recent data. Unit energy consumption values for personal computers are now higher and for televisions and furnace fans are lower.
- Technology choice consideration for both conventional lighting and torchiere lighting was added. This allows lighting efficiency levels to be determined by relative equipment costs and electricity prices.
- The responses to large price increases for shell efficiency improvements are lagged over a 5-year period, as opposed to a total response in 1 year.
- The nonfinancial part of consumer hurdle rates was made a function of energy prices. A doubling of energy prices results in about a 30-percent reduction in the nonfinancial hurdle rate, subject to a lower limit of 15 percent, the assumed financial discount rate.
- New technology databases were updated based on a report from Arthur D. Little.[115]
- Solar hot water heaters were added as a technology choice for electric hot water heating.
- Fuel switching methodology was reestimated.
- Recent Energy Star programs were incorporated that are aimed at cutting standby losses in televisions and VCRs.

Commercial

- Short-term price elasticities were added to all uses except commercial refrigeration, including “other” uses such as cogeneration and nonbuilding use. The short-term price elasticities were increased from -0.15 to -0.25 to capture a greater consumer response to increasing fuel prices, such as adjusting thermostats, turning off lights and office equipment when not in use, etc.

[115]Arthur D. Little, Inc., *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Reference Case,* Draft Report, 37125-00 (June 16, 1998).

- The proportion of consumers who consider all fuels in equipment purchase decisions for new construction was allowed to increase. The proportion varies by building type with all proportions showing a 15-percent increase over *AEO98* reference case values.
- The nonfinancial part of consumer hurdle rates was made a function of energy prices. A doubling of energy prices results in about a 30-percent reduction in the nonfinancial hurdle rate, with a lower limit of 15 percent, the assumed financial discount rate.
- New technology databases were updated based on the Arthur D. Little report cited previously.

Industrial

- Retirement rates were made a function of price changes.
- The rate of intensity decline, the technology possibility coefficient, was made a function of price changes.
- The representation of cogeneration was revised to better reflect the incremental energy requirements of cogeneration. Biomass cogeneration was made a function of the availability of byproduct biomass, and natural gas cogeneration was made a function of the difference between the electricity price and the natural gas price.

Transportation

- An algorithm which switched consumer preferences toward cars and away from light trucks was added as a function of fuel price.
- The vehicle-miles traveled fuel price elasticity was increased from -.05 to -0.2.
- A direct injection diesel, diesel electric hybrid, and gasoline fuel cell technologies were added to the technology menu.
- Additional fuel price sensitivity was added to reflect higher consumer purchase shifting toward smaller vehicles.
- A fuel switching algorithm based on fuel price was added for flexible fuel and bi-fuel vehicles.
- Ultra-high bypass engines for aircraft were currently made available.
- Air travel coefficients were adjusted as a function of jet fuel prices to a -0.2 fuel price elasticity from -0.04.
- Domestic load factors were increased to 69 percent for domestic flights and 72 percent for international flights by 2015 beginning in 2005.
- Technology trigger prices for freight trucks were based on a 10-percent discount rate and 20-year payback period.
- LE-55 and turbocompound diesel engine technologies were added to the technology menu for freight trucks.
- Time to maximum penetration for most freight truck technologies was changed to 20 years from 99 years.
- Rail ton-miles traveled was made a function of coal production and average miles traveled of east-west coal production shares.

Electricity

- For this analysis, the decision to retire nuclear plants is now made internal to the model. As noted before, a unit is retired after 30 years if the cost of continuing operation, including required capital expenditures, exceeds the cost of replacement power. For the carbon reduction cases, the status of the unit is also reviewed after 40 years, the time for relicensing. The license can be renewed for 20 years if the cost of continuing operation, including required capital expenditures, is lower than the cost of replacement power.
- With increasing competition in the electricity industry, electricity suppliers are reluctant to build excess capacity. In the revised reference case, total capacity is limited to 2 percent above the minimum reliability requirement, compared to 1 percent in *AEO98*.
- Coal-fired units in regions with sufficient biomass supplies are allowed to cofire with up to 5 percent biomass.

Renewables

- Capital costs for renewable technologies were increased to reflect impacts of expected short-term supply bottlenecks (e.g., site identification, permitting, and construction) that could result if capacity increases rapidly above existing levels. In *AEO98*, biomass, solar, and wind capacity could increase 25 percent annually without incurring higher capital costs. Costs were assumed to increase by one-half percent for every 1 percent increase of capacity in excess of 25 percent. With higher renewable penetration expected in this analysis, the supply curves were modified so that capital costs increase by 1 percent for every percent increase in capacity above 20 percent for all technologies except wind, for which the cost increase is 1.5 percent.
- Available biomass resources were updated by reestimating potential biomass resources from mill and agricultural residues, forestry products, and energy crops.
- The project life of geothermal units was reduced from 30 years to 20 years, the same as other renewable technologies, to reflect shorter cost recovery periods resulting from competition in the electricity

industry. The time period required to develop additional geothermal projects at an existing site was reduced by 1 year.

- In *AEO98*, capacity additions of hydroelectric power are limited to announced projects; however, carbon reduction targets are expected to raise the cost of fossil-fired technologies, which could attract additional hydroelectric capacity. For this analysis, regional hydroelectric supply curves based on projects identified by the Idaho National Engineering and Environmental Laboratory were included.

Oil and Gas

- The decline in flow rates for the discounted cash flow calculation was revised. The decline in flow rates is now linked to the ratio of reserve additions to production instead of to the decline in the finding rates. As a result, the decline in flow rates increases if reserve additions exceed production.

- For *AEO98*, the annual change in onshore drilling was limited to 20 percent for 1997 through 2001, and offshore drilling was not limited. For the revised reference case, the annual increase in onshore drilling is limited to 30 percent and offshore drilling to 20 percent throughout the forecast, and the minimum drilling limit was removed.

- The forecast of Canadian pipeline expansion in *AEO98* was modified to incorporate more recent information on historical and near-term expansions.

- In this analysis, the subsidy for both corn-based and cellulose-based ethanol is 54 cents per gallon, declining by the inflation rate throughout the forecasts. In the carbon reduction cases, the carbon fee applied to end-use product prices replaces the ethanol subsidy if the carbon fee is greater than the ethanol subsidy adjusted by inflation. Corn-based ethanol receives the full carbon fee as a subsidy because corn prices are carbon penalized through the price of diesel fuel, used in the production and harvesting of corn.

- Refinery efficiency increases linearly throughout the forecast based on the carbon fee as refineries become more efficient to reduce the effect of lost product demand on petroleum product margins. The consumption of steam, natural gas, and electricity decreases linearly at increasing rates based on the carbon fee to a maximum of 5.1, 4.3, and 12.0 percent respectively by 2020.

- In the reference case, the capital recovery investment decision factor for each refinery processing unit is based on a 15-percent return on investment with a 3-year construction and investment decision period and a 15-year plant life. For the carbon reduction cases, a 7.5-year plant life is used between 2000 to 2008 to reflect the additional risk from the declining market demand in that period. For the industrial migration sensitivity, refinery investment is not allowed beyond 2000, reflecting the inability of the U.S. refinery industry to compete with non-Annex I countries in energy-intensive industries.

Appendix B

Results for the Carbon Reduction Cases

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Production								
Crude Oil and Lease Condensate	13.71	12.74	12.72	12.71	12.71	12.70	12.69	12.70
Natural Gas Plant Liquids	2.46	2.53	2.56	2.56	2.59	2.62	2.62	2.62
Dry Natural Gas	19.55	22.03	22.24	22.26	22.53	22.74	22.77	22.72
Coal	22.64	25.83	24.73	23.04	21.02	20.07	19.69	18.65
Nuclear Power	7.20	6.95	7.29	7.30	7.30	7.45	7.45	7.45
Renewable Energy[1]	6.83	6.99	7.10	7.17	7.18	7.28	7.34	7.44
Other[2]	1.33	0.58	0.58	0.57	0.52	0.51	0.51	0.51
Total	**73.73**	**77.65**	**77.22**	**75.61**	**73.84**	**73.39**	**73.09**	**72.10**
Imports								
Crude Oil[3]	16.30	21.51	21.49	21.44	21.33	21.30	21.18	21.13
Petroleum Products[4]	3.98	5.79	5.78	5.49	5.23	5.06	5.06	5.08
Natural Gas	2.93	4.87	4.88	4.87	4.93	4.94	5.28	5.32
Other Imports[5]	0.57	1.04	0.52	0.52	0.52	0.47	0.47	0.47
Total	**23.78**	**33.21**	**32.67**	**32.33**	**32.00**	**31.78**	**32.00**	**32.00**
Exports								
Petroleum[6]	2.04	1.99	2.02	1.99	1.88	1.86	1.86	1.90
Natural Gas	0.16	0.28	0.15	0.15	0.15	0.15	0.14	0.14
Coal	2.37	2.64	2.27	2.27	2.27	2.11	2.11	2.11
Total	**4.57**	**4.91**	**4.44**	**4.41**	**4.30**	**4.11**	**4.11**	**4.14**
Discrepancy[7]	**0.82**	**-0.13**	**-0.13**	**-0.20**	**0.07**	**-0.07**	**-0.16**	**0.26**
Consumption								
Petroleum Products[8]	36.01	41.09	41.01	40.71	40.36	40.18	40.06	39.97
Natural Gas	22.43	26.51	26.85	26.86	27.18	27.41	27.80	27.74
Coal	20.90	23.50	22.75	20.97	19.28	18.32	17.86	17.29
Nuclear Power	7.20	6.95	7.29	7.30	7.30	7.45	7.45	7.45
Renewable Energy[1]	6.84	7.01	7.12	7.18	7.20	7.30	7.36	7.45
Other[9]	0.39	0.77	0.30	0.30	0.30	0.30	0.30	0.30
Total	**93.77**	**105.82**	**105.32**	**103.32**	**101.61**	**100.98**	**100.82**	**100.22**
Net Imports - Petroleum	**18.25**	**25.31**	**25.25**	**24.94**	**24.68**	**24.51**	**24.39**	**24.32**
Prices (1996 dollars per unit)								
World Oil Price (dollars per barrel)[10]	20.48	20.26	20.12	20.04	19.96	19.95	19.91	19.89
Gas Wellhead Price (dollars per Mcf)[11]	2.24	2.20	2.18	2.19	2.21	2.24	2.24	2.24
Coal Minemouth Price (dollars per ton)	18.50	15.03	15.39	15.78	16.10	16.13	16.17	16.36
Average Electric Price (cents per kwh)	6.8	6.0	6.1	6.9	7.4	7.7	7.8	7.9

Table B1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
12.40	12.32	12.19	12.14	12.07	12.03	12.00	10.96	10.59	10.46	10.44	10.24	10.12	10.02
2.82	2.88	2.99	3.11	3.16	3.14	3.11	3.24	3.41	3.50	3.57	3.55	3.48	3.37
24.33	24.79	25.70	26.67	27.09	26.91	26.50	27.66	29.05	29.78	30.27	30.13	29.37	28.52
26.75	21.71	16.90	13.69	9.49	8.44	7.21	28.15	17.30	11.90	9.08	4.86	4.14	3.51
6.17	6.68	6.90	6.98	7.36	7.36	7.41	3.80	5.06	5.63	5.90	6.67	6.86	7.41
7.25	7.42	7.58	7.70	7.96	8.21	8.41	7.56	8.26	9.39	9.73	11.01	11.88	12.89
0.57	0.53	0.57	0.56	0.56	0.70	0.75	0.64	0.63	0.65	0.66	0.81	0.89	0.87
80.29	**76.32**	**72.83**	**70.85**	**67.69**	**66.79**	**65.39**	**82.01**	**74.30**	**71.32**	**69.65**	**67.27**	**66.73**	**66.59**
22.09	22.08	22.03	21.94	21.13	20.89	20.31	24.73	24.47	24.65	24.67	24.57	24.56	24.13
7.77	7.07	5.86	5.34	4.21	3.74	3.54	9.26	8.14	7.53	7.42	6.47	5.77	4.96
5.12	5.12	5.29	5.49	5.64	5.92	5.94	5.50	5.80	5.97	6.10	6.06	6.37	6.37
1.05	0.43	0.44	0.44	0.34	0.34	0.34	1.08	0.47	0.48	0.49	0.41	0.41	0.41
36.03	**34.70**	**33.61**	**33.21**	**31.31**	**30.89**	**30.13**	**40.57**	**38.87**	**38.63**	**38.67**	**37.51**	**37.10**	**35.87**
1.75	1.90	1.86	1.87	1.54	1.61	1.68	1.69	1.67	1.65	1.67	1.66	1.66	1.52
0.29	0.14	0.14	0.14	0.14	0.14	0.14	0.32	0.14	0.14	0.14	0.14	0.14	0.14
2.88	2.28	2.28	2.28	1.95	1.95	1.95	3.29	2.37	2.37	2.37	1.92	1.92	1.92
4.93	**4.32**	**4.28**	**4.29**	**3.63**	**3.69**	**3.77**	**5.30**	**4.18**	**4.16**	**4.18**	**3.72**	**3.72**	**3.58**
-0.21	**-0.22**	**-0.31**	**-0.20**	**-0.14**	**-0.06**	**-0.08**	**-0.26**	**-0.34**	**-0.18**	**-0.34**	**-0.17**	**-0.17**	**-0.12**
43.82	42.83	41.64	41.12	39.49	38.89	38.06	46.88	45.25	44.87	44.78	43.75	42.94	41.67
28.97	29.57	30.65	31.82	32.38	32.49	32.09	32.65	34.50	35.40	36.02	35.84	35.39	34.54
24.14	19.70	14.81	11.68	7.80	6.72	5.44	25.27	15.28	10.02	7.06	3.34	2.59	1.98
6.17	6.68	6.90	6.98	7.36	7.36	7.41	3.80	5.06	5.63	5.90	6.67	6.86	7.41
7.27	7.44	7.61	7.72	7.98	8.23	8.44	7.59	8.29	9.43	9.77	11.05	11.91	12.92
0.80	0.25	0.25	0.25	0.24	0.23	0.23	0.83	0.26	0.26	0.26	0.25	0.25	0.24
111.18	**106.48**	**101.86**	**99.57**	**95.23**	**93.93**	**91.67**	**117.02**	**108.64**	**105.61**	**103.79**	**100.90**	**99.94**	**98.76**
28.11	**27.26**	**26.03**	**25.41**	**23.80**	**23.02**	**22.17**	**32.31**	**30.94**	**30.53**	**30.42**	**29.38**	**28.66**	**27.57**
20.77	19.99	19.15	18.72	18.11	17.82	17.54	21.69	20.14	19.81	19.73	19.08	18.74	18.38
2.33	2.38	2.62	2.78	3.01	3.01	3.03	2.62	3.02	3.50	3.71	3.74	3.67	3.53
14.29	14.72	15.81	16.42	17.53	17.90	18.29	12.53	14.29	15.51	16.24	18.58	19.63	20.50
5.9	7.1	8.2	8.8	10.0	10.5	11.0	5.6	7.3	7.8	8.1	8.7	8.9	9.3

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.

[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.

[5]Includes coal, coal coke (net), and electricity (net).

[6]Includes crude oil and petroleum products.

[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.

[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.

[9]Includes net electricity imports, methanol, and liquid hydrogen.

[10]Average refiner acquisition cost for imported crude oil.

[11]Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Mcf = Thousand cubic feet.

Kwh = Kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Figures may differ from published data due to internal conversion factors.

Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). 1996 coal minemouth price: *Coal Industry Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Energy Consumption								
Residential								
Distillate Fuel	0.89	0.77	0.77	0.75	0.74	0.74	0.73	0.73
Kerosene	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.42	0.44	0.43	0.43	0.43	0.43	0.42	0.42
Petroleum Subtotal	1.40	1.28	1.28	1.25	1.23	1.23	1.22	1.22
Natural Gas	5.39	5.53	5.52	5.35	5.25	5.21	5.19	5.16
Coal	0.05	0.06	0.05	0.05	0.04	0.04	0.04	0.04
Renewable Energy[1]	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Electricity	3.68	4.34	4.32	4.21	4.13	4.10	4.09	4.07
Delivered Energy	**11.13**	**11.81**	**11.77**	**11.47**	**11.26**	**11.19**	**11.16**	**11.10**
Electricity Related Losses	8.21	9.12	8.98	8.63	8.33	8.25	8.25	8.15
Total	**19.34**	**20.92**	**20.75**	**20.11**	**19.59**	**19.45**	**19.41**	**19.25**
Commercial								
Distillate Fuel	0.44	0.39	0.39	0.37	0.36	0.36	0.36	0.35
Residual Fuel	0.15	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.71	0.64	0.64	0.62	0.61	0.61	0.61	0.60
Natural Gas	3.30	3.63	3.62	3.51	3.42	3.39	3.37	3.34
Coal	0.08	0.09	0.09	0.09	0.09	0.09	0.08	0.08
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.37	3.91	3.90	3.80	3.70	3.65	3.65	3.63
Delivered Energy	**7.47**	**8.28**	**8.26**	**8.02**	**7.82**	**7.74**	**7.72**	**7.66**
Electricity Related Losses	7.52	8.23	8.11	7.78	7.46	7.36	7.37	7.27
Total	**14.98**	**16.51**	**16.37**	**15.80**	**15.29**	**15.10**	**15.09**	**14.93**
Industrial[4]								
Distillate Fuel	1.17	1.33	1.33	1.33	1.33	1.32	1.32	1.33
Liquefied Petroleum Gas	2.12	2.28	2.28	2.27	2.25	2.25	2.25	2.24
Petrochemical Feedstock	1.28	1.39	1.39	1.38	1.36	1.36	1.36	1.35
Residual Fuel	0.34	0.35	0.35	0.35	0.34	0.34	0.33	0.34
Motor Gasoline[2]	0.19	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Other Petroleum[5]	4.12	4.56	4.55	4.52	4.44	4.41	4.39	4.35
Petroleum Subtotal	9.23	10.14	10.12	10.06	9.95	9.90	9.87	9.83
Natural Gas[6]	9.96	10.97	10.97	11.01	11.11	11.13	11.15	11.14
Metallurgical Coal	0.85	0.76	0.76	0.75	0.75	0.74	0.74	0.74
Steam Coal	1.55	1.69	1.67	1.40	1.24	1.19	1.17	1.15
Net Coal Coke Imports	0.00	0.16	0.16	0.16	0.15	0.15	0.14	0.14
Coal Subtotal	2.40	2.60	2.58	2.30	2.13	2.08	2.06	2.04
Renewable Energy[7]	1.82	2.11	2.11	2.11	2.10	2.09	2.09	2.09
Electricity	3.46	4.05	4.03	3.98	3.92	3.88	3.88	3.85
Delivered Energy	**26.87**	**29.87**	**29.82**	**29.46**	**29.21**	**29.09**	**29.04**	**28.95**
Electricity Related Losses	7.72	8.52	8.39	8.16	7.91	7.82	7.81	7.71
Total	**34.59**	**38.39**	**38.22**	**37.61**	**37.12**	**36.91**	**36.86**	**36.66**

Table B2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
0.73	0.70	0.67	0.65	0.62	0.60	0.59	0.66	0.61	0.60	0.59	0.56	0.55	0.53
0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.05
0.45	0.44	0.44	0.43	0.42	0.41	0.41	0.47	0.46	0.46	0.46	0.45	0.44	0.42
1.25	1.21	1.17	1.15	1.10	1.08	1.05	1.20	1.13	1.12	1.11	1.07	1.04	1.01
5.71	5.43	5.15	5.00	4.72	4.64	4.51	5.98	5.45	5.22	5.10	4.89	4.81	4.68
0.05	0.04	0.04	0.04	0.04	0.03	0.03	0.05	0.04	0.04	0.04	0.04	0.03	0.03
0.61	0.61	0.62	0.62	0.63	0.63	0.63	0.62	0.63	0.64	0.64	0.65	0.66	0.67
4.62	4.42	4.27	4.19	4.05	3.99	3.93	5.30	4.97	4.88	4.82	4.73	4.71	4.65
12.24	**11.72**	**11.25**	**11.00**	**10.54**	**10.36**	**10.15**	**13.14**	**12.22**	**11.90**	**11.71**	**11.38**	**11.25**	**11.04**
9.30	8.49	7.71	7.27	6.89	6.85	6.72	9.81	8.19	7.60	7.28	7.04	7.11	7.25
21.55	**20.20**	**18.95**	**18.27**	**17.43**	**17.21**	**16.86**	**22.95**	**20.41**	**19.50**	**18.99**	**18.42**	**18.37**	**18.29**
0.38	0.36	0.34	0.33	0.30	0.28	0.26	0.36	0.33	0.32	0.31	0.30	0.28	0.26
0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
0.64	0.61	0.59	0.58	0.55	0.53	0.51	0.62	0.58	0.57	0.57	0.55	0.53	0.51
3.79	3.59	3.36	3.22	2.92	2.81	2.65	3.93	3.55	3.37	3.27	3.09	2.99	2.84
0.10	0.09	0.08	0.08	0.07	0.07	0.06	0.10	0.09	0.09	0.08	0.08	0.07	0.06
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.17	3.96	3.78	3.68	3.48	3.39	3.30	4.53	4.19	4.08	4.02	3.90	3.85	3.77
8.69	**8.26**	**7.82**	**7.56**	**7.02**	**6.80**	**6.52**	**9.18**	**8.41**	**8.12**	**7.94**	**7.61**	**7.45**	**7.18**
8.39	7.60	6.82	6.38	5.91	5.82	5.64	8.39	6.90	6.35	6.06	5.79	5.81	5.88
17.08	**15.86**	**14.64**	**13.94**	**12.93**	**12.63**	**12.16**	**17.57**	**15.31**	**14.48**	**14.00**	**13.40**	**13.26**	**13.06**
1.42	1.41	1.42	1.43	1.43	1.43	1.44	1.52	1.52	1.54	1.55	1.57	1.57	1.58
2.44	2.40	2.38	2.38	2.34	2.35	2.37	2.52	2.47	2.47	2.46	2.50	2.50	2.47
1.48	1.45	1.42	1.41	1.37	1.36	1.35	1.52	1.46	1.45	1.44	1.42	1.42	1.41
0.35	0.35	0.35	0.36	0.35	0.33	0.41	0.35	0.37	0.39	0.50	0.49	0.47	0.44
0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.26	0.25	0.25	0.25	0.25	0.25	0.25
4.79	4.68	4.62	4.61	4.42	4.31	4.22	5.08	5.08	5.20	5.16	5.03	4.96	4.82
10.72	10.53	10.41	10.41	10.14	10.02	10.01	11.25	11.16	11.30	11.37	11.26	11.16	10.97
11.43	11.47	11.52	11.54	11.44	11.43	11.12	11.78	11.65	11.45	11.31	11.29	11.24	11.37
0.70	0.65	0.61	0.61	0.60	0.60	0.59	0.58	0.44	0.41	0.40	0.39	0.38	0.38
1.74	1.36	1.14	1.07	0.92	0.87	0.83	1.79	1.36	1.30	1.26	1.09	1.00	0.90
0.20	0.22	0.23	0.23	0.22	0.22	0.22	0.27	0.32	0.33	0.33	0.34	0.34	0.34
2.65	2.22	1.98	1.91	1.73	1.69	1.64	2.64	2.12	2.04	1.99	1.82	1.73	1.62
2.25	2.25	2.24	2.23	2.19	2.18	2.17	2.35	2.39	2.39	2.39	2.39	2.39	2.40
4.30	4.13	3.99	3.95	3.78	3.74	3.67	4.51	4.27	4.19	4.13	4.04	4.01	3.98
31.35	**30.60**	**30.14**	**30.04**	**29.29**	**29.05**	**28.61**	**32.53**	**31.59**	**31.37**	**31.19**	**30.81**	**30.53**	**30.34**
8.65	7.92	7.21	6.85	6.44	6.43	6.28	8.37	7.05	6.51	6.23	6.01	6.06	6.20
40.00	**38.52**	**37.34**	**36.89**	**35.73**	**35.48**	**34.88**	**40.89**	**38.64**	**37.88**	**37.42**	**36.82**	**36.60**	**36.55**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Transportation								
Distillate Fuel[8]	4.48	5.65	5.64	5.59	5.54	5.52	5.51	5.49
Jet Fuel[9]	3.27	4.36	4.35	4.33	4.31	4.29	4.27	4.25
Motor Gasoline[2]	14.94	17.04	17.02	16.93	16.81	16.77	16.72	16.69
Residual Fuel	0.90	1.10	1.10	1.10	1.10	1.10	1.10	1.09
Liquefied Petroleum Gas	0.04	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Other Petroleum[10]	0.29	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Petroleum Subtotal	23.92	28.61	28.57	28.41	28.21	28.12	28.05	27.98
Pipeline Fuel Natural Gas	0.73	0.80	0.83	0.82	0.82	0.82	0.84	0.83
Compressed Natural Gas	0.01	0.18	0.18	0.17	0.17	0.17	0.17	0.17
Renewable Energy (E85)[11]	0.01	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Methanol[12]	0.01	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**24.73**	**29.81**	**29.81**	**29.64**	**29.45**	**29.35**	**29.30**	**29.22**
Electricity Related Losses	0.13	0.17	0.17	0.17	0.17	0.17	0.17	0.16
Total	**24.86**	**29.99**	**29.98**	**29.81**	**29.61**	**29.52**	**29.47**	**29.39**
Delivered Energy Consumption for All Sectors								
Distillate Fuel	6.98	8.15	8.13	8.04	7.97	7.94	7.93	7.90
Kerosene	0.14	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[9]	3.27	4.36	4.35	4.33	4.31	4.29	4.27	4.25
Liquefied Petroleum Gas	2.66	2.94	2.94	2.91	2.90	2.89	2.88	2.88
Motor Gasoline[2]	15.16	17.29	17.27	17.18	17.06	17.01	16.97	16.93
Petrochemical Feedstock	1.28	1.39	1.39	1.38	1.36	1.36	1.36	1.35
Residual Fuel	1.39	1.57	1.57	1.56	1.55	1.55	1.55	1.55
Other Petroleum[13]	4.37	4.85	4.84	4.81	4.74	4.70	4.68	4.65
Petroleum Subtotal	35.26	40.67	40.61	40.34	40.01	39.85	39.75	39.63
Natural Gas[6]	19.39	21.11	21.12	20.87	20.77	20.73	20.72	20.64
Metallurgical Coal	0.85	0.76	0.76	0.75	0.75	0.74	0.74	0.74
Steam Coal	1.68	1.83	1.81	1.53	1.37	1.32	1.30	1.28
Net Coal Coke Imports	0.00	0.16	0.16	0.16	0.15	0.15	0.14	0.14
Coal Subtotal	2.53	2.75	2.73	2.43	2.26	2.21	2.19	2.16
Renewable Energy[14]	2.44	2.79	2.79	2.79	2.78	2.78	2.78	2.77
Methanol[12]	0.01	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.57	12.38	12.33	12.07	11.83	11.72	11.70	11.63
Delivered Energy	**70.19**	**79.78**	**79.66**	**78.59**	**77.74**	**77.38**	**77.22**	**76.92**
Electricity Related Losses	23.57	26.04	25.66	24.73	23.87	23.60	23.60	23.29
Total	**93.77**	**105.82**	**105.32**	**103.32**	**101.61**	**100.98**	**100.82**	**100.22**
Electric Generators[15]								
Distillate Fuel	0.07	0.08	0.05	0.04	0.04	0.04	0.04	0.04
Residual Fuel	0.67	0.34	0.35	0.32	0.31	0.29	0.27	0.31
Petroleum Subtotal	0.75	0.42	0.40	0.37	0.35	0.33	0.31	0.34
Natural Gas	3.04	5.40	5.73	5.99	6.41	6.68	7.07	7.10
Steam Coal	18.36	20.75	20.02	18.54	17.01	16.11	15.67	15.13
Nuclear Power	7.20	6.95	7.29	7.30	7.30	7.45	7.45	7.45
Renewable Energy[16]	4.40	4.22	4.33	4.39	4.42	4.52	4.58	4.68
Electricity Imports[17]	0.39	0.69	0.22	0.22	0.22	0.22	0.22	0.22
Total	**34.14**	**38.43**	**37.99**	**36.80**	**35.70**	**35.32**	**35.30**	**34.93**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

