FOIA Number: 2017-1095-F

FOIA MARKER

This is not a textual record. This is used as an administrative marker by the William J. Clinton Presidential Library Staff.

Collection/Record Group: Clinton Presidential Records

Subgroup/Office of Origin: Council of Economic Advisers

Series/Staff Member: Subject Files

Subseries:

OA/ID Number: 21605

FolderID:

Folder Title:
[Global Climate Change and Domestic Energy Policy] [loose] [2]

Stack:	Row:	Section:	Shelf:	Position:
S	21	5	1	2

4. Electricity Supply

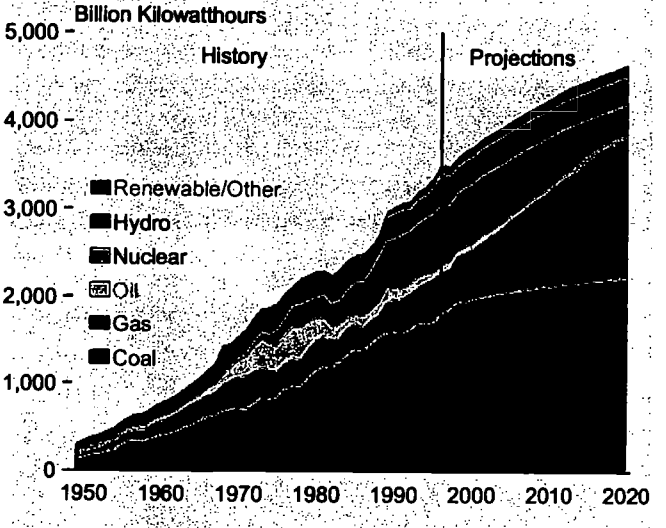
Introduction

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

Figure 65. Electricity Generation by Fuel in the Reference Case, 1949-2020



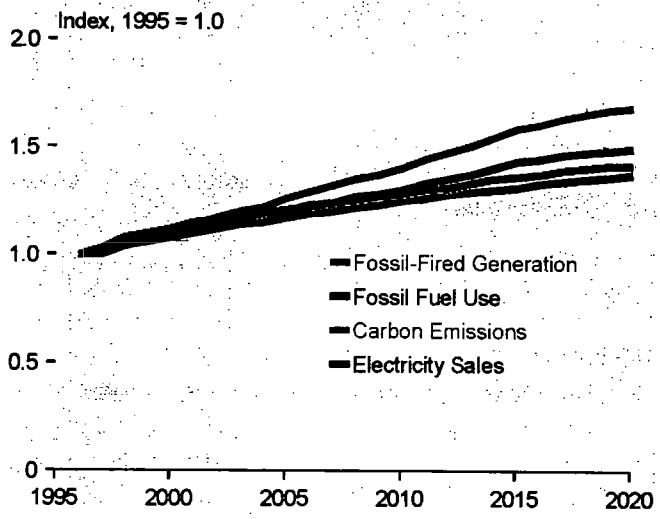
Note: Data on nonutility generation are not available for years before 1989, but it was small. In 1989, nonutility generation accounted for 6 percent of total U.S. electricity generation.

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.

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.

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)		Variable O&M (1996 Mills per kWh)	Fixed O&M (1996 Dollars per kW)	Heat Rate (Btu per kWh)		Carbon Emissions (Pounds per MWh)
				First-of-a-Kind	nth-of-a-Kind			First-of-a-kind	nth-of-a-Kind	
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.

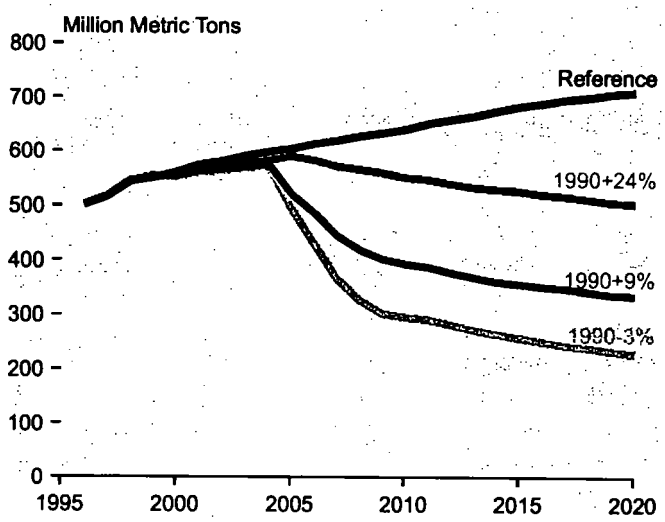
that developers will incorporate their expectations of carbon prices into their plans for new capacity additions, and that more lower-carbon generating capacity will be brought on line than would have been in the absence of the expected carbon reduction mandate.