	Projections													
	2010							2020						
	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
	6.03	5.91	5.78	5.73	5.57	5.54	5.49	6.38	6.15	5.99	5.93	5.83	5.80	5.77
	4.98	4.91	4.75	4.68	4.43	4.32	4.18	5.93	5.78	5.73	5.68	5.54	5.48	5.35
	18.03	17.57	16.90	16.55	15.71	15.32	14.71	19.03	18.08	17.75	17.49	16.65	16.22	15.59
	1.27	1.26	1.26	1.26	1.25	1.25	1.25	1.56	1.56	1.56	1.56	1.56	1.57	1.57
	0.20	0.20	0.19	0.19	0.18	0.17	0.17	0.27	0.26	0.26	0.25	0.24	0.24	0.23
	0.34	0.34	0.33	0.33	0.32	0.32	0.32	0.37	0.36	0.36	0.36	0.36	0.37	0.37
	30.86	30.19	29.23	28.75	27.46	26.93	26.11	33.54	32.19	31.65	31.27	30.19	29.67	28.88
	0.87	0.90	0.91	0.96	0.95	0.96	0.95	0.98	1.05	1.09	1.10	1.10	1.08	1.05
	0.25	0.25	0.23	0.23	0.22	0.21	0.21	0.33	0.32	0.31	0.31	0.30	0.29	0.29
	0.12	0.12	0.12	0.13	0.12	0.11	0.11	0.17	0.18	0.18	0.18	0.17	0.16	0.16
	0.14	0.15	0.14	0.14	0.14	0.13	0.13	0.22	0.22	0.22	0.21	0.21	0.20	0.20
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.13	0.12	0.12	0.12	0.12	0.12	0.12
	32.35	**31.70**	**30.74**	**30.30**	**28.98**	**28.44**	**27.60**	**35.37**	**34.08**	**33.57**	**33.19**	**32.08**	**31.54**	**30.69**
	0.21	0.19	0.18	0.17	0.16	0.16	0.16	0.23	0.20	0.19	0.18	0.18	0.18	0.18
	32.55	**31.90**	**30.92**	**30.47**	**29.14**	**28.61**	**27.76**	**35.60**	**34.29**	**33.76**	**33.38**	**32.26**	**31.71**	**30.87**
	8.55	8.38	8.21	8.14	7.92	7.86	7.77	8.91	8.62	8.45	8.39	8.25	8.21	8.14
	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.12	0.11	0.11	0.11	0.11	0.11	0.10
	4.98	4.91	4.75	4.68	4.43	4.32	4.18	5.93	5.78	5.73	5.68	5.54	5.48	5.35
	3.18	3.13	3.09	3.08	3.03	3.02	3.03	3.36	3.28	3.28	3.27	3.28	3.26	3.21
	18.30	17.83	17.16	16.81	15.96	15.58	14.97	19.31	18.36	18.03	17.76	16.93	16.49	15.87
	1.48	1.45	1.42	1.41	1.37	1.36	1.35	1.52	1.46	1.45	1.44	1.42	1.42	1.41
	1.74	1.74	1.73	1.73	1.71	1.70	1.78	2.03	2.05	2.06	2.18	2.17	2.15	2.13
	5.11	4.99	4.92	4.91	4.72	4.61	4.50	5.42	5.42	5.53	5.50	5.36	5.29	5.16
	43.46	42.54	41.40	40.88	39.24	38.56	37.68	46.60	45.07	44.64	44.32	43.06	42.41	41.37
	22.06	21.64	21.17	20.96	20.26	20.04	19.43	23.01	22.02	21.44	21.09	20.67	20.42	20.23
	0.70	0.65	0.61	0.61	0.60	0.60	0.59	0.58	0.44	0.41	0.40	0.39	0.38	0.38
	1.89	1.49	1.26	1.19	1.02	0.97	0.92	1.94	1.48	1.43	1.38	1.21	1.11	1.00
	0.20	0.22	0.23	0.23	0.22	0.22	0.22	0.27	0.32	0.33	0.33	0.34	0.34	0.34
	2.80	2.36	2.10	2.03	1.84	1.79	1.73	2.79	2.25	2.17	2.11	1.93	1.83	1.72
	2.98	2.98	2.98	2.98	2.94	2.93	2.92	3.13	3.20	3.21	3.21	3.21	3.22	3.23
	0.14	0.15	0.14	0.14	0.14	0.13	0.13	0.22	0.22	0.22	0.21	0.21	0.20	0.20
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	13.19	12.61	12.15	11.92	11.41	11.21	10.98	14.47	13.55	13.28	13.09	12.80	12.69	12.51
	84.63	**82.28**	**79.94**	**78.90**	**75.83**	**74.66**	**72.87**	**90.21**	**86.30**	**84.96**	**84.04**	**81.87**	**80.77**	**79.25**
	26.55	24.20	21.92	20.67	19.41	19.27	18.79	26.80	22.35	20.65	19.76	19.02	19.17	19.51
	111.18	**106.48**	**101.86**	**99.57**	**95.23**	**93.93**	**91.67**	**117.02**	**108.64**	**105.61**	**103.79**	**100.90**	**99.94**	**98.76**
	0.07	0.04	0.03	0.03	0.03	0.07	0.10	0.07	0.04	0.11	0.37	0.61	0.45	0.20
	0.29	0.25	0.21	0.21	0.21	0.26	0.28	0.21	0.14	0.11	0.09	0.08	0.08	0.10
	0.36	0.29	0.24	0.24	0.24	0.33	0.38	0.28	0.18	0.22	0.47	0.69	0.53	0.30
	6.91	7.93	9.48	10.86	12.12	12.45	12.66	9.64	12.49	13.96	14.93	15.17	14.97	14.32
	21.35	17.34	12.71	9.65	5.95	4.93	3.71	22.48	13.04	7.86	4.95	1.41	0.76	0.25
	6.17	6.68	6.90	6.98	7.36	7.36	7.41	3.80	5.06	5.63	5.90	6.67	6.86	7.41
	4.30	4.46	4.63	4.74	5.05	5.30	5.52	4.46	5.10	6.22	6.56	7.84	8.69	9.69
	0.66	0.10	0.10	0.10	0.10	0.10	0.10	0.61	0.04	0.04	0.04	0.04	0.04	0.04
	39.74	**36.81**	**34.07**	**32.58**	**30.82**	**30.48**	**29.78**	**41.27**	**35.90**	**33.93**	**32.85**	**31.82**	**31.86**	**32.02**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Total Energy Consumption								
Distillate Fuel	7.06	8.22	8.17	8.09	8.01	7.98	7.97	7.94
Kerosene	0.14	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[9]	3.27	4.36	4.35	4.33	4.31	4.29	4.27	4.25
Liquefied Petroleum Gas	2.66	2.94	2.94	2.91	2.90	2.89	2.88	2.88
Motor Gasoline[2]	15.16	17.29	17.27	17.18	17.06	17.01	16.97	16.93
Petrochemical Feedstock	1.28	1.39	1.39	1.38	1.36	1.36	1.36	1.35
Residual Fuel	2.07	1.92	1.92	1.89	1.86	1.84	1.82	1.86
Other Petroleum[13]	4.37	4.85	4.84	4.81	4.74	4.70	4.68	4.65
Petroleum Subtotal	36.01	41.09	41.01	40.71	40.36	40.18	40.06	39.97
Natural Gas	22.43	26.51	26.85	26.86	27.18	27.41	27.80	27.74
Metallurgical Coal	0.85	0.76	0.76	0.75	0.75	0.74	0.74	0.74
Steam Coal	20.05	22.58	21.83	20.07	18.38	17.44	16.97	16.41
Net Coal Coke Imports	0.00	0.16	0.16	0.16	0.15	0.15	0.14	0.14
Coal Subtotal	20.90	23.50	22.75	20.97	19.28	18.32	17.86	17.29
Nuclear Power	7.20	6.95	7.29	7.30	7.30	7.45	7.45	7.45
Renewable Energy[18]	6.84	7.01	7.12	7.18	7.20	7.30	7.36	7.45
Methanol[12]	0.01	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[17]	0.39	0.69	0.22	0.22	0.22	0.22	0.22	0.22
Total	**93.77**	**105.82**	**105.32**	**103.32**	**101.61**	**100.98**	**100.82**	**100.22**
Energy Use and Related Statistics								
Delivered Energy Use	70.19	79.78	79.66	78.59	77.74	77.38	77.22	76.92
Total Energy Use	93.77	105.83	105.34	103.33	101.63	100.99	100.83	100.23
Total Carbon Emissions (million metric tons)	1462.90	1690.92	1674.61	1623.73	1579.45	1555.16	1546.08	1529.60

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
8.62	8.42	8.24	8.17	7.96	7.94	7.87	8.98	8.65	8.56	8.76	8.86	8.66	8.34
0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.12	0.11	0.11	0.11	0.11	0.11	0.10
4.98	4.91	4.75	4.68	4.43	4.32	4.18	5.93	5.78	5.73	5.68	5.54	5.48	5.35
3.18	3.13	3.09	3.08	3.03	3.02	3.03	3.36	3.28	3.28	3.27	3.28	3.26	3.21
18.30	17.83	17.16	16.81	15.96	15.58	14.97	19.31	18.36	18.03	17.76	16.93	16.49	15.87
1.48	1.45	1.42	1.41	1.37	1.36	1.35	1.52	1.46	1.45	1.44	1.42	1.42	1.41
2.03	1.99	1.94	1.94	1.92	1.96	2.05	2.24	2.19	2.18	2.27	2.25	2.23	2.23
5.11	4.99	4.92	4.91	4.72	4.61	4.50	5.42	5.42	5.53	5.50	5.36	5.29	5.16
43.82	42.83	41.64	41.12	39.49	38.89	38.06	46.88	45.25	44.87	44.78	43.75	42.94	41.67
28.97	29.57	30.65	31.82	32.38	32.49	32.09	32.65	34.50	35.40	36.02	35.84	35.39	34.54
0.70	0.65	0.61	0.61	0.60	0.60	0.59	0.58	0.44	0.41	0.40	0.39	0.38	0.38
23.24	18.83	13.97	10.85	6.98	5.91	4.63	24.42	14.52	9.29	6.33	2.61	1.87	1.26
0.20	0.22	0.23	0.23	0.22	0.22	0.22	0.27	0.32	0.33	0.33	0.34	0.34	0.34
24.14	19.70	14.81	11.68	7.80	6.72	5.44	25.27	15.28	10.02	7.06	3.34	2.59	1.98
6.17	6.68	6.90	6.98	7.36	7.36	7.41	3.80	5.06	5.63	5.90	6.67	6.86	7.41
7.27	7.44	7.61	7.72	7.98	8.23	8.44	7.59	8.29	9.43	9.77	11.05	11.91	12.92
0.14	0.15	0.14	0.14	0.14	0.13	0.13	0.22	0.22	0.22	0.21	0.21	0.20	0.20
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.66	0.10	0.10	0.10	0.10	0.10	0.10	0.61	0.04	0.04	0.04	0.04	0.04	0.04
111.18	**106.48**	**101.86**	**99.57**	**95.23**	**93.93**	**91.67**	**117.02**	**108.64**	**105.61**	**103.79**	**100.90**	**99.94**	**98.76**
84.63	82.28	79.94	78.90	75.83	74.66	72.87	90.21	86.30	84.96	84.04	81.87	80.77	79.25
111.19	106.49	101.87	99.58	95.25	93.94	91.68	117.01	108.64	105.60	103.79	100.89	99.93	98.75
1790.62	1667.93	1535.00	1461.50	1339.98	1299.97	1243.42	1928.74	1668.05	1536.23	1467.78	1346.70	1303.26	1250.80

[1]Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps & solar thermal hot water heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel.
[7]Includes consumption of energy from hydroelectric, wood & wood waste, municipal solid waste, & other biomass; includes for cogeneration, both sales to the grid & for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[12]Only M85 (85 percent methanol and 15 percent motor gasoline).
[13]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
[15]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[17]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 natural gas lease, plant, and pipeline fuel values: Energy Information Administration, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo /pub/upd/aug97/index.html (August 21, 1997). 1996 electric utility fuel consumption: EIA, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997). 1996 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1996 values: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A , FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B3. Energy Prices by Sector and Source
(1996 Dollars per Million Btu)

Sector and Source	1996	Projections 2005: Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Residential	**12.86**	**12.18**	**12.37**	**13.85**	**14.92**	**15.40**	**15.54**	**15.84**
Primary Energy[1]	6.63	6.26	6.33	7.04	7.52	7.72	7.84	7.99
Petroleum Products[2]	8.51	9.18	9.28	10.04	10.51	10.70	10.85	11.01
Distillate Fuel	7.09	7.59	7.68	8.48	9.00	9.20	9.35	9.52
Liquefied Petroleum Gas	11.59	12.11	12.23	12.87	13.22	13.39	13.52	13.66
Natural Gas	6.19	5.63	5.69	6.37	6.85	7.05	7.16	7.31
Electricity	24.42	21.55	21.95	24.60	26.62	27.54	27.70	28.21
Commercial	**12.84**	**11.62**	**11.84**	**13.49**	**14.68**	**15.21**	**15.38**	**15.72**
Primary Energy[1]	5.26	4.81	4.88	5.58	6.07	6.27	6.39	6.54
Petroleum Products[2]	5.56	5.76	5.86	6.68	7.19	7.38	7.54	7.71
Distillate Fuel	5.27	5.37	5.46	6.27	6.79	6.98	7.14	7.31
Residual Fuel	3.24	3.07	3.20	4.13	4.67	4.89	5.06	5.24
Natural Gas[3]	5.28	4.73	4.79	5.46	5.93	6.13	6.24	6.39
Electricity	22.05	19.21	19.62	22.29	24.28	25.19	25.37	25.89
Industrial[4]	**5.35**	**4.96**	**5.07**	**5.86**	**6.37**	**6.59**	**6.70**	**6.85**
Primary Energy	3.99	3.75	3.83	4.48	4.88	5.04	5.15	5.28
Petroleum Products[2]	5.58	5.21	5.28	5.78	6.09	6.21	6.31	6.41
Distillate Fuel	5.50	5.43	5.53	6.35	6.87	7.05	7.22	7.38
Liquefied Petroleum Gas	7.80	6.70	6.83	7.45	7.80	7.97	8.10	8.24
Residual Fuel	2.99	2.75	2.84	3.77	4.34	4.55	4.72	4.90
Natural Gas[5]	2.96	2.80	2.88	3.51	3.93	4.12	4.22	4.36
Metallurgical Coal	1.77	1.63	1.76	2.88	3.60	3.86	4.06	4.28
Steam Coal	1.46	1.30	1.42	2.56	3.27	3.54	3.74	3.96
Electricity	13.37	11.57	11.83	13.41	14.61	15.14	15.25	15.56
Transportation	**8.77**	**8.62**	**8.78**	**9.53**	**10.03**	**10.22**	**10.37**	**10.53**
Primary Energy	8.76	8.61	8.77	9.52	10.02	10.21	10.36	10.52
Petroleum Products[2]	8.76	8.61	8.76	9.52	10.02	10.21	10.37	10.52
Distillate Fuel[6]	8.90	8.47	8.62	9.41	9.89	10.07	10.23	10.39
Jet Fuel[7]	5.52	5.37	5.51	6.30	6.79	6.97	7.11	7.26
Motor Gasoline[8]	9.89	9.92	10.10	10.83	11.35	11.55	11.69	11.85
Residual Fuel	2.55	2.70	2.80	3.72	4.30	4.50	4.68	4.84
Liquid Petroleum Gas[9]	12.63	12.99	13.10	13.74	14.07	14.24	14.37	14.50
Natural Gas[10]	5.42	5.82	5.88	6.52	6.98	7.17	7.27	7.41
E85[11]	15.85	16.35	16.38	16.60	16.69	16.73	16.75	16.78
M85[12]	12.24	12.54	12.60	13.32	13.78	13.96	14.09	14.23
Electricity	15.33	13.44	13.56	13.69	13.93	14.09	14.07	14.06
Average End-Use Energy	**8.65**	**8.21**	**8.36**	**9.32**	**9.97**	**10.24**	**10.38**	**10.56**
Primary Energy	8.32	7.92	8.07	8.97	9.57	9.82	9.96	10.13
Electricity	20.00	17.49	17.85	20.11	21.82	22.60	22.76	23.20
Electric Generators[13]								
Fossil Fuel Average	1.54	1.50	1.62	2.66	3.32	3.59	3.77	3.97
Petroleum Products	3.25	3.44	3.38	4.33	4.91	5.15	5.33	5.47
Distillate Fuel	4.91	4.97	5.10	5.93	6.45	6.65	6.81	6.98
Residual Fuel	3.07	3.10	3.15	4.11	4.71	4.95	5.12	5.29
Natural Gas	2.64	2.62	2.69	3.32	3.74	3.99	4.07	4.24
Steam Coal	1.29	1.17	1.28	2.42	3.13	3.39	3.60	3.81

Table B3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
12.24	**14.61**	**16.79**	**18.11**	**20.87**	**21.94**	**23.29**	**12.32**	**16.06**	**17.31**	**18.14**	**19.68**	**20.34**	**21.52**
6.24	7.32	8.50	9.18	10.79	11.39	12.27	6.42	8.32	9.12	9.61	10.56	11.06	11.91
9.54	10.54	11.47	11.94	13.39	14.07	15.03	9.72	11.19	11.51	11.83	12.79	13.43	14.51
7.78	8.86	9.93	10.47	12.10	12.83	13.85	7.82	9.44	9.87	10.21	11.24	11.90	13.06
12.50	13.29	13.91	14.27	15.34	15.93	16.79	12.49	13.61	13.73	13.99	14.83	15.42	16.39
5.56	6.64	7.86	8.58	10.20	10.78	11.65	5.80	7.76	8.64	9.16	10.10	10.57	11.37
21.36	25.63	29.11	31.29	35.46	37.17	38.98	20.37	26.37	28.01	29.20	31.23	31.94	33.34
11.51	**14.16**	**16.57**	**17.99**	**21.05**	**22.31**	**23.82**	**11.10**	**15.07**	**16.30**	**17.16**	**18.76**	**19.45**	**20.69**
4.74	5.82	7.02	7.71	9.36	9.99	10.91	4.70	6.60	7.39	7.88	8.86	9.39	10.28
5.99	7.07	8.11	8.64	10.22	10.95	11.98	6.12	7.70	8.07	8.40	9.43	10.12	11.30
5.57	6.65	7.72	8.26	9.87	10.60	11.62	5.66	7.24	7.64	7.98	9.02	9.68	10.85
3.18	4.43	5.62	6.26	8.10	8.90	10.02	3.38	5.23	5.69	6.06	7.21	8.01	9.33
4.61	5.67	6.88	7.60	9.24	9.83	10.72	4.57	6.49	7.35	7.87	8.82	9.30	10.12
18.87	23.21	26.77	28.85	32.94	34.71	36.43	17.67	23.61	25.09	26.21	28.18	28.85	30.13
5.12	**6.26**	**7.32**	**7.92**	**9.35**	**9.95**	**10.79**	**5.15**	**6.92**	**7.44**	**7.83**	**8.69**	**9.17**	**9.93**
3.96	4.86	5.75	6.26	7.55	8.09	8.90	4.16	5.62	6.09	6.44	7.25	7.73	8.52
5.46	6.05	6.60	6.87	7.79	8.25	8.95	5.58	6.41	6.55	6.75	7.39	7.80	8.49
5.68	6.76	7.83	8.35	9.93	10.66	11.70	5.86	7.40	7.76	8.10	9.14	9.80	10.97
7.01	7.79	8.41	8.76	9.85	10.44	11.37	6.99	8.12	8.18	8.47	9.36	9.95	10.87
2.94	4.17	5.35	5.96	7.73	8.56	9.65	3.16	4.97	5.39	5.74	6.85	7.63	8.91
2.98	3.96	5.06	5.74	7.26	7.81	8.65	3.25	5.06	5.86	6.35	7.24	7.71	8.50
1.58	3.28	4.85	5.69	7.98	8.98	10.36	1.51	4.00	4.60	5.05	6.55	7.56	9.19
1.26	2.96	4.53	5.37	7.65	8.65	10.03	1.18	3.67	4.27	4.72	6.19	7.20	8.83
11.28	13.86	15.96	17.12	19.50	20.51	21.51	10.31	13.83	14.74	15.38	16.52	17.00	17.67
8.75	**9.84**	**10.77**	**11.22**	**12.60**	**13.24**	**14.19**	**8.59**	**10.05**	**10.36**	**10.67**	**11.56**	**12.17**	**13.22**
8.74	9.83	10.76	11.21	12.59	13.24	14.18	8.57	10.04	10.35	10.66	11.55	12.17	13.22
8.73	9.82	10.75	11.20	12.58	13.23	14.18	8.55	10.02	10.32	10.63	11.52	12.14	13.20
8.49	9.58	10.67	11.18	12.66	13.37	14.39	8.22	9.75	10.10	10.42	11.50	12.18	13.34
5.62	6.69	7.65	8.15	9.61	10.24	11.20	5.76	7.32	7.70	8.01	9.04	9.66	10.73
10.12	11.25	12.14	12.55	13.87	14.50	15.44	10.01	11.46	11.74	12.05	12.88	13.49	14.53
2.90	4.16	5.34	5.96	7.72	8.54	9.66	3.08	4.92	5.36	5.70	6.85	7.63	8.96
13.18	13.95	14.55	14.89	15.93	16.52	17.36	12.76	13.88	14.02	14.27	15.09	15.66	16.61
6.53	7.60	8.74	9.39	10.93	11.49	12.32	7.17	8.95	9.67	10.15	10.99	11.44	12.20
16.73	16.79	16.38	16.39	18.13	18.83	19.61	16.58	16.20	16.27	16.54	17.43	17.92	19.09
12.63	13.54	14.31	14.71	16.01	16.60	17.21	12.69	13.86	14.14	14.42	15.18	15.76	16.74
13.27	13.78	14.08	14.74	15.45	15.80	15.91	12.39	12.77	12.90	13.15	13.38	13.15	13.27
8.31	**9.76**	**11.04**	**11.73**	**13.45**	**14.18**	**15.17**	**8.27**	**10.39**	**10.98**	**11.43**	**12.45**	**13.02**	**13.98**
8.04	9.38	10.54	11.16	12.75	13.44	14.38	7.98	9.90	10.40	10.80	11.75	12.31	13.24
17.22	20.92	23.94	25.70	29.23	30.68	32.19	16.31	21.44	22.79	23.77	25.49	26.10	27.21
1.55	3.14	4.65	5.49	7.38	8.04	8.96	1.68	4.22	5.20	5.90	7.17	7.70	8.52
3.67	4.87	6.09	6.71	8.52	9.34	10.48	4.03	5.94	6.71	7.36	8.50	9.16	10.28
5.21	6.35	7.47	8.03	9.55	10.14	11.14	5.36	6.99	7.21	7.52	8.55	9.21	10.38
3.29	4.63	5.88	6.52	8.35	9.11	10.24	3.56	5.67	6.24	6.72	8.06	8.84	10.06
2.82	3.81	4.99	5.70	7.28	7.80	8.63	3.20	4.97	5.81	6.31	7.21	7.68	8.48
1.11	2.81	4.37	5.23	7.53	8.55	9.95	1.00	3.48	4.07	4.52	6.04	7.10	8.80