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).

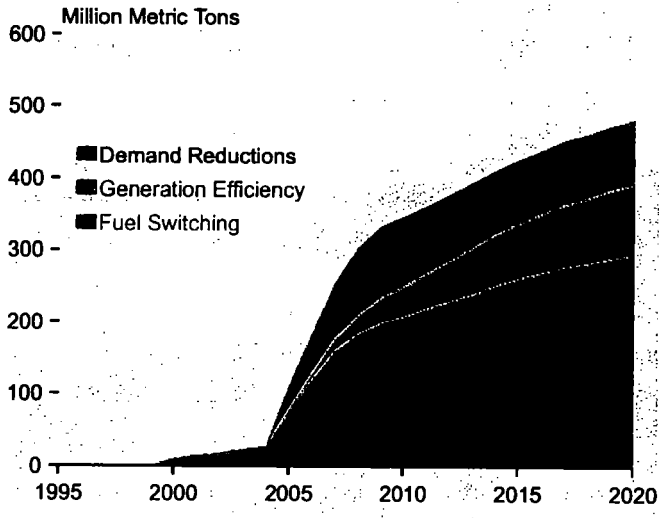
The shift away from coal-fired generation occurs because coal accounts for such a large share of power plant carbon emissions. In 1996, coal-fired power plants

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.

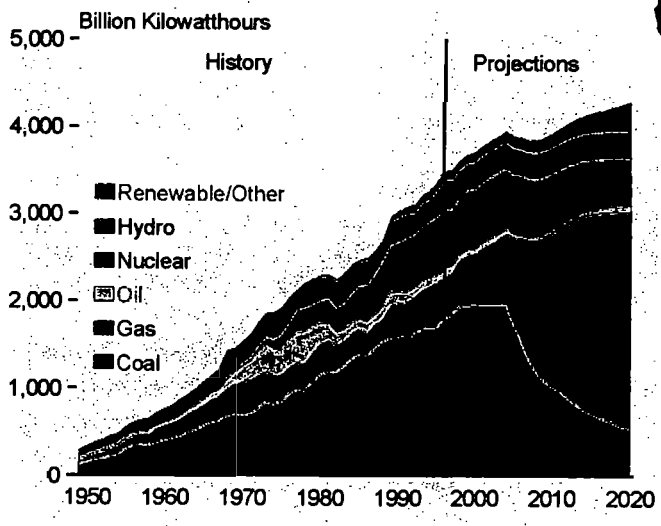
Figure 68. Projected Reductions in Carbon Emissions From the Electricity Supply Sector, 1990-3% Case, 1996-2020



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

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 megawatt-

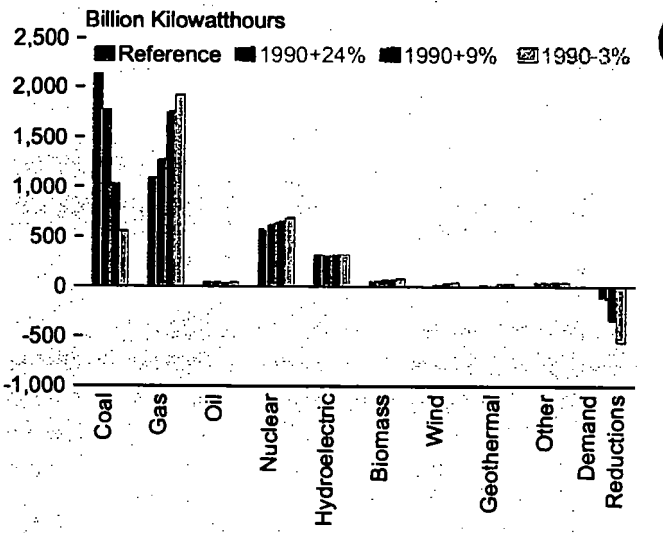
Figure 69. Electricity Generation by Fuel, 1990+9% Case, 1949-2020



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.

hour 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.

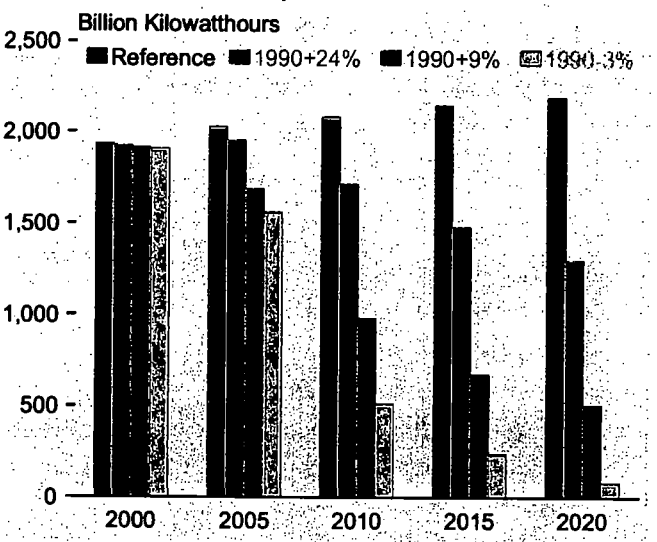
reference case (Figure 71). In 2020, the differences from the reference case are even larger: 41 percent in the 1990+24% case, 77 percent in the 1990+9% case, and over 96 percent in the 1990-3% case. In 1990-3% case, coal-fired generation is virtually eliminated. Coal plants simply are not very economical 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 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.

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.

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

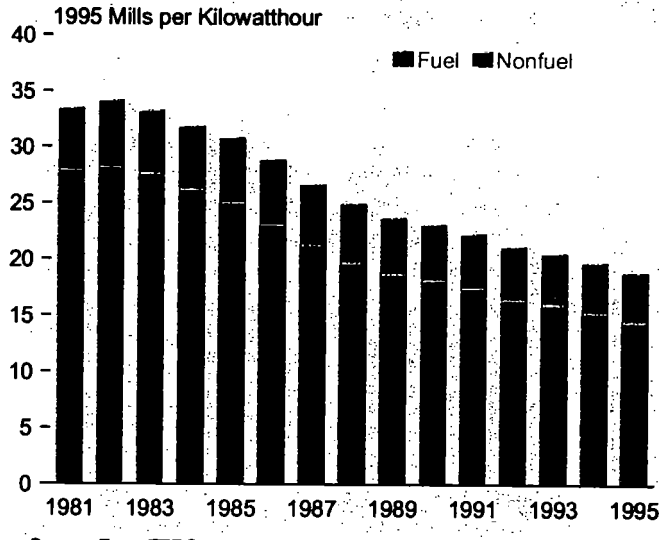
[55] In NEMS, the capacity factor for a particular plant type is determined by its operating costs. The values presented here are for illustration only.

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

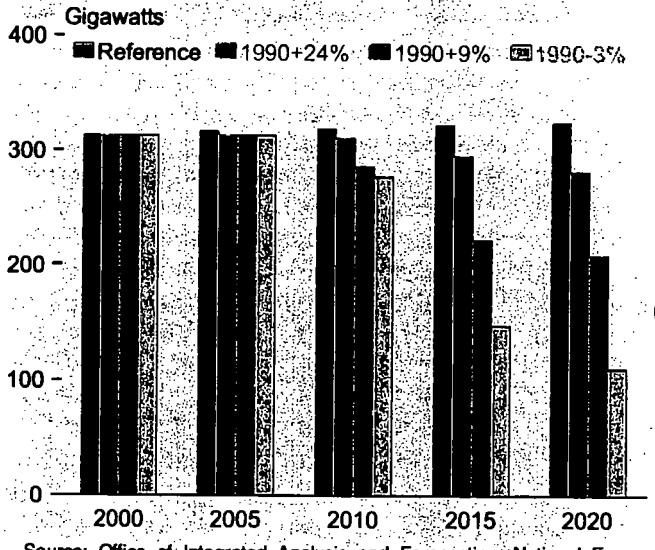
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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.