Table B3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu)

Sector and Source	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Average Price to All Users[14]								
Petroleum Products[2]	7.83	7.76	7.90	8.60	9.06	9.23	9.37	9.51
Distillate Fuel	7.84	7.71	7.86	8.66	9.15	9.33	9.49	9.66
Jet Fuel	5.52	5.37	5.51	6.30	6.79	6.97	7.11	7.26
Liquefied Petroleum Gas	8.53	7.89	8.01	8.64	8.98	9.16	9.28	9.42
Motor Gasoline[8]	9.89	9.91	10.08	10.82	11.33	11.53	11.68	11.83
Residual Fuel	2.84	2.81	2.89	3.82	4.39	4.61	4.78	4.95
Natural Gas	4.14	3.72	3.77	4.39	4.79	4.99	5.07	5.21
Coal	1.32	1.18	1.30	2.43	3.14	3.40	3.61	3.82
E85[11]	15.85	16.35	16.38	16.60	16.69	16.73	16.75	16.78
M85[12]	12.24	12.54	12.60	13.32	13.78	13.96	14.09	14.23
Electricity	20.00	17.49	17.85	20.11	21.82	22.60	22.76	23.20
Non-Renewable Energy Expenditures by Sector (billion 1996 dollars)								
Residential	135.23	136.41	138.12	150.47	158.96	162.96	163.94	166.15
Commercial	95.84	96.20	97.75	108.14	114.83	117.71	118.67	120.32
Industrial	111.91	112.58	114.87	131.62	142.18	146.51	148.83	151.70
Transportation	210.43	248.75	253.09	273.77	286.57	291.12	294.81	298.41
Total Non-Renewable Expenditures	**553.41**	**593.94**	**603.84**	**664.00**	**702.54**	**718.30**	**726.25**	**736.59**
Transportation Renewable Expenditures	0.08	1.13	1.13	1.17	1.19	1.20	1.21	1.22
Total Expenditures	**553.49**	**595.07**	**604.97**	**665.17**	**703.74**	**719.51**	**727.46**	**737.81**

Table B3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
7.94	8.91	9.74	10.14	11.39	11.98	12.83	7.88	9.18	9.43	9.69	10.49	11.06	12.02
7.81	8.91	9.99	10.50	12.01	12.71	13.72	7.67	9.21	9.54	9.79	10.78	11.49	12.73
5.62	6.69	7.65	8.15	9.61	10.24	11.20	5.76	7.32	7.70	8.01	9.04	9.66	10.73
8.29	9.05	9.67	10.00	11.07	11.64	12.52	8.32	9.44	9.52	9.80	10.62	11.19	12.11
10.11	11.23	12.12	12.53	13.86	14.49	15.43	10.00	11.45	11.73	12.04	12.86	13.48	14.51
2.98	4.24	5.42	6.04	7.81	8.64	9.76	3.15	4.99	5.43	5.77	6.91	7.70	9.02
3.76	4.71	5.80	6.45	7.96	8.49	9.31	3.96	5.69	6.48	6.95	7.84	8.30	9.09
1.12	2.82	4.39	5.24	7.56	8.57	9.97	1.01	3.50	4.10	4.57	6.12	7.18	8.84
16.73	16.79	16.38	16.39	18.13	18.83	19.61	16.58	16.20	16.27	16.54	17.43	17.92	19.09
12.63	13.54	14.31	14.71	16.01	16.60	17.21	12.69	13.86	14.14	14.42	15.18	15.76	16.74
17.22	20.92	23.94	25.70	29.23	30.68	32.19	16.31	21.44	22.79	23.77	25.49	26.10	27.21
142.47	162.27	178.46	187.98	206.89	213.60	221.60	154.21	186.09	194.97	200.87	211.16	215.46	223.12
100.04	116.91	129.55	136.02	147.66	151.70	155.24	101.88	126.71	132.32	136.19	142.68	144.77	148.56
121.43	145.88	168.16	181.59	209.59	222.20	238.74	125.47	164.58	176.32	184.55	203.62	214.30	231.62
273.12	301.43	320.24	328.53	353.51	364.91	379.60	292.00	329.71	334.53	340.63	357.11	370.26	392.18
637.05	**726.49**	**796.40**	**834.12**	**917.65**	**952.41**	**995.18**	**673.57**	**807.09**	**838.14**	**862.23**	**914.57**	**944.78**	**995.49**
1.97	2.01	2.04	2.07	2.12	2.15	2.18	2.81	2.86	2.91	2.93	2.92	2.94	3.02
639.03	**728.51**	**798.44**	**836.18**	**919.77**	**954.56**	**997.35**	**676.38**	**809.95**	**841.05**	**865.16**	**917.49**	**947.72**	**998.51**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Only M85 (85 percent methanol and 15 percent motor gasoline).
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: 1996 figures may differ from published data due to internal rounding.

Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(96/13-97/4) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). 1996 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1996 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). Other 1996 natural gas delivered prices: EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B. Values for 1996 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/ pub/state.data/021494.pdf (August 26, 1997) and the *Coal Industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997). 1996 electricity prices for commercial, industrial, and transportation: EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Key Indicators								
Households (millions)								
Single-Family	69.61	77.46	77.46	77.43	77.40	77.38	77.38	77.37
Multifamily	24.76	26.54	26.54	26.52	26.50	26.49	26.49	26.48
Mobile Homes	6.00	7.08	7.08	7.08	7.07	7.07	7.07	7.07
Total	**100.37**	**111.08**	**111.08**	**111.02**	**110.97**	**110.95**	**110.94**	**110.92**
Average House Square Footage	**1649**	**1691**	**1691**	**1691**	**1691**	**1691**	**1691**	**1691**
Energy Intensity (million Btu consumed per household)								
Delivered Energy Consumption	110.92	106.30	105.97	103.34	101.50	100.88	100.59	100.05
Electricity Related Losses	81.78	82.08	80.85	77.75	75.07	74.40	74.35	73.50
Total Energy Consumption	192.70	188.37	186.82	181.09	176.57	175.28	174.93	173.55
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.47	0.48	0.48	0.46	0.45	0.45	0.45	0.44
Space Cooling	0.46	0.51	0.51	0.49	0.48	0.47	0.47	0.47
Water Heating	0.37	0.37	0.37	0.36	0.35	0.35	0.35	0.35
Refrigeration	0.41	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Cooking	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Clothes Dryers	0.19	0.21	0.21	0.21	0.20	0.20	0.20	0.20
Freezers	0.13	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.32	0.37	0.37	0.36	0.35	0.35	0.35	0.34
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Color Televisions	0.21	0.29	0.29	0.28	0.28	0.28	0.27	0.27
Personal Computers	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Furnace Fans	0.09	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Other Uses[2]	0.79	1.35	1.34	1.30	1.27	1.26	1.26	1.25
Delivered Energy	**3.68**	**4.34**	**4.32**	**4.21**	**4.13**	**4.10**	**4.09**	**4.07**
Natural Gas								
Space Heating	3.77	3.86	3.85	3.73	3.65	3.62	3.61	3.58
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.31	1.35	1.35	1.31	1.28	1.27	1.27	1.26
Cooking	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[3]	0.09	0.10	0.10	0.10	0.09	0.09	0.09	0.09
Delivered Energy	**5.39**	**5.53**	**5.52**	**5.35**	**5.25**	**5.21**	**5.19**	**5.16**
Distillate								
Space Heating	0.80	0.68	0.68	0.66	0.65	0.65	0.64	0.64
Water Heating	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.89**	**0.77**	**0.77**	**0.75**	**0.74**	**0.74**	**0.73**	**0.73**
Liquefied Petroleum Gas								
Space Heating	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.30
Water Heating	0.07	0.08	0.08	0.08	0.07	0.07	0.07	0.07
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.42**	**0.44**	**0.43**	**0.43**	**0.43**	**0.43**	**0.42**	**0.42**
Marketed Renewables (wood)[5]	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Other Fuels[6]	0.13	0.13	0.13	0.12	0.11	0.11	0.11	0.11

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections							Projections						
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
81.55	81.48	81.37	81.34	81.19	81.14	81.08	89.52	89.50	89.53	89.50	89.41	89.59	89.61
27.92	27.85	27.71	27.68	27.52	27.47	27.42	30.84	30.76	30.75	30.71	30.56	30.70	30.70
7.58	7.57	7.56	7.56	7.55	7.54	7.54	8.35	8.37	8.39	8.40	8.41	8.45	8.47
117.04	**116.90**	**116.64**	**116.58**	**116.26**	**116.15**	**116.04**	**128.71**	**128.62**	**128.68**	**128.60**	**128.38**	**128.74**	**128.78**
1707	**1707**	**1707**	**1707**	**1708**	**1708**	**1708**	**1732**	**1732**	**1732**	**1732**	**1733**	**1732**	**1732**
104.60	100.24	96.41	94.35	90.64	89.21	87.44	102.07	94.99	92.50	91.07	88.64	87.41	85.69
79.49	72.59	66.09	62.35	59.29	58.97	57.88	76.23	63.67	59.04	56.62	54.82	55.26	56.32
184.09	172.83	162.50	156.70	149.94	148.18	145.32	178.30	158.66	151.53	147.68	143.47	142.67	142.01
0.48	0.46	0.43	0.42	0.40	0.40	0.39	0.51	0.47	0.46	0.45	0.44	0.44	0.43
0.53	0.50	0.47	0.46	0.44	0.43	0.42	0.57	0.52	0.50	0.49	0.47	0.47	0.46
0.38	0.36	0.35	0.34	0.33	0.32	0.31	0.41	0.38	0.37	0.37	0.36	0.35	0.34
0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27	0.27
0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.17	0.17	0.17	0.17	0.17	0.17
0.23	0.22	0.21	0.20	0.20	0.20	0.19	0.26	0.24	0.24	0.23	0.23	0.23	0.23
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
0.40	0.38	0.36	0.35	0.34	0.33	0.31	0.45	0.42	0.41	0.41	0.40	0.39	0.39
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
0.30	0.29	0.28	0.27	0.27	0.26	0.26	0.33	0.31	0.31	0.31	0.30	0.30	0.30
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.06	0.06	0.05	0.05	0.05	0.05	0.05
0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.14	0.13	0.13	0.13	0.13	0.12	0.12
1.55	1.48	1.43	1.41	1.36	1.34	1.32	1.96	1.84	1.81	1.79	1.76	1.75	1.73
4.62	**4.42**	**4.27**	**4.19**	**4.05**	**3.99**	**3.93**	**5.30**	**4.97**	**4.88**	**4.82**	**4.73**	**4.71**	**4.65**
3.97	3.76	3.55	3.44	3.22	3.15	3.05	4.13	3.74	3.57	3.47	3.31	3.25	3.15
0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
1.40	1.34	1.28	1.24	1.18	1.17	1.14	1.48	1.35	1.29	1.27	1.22	1.21	1.18
0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.19	0.19	0.19	0.19	0.19	0.19	0.19
0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.05	0.05	0.05
0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.11	0.11	0.10	0.10	0.10	0.10	0.10
5.71	**5.43**	**5.15**	**5.00**	**4.72**	**4.64**	**4.51**	**5.98**	**5.45**	**5.22**	**5.10**	**4.89**	**4.81**	**4.68**
0.64	0.61	0.58	0.57	0.54	0.52	0.51	0.57	0.53	0.51	0.51	0.48	0.47	0.45
0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.08	0.08
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.73	**0.70**	**0.67**	**0.65**	**0.62**	**0.60**	**0.59**	**0.66**	**0.61**	**0.60**	**0.59**	**0.56**	**0.55**	**0.53**
0.32	0.31	0.31	0.31	0.30	0.29	0.29	0.33	0.32	0.32	0.32	0.31	0.30	0.29
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.08	0.08
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.45	**0.44**	**0.44**	**0.43**	**0.42**	**0.41**	**0.41**	**0.47**	**0.46**	**0.46**	**0.46**	**0.45**	**0.44**	**0.42**
0.61	0.61	0.62	0.62	0.63	0.63	0.63	0.62	0.63	0.64	0.64	0.65	0.66	0.67
0.12	0.11	0.10	0.10	0.10	0.09	0.09	0.12	0.10	0.10	0.10	0.09	0.09	0.09

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Delivered Energy Consumption by End-Use								
Space Heating	6.10	6.06	6.05	5.89	5.78	5.75	5.73	5.69
Space Cooling	0.47	0.51	0.51	0.49	0.48	0.48	0.47	0.47
Water Heating	1.84	1.89	1.89	1.83	1.80	1.79	1.78	1.77
Refrigeration	0.41	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Cooking	0.33	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Clothes Dryers	0.24	0.27	0.27	0.26	0.25	0.25	0.25	0.25
Freezers	0.13	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.32	0.37	0.37	0.36	0.35	0.35	0.35	0.34
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Color Televisions	0.21	0.29	0.29	0.28	0.28	0.28	0.27	0.27
Personal Computers	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Furnace Fans	0.09	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Other Uses[7]	0.90	1.45	1.45	1.41	1.38	1.37	1.36	1.36
Delivered Energy	**11.13**	**11.81**	**11.77**	**11.47**	**11.26**	**11.19**	**11.16**	**11.10**
Electricity Related Losses	**8.21**	**9.12**	**8.98**	**8.63**	**8.33**	**8.25**	**8.25**	**8.15**
Total Energy Consumption by End-Use								
Space Heating	7.15	7.07	7.03	6.83	6.69	6.65	6.62	6.58
Space Cooling	1.50	1.58	1.56	1.49	1.44	1.43	1.42	1.41
Water Heating	2.66	2.68	2.66	2.58	2.51	2.49	2.49	2.47
Refrigeration	1.32	0.98	0.97	0.96	0.95	0.95	0.95	0.94
Cooking	0.62	0.65	0.64	0.64	0.63	0.63	0.63	0.63
Clothes Dryers	0.68	0.71	0.71	0.68	0.66	0.65	0.65	0.65
Freezers	0.42	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Lighting	1.05	1.15	1.13	1.09	1.05	1.04	1.04	1.03
Clothes Washers	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08
Dishwashers	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Color Televisions	0.68	0.91	0.90	0.87	0.84	0.83	0.83	0.82
Personal Computers	0.05	0.10	0.10	0.09	0.09	0.09	0.09	0.09
Furnace Fans	0.29	0.33	0.33	0.32	0.30	0.30	0.30	0.30
Other Uses[7]	2.67	4.28	4.23	4.08	3.95	3.91	3.90	3.86
Total	**19.34**	**20.92**	**20.75**	**20.11**	**19.59**	**19.45**	**19.41**	**19.25**
Non-Marketed Renewables								
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections							Projections						
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
6.14	5.86	5.59	5.45	5.18	5.09	4.96	6.28	5.78	5.60	5.49	5.29	5.21	5.08
0.54	0.50	0.48	0.46	0.44	0.43	0.42	0.58	0.53	0.51	0.50	0.48	0.48	0.47
1.96	1.87	1.79	1.75	1.67	1.64	1.61	2.06	1.90	1.84	1.81	1.75	1.72	1.68
0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27	0.27
0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.40	0.40	0.40	0.40	0.40	0.40	0.40
0.28	0.27	0.26	0.26	0.25	0.24	0.24	0.32	0.30	0.29	0.29	0.29	0.28	0.28
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
0.40	0.38	0.36	0.35	0.34	0.33	0.31	0.45	0.42	0.41	0.41	0.40	0.39	0.39
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
0.30	0.29	0.28	0.27	0.27	0.26	0.26	0.33	0.31	0.31	0.31	0.30	0.30	0.30
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.06	0.06	0.05	0.05	0.05	0.05	0.05
0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.14	0.13	0.13	0.13	0.13	0.12	0.12
1.67	1.59	1.54	1.51	1.46	1.44	1.42	2.09	1.96	1.93	1.91	1.87	1.87	1.84
12.24	**11.72**	**11.25**	**11.00**	**10.54**	**10.36**	**10.15**	**13.14**	**12.22**	**11.90**	**11.71**	**11.38**	**11.25**	**11.04**
9.30	**8.49**	**7.71**	**7.27**	**6.89**	**6.85**	**6.72**	**9.81**	**8.19**	**7.60**	**7.28**	**7.04**	**7.11**	**7.25**
7.11	6.74	6.37	6.18	5.87	5.77	5.63	7.23	6.55	6.31	6.17	5.95	5.87	5.75
1.60	1.46	1.33	1.26	1.18	1.16	1.14	1.63	1.38	1.29	1.24	1.18	1.18	1.18
2.72	2.56	2.42	2.34	2.22	2.19	2.14	2.82	2.53	2.42	2.36	2.28	2.25	2.22
0.86	0.83	0.80	0.78	0.76	0.77	0.77	0.78	0.72	0.70	0.68	0.68	0.69	0.70
0.67	0.65	0.63	0.62	0.62	0.62	0.62	0.71	0.68	0.66	0.65	0.65	0.65	0.66
0.74	0.68	0.64	0.61	0.58	0.58	0.57	0.80	0.70	0.66	0.64	0.63	0.63	0.63
0.23	0.22	0.21	0.21	0.20	0.20	0.20	0.21	0.19	0.18	0.18	0.18	0.18	0.18
1.20	1.10	1.02	0.97	0.91	0.88	0.85	1.28	1.11	1.05	1.02	0.99	0.99	0.99
0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.08
0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.15	0.14	0.14	0.14	0.13	0.14	0.14
0.91	0.84	0.78	0.75	0.72	0.71	0.70	0.96	0.83	0.79	0.77	0.75	0.75	0.76
0.12	0.12	0.11	0.10	0.10	0.10	0.10	0.17	0.15	0.14	0.14	0.13	0.13	0.13
0.36	0.33	0.31	0.29	0.28	0.28	0.27	0.40	0.35	0.33	0.32	0.31	0.31	0.31
4.79	4.44	4.12	3.95	3.78	3.74	3.69	5.72	4.99	4.74	4.61	4.49	4.52	4.55
21.55	**20.20**	**18.95**	**18.27**	**17.43**	**17.21**	**16.86**	**22.95**	**20.41**	**19.50**	**18.99**	**18.42**	**18.37**	**18.29**
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.04	0.04	0.05	0.05
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**

[1]Does not include water heating of load.
[2]Includes small electric devices, heating elements and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996: Energy Information Administration (EIA) *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Key Indicators								
Total Floor Space (billion square feet)								
Surviving	69.2	77.3	77.3	77.3	77.3	77.3	77.3	77.3
New Additions	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total	**70.9**	**79.0**	**79.0**	**79.0**	**79.0**	**79.0**	**79.0**	**79.0**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	105.3	104.8	104.5	101.5	99.0	98.0	97.7	96.9
Electricity Related Losses	106.0	104.2	102.6	98.4	94.5	93.2	93.3	92.0
Total Energy Consumption	211.2	209.0	207.2	199.9	193.5	191.2	191.0	188.9
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.10
Space Cooling	0.51	0.54	0.54	0.52	0.51	0.50	0.50	0.50
Water Heating	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16
Ventilation	0.17	0.18	0.18	0.18	0.17	0.17	0.17	0.17
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.16	1.25	1.24	1.21	1.17	1.16	1.16	1.15
Refrigeration	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Office Equipment (PC)	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Office Equipment (non-PC)	0.20	0.25	0.25	0.24	0.24	0.23	0.23	0.23
Other Uses[1]	0.80	1.15	1.14	1.12	1.09	1.07	1.08	1.07
Delivered Energy	**3.37**	**3.91**	**3.90**	**3.80**	**3.70**	**3.65**	**3.65**	**3.63**
Natural Gas[2]								
Space Heating	1.34	1.38	1.37	1.33	1.29	1.28	1.28	1.26
Space Cooling	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating	0.46	0.50	0.49	0.48	0.47	0.46	0.46	0.45
Cooking	0.18	0.21	0.21	0.20	0.20	0.20	0.20	0.19
Other Uses[3]	1.29	1.52	1.52	1.47	1.44	1.42	1.41	1.40
Delivered Energy	**3.30**	**3.63**	**3.62**	**3.51**	**3.42**	**3.39**	**3.37**	**3.34**
Distillate								
Space Heating	0.20	0.17	0.17	0.16	0.16	0.16	0.16	0.15
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Other Uses[4]	0.19	0.17	0.17	0.16	0.16	0.16	0.16	0.16
Delivered Energy	**0.44**	**0.39**	**0.39**	**0.37**	**0.36**	**0.36**	**0.36**	**0.35**
Other Fuels[5]	**0.36**	**0.34**	**0.34**	**0.34**	**0.33**	**0.33**	**0.33**	**0.33**
Marketed Renewable Fuels								
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Delivered Energy Consumption by End-Use								
Space Heating	1.65	1.65	1.65	1.60	1.55	1.54	1.53	1.52
Space Cooling	0.53	0.57	0.57	0.55	0.54	0.53	0.53	0.53
Water Heating	0.68	0.72	0.72	0.69	0.68	0.67	0.67	0.66
Ventilation	0.17	0.18	0.18	0.18	0.17	0.17	0.17	0.17
Cooking	0.21	0.24	0.24	0.23	0.23	0.22	0.22	0.22
Lighting	1.16	1.25	1.24	1.21	1.17	1.16	1.16	1.15
Refrigeration	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Office Equipment (PC)	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Office Equipment (non-PC)	0.20	0.25	0.25	0.24	0.24	0.23	0.23	0.23
Other Uses[6]	2.64	3.18	3.18	3.09	3.02	2.99	2.98	2.96
Delivered Energy	**7.47**	**8.28**	**8.26**	**8.02**	**7.82**	**7.74**	**7.72**	**7.66**

Table B5. Commercial Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
81.1	81.1	81.0	80.9	80.8	80.7	80.7	85.7	85.5	85.5	85.5	85.4	85.4	85.3
1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1
82.8	**82.7**	**82.6**	**82.6**	**82.4**	**82.4**	**82.3**	**86.8**	**86.7**	**86.6**	**86.6**	**86.5**	**86.5**	**86.4**
105.0	99.8	94.6	91.6	85.2	82.6	79.2	105.8	97.0	93.8	91.7	88.0	86.1	83.1
101.3	91.8	82.6	77.2	71.7	70.7	68.6	96.7	79.6	73.4	70.0	67.0	67.2	68.0
206.2	191.6	177.2	168.9	156.9	153.3	147.8	202.4	176.7	167.1	161.7	154.9	153.4	151.1
0.11	0.10	0.10	0.09	0.09	0.09	0.08	0.10	0.09	0.09	0.09	0.08	0.08	0.08
0.54	0.51	0.49	0.48	0.45	0.44	0.43	0.54	0.50	0.49	0.48	0.47	0.46	0.45
0.17	0.16	0.16	0.15	0.14	0.14	0.13	0.16	0.15	0.15	0.14	0.14	0.14	0.13
0.19	0.18	0.17	0.16	0.15	0.15	0.15	0.19	0.17	0.17	0.16	0.16	0.16	0.15
0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02
1.28	1.20	1.12	1.08	1.01	0.97	0.94	1.31	1.16	1.12	1.09	1.04	1.02	0.98
0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.16	0.16	0.16	0.16	0.16	0.16
0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.11	0.10	0.10	0.10	0.09	0.09	0.09
0.28	0.27	0.26	0.25	0.24	0.24	0.23	0.34	0.32	0.32	0.31	0.31	0.30	0.30
1.33	1.27	1.22	1.19	1.13	1.11	1.08	1.59	1.50	1.47	1.45	1.42	1.41	1.39
4.17	**3.96**	**3.78**	**3.68**	**3.48**	**3.39**	**3.30**	**4.53**	**4.19**	**4.08**	**4.02**	**3.90**	**3.85**	**3.77**
1.42	1.34	1.25	1.20	1.08	1.04	0.97	1.43	1.29	1.22	1.18	1.11	1.07	1.02
0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.04	0.03	0.03	0.03	0.03	0.03	0.03
0.52	0.49	0.46	0.44	0.39	0.38	0.35	0.56	0.50	0.47	0.45	0.43	0.41	0.39
0.22	0.21	0.19	0.19	0.17	0.16	0.15	0.24	0.21	0.20	0.19	0.18	0.17	0.16
1.60	1.52	1.43	1.38	1.26	1.21	1.15	1.66	1.52	1.45	1.41	1.34	1.30	1.24
3.79	**3.59**	**3.36**	**3.22**	**2.92**	**2.81**	**2.65**	**3.93**	**3.55**	**3.37**	**3.27**	**3.09**	**2.99**	**2.84**
0.16	0.15	0.14	0.14	0.12	0.12	0.11	0.14	0.13	0.12	0.12	0.11	0.11	0.10
0.05	0.04	0.04	0.04	0.04	0.03	0.03	0.04	0.04	0.04	0.04	0.03	0.03	0.03
0.17	0.16	0.15	0.15	0.14	0.13	0.12	0.18	0.16	0.16	0.16	0.15	0.14	0.13
0.38	**0.36**	**0.34**	**0.33**	**0.30**	**0.28**	**0.26**	**0.36**	**0.33**	**0.32**	**0.31**	**0.30**	**0.28**	**0.26**
0.35	**0.34**	**0.33**	**0.33**	**0.32**	**0.32**	**0.31**	**0.36**	**0.34**	**0.34**	**0.34**	**0.33**	**0.32**	**0.31**
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
1.68	1.59	1.49	1.43	1.29	1.24	1.17	1.67	1.51	1.44	1.39	1.31	1.27	1.20
0.58	0.55	0.52	0.51	0.48	0.47	0.45	0.58	0.54	0.52	0.51	0.50	0.49	0.48
0.74	0.70	0.65	0.63	0.57	0.55	0.52	0.76	0.69	0.65	0.63	0.60	0.58	0.55
0.19	0.18	0.17	0.16	0.15	0.15	0.15	0.19	0.17	0.17	0.16	0.16	0.16	0.15
0.25	0.24	0.22	0.21	0.19	0.18	0.17	0.26	0.23	0.22	0.21	0.20	0.19	0.18
1.28	1.20	1.12	1.08	1.01	0.97	0.94	1.31	1.16	1.12	1.09	1.04	1.02	0.98
0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.16	0.16	0.16	0.16	0.16	0.16
0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.11	0.10	0.10	0.10	0.09	0.09	0.09
0.28	0.27	0.26	0.25	0.24	0.24	0.23	0.34	0.32	0.32	0.31	0.31	0.30	0.30
3.45	3.30	3.14	3.05	2.85	2.77	2.66	3.79	3.52	3.43	3.36	3.24	3.18	3.07
8.69	**8.26**	**7.82**	**7.56**	**7.02**	**6.80**	**6.52**	**9.18**	**8.41**	**8.12**	**7.94**	**7.61**	**7.45**	**7.18**

Table B5. Commercial Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Electricity Related Losses	**7.52**	**8.23**	**8.11**	**7.78**	**7.46**	**7.36**	**7.37**	**7.27**
Total Energy Consumption by End-Use								
Space Heating	1.91	1.88	1.87	1.81	1.76	1.74	1.74	1.72
Space Cooling	1.67	1.70	1.68	1.62	1.56	1.54	1.54	1.52
Water Heating	1.07	1.08	1.08	1.04	1.01	0.99	0.99	0.98
Ventilation	0.55	0.57	0.56	0.54	0.52	0.51	0.51	0.50
Cooking	0.28	0.30	0.30	0.29	0.28	0.28	0.28	0.28
Lighting	3.76	3.88	3.83	3.68	3.53	3.49	3.48	3.44
Refrigeration	0.45	0.47	0.47	0.46	0.46	0.46	0.46	0.46
Office Equipment (PC)	0.22	0.25	0.25	0.24	0.23	0.23	0.23	0.23
Office Equipment (non-PC)	0.63	0.78	0.77	0.74	0.71	0.70	0.70	0.70
Other Uses[6]	4.43	5.59	5.56	5.38	5.22	5.16	5.16	5.10
Total	**14.98**	**16.51**	**16.37**	**15.80**	**15.29**	**15.10**	**15.09**	**14.93**
Non-Marketed Renewable Fuels								
Solar[7]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

Table B5. Commercial Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
8.39	**7.60**	**6.82**	**6.38**	**5.91**	**5.82**	**5.64**	**8.39**	**6.90**	**6.35**	**6.06**	**5.79**	**5.81**	**5.88**
1.89	1.78	1.66	1.59	1.44	1.39	1.31	1.85	1.66	1.57	1.52	1.44	1.39	1.33
1.66	1.53	1.41	1.34	1.25	1.23	1.19	1.58	1.36	1.28	1.24	1.20	1.19	1.19
1.08	1.01	0.93	0.89	0.81	0.79	0.75	1.06	0.93	0.88	0.85	0.80	0.79	0.76
0.56	0.52	0.47	0.45	0.41	0.41	0.39	0.54	0.46	0.43	0.41	0.39	0.39	0.39
0.31	0.29	0.27	0.25	0.23	0.22	0.21	0.31	0.27	0.25	0.24	0.23	0.22	0.21
3.85	3.49	3.15	2.96	2.72	2.64	2.54	3.73	3.08	2.86	2.74	2.59	2.55	2.52
0.48	0.46	0.44	0.43	0.42	0.43	0.42	0.47	0.44	0.42	0.41	0.41	0.41	0.42
0.27	0.25	0.23	0.22	0.21	0.20	0.20	0.30	0.26	0.25	0.24	0.23	0.23	0.24
0.85	0.79	0.73	0.69	0.65	0.64	0.62	0.98	0.86	0.81	0.79	0.76	0.76	0.77
6.12	5.73	5.35	5.12	4.78	4.68	4.52	6.74	5.99	5.72	5.56	5.35	5.31	5.24
17.08	**15.86**	**14.64**	**13.94**	**12.93**	**12.63**	**12.16**	**17.57**	**15.31**	**14.48**	**14.00**	**13.40**	**13.26**	**13.06**
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.000 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 Energy Information Administration, *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/ pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B , and FD07BLW.D080398B.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Key Indicators								
Value of Gross Output (billion 1987 dollars)								
Manufacturing	3030	3798	3797	3776	3756	3747	3744	3736
Nonmanufacturing	774	896	895	888	883	879	879	877
Total	**3805**	**4694**	**4692**	**4664**	**4639**	**4626**	**4623**	**4613**
Energy Prices (1996 dollars per million Btu)								
Electricity	13.37	11.57	11.83	13.41	14.61	15.14	15.25	15.56
Natural Gas	2.96	2.80	2.88	3.51	3.93	4.12	4.22	4.36
Steam Coal	1.46	1.30	1.42	2.56	3.27	3.54	3.74	3.96
Residual Oil	2.99	2.75	2.84	3.77	4.34	4.55	4.72	4.90
Distillate Oil	5.50	5.43	5.53	6.35	6.87	7.05	7.22	7.38
Liquefied Petroleum Gas	7.80	6.70	6.83	7.45	7.80	7.97	8.10	8.24
Motor Gasoline	9.86	8.77	8.94	9.68	10.21	10.41	10.55	10.71
Metallurgical Coal	1.77	1.63	1.76	2.88	3.60	3.86	4.06	4.28
Energy Consumption								
Consumption[1]								
Purchased Electricity	3.46	4.05	4.03	3.98	3.92	3.88	3.88	3.85
Natural Gas[2]	9.96	10.97	10.97	11.01	11.11	11.13	11.15	11.14
Steam Coal	1.55	1.69	1.67	1.40	1.24	1.19	1.17	1.15
Metallurgical Coal and Coke[3]	0.85	0.92	0.92	0.90	0.89	0.89	0.89	0.88
Residual Fuel	0.34	0.35	0.35	0.35	0.34	0.34	0.33	0.34
Distillate	1.17	1.33	1.33	1.33	1.33	1.32	1.32	1.33
Liquefied Petroleum Gas	2.12	2.28	2.28	2.27	2.25	2.25	2.25	2.24
Petrochemical Feedstocks	1.28	1.39	1.39	1.38	1.36	1.36	1.36	1.35
Other Petroleum[4]	4.31	4.78	4.77	4.74	4.67	4.63	4.61	4.58
Renewables[5]	1.82	2.11	2.11	2.11	2.10	2.09	2.09	2.09
Delivered Energy	**26.87**	**29.87**	**29.82**	**29.46**	**29.21**	**29.09**	**29.04**	**28.95**
Electricity Related Losses	7.72	8.52	8.39	8.16	7.91	7.82	7.81	7.71
Total	**34.59**	**38.39**	**38.22**	**37.61**	**37.12**	**36.91**	**36.86**	**36.66**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)								
Purchased Electricity	0.91	0.86	0.86	0.85	0.84	0.84	0.84	0.83
Natural Gas[2]	2.62	2.34	2.34	2.36	2.39	2.41	2.41	2.41
Steam Coal	0.41	0.36	0.36	0.30	0.27	0.26	0.25	0.25
Metallurgical Coal and Coke[3]	0.22	0.20	0.20	0.19	0.19	0.19	0.19	0.19
Residual Fuel	0.09	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Distillate	0.31	0.28	0.28	0.28	0.29	0.29	0.29	0.29
Liquefied Petroleum Gas	0.56	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Petrochemical Feedstocks	0.34	0.30	0.30	0.29	0.29	0.29	0.29	0.29
Other Petroleum[4]	1.13	1.02	1.02	1.02	1.01	1.00	1.00	0.99
Renewables[5]	0.48	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Delivered Energy	**7.06**	**6.36**	**6.36**	**6.32**	**6.30**	**6.29**	**6.28**	**6.27**
Electricity Related Losses	2.03	1.82	1.79	1.75	1.71	1.69	1.69	1.67
Total	**9.09**	**8.18**	**8.15**	**8.06**	**8.00**	**7.98**	**7.97**	**7.95**

Table B6. Industrial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
4316	4262	4202	4188	4083	4063	4026	4954	4850	4828	4797	4772	4766	4751
967	952	940	937	916	912	906	1061	1044	1037	1035	1031	1035	1036
5283	**5214**	**5142**	**5126**	**5000**	**4975**	**4932**	**6015**	**5894**	**5865**	**5832**	**5803**	**5801**	**5786**
11.28	13.86	15.96	17.12	19.50	20.51	21.51	10.31	13.83	14.74	15.38	16.52	17.00	17.67
2.98	3.96	5.06	5.74	7.26	7.81	8.65	3.25	5.06	5.86	6.35	7.24	7.71	8.50
1.26	2.96	4.53	5.37	7.65	8.65	10.03	1.18	3.67	4.27	4.72	6.19	7.20	8.83
2.94	4.17	5.35	5.96	7.73	8.56	9.65	3.16	4.97	5.39	5.74	6.85	7.63	8.91
5.68	6.76	7.83	8.35	9.93	10.66	11.70	5.86	7.40	7.76	8.10	9.14	9.80	10.97
7.01	7.79	8.41	8.76	9.85	10.44	11.37	6.99	8.12	8.18	8.47	9.36	9.95	10.87
9.13	10.26	11.17	11.57	12.91	13.55	14.50	9.33	10.78	11.04	11.36	12.17	12.79	13.83
1.58	3.28	4.85	5.69	7.98	8.98	10.36	1.51	4.00	4.60	5.05	6.55	7.56	9.19
4.30	4.13	3.99	3.95	3.78	3.74	3.67	4.51	4.27	4.19	4.13	4.04	4.01	3.98
11.43	11.47	11.52	11.54	11.44	11.43	11.12	11.78	11.65	11.45	11.31	11.29	11.24	11.37
1.74	1.36	1.14	1.07	0.92	0.87	0.83	1.79	1.36	1.30	1.26	1.09	1.00	0.90
0.90	0.87	0.84	0.83	0.82	0.82	0.81	0.85	0.76	0.74	0.73	0.72	0.72	0.72
0.35	0.35	0.35	0.36	0.35	0.33	0.41	0.35	0.37	0.39	0.50	0.49	0.47	0.44
1.42	1.41	1.42	1.43	1.43	1.43	1.44	1.52	1.52	1.54	1.55	1.57	1.57	1.58
2.44	2.40	2.38	2.38	2.34	2.35	2.37	2.52	2.47	2.47	2.46	2.50	2.50	2.47
1.48	1.45	1.42	1.41	1.37	1.36	1.35	1.52	1.46	1.45	1.44	1.42	1.42	1.41
5.03	4.92	4.85	4.84	4.65	4.54	4.44	5.34	5.34	5.45	5.41	5.28	5.21	5.08
2.25	2.25	2.24	2.23	2.19	2.18	2.17	2.35	2.39	2.39	2.39	2.39	2.39	2.40
31.35	**30.60**	**30.14**	**30.04**	**29.29**	**29.05**	**28.61**	**32.53**	**31.59**	**31.37**	**31.19**	**30.81**	**30.53**	**30.34**
8.65	7.92	7.21	6.85	6.44	6.43	6.28	8.37	7.05	6.51	6.23	6.01	6.06	6.20
40.00	**38.52**	**37.34**	**36.89**	**35.73**	**35.48**	**34.88**	**40.89**	**38.64**	**37.88**	**37.42**	**36.82**	**36.60**	**36.55**
0.81	0.79	0.78	0.77	0.76	0.75	0.74	0.75	0.73	0.71	0.71	0.70	0.69	0.69
2.16	2.20	2.24	2.25	2.29	2.30	2.26	1.96	1.98	1.95	1.94	1.95	1.94	1.97
0.33	0.26	0.22	0.21	0.18	0.17	0.17	0.30	0.23	0.22	0.22	0.19	0.17	0.16
0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.14	0.13	0.13	0.13	0.12	0.12	0.12
0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.06	0.06	0.07	0.09	0.08	0.08	0.08
0.27	0.27	0.28	0.28	0.29	0.29	0.29	0.25	0.26	0.26	0.27	0.27	0.27	0.27
0.46	0.46	0.46	0.46	0.47	0.47	0.48	0.42	0.42	0.42	0.42	0.43	0.43	0.43
0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.24	0.24	0.24
0.95	0.94	0.94	0.94	0.93	0.91	0.90	0.89	0.91	0.93	0.93	0.91	0.90	0.88
0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.39	0.41	0.41	0.41	0.41	0.41	0.41
5.93	**5.87**	**5.86**	**5.86**	**5.86**	**5.84**	**5.80**	**5.41**	**5.36**	**5.35**	**5.35**	**5.31**	**5.26**	**5.24**
1.64	1.52	1.40	1.34	1.29	1.29	1.27	1.39	1.20	1.11	1.07	1.04	1.05	1.07
7.57	**7.39**	**7.26**	**7.20**	**7.15**	**7.13**	**7.07**	**6.80**	**6.56**	**6.46**	**6.42**	**6.34**	**6.31**	**6.32**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1996 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996 - 97). 1996 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). 1996 electricity prices: EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B. Other 1996 prices derived from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). Other 1996 values: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Key Indicators								
Level of Travel (billions)								
Light-Duty Vehicles <8,500 lbs. (VMT)	2276	2668	2665	2654	2639	2633	2626	2622
Commercial Light Trucks (VMT)[1]	67	80	80	79	79	79	79	78
Freight Trucks >10,000 lbs. (VMT)	162	212	212	211	210	209	209	208
Air (seat miles available)	999	1472	1471	1462	1453	1445	1438	1431
Rail (ton miles traveled)	1218	1529	1499	1444	1379	1356	1342	1311
Marine (ton miles traveled)	779	862	859	848	841	831	834	831
Energy Efficiency Indicators								
New Car (miles per gallon)[2]	28.2	29.8	29.9	30.4	30.7	30.8	30.9	31.0
New Light Truck (miles per gallon)[2]	20.9	20.0	20.1	20.4	20.6	20.7	20.7	20.8
Light-Duty Fleet (miles per gallon)[3]	20.2	20.3	20.3	20.3	20.3	20.3	20.3	20.3
New Commercial Light Truck (MPG)[1]	20.2	19.3	19.4	19.7	19.9	19.9	20.0	20.1
Stock Commercial Light Truck (MPG)[1]	14.5	14.8	14.8	14.9	14.9	14.9	14.9	14.9
Aircraft Efficiency (seat miles per gallon)	50.6	53.9	53.9	53.9	53.9	53.8	53.8	53.8
Freight Truck Efficiency (miles per gallon)	5.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Rail Efficiency (ton miles per thousand Btu)	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	13.95	16.51	16.49	16.40	16.29	16.24	16.20	16.16
Commercial Light Trucks[1]	0.58	0.67	0.67	0.67	0.66	0.66	0.66	0.66
Freight Trucks	4.04	4.93	4.93	4.91	4.89	4.88	4.88	4.88
Air	3.32	4.40	4.40	4.37	4.35	4.33	4.31	4.30
Rail	0.53	0.63	0.62	0.60	0.58	0.57	0.56	0.55
Marine	1.43	1.70	1.70	1.70	1.70	1.69	1.69	1.69
Pipeline Fuel	0.73	0.80	0.83	0.82	0.82	0.82	0.84	0.83
Other[4]	0.24	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Total	**24.73**	**29.81**	**29.81**	**29.64**	**29.45**	**29.35**	**29.30**	**29.22**

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
2895	2857	2790	2752	2643	2591	2505	3247	3191	3168	3147	3079	3035	2960
87	86	85	84	82	81	79	98	97	96	96	95	94	93
232	229	227	226	222	221	220	250	247	246	245	245	246	246
1753	1729	1667	1638	1537	1496	1434	2285	2232	2215	2197	2144	2119	2060
1644	1499	1349	1266	1145	1117	1084	1784	1457	1313	1242	1143	1127	1113
916	889	869	863	831	829	818	965	913	893	884	861	855	846
30.6	32.0	33.0	33.6	35.0	35.6	36.4	31.6	33.1	33.3	33.6	34.4	34.9	35.6
20.4	21.2	21.8	22.1	22.9	23.3	23.7	21.8	22.7	22.8	23.0	23.4	23.7	24.1
20.5	20.7	21.0	21.2	21.4	21.5	21.7	21.4	22.2	22.4	22.6	23.3	23.6	24.0
19.5	20.4	21.0	21.3	22.1	22.4	22.9	20.4	21.3	21.5	21.7	22.1	22.3	22.8
15.0	15.1	15.3	15.3	15.4	15.5	15.5	15.4	15.8	15.9	16.0	16.3	16.5	16.6
55.6	55.6	55.6	55.6	55.6	55.5	55.4	59.4	59.7	59.8	59.8	59.9	60.0	59.9
6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.3	6.3	6.4	6.5	6.5	6.6	6.6
2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0
2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0
17.75	17.29	16.62	16.27	15.40	15.01	14.39	19.04	18.09	17.76	17.49	16.63	16.19	15.54
0.73	0.71	0.70	0.69	0.66	0.65	0.64	0.80	0.77	0.75	0.75	0.72	0.71	0.70
5.21	5.15	5.09	5.07	4.97	4.95	4.92	5.41	5.31	5.19	5.17	5.11	5.10	5.09
5.03	4.96	4.80	4.73	4.48	4.37	4.23	6.00	5.84	5.79	5.74	5.61	5.55	5.41
0.66	0.61	0.56	0.53	0.49	0.48	0.46	0.69	0.58	0.53	0.51	0.47	0.47	0.46
1.91	1.90	1.89	1.89	1.87	1.87	1.86	2.25	2.24	2.23	2.23	2.23	2.23	2.23
0.87	0.90	0.91	0.96	0.95	0.96	0.95	0.98	1.05	1.09	1.10	1.10	1.08	1.05
0.30	0.30	0.29	0.29	0.28	0.28	0.27	0.32	0.32	0.32	0.32	0.32	0.32	0.33
32.35	**31.70**	**30.74**	**30.30**	**28.98**	**28.44**	**27.60**	**35.37**	**34.08**	**33.57**	**33.19**	**32.08**	**31.54**	**30.69**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996: Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1996-2007*, (Washington, DC, February 1995); Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://ww.eia.doe.gov/emeu/steo/pub/upd /aug97/index.html (August 21, 1997); EIA, *Fuel Oil and Kerosene Sales 1996*, DOE/EIA-0535(96) (Washington, DC, September 1997); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Generation by Fuel Type								
Electric Generators[1]								
Coal	1758	2019	1949	1820	1681	1597	1556	1504
Petroleum	80	42	41	37	36	34	32	35
Natural Gas	288	612	671	714	777	807	841	863
Nuclear Power	675	651	683	683	683	698	698	698
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	392	369	379	385	385	392	396	401
Total	**3191**	**3690**	**3720**	**3637**	**3559**	**3525**	**3519**	**3498**
Non-Utility Generation for Own Use	6	6	6	6	6	6	6	6
Cogenerators[3]								
Coal	51	51	51	51	50	50	50	50
Petroleum	6	6	6	6	6	6	6	6
Natural Gas	196	214	214	218	222	224	223	224
Other Gaseous Fuels[4]	7	7	7	7	7	7	7	7
Renewable Sources[2]	42	47	47	47	46	46	46	46
Other[5]	3	3	3	3	3	3	3	3
Total	**305**	**329**	**329**	**332**	**335**	**337**	**337**	**337**
Sales to Utilities	156	161	161	161	162	162	162	162
Generation for Own Use	149	168	168	171	174	175	175	175
Net Imports[6]	**38**	**67**	**21**	**21**	**21**	**21**	**21**	**21**
Electricity Sales by Sector								
Residential	1079	1271	1265	1235	1210	1201	1199	1193
Commercial	988	1147	1143	1112	1084	1071	1071	1064
Industrial	1014	1188	1183	1167	1149	1138	1136	1129
Transportation	17	24	24	24	24	24	24	24
Total	**3098**	**3630**	**3615**	**3538**	**3467**	**3435**	**3430**	**3410**
End-Use Prices (1996 cents per kilowatthour)[7]								
Residential	8.3	7.4	7.5	8.4	9.1	9.4	9.5	9.6
Commercial	7.5	6.6	6.7	7.6	8.3	8.6	8.7	8.8
Industrial	4.6	3.9	4.0	4.6	5.0	5.2	5.2	5.3
Transportation	5.2	4.6	4.6	4.7	4.8	4.8	4.8	4.8
All Sectors Average	**6.8**	**6.0**	**6.1**	**6.9**	**7.4**	**7.7**	**7.8**	**7.9**

Table B8. Electricity Supply, Disposition, and Prices (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
2075	1709	1273	977	612	510	385	2186	1297	797	508	146	79	27
36	30	25	25	26	35	40	29	19	27	64	99	75	40
868	1050	1309	1518	1664	1683	1708	1362	1858	2098	2243	2283	2249	2138
578	626	646	654	689	689	693	356	474	528	552	625	642	694
-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
373	389	404	409	435	446	466	383	437	548	571	692	766	857
3928	**3801**	**3654**	**3581**	**3422**	**3360**	**3288**	**4312**	**4081**	**3994**	**3935**	**3843**	**3809**	**3752**
6	5	5	5	5	5	5	6	5	5	5	5	5	5
51	50	50	50	49	49	49	51	50	49	49	49	49	49
6	6	6	6	6	6	6	6	6	7	7	8	7	7
222	227	230	233	238	239	240	217	222	225	228	231	232	234
7	7	7	7	7	7	7	7	7	7	7	7	7	7
50	50	49	49	48	48	48	51	53	53	53	53	53	53
3	3	3	3	3	3	3	3	3	3	3	3	3	3
339	**343**	**346**	**349**	**352**	**353**	**353**	**336**	**341**	**345**	**348**	**351**	**351**	**353**
163	163	163	164	164	165	165	162	163	163	164	165	165	165
177	180	183	185	188	188	189	174	178	181	184	187	187	188
64	**10**	**10**	**10**	**10**	**10**	**10**	**59**	**4**	**4**	**4**	**4**	**4**	**4**
1354	1296	1252	1228	1188	1168	1150	1552	1456	1431	1414	1388	1380	1363
1221	1161	1108	1078	1019	993	966	1328	1227	1197	1177	1142	1127	1104
1260	1210	1171	1157	1109	1097	1075	1323	1253	1227	1210	1185	1176	1165
30	30	29	29	28	28	27	37	36	36	36	35	34	34
3865	**3696**	**3561**	**3492**	**3344**	**3286**	**3219**	**4240**	**3972**	**3892**	**3837**	**3750**	**3718**	**3665**
7.3	8.7	9.9	10.7	12.1	12.7	13.3	6.9	9.0	9.6	10.0	10.7	10.9	11.4
6.4	7.9	9.1	9.8	11.2	11.8	12.4	6.0	8.1	8.6	8.9	9.6	9.8	10.3
3.8	4.7	5.4	5.8	6.7	7.0	7.3	3.5	4.7	5.0	5.2	5.6	5.8	6.0
4.5	4.7	4.8	5.0	5.3	5.4	5.4	4.2	4.4	4.4	4.5	4.6	4.5	4.5
5.9	**7.1**	**8.2**	**8.8**	**10.0**	**10.5**	**11.0**	**5.6**	**7.3**	**7.8**	**8.1**	**8.7**	**8.9**	**9.3**

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.