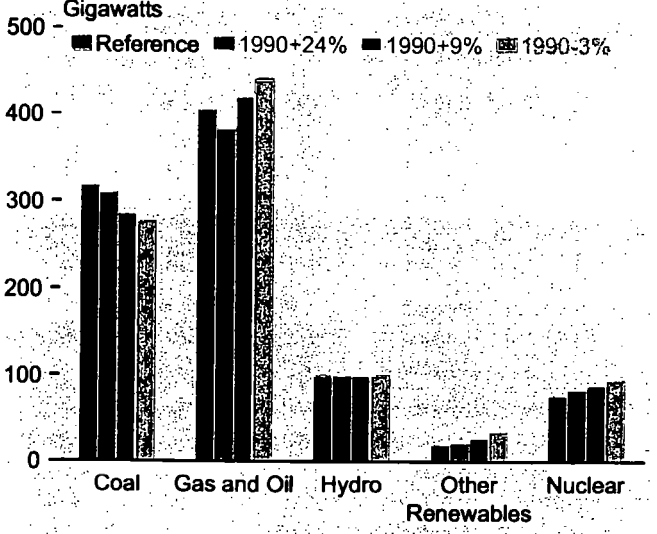
unrecovered costs would be stranded. Most coal plants are fairly old, however, and their construction costs have already been recovered. On the other hand, some plant owners could suffer losses because plants they expected to be profitable might no longer be profitable when carbon prices are imposed.

Natural Gas

Generation

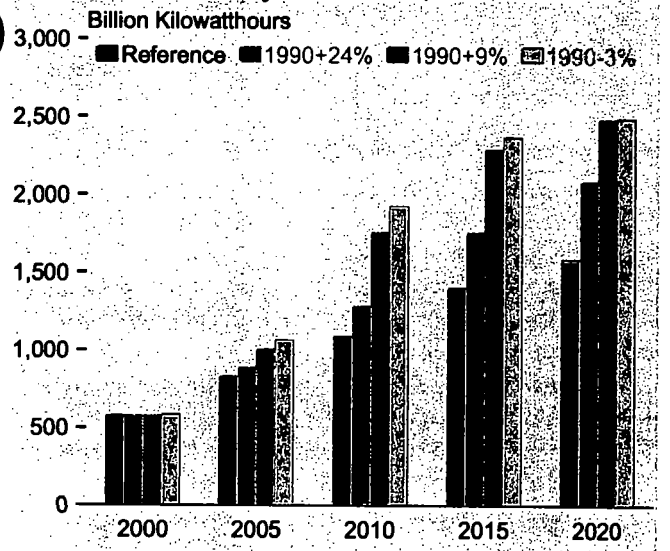
The story for natural gas generation is the opposite of that for coal (Figure 75). As the requirement to reduce carbon emissions tightens and the associated carbon price rises, natural-gas-fired generation becomes more economical than coal-fired generation. In 2010 and beyond, electricity generation 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 74. Electricity Generation Capacity by Fuel, 2010



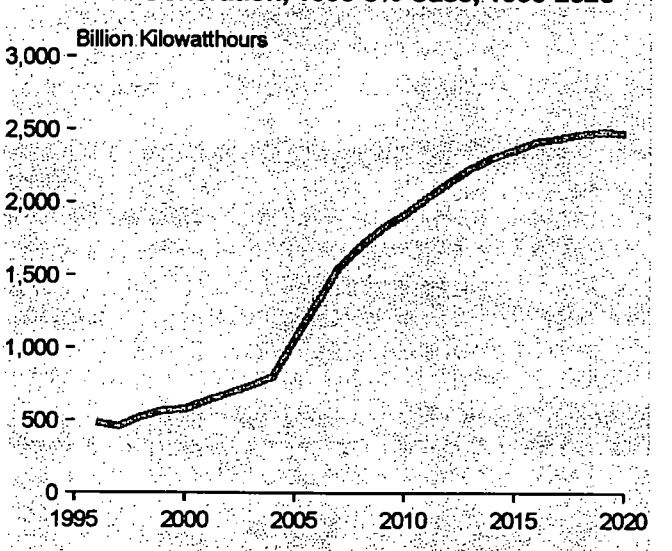
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

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.