[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.

[4]Other gaseous fuels include refinery and still gas.

[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[6]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.

[7]Prices represent average revenue per kilowatthour.

Kwh = kilowatthour.

Note: Totals may not equal sum of components due to independent rounding.

Sources: 1996 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 16* (July 1996) which indicates the transportation value should be higher. 1996 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996 residential electricity prices derived from EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/ teo/pub/upd/aug97/index.html (August 21, 1997). **1996 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Electric Generators[2]								
Capability								
Coal Steam	303.7	305.3	302.1	302.1	302.1	302.0	301.9	301.9
Other Fossil Steam[3]	136.6	128.2	126.0	125.6	125.4	125.4	126.1	124.4
Combined Cycle	15.2	50.7	61.6	66.0	74.7	72.6	70.8	78.5
Combustion Turbine/Diesel	61.6	123.9	115.6	105.7	99.0	99.2	99.3	96.2
Nuclear Power	100.8	89.6	94.1	94.1	94.1	96.1	96.1	96.1
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	87.8	91.1	91.3	92.5	93.1	94.8	95.7	97.0
Total	**725.5**	**808.8**	**810.5**	**805.9**	**808.2**	**810.0**	**809.8**	**814.0**
Cumulative Planned Additions[5]								
Coal Steam	2.1	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.7	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Total	**11.1**	**16.3**	**16.3**	**16.3**	**16.3**	**16.3**	**16.3**	**16.3**
Cumulative Unplanned Additions[5]								
Coal Steam	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	34.2	45.1	49.5	58.2	56.1	54.3	62.0
Combustion Turbine/Diesel	5.7	68.4	59.6	49.7	43.3	43.3	43.7	40.4
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.8	1.4	1.6	2.9	3.4	5.1	6.0	7.3
Total	**6.6**	**107.1**	**106.2**	**102.1**	**104.9**	**104.5**	**104.1**	**109.7**
Cumulative Total Additions	**17.7**	**123.4**	**122.5**	**118.4**	**121.2**	**120.8**	**120.4**	**126.0**
Cumulative Retirements[6]	**15.2**	**40.1**	**37.5**	**38.0**	**38.5**	**36.4**	**36.1**	**37.5**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
307.8	299.9	288.5	275.8	268.1	266.4	258.9	313.6	270.5	232.2	197.5	136.3	100.1	77.8
123.1	104.2	87.0	92.7	105.4	109.8	108.0	109.3	73.7	53.6	49.7	53.1	70.2	71.1
90.1	117.1	157.6	186.7	191.4	185.9	191.3	182.9	244.3	288.1	318.0	336.7	334.0	321.4
152.1	121.8	106.0	100.1	102.5	103.5	97.9	186.6	137.4	116.7	109.3	113.9	118.1	116.9
76.0	83.2	86.6	88.8	94.1	94.1	95.4	47.9	62.9	71.1	73.8	84.1	86.4	93.4
19.5	19.2	19.2	19.5	19.5	19.5	19.9	19.2	19.2	19.2	19.5	19.5	19.5	19.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
91.8	93.7	98.0	100.1	106.1	108.2	114.9	93.6	107.7	132.7	140.3	161.7	172.7	191.0
860.5	**839.2**	**843.0**	**863.7**	**887.2**	**887.3**	**886.2**	**953.1**	**915.7**	**913.5**	**908.2**	**905.4**	**901.0**	**891.1**
2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
16.7	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**	**16.7**
5.8	0.0	0.0	0.0	0.0	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73.4	100.3	141.1	169.9	174.7	169.1	174.5	166.2	227.8	271.5	301.5	320.2	317.2	305.1
97.9	67.3	51.5	45.6	47.8	48.5	43.4	132.4	83.2	62.5	55.2	59.5	64.0	62.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.2	4.1	8.4	10.5	16.5	18.6	25.2	4.5	18.5	43.5	51.1	72.6	83.6	101.8
179.2	**171.8**	**201.0**	**226.0**	**239.0**	**236.2**	**243.1**	**317.1**	**329.5**	**377.6**	**407.8**	**452.2**	**464.8**	**469.6**
195.8	**188.4**	**217.7**	**242.7**	**255.7**	**252.9**	**259.8**	**333.8**	**346.1**	**394.2**	**424.5**	**468.9**	**481.5**	**486.3**
60.9	**73.7**	**99.2**	**104.5**	**94.0**	**91.1**	**99.1**	**106.3**	**155.0**	**205.3**	**241.8**	**288.1**	**305.6**	**320.2**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Cogenerators[7]								
Capability								
Coal	9.2	9.9	9.9	9.9	9.9	9.8	9.8	9.8
Petroleum	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Natural Gas	31.4	34.9	35.0	35.4	36.0	36.3	36.2	36.2
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewable Sources[4]	5.9	6.9	6.9	6.8	6.8	6.8	6.8	6.8
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**48.8**	**54.2**	**54.2**	**54.6**	**55.0**	**55.3**	**55.2**	**55.3**
Cumulative Additions[5]	**18.2**	**23.6**	**23.6**	**23.9**	**24.4**	**24.7**	**24.6**	**24.6**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
10.0	10.0	9.9	9.9	9.8	9.8	9.8	10.0	10.0	10.0	10.0	9.9	9.9	9.9
1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
36.0	36.6	37.1	37.5	38.2	38.3	38.4	35.4	36.1	36.6	37.0	37.6	37.7	37.8
1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
7.1	7.1	7.1	7.1	6.9	6.9	6.9	7.3	7.4	7.4	7.4	7.4	7.4	7.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55.6	**56.1**	**56.6**	**56.9**	**57.4**	**57.5**	**57.5**	**55.2**	**56.0**	**56.5**	**56.9**	**57.4**	**57.4**	**57.6**
24.9	**25.5**	**25.9**	**26.3**	**26.7**	**26.8**	**26.9**	**24.6**	**25.4**	**25.8**	**26.2**	**26.7**	**26.8**	**27.0**

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.

[3]Includes oil-, gas-, and dual-fired capability.

[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.

[5]Cumulative additions after December 31, 1995.

[6]Cumulative total retirements from 1990.

[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 25, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1996 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1996 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Interregional Electricity Trade								
Gross Domestic Firm Power Sales	173.4	139.2	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	54.7	66.3	77.5	58.3	49.8	46.7	50.5	51.8
Gross Domestic Trade	**228.1**	**205.5**	**216.7**	**197.5**	**189.0**	**185.9**	**189.7**	**191.0**
Gross Domestic Firm Power Sales (million 1996 dollars)	8050.2	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9
Gross Domestic Economy Sales (million 1996 dollars)	1283.9	1551.5	1801.0	1919.6	1914.1	1889.6	2125.6	2204.0
Gross Domestic Sales (million 1996 dollars)	**9334.1**	**8014.3**	**8263.9**	**8382.5**	**8377.0**	**8352.5**	**8588.4**	**8666.9**
International Electricity Trade								
Firm Power Imports From Canada and Mexico[1]	26.1	51.4	5.6	5.6	5.6	5.6	5.6	5.6
Economy Imports From Canada and Mexico[1]	20.7	35.8	35.8	35.9	35.9	35.9	35.8	35.8
Gross Imports From Canada and Mexico[1]	**46.8**	**87.2**	**41.5**	**41.5**	**41.5**	**41.5**	**41.4**	**41.5**
Firm Power Exports To Canada and Mexico	2.8	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Economy Exports To Canada and Mexico	6.4	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Gross Exports To Canada and Mexico	**9.3**	**20.3**	**20.3**	**20.3**	**20.3**	**20.3**	**20.3**	**20.3**

Table B10. Electricity Trade (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2
66.2	54.8	39.6	27.2	29.7	27.7	39.6	81.5	63.3	52.0	44.2	51.4	67.0	64.5
205.4	**194.0**	**178.8**	**166.4**	**168.9**	**167.0**	**178.8**	**220.7**	**202.5**	**191.3**	**183.4**	**190.6**	**206.2**	**203.7**
6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9
1567.0	1918.0	1884.0	1467.6	2017.4	2071.5	3356.4	1831.8	2478.3	2210.6	2013.1	2640.1	3602.1	3901.1
8029.9	**8380.9**	**8346.8**	**7930.5**	**8480.3**	**8534.4**	**9819.3**	**8294.7**	**8941.2**	**8673.4**	**8475.9**	**9103.0**	**10065.0**	**10364.0**
51.4	5.6	5.6	5.6	5.6	5.6	5.6	50.3	5.6	5.6	5.6	5.6	5.6	5.6
33.4	25.5	25.5	25.5	25.1	25.2	25.2	30.1	19.6	19.6	19.6	19.6	19.6	19.6
84.8	**31.1**	**31.1**	**31.1**	**30.7**	**30.8**	**30.8**	**80.4**	**25.2**	**25.2**	**25.2**	**25.2**	**25.2**	**25.2**
13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
21.0	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1996 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1996 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993.* Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Crude Oil								
Domestic Crude Production[1]	6.48	6.02	6.01	6.00	6.00	6.00	6.00	6.00
Alaska	1.40	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Lower 48 States	5.08	5.09	5.07	5.07	5.07	5.07	5.06	5.07
Net Imports	7.40	9.81	9.80	9.77	9.72	9.71	9.65	9.63
Gross Imports	7.51	9.91	9.90	9.87	9.82	9.81	9.76	9.73
Exports	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Other Crude Supply[2]	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**13.87**	**15.83**	**15.81**	**15.78**	**15.73**	**15.71**	**15.65**	**15.63**
Natural Gas Plant Liquids	**1.83**	**1.95**	**1.97**	**1.98**	**2.00**	**2.02**	**2.02**	**2.01**
Other Inputs[3]	**0.39**	**0.28**	**0.28**	**0.28**	**0.23**	**0.23**	**0.23**	**0.23**
Refinery Processing Gain[4]	**0.84**	**0.86**	**0.84**	**0.83**	**0.81**	**0.81**	**0.81**	**0.82**
Net Product Imports[5]	**1.10**	**2.08**	**2.07**	**1.95**	**1.87**	**1.78**	**1.78**	**1.75**
Gross Refined Prod. Imports	1.39	2.07	2.16	2.06	1.94	1.85	1.86	1.85
Unfinished Oil Imports	0.37	0.82	0.72	0.68	0.68	0.67	0.66	0.66
Ethers Imported	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Blending Components Imported	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.87	0.85	0.86	0.85	0.80	0.79	0.79	0.81
Total Primary Supply[6]	**18.03**	**21.00**	**20.96**	**20.81**	**20.63**	**20.55**	**20.49**	**20.45**
Refined Petroleum Products Supplied								
Motor Gasoline[7]	7.99	9.12	9.11	9.06	9.00	8.97	8.95	8.93
Jet Fuel[8]	1.58	2.11	2.10	2.09	2.08	2.07	2.06	2.06
Distillate Fuel[9]	3.32	3.87	3.84	3.80	3.77	3.75	3.75	3.73
Residual Fuel	0.90	0.83	0.84	0.82	0.81	0.80	0.79	0.81
Other[10]	4.66	5.13	5.12	5.08	5.03	5.00	4.99	4.97
Total	**18.45**	**21.05**	**21.01**	**20.86**	**20.69**	**20.60**	**20.54**	**20.49**
Refined Petroleum Products Supplied								
Residential and Commercial	1.13	1.05	1.05	1.03	1.01	1.01	1.00	1.00
Industrial[11]	4.87	5.33	5.33	5.29	5.24	5.21	5.20	5.18
Transportation	12.12	14.48	14.46	14.38	14.28	14.23	14.20	14.16
Electric Generators[12]	0.33	0.19	0.18	0.16	0.15	0.15	0.14	0.15
Total	**18.45**	**21.05**	**21.01**	**20.86**	**20.69**	**20.60**	**20.54**	**20.49**
Discrepancy[13]	**-0.42**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**
World Oil Price (1996 dollars per barrel)[14]	**20.48**	**20.26**	**20.12**	**20.04**	**19.96**	**19.95**	**19.91**	**19.89**
Import Share of Product Supplied	**0.46**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1996 dollars)	**62.27**	**89.00**	**88.36**	**86.88**	**85.69**	**85.01**	**84.39**	**83.98**
Domestic Refinery Distillation Capacity	**15.4**	**16.7**	**16.7**	**16.6**	**16.6**	**16.5**	**16.5**	**16.4**
Capacity Utilization Rate (percent)	**94.0**	**95.0**	**95.1**	**95.2**	**95.3**	**95.3**	**95.3**	**95.3**

Table B11. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
5.86	5.82	5.76	5.74	5.70	5.68	5.67	5.18	5.00	4.94	4.93	4.84	4.78	4.73
0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.47	0.47	0.47	0.47	0.47	0.47	0.47
5.11	5.07	5.02	4.99	4.96	4.94	4.93	4.70	4.53	4.47	4.46	4.37	4.32	4.27
10.17	10.13	10.10	10.03	9.73	9.56	9.24	11.34	11.22	11.31	11.32	11.30	11.26	11.12
10.17	10.17	10.15	10.10	9.73	9.62	9.35	11.39	11.27	11.35	11.36	11.32	11.31	11.12
0.00	0.04	0.05	0.08	0.00	0.06	0.11	0.05	0.05	0.05	0.04	0.01	0.05	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16.03	**15.95**	**15.86**	**15.77**	**15.44**	**15.24**	**14.91**	**16.52**	**16.23**	**16.25**	**16.25**	**16.14**	**16.04**	**15.85**
2.15	**2.18**	**2.26**	**2.35**	**2.39**	**2.37**	**2.33**	**2.43**	**2.56**	**2.62**	**2.67**	**2.65**	**2.59**	**2.51**
0.29	**0.25**	**0.28**	**0.28**	**0.28**	**0.40**	**0.43**	**0.29**	**0.28**	**0.31**	**0.31**	**0.44**	**0.49**	**0.49**
0.82	**0.79**	**0.79**	**0.78**	**0.74**	**0.73**	**0.72**	**0.77**	**0.70**	**0.69**	**0.66**	**0.65**	**0.69**	**0.69**
3.14	**2.74**	**2.12**	**1.86**	**1.38**	**1.17**	**1.09**	**3.96**	**3.37**	**3.07**	**2.99**	**2.47**	**2.12**	**1.74**
2.96	2.80	2.19	1.93	1.61	1.54	1.49	3.58	3.09	2.85	2.81	2.44	2.11	1.74
0.95	0.74	0.72	0.70	0.50	0.34	0.30	1.04	0.93	0.90	0.88	0.81	0.76	0.74
0.06	0.06	0.05	0.05	0.02	0.00	0.00	0.11	0.10	0.08	0.07	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.84	0.87	0.84	0.82	0.74	0.71	0.70	0.77	0.76	0.75	0.77	0.79	0.75	0.74
22.42	**21.92**	**21.31**	**21.04**	**20.22**	**19.91**	**19.48**	**23.98**	**23.14**	**22.94**	**22.88**	**22.34**	**21.93**	**21.28**
9.66	9.41	9.06	8.88	8.42	8.22	7.89	10.20	9.70	9.52	9.38	8.93	8.70	8.37
2.40	2.37	2.30	2.26	2.14	2.09	2.02	2.87	2.79	2.77	2.74	2.68	2.65	2.58
4.06	3.96	3.87	3.84	3.74	3.73	3.70	4.23	4.07	4.03	4.12	4.17	4.07	3.92
0.89	0.87	0.85	0.85	0.84	0.85	0.90	0.98	0.95	0.95	0.99	0.98	0.97	0.97
5.47	5.36	5.28	5.26	5.12	5.05	5.01	5.75	5.67	5.71	5.68	5.62	5.57	5.47
22.47	**21.97**	**21.36**	**21.09**	**20.25**	**19.95**	**19.51**	**24.02**	**23.18**	**22.98**	**22.92**	**22.38**	**21.96**	**21.31**
1.04	1.00	0.97	0.96	0.92	0.90	0.87	1.01	0.96	0.95	0.95	0.91	0.89	0.86
5.65	5.55	5.49	5.49	5.35	5.30	5.30	5.91	5.85	5.92	5.94	5.90	5.86	5.76
15.63	15.29	14.79	14.54	13.88	13.61	13.18	16.97	16.29	16.01	15.81	15.24	14.97	14.56
0.16	0.13	0.11	0.11	0.11	0.15	0.17	0.13	0.08	0.10	0.22	0.32	0.25	0.14
22.47	**21.97**	**21.36**	**21.09**	**20.25**	**19.95**	**19.51**	**24.02**	**23.18**	**22.98**	**22.92**	**22.38**	**21.96**	**21.31**
-0.05	**-0.05**	**-0.04**	**-0.05**	**-0.04**	**-0.04**	**-0.03**	**-0.04**	**-0.04**	**-0.04**	**-0.04**	**-0.03**	**-0.04**	**-0.04**
20.77	**19.99**	**19.15**	**18.72**	**18.11**	**17.82**	**17.54**	**21.69**	**20.14**	**19.81**	**19.73**	**19.08**	**18.74**	**18.38**
0.59	**0.59**	**0.57**	**0.56**	**0.55**	**0.54**	**0.53**	**0.64**	**0.63**	**0.63**	**0.62**	**0.62**	**0.61**	**0.60**
103.21	**96.11**	**86.36**	**81.85**	**73.36**	**69.65**	**65.92**	**123.11**	**108.06**	**104.10**	**103.12**	**95.98**	**91.83**	**85.88**
16.9	**16.8**	**16.7**	**16.6**	**16.6**	**16.5**	**16.4**	**17.5**	**17.1**	**17.1**	**17.2**	**17.1**	**17.0**	**16.7**
95.1	**95.2**	**95.2**	**95.0**	**93.4**	**92.8**	**90.9**	**95.1**	**95.2**	**95.2**	**95.1**	**94.9**	**94.9**	**95.2**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1996 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B12. Petroleum Product Prices
(1996 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
World Oil Price (1996 dollars per barrel)	**20.48**	**20.26**	**20.12**	**20.04**	**19.96**	**19.95**	**19.91**	**19.89**
Delivered Sector Product Prices								
Residential								
Distillate Fuel	98.4	105.3	106.5	117.6	124.8	127.6	129.7	132.0
Liquefied Petroleum Gas	100.0	104.5	105.5	111.1	114.1	115.5	116.7	117.9
Commercial								
Distillate Fuel	73.1	74.5	75.8	87.0	94.2	96.9	99.0	101.4
Residual Fuel	48.4	46.0	47.8	61.8	70.0	73.3	75.8	78.5
Residual Fuel (1996 dollars per barrel)	20.35	19.31	20.09	25.97	29.39	30.77	31.82	32.95
Industrial[1]								
Distillate Fuel	76.3	75.3	76.7	88.0	95.2	97.8	100.1	102.4
Liquefied Petroleum Gas	67.3	57.9	58.9	64.3	67.3	68.8	69.9	71.1
Residual Fuel	44.8	41.1	42.6	56.4	64.9	68.2	70.7	73.4
Residual Fuel (1996 dollars per barrel)	18.81	17.28	17.88	23.68	27.27	28.62	29.70	30.84
Transportation								
Diesel Fuel (distillate)[2]	123.5	117.4	119.5	130.5	137.2	139.7	141.9	144.1
Jet Fuel[3]	74.6	72.5	74.4	85.1	91.6	94.0	96.0	98.0
Motor Gasoline[4]	122.5	123.0	125.1	134.2	140.6	143.1	144.9	146.8
Liquefied Petroleum Gas	109.0	112.1	113.1	118.6	121.5	122.9	124.0	125.2
Residual Fuel	38.2	40.5	41.8	55.6	64.3	67.4	70.0	72.5
Residual Fuel (1996 dollars per barrel)	16.04	17.00	17.58	23.36	27.00	28.32	29.40	30.45
E85	141.7	146.2	146.5	148.4	149.2	149.6	149.8	150.1
M85	89.6	91.8	92.3	97.6	100.9	102.2	103.2	104.2
Electric Generators[5]								
Distillate Fuel	68.1	68.9	70.7	82.2	89.5	92.2	94.5	96.9
Residual Fuel	45.9	46.4	47.2	61.6	70.4	74.1	76.7	79.1
Residual Fuel (1996 dollars per barrel)	19.28	19.49	19.81	25.86	29.58	31.14	32.19	33.23
Refined Petroleum Product Prices[6]								
Distillate Fuel	108.7	107.0	109.0	120.1	126.9	129.4	131.7	133.9
Jet Fuel[3]	74.6	72.5	74.4	85.1	91.6	94.0	96.0	98.0
Liquefied Petroleum Gas	73.6	68.1	69.2	74.6	77.5	79.0	80.1	81.3
Motor Gasoline[4]	122.5	122.8	124.9	134.0	140.4	142.9	144.7	146.6
Residual Fuel	42.5	42.0	43.3	57.2	65.8	69.0	71.5	74.1
Residual Fuel (1996 dollars per barrel)	17.87	17.64	18.20	24.01	27.63	28.98	30.03	31.13
Average	**102.8**	**101.9**	**103.7**	**113.0**	**119.0**	**121.4**	**123.2**	**125.0**

Table B12. Petroleum Product Prices (Continued)
(1996 Cents per Gallon Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
20.77	**19.99**	**19.15**	**18.72**	**18.11**	**17.82**	**17.54**	**21.69**	**20.14**	**19.81**	**19.73**	**19.08**	**18.74**	**18.38**
107.9	122.9	137.7	145.2	167.9	177.9	192.0	108.5	130.9	136.9	141.6	155.9	165.1	181.2
107.9	114.7	120.1	123.1	132.4	137.5	144.9	107.8	117.5	118.5	120.7	128.0	133.1	141.5
77.3	92.3	107.1	114.5	136.9	147.0	161.2	78.5	100.5	106.0	110.7	125.1	134.3	150.5
47.6	66.3	84.2	93.8	121.2	133.2	150.0	50.5	78.3	85.1	90.7	107.9	120.0	139.6
20.01	27.86	35.35	39.38	50.90	55.96	63.01	21.23	32.90	35.75	38.08	45.31	50.38	58.65
78.7	93.7	108.6	115.8	137.7	147.9	162.2	81.3	102.7	107.6	112.3	126.7	135.9	152.1
60.5	67.2	72.6	75.6	85.0	90.1	98.1	60.3	70.0	70.6	73.1	80.8	85.9	93.8
44.0	62.5	80.1	89.2	115.7	128.1	144.5	47.3	74.4	80.7	85.9	102.5	114.2	133.4
18.47	26.23	33.64	37.47	48.61	53.79	60.70	19.86	31.26	33.89	36.10	43.04	47.95	56.04
117.8	132.9	147.9	155.1	175.6	185.4	199.5	114.0	135.2	140.1	144.6	159.5	168.9	185.1
75.8	90.3	103.3	110.1	129.8	138.3	151.1	77.8	98.9	104.0	108.2	122.0	130.5	144.9
125.4	139.3	150.4	155.5	172.0	179.8	191.6	124.0	142.0	145.5	149.3	159.7	167.4	180.2
113.7	120.4	125.6	128.6	137.5	142.6	149.8	110.1	119.8	121.0	123.2	130.2	135.2	143.4
43.5	62.3	80.0	89.2	115.5	127.8	144.7	46.1	73.6	80.2	85.3	102.5	114.3	134.1
18.25	26.17	33.59	37.45	48.51	53.67	60.76	19.35	30.93	33.68	35.83	43.05	47.99	56.32
149.6	150.2	146.5	146.5	162.1	168.4	175.4	148.3	144.8	145.5	147.9	155.9	160.3	170.7
92.5	99.1	104.8	107.7	117.2	121.5	126.0	92.9	101.5	103.5	105.6	111.2	115.4	122.6
72.3	88.0	103.6	111.4	132.5	140.7	154.5	74.4	96.9	100.0	104.3	118.6	127.8	144.0
49.2	69.2	88.0	97.6	125.1	136.3	153.3	53.2	84.8	93.3	100.6	120.7	132.3	150.5
20.67	29.08	36.95	41.00	52.52	57.25	64.40	22.36	35.62	39.20	42.25	50.68	55.57	63.22
108.4	123.5	138.5	145.6	166.6	176.3	190.3	106.3	127.7	132.3	135.7	149.5	159.4	176.5
75.8	90.3	103.3	110.1	129.8	138.3	151.1	77.8	98.9	104.0	108.2	122.0	130.5	144.9
71.5	78.1	83.4	86.3	95.6	100.5	108.1	71.8	81.5	82.2	84.6	91.7	96.6	104.5
125.2	139.1	150.2	155.3	171.8	179.6	191.4	123.9	141.8	145.3	149.2	159.6	167.3	180.1
44.6	63.5	81.1	90.4	116.9	129.3	146.1	47.2	74.7	81.2	86.4	103.4	115.2	135.0
18.73	26.65	34.07	37.95	49.10	54.29	61.37	19.81	31.39	34.11	36.27	43.43	48.39	56.69
104.1	**117.0**	**128.2**	**133.4**	**150.0**	**157.8**	**169.1**	**102.9**	**120.6**	**124.0**	**127.5**	**138.3**	**146.0**	**158.9**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections**: EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Production								
Dry Gas Production[1]	19.02	21.43	21.63	21.65	21.91	22.12	22.15	22.10
Supplemental Natural Gas[2]	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**2.72**	**4.49**	**4.63**	**4.62**	**4.68**	**4.69**	**5.03**	**5.07**
Canada	2.76	4.36	4.32	4.32	4.37	4.38	4.46	4.50
Mexico	-0.02	-0.14	0.04	0.04	0.04	0.04	0.30	0.30
Liquefied Natural Gas	-0.03	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Total Supply	**21.86**	**26.03**	**26.37**	**26.38**	**26.70**	**26.92**	**27.30**	**27.28**
Consumption by Sector								
Residential	5.23	5.37	5.36	5.20	5.10	5.07	5.05	5.01
Commercial	3.20	3.53	3.52	3.41	3.33	3.30	3.28	3.24
Industrial[3]	8.43	9.23	9.23	9.26	9.35	9.36	9.38	9.37
Electric Generators[4]	2.98	5.28	5.60	5.86	6.27	6.54	6.92	6.95
Lease and Plant Fuel[5]	1.25	1.42	1.43	1.44	1.45	1.46	1.46	1.46
Pipeline Fuel	0.71	0.78	0.81	0.80	0.80	0.80	0.81	0.81
Transportation[6]	0.01	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Total	**21.82**	**25.80**	**26.13**	**26.15**	**26.46**	**26.69**	**27.06**	**27.01**
Discrepancy[7]	**0.04**	**0.23**	**0.24**	**0.23**	**0.24**	**0.23**	**0.23**	**0.27**

Table B13. Natural Gas Supply and Disposition (Continued)
(Trillion Cubic Feet per Year)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
23.67	24.11	25.00	25.94	26.35	26.18	25.78	26.91	28.26	28.97	29.44	29.31	28.57	27.74
0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06
4.72	**4.87**	**5.03**	**5.23**	**5.37**	**5.66**	**5.68**	**5.07**	**5.53**	**5.70**	**5.83**	**5.79**	**6.10**	**6.10**
4.58	4.52	4.69	4.89	4.99	5.01	5.03	4.95	5.12	5.29	5.41	5.38	5.41	5.41
-0.15	0.06	0.06	0.06	0.06	0.32	0.32	-0.17	0.09	0.09	0.09	0.09	0.36	0.36
0.29	0.29	0.29	0.29	0.33	0.33	0.33	0.29	0.33	0.33	0.33	0.33	0.33	0.33
28.44	**29.03**	**30.09**	**31.23**	**31.78**	**31.90**	**31.51**	**32.03**	**33.85**	**34.73**	**35.33**	**35.16**	**34.73**	**33.90**
5.55	5.28	5.00	4.86	4.59	4.50	4.38	5.81	5.29	5.07	4.95	4.75	4.67	4.55
3.69	3.49	3.27	3.13	2.84	2.73	2.57	3.82	3.45	3.28	3.18	3.00	2.91	2.76
9.56	9.58	9.58	9.56	9.44	9.44	9.16	9.69	9.50	9.27	9.11	9.10	9.09	9.26
6.76	7.76	9.28	10.63	11.86	12.18	12.39	9.43	12.22	13.66	14.61	14.84	14.65	14.01
1.55	1.57	1.61	1.66	1.68	1.67	1.65	1.76	1.82	1.86	1.88	1.87	1.83	1.79
0.85	0.87	0.88	0.93	0.92	0.93	0.92	0.96	1.03	1.06	1.07	1.07	1.05	1.02
0.25	0.24	0.23	0.22	0.21	0.21	0.20	0.32	0.31	0.30	0.30	0.29	0.28	0.28
28.20	**28.79**	**29.86**	**31.00**	**31.55**	**31.66**	**31.28**	**31.79**	**33.62**	**34.50**	**35.11**	**34.93**	**34.49**	**33.67**
0.24	**0.24**	**0.23**	**0.23**	**0.23**	**0.23**	**0.23**	**0.24**	**0.23**	**0.23**	**0.22**	**0.23**	**0.23**	**0.23**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1996 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.

Sources: 1996 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). 1996 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, November 1997). 1996 transportation sector consumption: EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A,FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B. Other 1996 consumption: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B14. Natural Gas Prices, Margins, and Revenue
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Source Price								
Average Lower 48 Wellhead Price[1]	2.24	2.20	2.18	2.19	2.21	2.24	2.24	2.24
Average Import Price	1.98	2.10	2.13	2.18	2.12	2.11	2.23	2.23
Average[2]	**2.21**	**2.18**	**2.17**	**2.19**	**2.20**	**2.21**	**2.24**	**2.24**
Delivered Prices								
Residential	6.37	5.79	5.85	6.56	7.05	7.26	7.37	7.52
Commercial	5.43	4.87	4.93	5.62	6.11	6.31	6.42	6.58
Industrial[3]	3.05	2.88	2.96	3.62	4.04	4.23	4.35	4.49
Electric Generators[4]	2.70	2.68	2.75	3.40	3.82	4.08	4.16	4.33
Transportation[5]	5.57	5.99	6.06	6.71	7.18	7.38	7.48	7.62
Average[6]	**4.26**	**3.82**	**3.88**	**4.51**	**4.93**	**5.13**	**5.21**	**5.36**
Transmission and Distribution Margins[7]								
Residential	4.17	3.61	3.68	4.37	4.85	5.05	5.13	5.28
Commercial	3.23	2.69	2.76	3.43	3.91	4.10	4.18	4.34
Industrial[3]	0.84	0.70	0.79	1.43	1.85	2.02	2.11	2.25
Electric Generators[4]	0.49	0.50	0.58	1.21	1.62	1.86	1.92	2.09
Transportation[5]	3.37	3.81	3.88	4.52	4.98	5.17	5.24	5.38
Average[6]	**2.05**	**1.64**	**1.70**	**2.33**	**2.73**	**2.91**	**2.97**	**3.12**
Transmission and Distribution Revenue (billion 1996 dollars)								
Residential	21.81	19.42	19.74	22.75	24.76	25.56	25.90	26.47
Commercial	10.34	9.50	9.71	11.70	13.00	13.51	13.71	14.07
Industrial[3]	7.10	6.49	7.29	13.23	17.26	18.91	19.77	21.08
Electric Generators[4]	1.47	2.67	3.24	7.09	10.18	12.18	13.30	14.52
Transportation[5]	0.04	0.65	0.66	0.77	0.84	0.87	0.88	0.90
Total	**40.76**	**38.72**	**40.64**	**55.54**	**66.04**	**71.02**	**73.56**	**77.04**

Table B14. Natural Gas Prices, Margins, and Revenue (Continued)
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
2.33	2.38	2.62	2.78	3.01	3.01	3.03	2.62	3.02	3.50	3.71	3.74	3.67	3.53
2.39	2.40	2.66	2.82	3.00	3.05	3.07	2.76	3.11	3.60	3.82	3.84	3.74	3.57
2.34	**2.39**	**2.63**	**2.79**	**3.00**	**3.02**	**3.04**	**2.64**	**3.03**	**3.52**	**3.73**	**3.76**	**3.69**	**3.54**
5.72	6.83	8.09	8.83	10.50	11.10	11.98	5.97	7.99	8.89	9.42	10.39	10.88	11.70
4.75	5.84	7.08	7.82	9.51	10.12	11.03	4.70	6.68	7.57	8.10	9.07	9.57	10.42
3.06	4.08	5.21	5.91	7.47	8.04	8.90	3.35	5.21	6.03	6.53	7.45	7.94	8.75
2.88	3.89	5.10	5.83	7.44	7.97	8.82	3.28	5.08	5.94	6.44	7.37	7.85	8.66
6.72	7.82	8.99	9.66	11.25	11.82	12.67	7.37	9.21	9.95	10.44	11.31	11.77	12.56
3.87	**4.85**	**5.96**	**6.63**	**8.18**	**8.72**	**9.57**	**4.07**	**5.85**	**6.66**	**7.14**	**8.05**	**8.54**	**9.35**
3.38	4.44	5.46	6.04	7.50	8.08	8.95	3.33	4.95	5.37	5.69	6.64	7.19	8.17
2.40	3.45	4.45	5.03	6.50	7.09	7.99	2.06	3.65	4.05	4.37	5.32	5.89	6.88
0.72	1.69	2.58	3.12	4.46	5.02	5.86	0.71	2.18	2.51	2.81	3.70	4.25	5.21
0.54	1.51	2.47	3.04	4.43	4.95	5.78	0.64	2.05	2.42	2.72	3.61	4.17	5.13
4.38	5.43	6.36	6.87	8.25	8.80	9.64	4.73	6.17	6.43	6.72	7.56	8.08	9.02
1.52	**2.46**	**3.33**	**3.84**	**5.17**	**5.70**	**6.53**	**1.43**	**2.82**	**3.14**	**3.42**	**4.30**	**4.85**	**5.81**
18.76	23.47	27.32	29.37	34.42	36.38	39.19	19.32	26.22	27.21	28.20	31.53	33.61	37.14
8.86	12.05	14.55	15.77	18.46	19.38	20.55	7.87	12.57	13.27	13.89	15.94	17.13	18.98
6.89	16.22	24.73	29.83	42.14	47.34	53.72	6.84	20.68	23.26	25.59	33.65	38.64	48.29
3.62	11.68	22.96	32.35	52.56	60.35	71.58	5.99	25.01	33.02	39.69	53.63	61.01	71.82
1.08	1.30	1.45	1.54	1.75	1.83	1.93	1.54	1.90	1.95	2.00	2.17	2.30	2.51
39.21	**64.72**	**91.01**	**108.86**	**149.33**	**165.28**	**186.97**	**41.56**	**86.39**	**98.71**	**109.38**	**136.93**	**152.70**	**178.74**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding.

Sources: 1996 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991*. 1996 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). **Other 1995 values, other 1996 values, and projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B15. Oil and Gas Supply

Production and Supply	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Crude Oil								
Lower 48 Average Wellhead Price[1]								
(1996 dollars per barrel)	**19.41**	**19.78**	**19.69**	**19.54**	**19.44**	**19.39**	**19.32**	**19.31**
Production (million barrels per day)[2]								
U.S. Total	**6.48**	**6.02**	**6.01**	**6.00**	**6.00**	**6.00**	**6.00**	**6.00**
Lower 48 Onshore	3.76	3.39	3.39	3.38	3.38	3.38	3.38	3.38
Conventional	3.15	2.76	2.75	2.75	2.75	2.75	2.75	2.75
Enhanced Oil Recovery	0.61	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Lower 48 Offshore	1.32	1.69	1.69	1.69	1.69	1.68	1.68	1.69
Alaska	1.40	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Lower 48 End of Year Reserves (billion barrels)	**16.82**	**15.28**	**15.25**	**15.24**	**15.23**	**15.23**	**15.22**	**15.23**
Natural Gas								
Lower 48 Average Wellhead Price[1]								
(1996 dollars per thousand cubic feet)	**2.24**	**2.20**	**2.18**	**2.19**	**2.21**	**2.24**	**2.24**	**2.24**
Production (trillion cubic feet)[3]								
U.S. Total	**19.01**	**21.43**	**21.63**	**21.65**	**21.91**	**22.12**	**22.15**	**22.10**
Lower 48 Onshore	13.07	14.49	14.68	14.67	14.87	15.06	15.13	15.02
Associated-Dissolved[4]	1.84	1.53	1.52	1.52	1.52	1.52	1.52	1.52
Non-Associated	11.23	12.96	13.16	13.15	13.35	13.54	13.60	13.50
Conventional	7.96	9.09	9.17	9.24	9.34	9.45	9.43	9.43
Unconventional	3.27	3.88	3.99	3.91	4.02	4.09	4.18	4.07
Lower 48 Offshore	5.50	6.41	6.42	6.45	6.51	6.53	6.50	6.55
Associated-Dissolved[4]	0.80	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Non-Associated	4.70	5.49	5.50	5.53	5.59	5.61	5.58	5.63
Alaska	0.43	0.53	0.53	0.53	0.53	0.53	0.53	0.53
Lower 48 End of Year Reserves (trillion cubic feet)	**157.23**	**172.31**	**171.86**	**171.61**	**171.58**	**171.03**	**170.87**	**171.25**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.12**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**22.07**	**28.12**	**28.06**	**28.08**	**28.04**	**28.06**	**28.16**	**28.15**

Table B15. Oil and Gas Supply (Continued)

Projections							Projections						
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
20.24	19.42	18.57	18.09	17.35	17.00	16.68	20.70	19.10	18.79	18.67	18.05	17.73	17.35
5.86	5.82	5.76	5.74	5.70	5.68	5.67	5.18	5.00	4.94	4.93	4.84	4.78	4.73
3.50	3.47	3.42	3.40	3.38	3.36	3.35	3.39	3.24	3.17	3.16	3.06	3.02	2.98
2.76	2.74	2.71	2.70	2.69	2.67	2.67	2.75	2.65	2.62	2.61	2.56	2.53	2.50
0.74	0.73	0.71	0.70	0.70	0.69	0.68	0.65	0.59	0.55	0.55	0.51	0.49	0.48
1.62	1.60	1.59	1.59	1.58	1.57	1.57	1.31	1.29	1.30	1.31	1.30	1.30	1.29
0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.47	0.47	0.47	0.47	0.47	0.47	0.47
15.60	15.49	15.29	15.20	15.09	15.02	14.97	14.95	14.32	14.03	13.97	13.62	13.43	13.27
2.33	2.38	2.62	2.78	3.01	3.01	3.03	2.62	3.02	3.50	3.71	3.74	3.67	3.53
23.67	24.11	25.00	25.94	26.35	26.18	25.77	26.91	28.26	28.97	29.44	29.31	28.57	27.74
16.31	16.73	17.39	18.14	18.52	18.39	18.09	18.87	19.75	20.34	20.55	20.56	20.01	19.48
1.45	1.45	1.44	1.44	1.44	1.44	1.44	1.32	1.30	1.30	1.30	1.29	1.29	1.28
14.86	15.28	15.94	16.70	17.08	16.95	16.65	17.55	18.45	19.03	19.24	19.26	18.72	18.20
9.99	10.11	10.67	11.05	11.33	11.27	11.19	12.08	12.65	13.00	13.19	13.13	12.83	12.44
4.86	5.17	5.28	5.65	5.75	5.68	5.46	5.47	5.80	6.03	6.05	6.13	5.88	5.76
6.80	6.82	7.06	7.25	7.28	7.24	7.13	7.43	7.90	8.02	8.29	8.14	7.96	7.66
0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.84	0.84	0.84	0.84	0.84	0.84	0.84
5.88	5.91	6.15	6.34	6.37	6.34	6.23	6.58	7.06	7.18	7.45	7.30	7.12	6.82
0.56	0.56	0.56	0.56	0.55	0.55	0.55	0.62	0.61	0.61	0.61	0.61	0.60	0.60
180.45	179.42	179.51	178.60	178.95	178.77	180.42	172.73	175.74	184.71	189.12	191.43	192.82	193.82
0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06
30.34	30.23	30.98	31.46	32.12	32.06	31.91	33.63	34.68	36.90	37.85	37.67	37.08	35.92

Ft. = feet.
[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.

Sources: 1996 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1996 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1996 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). 1996 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies. EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). Other 1996 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Production[1]								
Appalachia	452	465	451	440	415	398	396	378
Interior	173	148	147	137	142	146	134	129
West	439	629	584	513	432	402	394	360
East of the Mississippi	564	551	537	524	516	498	494	480
West of the Mississippi	500	691	645	565	473	447	429	387
Total	**1064**	**1242**	**1182**	**1090**	**989**	**946**	**924**	**867**
Net Imports								
Imports	7	8	6	6	6	4	4	4
Exports	90	104	89	89	89	83	83	83
Total	**-83**	**-96**	**-83**	**-83**	**-83**	**-78**	**-78**	**-78**
Total Supply[2]	**981**	**1146**	**1099**	**1006**	**906**	**867**	**845**	**789**
Consumption by Sector								
Residential and Commercial	6	6	6	6	6	6	6	6
Industrial[3]	70	77	76	63	56	54	53	52
Coke Plants	32	28	28	28	28	28	28	28
Electric Generators[4]	896	1034	989	905	829	786	761	729
Total	**1003**	**1146**	**1099**	**1002**	**918**	**873**	**847**	**814**
Discrepancy and Stock Change[5].	**-23**	**0**	**-0**	**4**	**-12**	**-6**	**-2**	**-25**
Average Minemouth Price								
(1996 dollars per short ton)	18.50	15.03	15.39	15.78	16.10	16.13	16.17	16.36
(1996 dollars per million Btu)	0.87	0.72	0.74	0.75	0.76	0.76	0.76	0.76
Delivered Prices (1996 dollars per short ton)[6]								
Industrial	32.28	28.68	31.28	56.50	72.61	78.62	83.09	87.93
Coke Plants	47.33	43.77	47.09	77.15	96.41	103.35	108.84	114.62
Electric Generators								
(1996 dollars per short ton)	26.45	23.37	25.96	49.51	64.24	69.51	74.07	79.18
(1996 dollars per million Btu)	1.29	1.17	1.28	2.42	3.13	3.39	3.60	3.81
Average	**27.52**	**24.23**	**26.87**	**50.73**	**65.73**	**71.15**	**75.78**	**80.95**
Exports[7]	**40.77**	**36.27**	**37.03**	**36.96**	**36.96**	**37.30**	**37.21**	**37.15**

Table B16. Coal Supply, Disposition, and Prices (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
479	401	357	306	240	222	196	458	385	295	238	146	129	111
135	122	112	89	57	46	35	128	72	59	45	19	14	11
673	510	316	229	121	101	82	791	349	184	123	42	30	21
555	479	442	378	292	264	228	545	442	344	274	160	139	119
732	553	343	246	126	104	85	831	364	194	131	46	33	24
1287	**1032**	**785**	**624**	**418**	**369**	**313**	**1376**	**805**	**538**	**405**	**207**	**172**	**144**
8	4	4	4	1	1	1	8	4	4	4	1	1	1
113	89	89	89	76	76	76	130	93	93	93	75	75	75
-105	**-85**	**-85**	**-85**	**-75**	**-75**	**-75**	**-122**	**-89**	**-89**	**-89**	**-74**	**-74**	**-74**
1181	**948**	**700**	**539**	**344**	**294**	**238**	**1254**	**716**	**449**	**316**	**133**	**98**	**70**
7	6	5	5	5	5	4	7	6	5	5	5	5	4
79	61	51	48	41	39	37	82	61	59	57	50	45	41
26	24	23	23	22	22	22	22	16	15	15	14	14	14
1065	854	614	460	276	227	172	1144	630	373	235	66	34	11
1177	**946**	**694**	**537**	**344**	**293**	**235**	**1254**	**713**	**452**	**312**	**134**	**99**	**71**
4	**2**	**7**	**3**	**-0**	**1**	**3**	**0**	**3**	**-3**	**4**	**-1**	**-0**	**-1**
14.29	14.72	15.81	16.42	17.53	17.90	18.29	12.53	14.29	15.51	16.24	18.58	19.63	20.50
0.69	0.70	0.73	0.75	0.77	0.78	0.79	0.61	0.67	0.70	0.72	0.79	0.82	0.84
27.58	65.34	100.54	119.45	171.05	193.69	224.73	25.83	81.21	94.49	104.28	136.65	159.35	195.43
42.45	87.78	129.91	152.49	213.80	240.69	277.69	40.36	107.18	123.32	135.28	175.42	202.70	246.16
22.20	57.03	90.53	109.56	162.69	185.47	214.75	19.56	71.95	85.72	95.33	129.43	156.60	197.61
1.11	2.81	4.37	5.23	7.53	8.55	9.95	1.00	3.48	4.07	4.52	6.04	7.10	8.80
23.02	**58.36**	**92.59**	**112.28**	**167.07**	**190.84**	**222.39**	**20.33**	**73.57**	**88.15**	**98.93**	**137.30**	**164.92**	**206.64**
34.98	**35.97**	**35.66**	**35.51**	**36.21**	**36.13**	**36.01**	**32.52**	**33.40**	**33.07**	**32.82**	**34.20**	**34.04**	**33.84**

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7] F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B17. Renewable Energy Generating Capability and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1996	Projections 2005: Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Electric Generators[1]								
(excluding cogenerators)								
Net Summer Capability								
Conventional Hydropower	77.66	79.73	79.73	79.74	79.74	79.74	80.69	80.70
Geothermal[2]	3.02	2.76	2.92	2.99	3.11	3.32	3.39	3.74
Municipal Solid Waste[3]	3.26	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Wood and Other Biomass[4]	1.64	1.76	1.76	2.25	1.93	2.25	2.18	2.18
Solar Thermal	0.36	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Wind	1.85	2.75	2.75	3.44	4.22	5.35	5.32	6.27
Total	**87.81**	**91.10**	**91.26**	**92.53**	**93.12**	**94.78**	**95.69**	**97.00**
Generation (billion kilowatthours)								
Conventional Hydropower	346.28	312.51	312.50	312.55	312.53	312.54	317.00	317.03
Geothermal[2]	15.70	16.12	17.25	17.76	18.61	20.02	20.52	23.01
Municipal Solid Waste[3]	18.85	24.54	24.54	24.53	24.53	24.53	24.53	24.53
Wood and Other Biomass[4]	7.27	8.72	17.72	21.00	18.30	20.20	19.67	19.51
Solar Thermal	0.82	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Solar Photovoltaic	0.00	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Wind	3.17	6.17	6.17	8.03	10.14	13.40	13.26	15.80
Total	**392.09**	**369.22**	**379.33**	**385.03**	**385.27**	**391.84**	**396.14**	**401.04**
Cogenerators[5]								
Net Summer Capability								
Municipal Solid Waste	0.43	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Biomass	5.44	6.42	6.41	6.38	6.35	6.34	6.34	6.32
Total	**5.87**	**6.86**	**6.85**	**6.83**	**6.80**	**6.78**	**6.78**	**6.77**
Generation (billion kilowatthours)								
Municipal Solid Waste	2.21	2.27	2.27	2.27	2.27	2.27	2.27	2.27
Biomass	39.40	44.47	44.42	44.37	44.21	44.12	44.09	44.01
Total	**41.61**	**46.74**	**46.69**	**46.64**	**46.48**	**46.39**	**46.36**	**46.28**