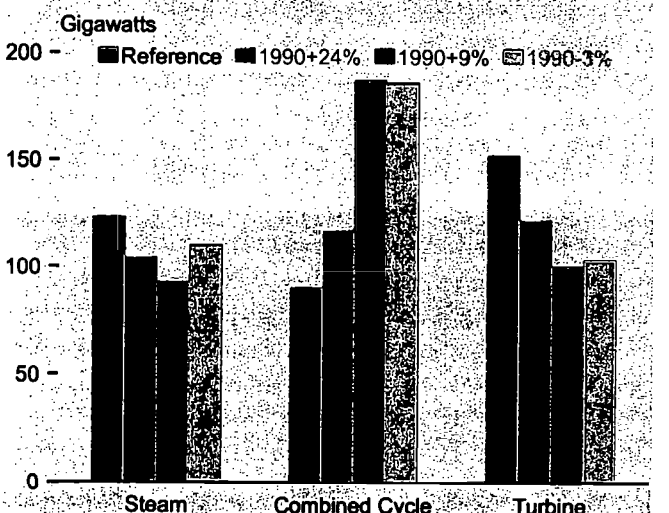
The rate of increase in natural-gas-fired generation varies over the 24-year projection period (Figure 76). When carbon emission limits are first imposed in 2005, there is rapid growth in natural gas generation, both because the rising carbon price makes existing natural gas plants more economical than 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."

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

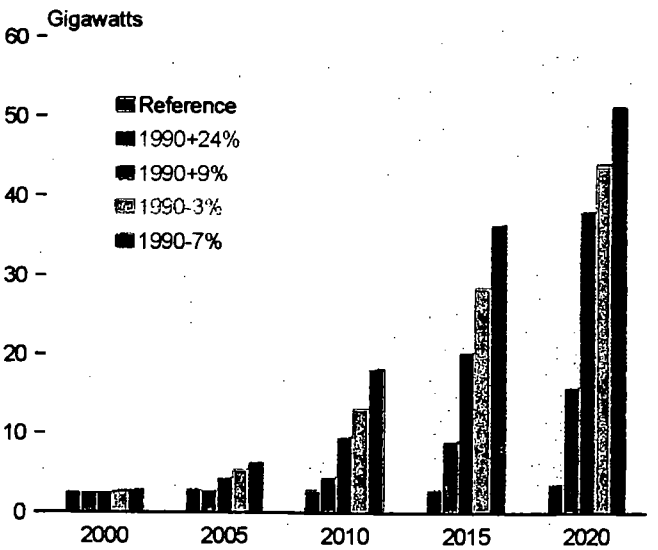
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

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



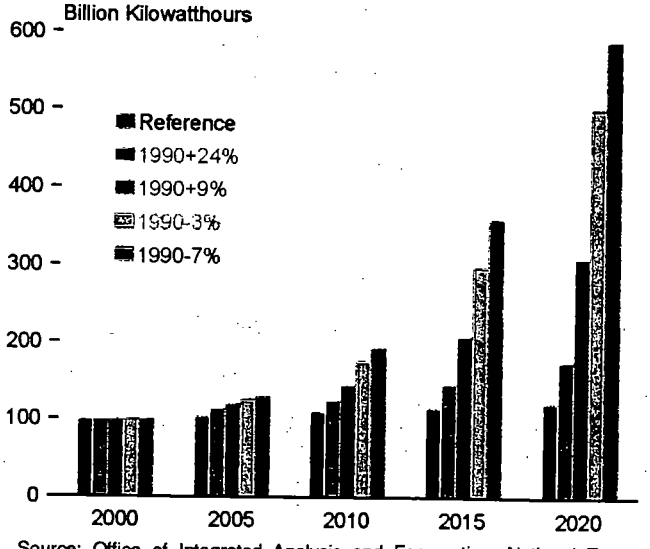
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

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 20. Projected U.S. Electricity Generation Capacity From Renewable Fuels
(Gigawatts)

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	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.

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

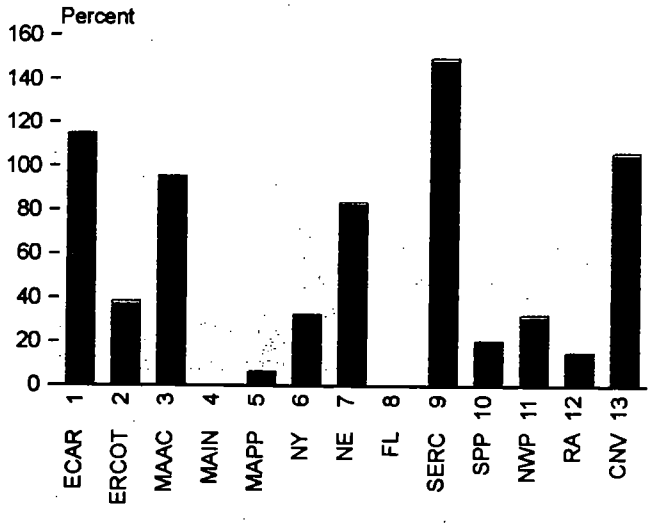
in the United States to date and that, if prices are high enough, capacity can be added fairly rapidly.[61]

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

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.