Table B17. Renewable Energy Generating Capability and Generation (Continued)
Thousand Megawatts, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
79.78	79.78	79.80	79.80	80.74	80.74	81.84	79.78	79.79	79.80	79.80	80.74	80.78	81.92
2.80	2.98	3.13	3.51	3.76	4.68	4.75	3.02	3.77	4.26	4.95	5.76	6.94	7.81
4.02	4.01	3.99	3.99	3.96	3.95	3.95	4.42	4.42	4.42	4.41	4.42	4.43	4.44
1.76	1.80	2.91	2.70	4.54	4.93	5.32	1.76	2.74	11.81	11.95	26.13	35.27	43.99
0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.54	0.54	0.54	0.54	0.54	0.54	0.54
0.22	0.22	0.22	0.22	0.22	0.27	0.39	0.56	0.56	0.56	0.56	0.56	0.71	0.91
2.75	4.47	7.54	9.44	12.47	13.19	18.17	3.52	15.87	31.31	38.08	43.57	44.06	51.37
91.77	**93.71**	**98.01**	**100.10**	**106.14**	**108.20**	**114.85**	**93.60**	**107.68**	**132.69**	**140.29**	**161.72**	**172.72**	**190.97**
313.01	312.97	312.99	312.96	317.40	317.38	321.93	313.15	313.10	313.12	313.12	317.57	317.66	322.35
16.79	18.04	19.04	21.72	23.48	29.88	30.37	19.87	25.08	28.49	33.35	39.02	47.23	53.35
27.05	26.96	26.81	26.78	26.59	26.53	26.49	29.83	29.76	29.77	29.75	29.76	29.83	29.88
8.72	17.64	23.63	21.01	31.91	34.73	36.40	8.72	22.52	83.48	83.07	180.64	244.44	305.05
1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.47	1.47	1.47	1.47	1.47	1.47	1.47
0.60	0.60	0.60	0.60	0.60	0.73	1.01	1.45	1.45	1.45	1.45	1.45	1.81	2.30
6.17	11.20	19.38	24.73	33.54	35.72	48.87	8.70	43.58	89.81	108.33	122.06	123.41	142.77
373.50	**388.56**	**403.61**	**408.95**	**434.68**	**446.12**	**466.22**	**383.19**	**436.96**	**547.60**	**570.54**	**691.97**	**765.86**	**857.17**
0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
6.70	6.68	6.62	6.60	6.49	6.48	6.44	6.84	6.96	6.94	6.93	6.92	6.93	6.94
7.14	**7.13**	**7.07**	**7.05**	**6.93**	**6.92**	**6.89**	**7.29**	**7.41**	**7.39**	**7.38**	**7.37**	**7.38**	**7.39**
2.30	2.30	2.29	2.29	2.29	2.29	2.29	2.32	2.32	2.32	2.32	2.32	2.32	2.32
47.26	47.40	47.04	46.94	45.96	45.90	45.62	48.89	50.23	50.30	50.20	50.22	50.36	50.49
49.56	**49.69**	**49.34**	**49.23**	**48.25**	**48.19**	**47.91**	**51.21**	**52.55**	**52.62**	**52.51**	**52.53**	**52.68**	**52.80**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of August 25, 1997. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1996 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report," 1996 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1996 generation: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Marketed Renewable Energy[2]								
Residential	**0.61**	**0.61**	**0.61**	**0.61**	**0.61**	**0.61**	**0.61**	**0.61**
Wood	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Commercial[3]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	**1.82**	**2.11**	**2.11**	**2.11**	**2.10**	**2.09**	**2.09**	**2.09**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.78	2.08	2.07	2.07	2.06	2.06	2.06	2.05
Transportation	**0.10**	**0.18**	**0.18**	**0.18**	**0.13**	**0.13**	**0.13**	**0.13**
Ethanol used in E85[5]	0.00	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Ethanol used in Gasoline Blending	0.10	0.13	0.13	0.12	0.07	0.07	0.07	0.07
Electric Generators[6]	**4.40**	**4.22**	**4.33**	**4.40**	**4.42**	**4.52**	**4.58**	**4.68**
Conventional Hydroelectric	3.56	3.21	3.21	3.21	3.21	3.21	3.26	3.26
Geothermal	0.43	0.46	0.49	0.51	0.54	0.59	0.61	0.68
Municipal Solid Waste	0.30	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Biomass	0.06	0.08	0.16	0.19	0.16	0.18	0.18	0.17
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.03	0.06	0.06	0.08	0.10	0.14	0.14	0.16
Total Marketed Renewable Energy	**6.94**	**7.12**	**7.23**	**7.29**	**7.26**	**7.35**	**7.41**	**7.51**
Non-Marketed Renewable Energy[7]								
Selected Consumption								
Residential	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Commercial	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Table B18. Renewable Energy Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
0.61	**0.61**	**0.62**	**0.62**	**0.63**	**0.63**	**0.63**	**0.62**	**0.63**	**0.64**	**0.64**	**0.65**	**0.66**	**0.67**
0.61	0.61	0.62	0.62	0.63	0.63	0.63	0.62	0.63	0.64	0.64	0.65	0.66	0.67
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.25	**2.25**	**2.24**	**2.23**	**2.19**	**2.18**	**2.17**	**2.35**	**2.39**	**2.39**	**2.39**	**2.39**	**2.39**	**2.40**
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.21	2.21	2.20	2.20	2.15	2.15	2.13	2.31	2.35	2.36	2.35	2.35	2.36	2.36
0.23	**0.19**	**0.23**	**0.22**	**0.23**	**0.39**	**0.53**	**0.31**	**0.29**	**0.38**	**0.40**	**0.57**	**0.69**	**0.69**
0.09	0.09	0.10	0.10	0.09	0.09	0.09	0.13	0.14	0.14	0.14	0.13	0.13	0.13
0.13	0.09	0.13	0.12	0.13	0.30	0.45	0.18	0.15	0.24	0.26	0.44	0.56	0.56
4.30	**4.47**	**4.63**	**4.75**	**5.05**	**5.31**	**5.53**	**4.47**	**5.11**	**6.23**	**6.58**	**7.85**	**8.71**	**9.72**
3.22	3.22	3.22	3.22	3.26	3.26	3.31	3.22	3.22	3.22	3.22	3.26	3.27	3.31
0.49	0.53	0.56	0.64	0.72	0.93	0.95	0.59	0.75	0.85	1.01	1.23	1.50	1.71
0.43	0.43	0.43	0.43	0.43	0.42	0.42	0.48	0.48	0.48	0.48	0.48	0.48	0.48
0.08	0.16	0.21	0.19	0.28	0.31	0.32	0.08	0.20	0.74	0.74	1.61	2.18	2.72
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
0.06	0.12	0.20	0.25	0.34	0.37	0.50	0.09	0.45	0.92	1.11	1.25	1.27	1.47
7.39	**7.52**	**7.71**	**7.83**	**8.10**	**8.52**	**8.87**	**7.75**	**8.42**	**9.65**	**10.01**	**11.47**	**12.45**	**13.47**
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.04	0.04	0.05	0.05
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table B8.

[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.

[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.

[5]Excludes motor gasoline component of E85.

[6]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.

[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Notes: Totals may not equal sum of components due to independent rounding.

Sources: 1996 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Utility Report" and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1996 ethanol: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96/1) (Washington, DC, June 1997). Other 1996: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1996	Projections 2005 Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
Residential								
Petroleum	27.3	24.0	24.0	23.4	23.1	23.0	22.9	22.8
Natural Gas	77.4	79.6	79.4	77.1	75.6	75.1	74.8	74.3
Coal	1.4	1.4	1.4	1.2	1.2	1.1	1.1	1.1
Electricity	179.9	217.6	212.3	199.3	187.5	181.0	178.6	174.4
Total	**286.0**	**322.6**	**317.1**	**301.0**	**287.3**	**280.2**	**277.4**	**272.5**
Commercial								
Petroleum	15.3	12.6	12.6	12.2	12.0	11.9	11.9	11.8
Natural Gas	47.4	52.3	52.2	50.5	49.3	48.8	48.6	48.1
Coal	2.1	2.3	2.3	2.3	2.2	2.2	2.2	2.2
Electricity	164.8	196.4	191.7	179.5	168.0	161.4	159.6	155.5
Total	**229.6**	**263.6**	**258.8**	**244.5**	**231.5**	**224.4**	**222.2**	**217.5**
Industrial[1]								
Petroleum	104.8	110.5	110.1	109.7	108.2	107.5	107.0	106.6
Natural Gas[2]	142.8	155.9	156.0	156.5	158.0	158.3	158.6	158.4
Coal	59.3	66.0	65.5	58.2	54.0	52.8	52.2	51.6
Electricity	169.2	203.4	198.4	188.3	178.0	171.5	169.2	164.9
Total	**476.1**	**535.7**	**530.0**	**512.8**	**498.2**	**490.0**	**487.0**	**481.6**
Transportation								
Petroleum[3]	457.9	549.4	548.7	545.6	543.0	541.2	539.9	538.5
Natural Gas[4]	10.5	14.0	14.5	14.4	14.3	14.4	14.5	14.5
Other[5]	0.0	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Electricity	2.8	4.2	4.1	3.9	3.7	3.6	3.6	3.5
Total[3]	**471.2**	**569.0**	**568.7**	**565.4**	**562.5**	**560.6**	**559.5**	**557.9**
Total Carbon Emissions[6]								
Petroleum[3]	605.3	696.4	695.4	691.0	686.3	683.6	681.6	679.7
Natural Gas	278.1	301.9	302.1	298.6	297.2	296.5	296.5	295.2
Coal	62.8	69.7	69.2	61.7	57.4	56.1	55.5	54.8
Other[5]	0.0	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Electricity	516.7	621.5	606.4	571.0	537.1	517.5	511.0	498.3
Total[3]	**1462.9**	**1690.9**	**1674.6**	**1623.7**	**1579.5**	**1555.2**	**1546.1**	**1529.6**
Electric Generators[7]								
Petroleum	15.5	8.8	8.4	7.7	7.3	7.0	6.5	7.2
Natural Gas	40.3	77.8	82.5	86.3	92.3	96.3	101.8	102.3
Coal	460.9	534.9	515.5	476.9	437.5	414.3	402.7	388.9
Total	**516.7**	**621.5**	**606.4**	**571.0**	**537.1**	**517.5**	**511.0**	**498.3**
Total Carbon Emissions[8]								
Petroleum[3]	620.8	705.2	703.8	698.7	693.6	690.5	688.1	686.9
Natural Gas	318.4	379.7	384.6	384.9	389.4	392.8	398.3	397.5
Coal	523.7	604.6	584.7	538.7	494.9	470.4	458.2	443.7
Other[5]	0.0	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Total[3]	**1462.9**	**1690.9**	**1674.6**	**1623.7**	**1579.5**	**1555.2**	**1546.1**	**1529.6**
Carbon Emissions (tons per person)	**5.5**	**5.9**	**5.8**	**5.7**	**5.5**	**5.4**	**5.4**	**5.3**

Table B19. Carbon Emissions by Sector and Source (Continued)
(Million Metric Tons per Year)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
23.3	22.5	21.7	21.4	20.5	20.0	19.5	22.2	21.0	20.8	20.6	19.8	19.3	18.6
82.3	78.3	74.2	72.0	68.0	66.8	64.9	86.1	78.4	75.1	73.4	70.4	69.2	67.4
1.4	1.2	1.0	1.0	0.9	0.9	0.9	1.4	1.1	1.0	1.0	0.9	0.9	0.9
230.3	198.8	164.7	143.9	117.9	111.1	101.9	265.7	190.3	149.9	129.5	99.2	91.1	81.3
337.3	**300.7**	**261.7**	**238.3**	**207.3**	**198.7**	**187.1**	**375.4**	**290.8**	**246.8**	**224.4**	**190.3**	**180.5**	**168.1**
12.5	12.0	11.5	11.3	10.7	10.4	10.0	12.1	11.4	11.2	11.1	10.7	10.4	10.0
54.6	51.7	48.4	46.4	42.1	40.5	38.1	56.6	51.1	48.6	47.1	44.4	43.1	40.9
2.5	2.3	2.1	2.1	1.9	1.8	1.7	2.6	2.3	2.2	2.1	2.0	1.8	1.7
207.6	178.0	145.8	126.3	101.1	94.4	85.6	227.3	160.4	125.3	107.8	81.7	74.4	65.8
277.2	**244.1**	**207.9**	**186.1**	**155.7**	**147.1**	**135.3**	**298.6**	**225.2**	**187.4**	**168.1**	**138.7**	**129.8**	**118.3**
115.7	113.7	113.1	113.5	110.5	108.6	109.2	120.7	121.9	124.8	127.0	125.5	123.6	120.2
162.4	163.1	163.7	164.1	162.7	162.5	158.2	167.4	165.6	162.6	160.7	160.5	159.7	161.6
67.1	56.4	50.1	48.4	43.9	42.7	41.4	66.9	53.6	51.8	50.4	46.1	43.7	41.1
214.3	185.6	154.0	135.6	110.1	104.2	95.2	226.6	163.8	128.5	110.8	84.7	77.7	69.5
559.4	**518.7**	**480.9**	**461.5**	**427.3**	**418.0**	**403.9**	**581.6**	**504.9**	**467.7**	**449.0**	**416.8**	**404.7**	**392.4**
592.9	580.9	561.7	552.6	527.6	514.4	495.7	644.1	618.8	606.6	598.9	574.6	562.5	547.2
16.2	16.4	16.5	17.1	16.8	16.8	16.6	19.0	19.7	20.2	20.3	20.1	19.8	19.3
2.5	2.6	2.5	2.5	2.4	2.3	2.3	3.8	3.8	3.8	3.7	3.6	3.5	3.4
5.1	4.6	3.8	3.4	2.8	2.6	2.4	6.4	4.8	3.8	3.3	2.5	2.3	2.0
616.7	**604.5**	**584.5**	**575.6**	**549.6**	**536.2**	**517.1**	**673.2**	**647.1**	**634.3**	**626.3**	**600.8**	**588.2**	**571.9**
744.3	729.1	708.1	698.7	669.3	653.3	634.3	799.1	773.1	763.5	757.6	730.6	715.9	696.0
315.5	309.5	302.8	299.7	289.7	286.6	277.8	329.0	314.8	306.5	301.6	295.4	291.8	289.1
70.9	59.8	53.3	51.4	46.7	45.4	43.9	70.8	57.0	55.0	53.6	49.0	46.5	43.6
2.5	2.6	2.5	2.5	2.4	2.3	2.3	3.8	3.8	3.8	3.7	3.6	3.5	3.4
657.4	567.0	468.3	409.1	331.9	312.4	285.0	726.0	519.4	407.5	351.3	268.0	245.5	218.6
1790.6	**1667.9**	**1535.0**	**1461.5**	**1340.0**	**1300.0**	**1243.4**	**1928.7**	**1668.0**	**1536.2**	**1467.8**	**1346.7**	**1303.3**	**1250.8**
7.5	6.2	5.1	5.0	5.1	6.9	7.9	5.9	3.8	4.6	9.3	13.8	10.7	6.1
99.5	114.2	136.5	156.4	174.5	179.3	182.3	138.8	179.8	201.0	215.0	218.4	215.6	206.1
550.4	446.6	326.7	247.7	152.3	126.1	94.8	581.3	335.8	201.9	127.0	35.9	19.2	6.4
657.4	**567.0**	**468.3**	**409.1**	**331.9**	**312.4**	**285.0**	**726.0**	**519.4**	**407.5**	**351.3**	**268.0**	**245.5**	**218.6**
751.8	735.3	713.2	703.8	674.4	660.3	642.2	805.0	776.9	768.1	767.0	744.4	726.6	702.1
415.0	423.7	439.3	456.1	464.2	465.9	460.2	467.8	494.6	507.5	516.5	513.8	507.4	495.3
621.3	506.4	379.9	299.1	199.1	171.5	138.7	652.1	392.8	256.9	180.5	84.9	65.7	50.0
2.5	2.6	2.5	2.5	2.4	2.3	2.3	3.8	3.8	3.8	3.7	3.6	3.5	3.4
1790.6	**1667.9**	**1535.0**	**1461.5**	**1340.0**	**1300.0**	**1243.4**	**1928.7**	**1668.0**	**1536.2**	**1467.8**	**1346.7**	**1303.3**	**1250.8**
6.0	**5.6**	**5.1**	**4.9**	**4.5**	**4.3**	**4.2**	**6.0**	**5.2**	**4.7**	**4.5**	**4.2**	**4.0**	**3.9**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuels which, by convention, are excluded from the international accounting of carbon emissions. In the years from 1989 through 1996, international bunker fuels account for 22 to 24 million metric tons of carbon annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Measured for delivered energy consumption.
[7]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[8]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). 1996 consumption estimates based on: EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table B20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1996	Projections						
		2005						
		Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
GDP Chain-Type Price Index (1992=1.000)	**1.102**	**1.380**	**1.382**	**1.393**	**1.401**	**1.404**	**1.406**	**1.408**
Real Gross Domestic Product	**6928**	**8525**	**8520**	**8495**	**8474**	**8464**	**8462**	**8454**
Real Consumption	4714	5738	5735	5730	5724	5721	5722	5719
Real Investment	1069	1513	1509	1488	1473	1464	1462	1457
Real Government Spending	1258	1386	1386	1385	1384	1383	1383	1383
Real Exports	857	1753	1753	1749	1746	1745	1744	1744
Real Imports	971	1859	1857	1854	1853	1851	1852	1852
Real Disposable Personal Income	**5077**	**6206**	**6205**	**6218**	**6224**	**6225**	**6230**	**6228**
AA Utility Bond Rate (percent)	7.57	7.14	7.17	7.39	7.55	7.62	7.66	7.70
Real Yield on Government 10 Year Bonds (percent)	4.99	3.78	3.79	3.89	3.97	4.00	4.02	4.04
Energy Intensity (thousand Btu per 1992 dollar of GDP)								
Delivered Energy	10.14	9.36	9.36	9.26	9.18	9.15	9.13	9.11
Total Energy	13.54	12.42	12.37	12.17	12.00	11.94	11.92	11.86
Consumer Price Index (1982-84=1.00)	1.57	2.04	2.04	2.06	2.07	2.08	2.08	2.09
Unemployment Rate (percent)	5.38	5.70	5.72	5.80	5.87	5.91	5.91	5.94
Unit Sales of Light-Duty Vehicles (million)	**15.10**	**15.69**	**15.60**	**15.19**	**14.91**	**14.79**	**14.73**	**14.64**
Millions of People								
Population with Armed Forces Overseas	266.1	287.1	287.1	287.1	287.1	287.1	287.1	287.1
Population (aged 16 and over)	204.2	223.8	223.8	223.8	223.8	223.8	223.8	223.8
Labor Force	133.9	149.7	149.7	149.7	149.6	149.6	149.6	149.6

Table B20. Macroeconomic Indicators (Continued)
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Projections													
2010							2020						
Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below	Reference Case	24 Percent Above	14 Percent Above	9 Percent Above	1990 Level	3 Percent Below	7 Percent Below
1.606	**1.628**	**1.645**	**1.655**	**1.679**	**1.688**	**1.701**	**2.281**	**2.303**	**2.308**	**2.317**	**2.327**	**2.333**	**2.337**
9429	**9333**	**9268**	**9241**	**9137**	**9102**	**9032**	**10865**	**10815**	**10808**	**10796**	**10799**	**10793**	**10782**
6347	6292	6258	6248	6207	6198	6160	7599	7573	7582	7583	7615	7631	7636
1745	1714	1716	1719	1692	1682	1662	2100	2101	2099	2098	2101	2100	2095
1499	1486	1473	1468	1454	1450	1442	1636	1622	1623	1622	1623	1622	1621
2337	2318	2296	2283	2248	2232	2215	3333	3316	3296	3282	3252	3233	3218
2519	2509	2520	2532	2541	2550	2548	4123	4153	4179	4195	4247	4274	4290
6891	**6835**	**6794**	**6783**	**6752**	**6751**	**6719**	**8192**	**8144**	**8151**	**8153**	**8188**	**8209**	**8214**
7.31	7.42	7.38	7.36	7.43	7.47	7.66	8.50	8.37	8.33	8.34	8.30	8.31	8.27
3.58	3.55	3.64	3.71	3.74	3.81	3.95	4.10	4.15	4.17	4.20	4.29	4.33	4.33
8.98	8.82	8.63	8.54	8.30	8.21	8.08	8.31	7.99	7.87	7.79	7.59	7.49	7.36
11.80	11.42	11.00	10.78	10.43	10.33	10.16	10.78	10.05	9.78	9.62	9.35	9.27	9.17
2.43	2.46	2.49	2.51	2.56	2.57	2.60	3.56	3.61	3.62	3.63	3.65	3.66	3.68
5.58	6.06	6.38	6.51	7.01	7.16	7.49	5.78	5.90	5.91	5.94	5.86	5.84	5.85
16.57	**16.06**	**15.96**	**15.96**	**15.61**	**15.48**	**15.16**	**17.04**	**16.69**	**16.70**	**16.66**	**16.69**	**16.68**	**16.51**
298.9	298.9	298.9	298.9	298.9	298.9	298.9	323.5	323.5	323.5	323.5	323.5	323.5	323.5
235.4	235.4	235.4	235.4	235.4	235.4	235.4	255.6	255.6	255.6	255.6	255.6	255.6	255.6
156.5	156.0	155.6	155.4	154.9	154.7	154.4	162.2	162.0	161.9	161.9	161.9	161.8	161.8

GDP = Gross domestic product.
Btu = British thermal unit.
Source: Simulations of the Data Resources, Inc. (DRI) Model of the U.S. Economy.

Appendix C

Summary Comparison of Analyses

Table C1. Summary of the WEFA Analysis

Parameter	1996	Reference Case in 2010	1990-7% Case in 2010	Reference Case in 2020	1990-7% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	265	NA	360
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,314	9,013	11,478	11,245
Total Carbon Emissions (Million Metric Tons)	1,463	1,700	1,247	1,953	1,231
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	5.7	4.2	6.0	3.8
Real Disposable Personal Income (Billion 1992 Dollars)	5,077	6,942	6,840	8,671	8,596
Real Investment (Billion 1992 Dollars)[a]	1,067	1,527	1,468	1,923	1,894
Real Consumption (Billion 1992 Dollars)	4,714	6,303	6,152	7,705	7,651
Light-Duty Vehicle Sales (Millions)	15.1	16.7	16.2	18.3	18.3
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	11.08	9.30	9.98	7.50
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.16	8.24	7.20	7.45	6.05
World Oil Price (Refiners Acquisition Price, 1996 Dollars per Barrel)	20.48	19.77	17.58	21.38	17.57
Natural Gas Wellhead Price (1996 Dollars per Thousand Cubic Feet)	2.24	2.09	2.19	2.24	2.46
Minemouth Coal Price (1996 Dollars per Short Ton)	18.50	16.43	12.82	15.05	11.44
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.217	0.183	0.138	0.170	0.109
Delivered Energy Prices (1996 Dollars)					
Coal (Dollars per Million Btu to Utilities)	1.29	1.19	7.71	1.11	10.06
Natural Gas (Dollars per Thousand Cubic Feet)	4.25	3.92	7.61	3.79	8.95
Distillate (Dollars per Gallon)	1.09	1.21	1.89	1.23	2.14
Motor Gasoline (Dollars per Gallon)	1.23	1.24	1.83	1.30	2.08
Electricity (Cents per Kilowatthour)	6.9	5.9	9.8	5.6	10.3
Total Primary Energy Consumption (Quadrillion Btu)	94.0	103.2	83.9	114.5	84.4
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	29.9	30.1	36.4	37.0
Coal	20.9	22.8	8.4	25.8	2.7
Petroleum	36.0	40.7	35.3	45.2	37.2
Total	79.5	93.4	73.9	107.4	76.9
Total End-Use Carbon Emissions (Million Metric Tons)	1,463	1,700	1,247	1,952	1,231
Buildings (Residential/Commercial)[b]	170.9	—	—	—	—
Industrial[c]	306.9	470.3	369.1	501.1	359.6
Transportation	468.4	564.0	507.6	642.5	550.1
Electricity	516.7	665.7	370.8	809.0	321.9
Energy Consumption for Electricity Generation (Quadrillion Btu)					
Coal	18.36	20.35	7.10	23.32	1.64
Natural Gas	3.04	8.91	12.64	13.62	19.26
Nuclear	7.20	6.02	6.02	3.25	3.25
Renewables	4.47	3.79	4.00	3.81	4.22
Petroleum	0.75	0.69	0.52	0.63	0.05
Electricity Sales (Quadrillion Btu)	10.57	13.24	11.04	15.63	12.06

[a]Calculated as the sum of residential investment plus nonresidential fixed investment.
[b]Excludes emissions related to electricity generation.
[c]The WEFA projection provides an “other category” which combines direct emissions from the Buildings and Industrial sectors.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts* (1998). The WEFA report did not cover analyses of alternative carbon emissions targets because they did not believe that a workable comprehensive international trading system could be implemented in time and that developing countries would not participate in the clean development mechanism.

Table C2. Summary of the CRA Analysis of the 1990-7% Case

Parameter	1996	Reference Case in 2010	1990-7% Case in 2010	Reference Case in 2020	1990-7% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	295	NA	316
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,607	9,401	11,871	11,589
Total Carbon Emissions (Million Metric Tons)	1,463	1,806	1,252	1,955	1,252
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.2	6.0	3.9
Real Investment (Billion 1992 Dollars)	1,067	2,472	2,342	2,999	2,890
Real Consumption (Billion 1992 Dollars)	4,714	6,872	6,805	8,666	8,543
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.22	0.19	0.13	0.16	0.11
Delivered Energy Prices (1996 Dollars per Million Btu)					
Electricity (Cents per Kilowatthour, National Average)	6.9	5.9	8.3	5.5	7.7
Natural Gas (Dollars per Thousand Cubic Feet	4.25	3.19	8.74	4.12	11.82
Petroleum Prices (Average Dollars per Gallon)	1.03	1.20	3.26	1.64	4.00
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	26.9	18.5	29.9	18.9
Coal	20.9	20.7	12.6	23.5	11.5
Petroleum	36.0	43.2	32.2	44.9	33.4
Total	79.5	90.8	63.3	98.2	63.7

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Paul M. Bernstein, Charles River Associates, e-mail communications, August 24, 1998.

Table C3. Summary of the CRA Analysis of the Kyoto Protocol With Annex I Trading

Parameter	1996	Reference Case in 2010	Annex I Trading Case in 2010	Reference Case in 2020	Annex I Trading Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	109	NA	175
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,607	9,486	11,871	11,666
Total Carbon Emissions (Million Metric Tons)	1,463	1,806	1,540	1,955	1,480
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.2	6.0	3.9
Real Investment (Billion 1992 Dollars)	1,067	2,472	2,342	2,999	2,923
Real Consumption (Billion 1992 Dollars)	4,714	6,872	6,838	8,666	8,591
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.217	0.19	0.16	0.16	0.13
Delivered Energy Prices (1996 Dollars)					
Electricity (Cents per Kilowatthour, National Average)	6.9	5.9	6.6	5.5	6.6
Natural Gas (Dollars per Thousand Cubic Feet)	4.25	3.19	5.17	4.12	8.03
Petroleum Prices (Average, Dollars per Gallon)	1.03	1.20	1.94	1.64	2.92
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	26.9	22.7	29.9	23.2
Coal	20.9	20.7	16.8	23.5	14.7
Petroleum	36.0	43.2	38.0	44.9	37.4
Total	79.5	90.8	77.6	98.2	75.3

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Paul M. Bernstein, Charles River Associates, e-mail communications, August 24, 1998.

Table C4. Summary of the EPRI Analysis of the 1990-7% Case

Parameter	1996	Reference Case in 2010	1990-7% Case in 2010	Reference Case in 2020	1990-7% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)[a]	NA	0	280	0	251
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,296	9,203	11,389	11,280
Total Carbon Emissions (Million Metric Tons)	1,463	1,827	1,305	1,947	1,305
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.1	4.4	6.0	4.0
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	10.86	9.13	9.48	7.54
World Oil Price (Refiners Acquisition Price, 1996 Dollars per Barrel)	20.48	23.56	20.03	28.27	24.74
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP) (Calculated)	0.217	0.197	0.142	0.171	0.116
Total Primary Energy Consumption (Quadrillion Btu)	94	101	84	108	85
Total Fossil Fuel Consumption (Quadrillion Btu)	79.51	87.31	—	94.74	—

[a]All dollars values were given in 1990 dollars by R. Richels, EPRI. To convert from 1990 to 1992 dollars, a deflator of 1.068 was used. To convert from 1990 to 1996 dollars, a deflator of 1.178 was used.

[b]Calculated by dividing total primary energy by value of GDP.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** R. Richels, EPRI, e-mail communications, July 6, 1998.

Table C5. Summary of the EPRI Analysis of the Kyoto Protocol With Annex I Trading

Parameter	1996	Reference Case in 2010	Annex I Trading Case in 2010	Reference Case in 2020	Annex I Trading Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	0	114	0	188
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,296	9,245	11,389	11,199
Total Carbon Emissions (Million Metric Tons)	1,463	1,827	1,535	1,947	1,483
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.1	5.14	6.0	4.58
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP) (Calculated)	13.57	10.86	9.73	9.48	8.13
World Oil Price (Refiners Acquisition Price, 1996 Dollars per Barrel)	20.48	23.56	21.20	28.27	24.74
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP) (Calculated)	0.217	0.197	0.166	0.171	0.132
Total Primary Energy Consumption (Quadrillion Btu)	94.0	101.0	90.0	108.0	91.0
Total Fossil Fuel Consumption (Quadrillion Btu)	79.51	87.31	75.78	94.74	77.01

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** R. Richels, EPRI, e-mail communications, July 6, 1998.

Table C6. Summary of the PNNL Analysis of the 1990-7% Case

Parameter	1996	Reference Case in 2010	1990-7% Case in 2010	Reference Case in 2020	1990-7% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	—	221	—	286
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,416	9,357[a]	10,875	10,775
Total Carbon Emissions (Million Metric Tons)	1,463	1,853	1,267	2,035	1,267
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.3	6.1	4.0
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	12.5	10.0	11.6	8.7
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.217	0.197	0.135	0.187	0.118
Total Primary Energy Consumption (Quadrillion Btu)	94.0	117.7	93.9	125.7	93.5
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	33.3	33.5	38.4	38.5
Coal	20.9	24.5	5.8	26.6	2.9
Petroleum	36.0	44.5	38.0	47.9	38.0
Total	79.5	102.3	77.3	112.9	79.4
Energy Consumption for Electricity Generation (Quadrillion Btu)					
Coal	18.4	20.7	3.0	22.2	0.5
Natural Gas	3.0	5.0	9.3	6.8	11.8
Nuclear[b]	7.2	8.8	9.9	5.7	6.7
Renewables	4.5	4.5	4.6	4.5	4.8
Petroleum	0.8	0.1	0.1	0.2	0.0
Electricity Sales (Quadrillion Btu)	10.6	13.1	10.2	13.6	9.8

[a]The GDP values provided are equal to reference level GDP minus the domestic direct cost of meeting the required commitment level. This direct cost may be different from the welfare loss to the economy.

[b]For nuclear and renewable resources, estimated using 1995 benchmark for nuclear resources and corresponding PNNL generation.

Note: The PNL analysis includes a provision for the abatement costs of non-CO_2 gases. Abatement costs for the non-CO_2 gases are set such that the same percentage reduction per dollar of carbon price for those gases is obtained as for CO_2. No credits are included for sinks.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Ronald Sands, PNNL, e-mail communication, August 26, 1998.

Table C7. Summary of the PNNL Analysis of the Kyoto Protocol With Annex I Trading

Parameter	1996	Reference Case in 2010	Annex I Trading Case in 2010	Reference Case in 2020	Annex I Trading Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	—	100	—	142
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,416	9,381[a]	10,875	10,811
Total Carbon Emissions (Million Metric Tons)	1,463	1,853	1,439	2,035	1486
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.9	6.1	4.5
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.6	12.5	10.8	11.6	9.6
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.217	0.197	0.153	0.187	0.137
Total Primary Energy Consumption (Quadrillion Btu)	94.0	117.7	101.5	125.7	103.3
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	33.3	33.6	38.4	39.2
Coal	20.9	24.5	10.4	26.6	8.6
Petroleum	36.0	44.5	41.0	47.9	41.8
Total	79.5	102.3	85.0	112.9	89.6
Energy Consumption for Electricity Generation (Quadrillion Btu)					
Coal	18.4	20.7	7.3	22.2	5.6
Natural Gas	3.0	5.0	8.2	6.8	10.5
Nuclear[b]	7.2	8.8	9.6	5.7	6.4
Renewables	4.5	4.5	4.5	4.5	4.7
Petroleum	0.8	0.1	0.1	0.2	0.1
Electricity Sales (Quadrillion Btu)	10.6	13.1	11.0	13.6	10.9

[a]The GDP values provided are equal to reference level GDP minus the domestic direct cost of meeting the required commitment level. This direct cost may be different from the welfare loss to the economy.

[b]For nuclear and renewable resources, estimated using 1995 benchmark for nuclear resources and corresponding PNNL generation.

Note: The PNL analysis includes a provision for the abatement costs of non-CO_2 gases. Abatement costs for the non-CO_2 gases are set such that the same percentage reduction per dollar of carbon price for those gases is obtained as for CO_2. No credits are included for sinks.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Ronald Sands, PNNL, e-mail communication, August 26, 1998.

Table C8. Summary of the EIA Analysis of the 1990-7% Case

Parameter	1996	Reference Case in 2010	1990-7% Case in 2010	Reference Case in 2020	1990-7% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	348	NA	305
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,429	9,032	10,865	10,782
Total Carbon Emissions (Million Metric Tons)	1,463	1,791	1,243	1,929	1,251
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.2	6.0	3.9
Real Disposable Personal Income (Billion 1992 Dollars)	5,077	6,891	6,719	8,192	8,214
Real Investment (Billion 1992 Dollars)	1,067	1,745	1,662	2,100	2,095
Real Consumption (Billion 1992 Dollars)	4,714	6,347	6,160	7,599	7,636
Light-Duty Vehicle Sales (Millions)	15.1	16.6	15.2	17.0	16.5
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	11.80	10.16	10.78	9.17
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.16	8.98	8.08	8.31	7.36
World Oil Price (Refiners Acquisition Price, 1996 Dollars per Barrel)	20.48	20.77	17.54	21.69	18.38
Natural Gas Wellhead Price (1996 Dollars per Thousand Cubic Feet)	2.24	2.33	3.03	2.62	3.53
Minemouth Coal Price (1996 Dollars per Short Ton)	18.50	14.29	18.29	12.53	20.50
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.22	0.19	0.14	0.18	0.11
Delivered Energy Prices (1996 Dollars)					
Coal (Dollars per Million Btu to Utilities)	1.29	1.11	9.95	1.00	8.80
Natural Gas (Dollars per Thousand Cubic Feet)	4.25	3.87	9.57	4.07	9.35
Distillate (Dollars per Gallon)	1.09	1.08	1.90	1.06	1.77
Motor Gasoline (Dollars per Gallon)	1.23	1.25	1.91	1.24	1.80
Electricity (Cents per Kilowatthour)	6.9	5.9	11.0	5.6	9.3
Total Primary Energy Consumption (Quadrillion Btu)	94.0	111.2	91.7	117.0	98.8
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.6	29.0	32.1	32.7	34.5
Coal	20.9	24.1	5.4	25.3	2.0
Petroleum	36.0	43.8	38.1	46.9	41.7
Total	79.5	96.9	75.6	104.9	78.2
Total End-Use Carbon Emissions (Million Metric Tons)[a]	1,463	1,791	1,243	1,929	1,251
Buildings (Residential/Commercial)	170.9	176.6	135.1	181.0	139.3
Industrial	306.9	345.1	308.7	355.0	322.9
Transportation	468.4	611.6	514.7	668.8	569.9
Electricity	516.7	657.4	285.0	726.0	218.6
Energy Consumption for Electricity Generation (Quadrillion Btu)					
Coal	18.4	21.4	3.7	22.5	0.3
Natural Gas	3.0	6.9	12.7	9.6	14.3
Nuclear	7.2	6.2	7.4	3.8	7.4
Renewables	4.5	4.3	5.5	4.5	9.7
Petroleum	0.8	0.4	0.4	0.3	0.3
Electricity Sales (Quadrillion Btu)	10.57	13.19	10.98	14.47	12.51

[a]Excludes emissions related to electricity generation.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A and FD07BLW.D080398B.

Table C9. Summary of the EIA Analysis of the 1990+9% and 1990+14% Cases

Parameter	1996	Reference Case in 2010	1990+9% Case in 2010	1990+14% Case in 2010	Reference Case in 2020	1990+9% Case in 2020	1990+14% Case in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	163	129	NA	141	123
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	6,928	9,429	9,241	9,268	10,865	10,796	10,808
Total Carbon Emissions (Million Metric Tons)	1,463	1,791	1,462	1,535	1,929	1,468	1,536
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	6.0	4.9	5.1	6.0	4.5	4.7
Real Disposable Personal Income (Billion 1992 Dollars)	5,077	6,891	6,783	6,794	8,192	8,153	8,151
Real Investment (Billion 1992 Dollars)	1,067	1,745	1,719	1,716	2,100	2,098	2,099
Real Consumption (Billion 1992 Dollars)	4,714	6,347	6,248	6,258	7,599	7,583	7,582
Light-Duty Vehicle Sales (Millions)	15.1	16.6	16.0	16.0	17.0	16.7	16.7
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	11.80	10.78	11.0	10.78	9.62	9.78
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.16	8.98	8.54	8.63	8.31	7.79	7.87
World Oil Price (Refiners Acquisition Price, 1996 Dollars per Barrel)	20.48	20.77	18.72	19.15	21.69	19.73	19.81
Natural Gas Wellhead Price (1996 Dollars per Thousand Cubic Feet)	2.24	2.33	2.78	2.62	2.62	3.71	3.50
Minemouth Coal Price (1996 Dollars per Short Ton)	18.50	14.29	16.42	15.81	12.53	16.24	15.51
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.22	0.19	0.16	0.17	0.18	0.14	0.14
Delivered Energy Prices (1996 Dollars)							
Coal (Dollars per Million Btu to Utilities)	1.29	1.11	5.23	4.37	1.00	4.52	4.07
Natural Gas (Dollars per Thousand Cubic Feet)	4.25	3.87	6.63	5.96	4.07	7.14	6.66
Distillate (Dollars per Gallon)	1.09	1.08	1.46	1.39	1.06	1.36	1.32
Motor Gasoline (Dollars per Gallon)	1.23	1.25	1.55	1.50	1.24	1.49	1.45
Electricity (Cents per Kilowatthour)	6.9	5.9	8.8	8.2	5.6	8.1	7.8
Total Primary Energy Consumption (Quadrillion Btu)	94.0	111.2	99.6	101.9	117.0	103.8	105.6
Fossil Fuel Consumption (Quadrillion Btu)							
Natural Gas	22.6	29.0	31.8	30.7	32.7	36.0	35.4
Coal	20.9	24.1	11.7	14.8	25.3	7.1	10.0
Petroleum	36.0	43.8	41.1	41.6	46.9	44.8	44.9
Total	79.5	96.9	84.6	87.1	104.9	87.9	90.3
Total End-Use Carbon Emissions (Million Metric Tons)[a]	1,463	1,791	1,462	1,535	1,929	1,468	1,536
Buildings (Residential/Commercial)	170.9	176.6	154.2	159.1	181.0	155.2	159.0
Industrial	306.9	345.1	325.9	326.9	355.0	338.2	339.2
Transportation	468.4	611.6	572.2	580.7	666.8	623.0	630.5
Electricity	516.7	657.4	409.1	468.3	726.0	351.3	407.5
Energy Consumption for Electricity Generation (Quadrillion Btu)							
Coal	18.4	21.4	9.7	12.7	22.5	5.0	7.9
Natural Gas	3.0	6.9	10.9	9.5	9.6	14.9	14.0
Nuclear	7.2	6.2	7.0	6.9	3.8	5.9	5.6
Renewables	4.5	4.3	4.7	4.6	4.5	6.6	6.2
Petroleum	0.8	0.4	0.2	0.2	0.3	0.5	0.2
Electricity Sales (Quadrillion Btu)	10.57	13.19	11.92	12.15	14.47	13.09	13.28

[a]Excludes emissions related to electricity generation.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and FD1998.D080398B.

Table C10. DRI Case Summary

Parameter	1996	Reference Case in 2010	Case 1 in 2010	Case 2 in 2010	Case 3 in 2010	Reference Case in 2020	Case 1 in 2020	Case 2 in 2020	Case 3 in 2020
Carbon Price (1996 Dollars per Metric Ton)	NA	NA	174	110	37	NA	190	131	70
GDP (Billion 1992 Chain-Weighted Dollars)	6,928	9,428	9,273	9,321	9,366	10,865	10,836	10,828	10,813
Total Carbon Emissions (Million Metric Tons)	1,463	1,740	1,354	1,452	1,593	1,886	1,297	1,416	1,589
Per Capita Carbon Emissions (Metric Tons per Person)	5.5	5.8	4.5	4.9	5.3	5.8	4.0	4.4	4.9
Real Disposable Personal Income (Billion 1992 Dollars)	5,077	6,891	6,724	6,769	6,819	8,193	8,092	8,104	8,108
Real Investment (Billion 1992 Dollars)	1,067	1,746	1,780	1,762	1,738	2,150	2,225	2,199	2,181
Real Consumption (Billion 1992 Dollars)	4,714	6,346	6,203	6,246	6,289	7,599	7,555	7,550	7,535
Light-Duty Vehicle Sales (Millions)	15.1	16.6	15.9	16.1	16.3	17.0	16.8	16.8	17.1
Primary Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	13.57	11.63	9.79	10.28	10.99	10.43	7.79	8.42	9.27
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.16	8.36	7.06	7.42	7.96	7.64	5.79	6.25	6.90
Carbon Intensity (Metric Tons per Thousand 1992 Dollars of GDP)	0.22	0.19	0.15	0.16	0.17	0.17	0.12	0.13	0.15
Delivered Energy Prices (1996 Dollars)									
Coal (Dollars per Million Btu to Utilities)	1.29	1.16	5.89	4.16	2.15	1.09	12.34	4.62	2.98
Natural Gas to Utilities (Dollars per Thousand Cubic Feet)	2.70	2.47	5.20	4.15	3.10	2.96	5.64	4.77	4.01
Motor Gasoline (Dollars per Gallon)	1.23	1.31	1.70	1.56	1.41	1.48	1.89	1.76	1.64
Electricity (Cents per Kilowatthour)	6.9	5.4	8.4	7.5	6.3	5.3	8.2	7.3	6.5
Total Primary Energy Consumption (Quadrillion Btu)	94.0	108.1	91.0	95.4	102.9	112.9	84.4	91.1	100.2
Fossil Fuel Consumption (Quadrillion Btu)									
Natural Gas	22.6	28.5	25.3	26.1	29.1	31.5	21.1	24.3	29.4
Coal	20.9	24.5	13.9	16.5	18.7	26.3	13.9	15.4	17.4
Petroleum	36.0	42.1	38.4	39.6	41.8	44.7	38.5	40.3	42.7
Total	79.5	95.1	77.7	82.2	89.6	102.5	73.5	80.0	89.5
Total End-Use Carbon Emissions (Million Metric Tons)[a]	1,463	1,740	1,354	1,452	1,593	1,886	1,297	1,416	1,589
Buildings (Residential/Commercial)	170.9	176.7	149.1	157.6	170.8	181.9	131.0	145.0	163.4
Industrial	306.9	344.0	267.6	286.4	323.5	357.6	225.8	255.4	306.0
Transportation	468.4	558.1	485.1	507.7	542.3	600.0	513.1	537.6	564.7
Electricity	516.7	661.6	452.4	500.7	556.7	746.8	426.9	477.8	555.1
Electricity Sales (Quadrillion Btu)	10.6	13.2	11.1	11.5	12.4	14.9	10.4	11.3	12.6

[a]Excludes emissions related to electricity generation.

Sources: **1996:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). **2010 and 2020:** Standard and Poors DRI, *The Impact of Meeting the Kyoto Protocol on Energy Markets and the Economy*, Appendix I: National Impacts (July 1998).

Appendix D

Letters from the Committee on Science

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

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March 3, 1998

The Honorable Jay E. Hakes
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Dr. Hakes:

We appreciated your verbal offer for the Energy Information Administration (EIA) to undertake an analysis of the Kyoto Protocol, particularly focusing on U.S. energy use and prices and the economy in the 2008-2012 time frame. The purpose of this letter is to confirm that offer and to formally request that analysis. We would also like you to include in your study the impact of the penetration of more major efficient technologies that are or near commercial availability and other assumptions that have a major bearing on carbon reductions in the United States.

Given the uncertainties that exist regarding the level of carbon reductions that the United States must commit to if it is to be in compliance with the Kyoto Protocol, we suggest that several cases be analyzed. Those cases should bound the possible range of carbon reductions and include intermediate reduction targets that provide sufficient information to guide policy decisions. As resources permit, cases should also be examined that deal with major policy alternatives in the energy area.

Our staffs will be happy to work with you on this study. We realize that there are numerous alternatives to how the Nation can proceed to reduce carbon emissions and our mutual discussions of those issues should help to frame the analysis. We would appreciate the results of your analysis by this fall. In advance, thank you for your assistance and we commend you and your agency for your consistently reliable energy information and analyses.

Sincerely,

F. JAMES SENSENBRENNER, JR.
Chairman

GEORGE E. BROWN, JR.
Ranking Minority Member

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

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April 22, 1998

The Honorable Jay E. Hakes
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Dr. Hakes:

On March 3, 1998, we formally requested that the Energy Information Administration (EIA) undertake an analysis of the impact of the Kyoto Protocol on U.S. energy use, prices and the economy in the 2008-2012 time frame. The purposes of this letter are to more fully define the assumptions for that study and to recommend the specific cases we would like you to consider.

Because of the uncertainties associated with the level of sinks, offsets, emissions of all six greenhouse gases, and carbon trading that could result, we would like you to examine several different targets for U.S. energy-related carbon emissions reductions. The plausible cases should span a range of targets, from 7 percent below 1990 levels as the most extreme case to 34 percent above 1990 levels, representing the 2010 emissions level in the *Annual Energy Outlook 1998 (AEO98)* reference case. Also, for this set of cases we would prefer that you use *AEO98* policy, technology and market assumptions—that is, no additional policies or funding should be assumed unless those changes can be justified solely based on the existence of the Protocol. Also, the nuclear option should be limited to life extension of existing nuclear units, if they are economic.

The recommended cases are:

- 7% below 1990 levels (the Kyoto Protocol target without offsets, sinks and international trading);
- 3% below 1990 levels (State Department estimate of sinks and offsets from reforestation, afforestation, and reductions in other greenhouse gases);
- stabilization at 1990 levels;
- 9% above 1990 levels (State Department estimate of sinks and offsets, plus the EIA estimate of permits available from Annex I countries of the Former Soviet Union);
- 14% above 1990 levels (stabilization at 1998 emissions levels),

The Honorable Jay E. Hakes
April 22, 1998
Page two

- 24% above 1990 levels (State Department estimate plus global international trading as defined by Dr. Janet Yellen's testimony of March 4, 1998 before the House Commerce Subcommittee on Energy and Power); and

- 34% above 1990 levels (EIA reference case levels in *AEO98*).

With this set of cases, we expect that the EIA will be able to closely estimate the impact on the U.S. energy system and economy for a wide range of values for offsets, sinks, and carbon trading. For example, if sinks and offsets from reforestation, afforestation, and reductions in other greenhouse gases relax the Kyoto target by 4 percent as the State Department has estimated, and if the United States could purchase all of the estimated 165 permits from the Annex I countries of the former Soviet Union, and if no permits were allowed for the Clean Development Mechanism, the carbon target to be examined for the United States would be 9 percent above 1990 levels, or 1,471 million metric tons.

For each case examined, the target should be achieved on average for the 2008 to 2012 period and stabilize at that target post-2012. You should assume that the United States will begin to respond by 2005 to both reflect anticipatory actions by industry and consumers, and to meet the Kyoto Protocol's Article 3.2 requirement that "Each Party included in Annex I shall, by 2005, have made demonstrable progress achieving its commitments under this Protocol."

We would also like you to evaluate other uncertainties regarding: (1) economic growth; (2) construction of new nuclear plants; and (3) technology cost, performance, and penetration as sensitivity cases for some of the target cases described above (e.g., carbon stabilization at 1990 and 1998 levels).

If you have questions concerning these assumptions, please contact Harlan Watson and Mike Rodemeyer of the Science Committee staff.

Sincerely,

George E. Brown, Jr.

F. JAMES SENSENBRENNER, JR.
Chairman

GEORGE E. BROWN, JR.
Ranking Minority Member