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.

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

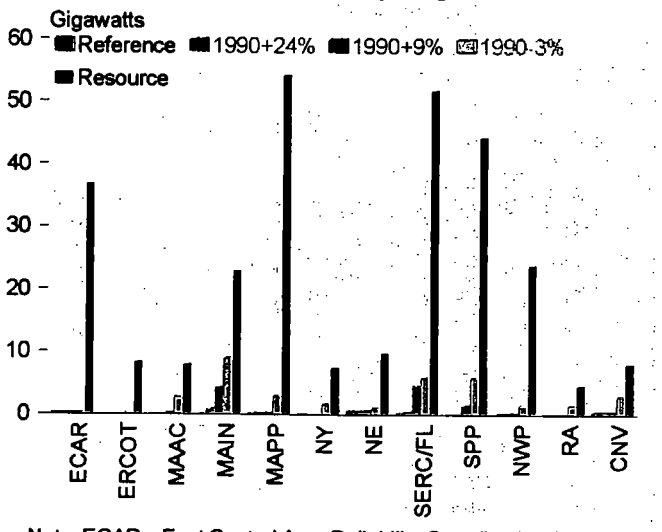
Unlike wind plants, which are intermittent, biomass plants operate continuously. Biomass currently is being used to supply energy for power generation and in the industrial, transportation, and residential sectors. The largest amount of biomass is used in the paper and lumber industries, where residue 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

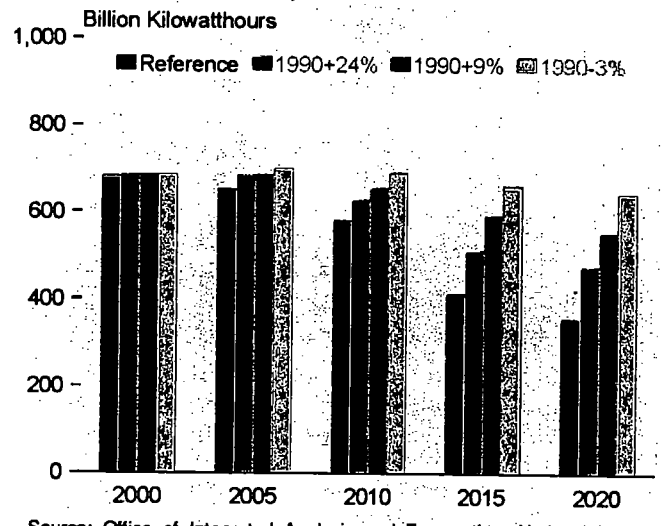
Nuclear generation is expected to be higher in the carbon reduction cases than in the reference case. In the reference case, more than half of the nuclear plants existing today are expected to be retired when their licenses expire. The economics of the retirement versus life extension decision will change, 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.

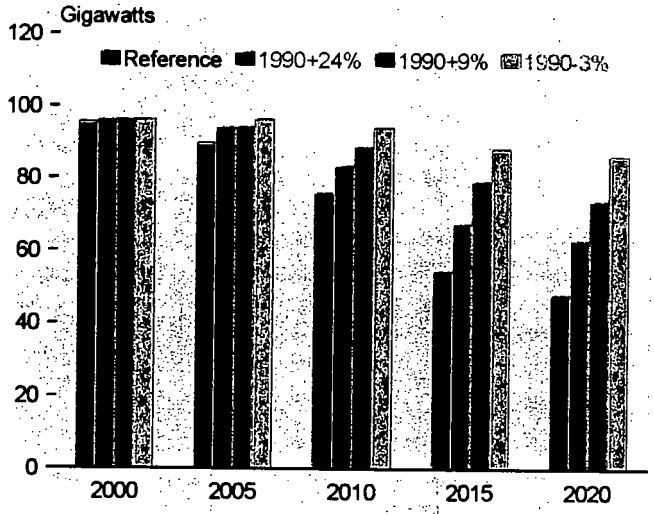
In the 1990-3% case, additional generation from nuclear plants operating beyond 40 years offsets approximately 30 to 40 million metric tons of carbon emissions—approximately equal to the difference between the carbon targets in the 1990-3% and 1990-7% cases. Thus, in the absence of the projected nuclear 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.

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.

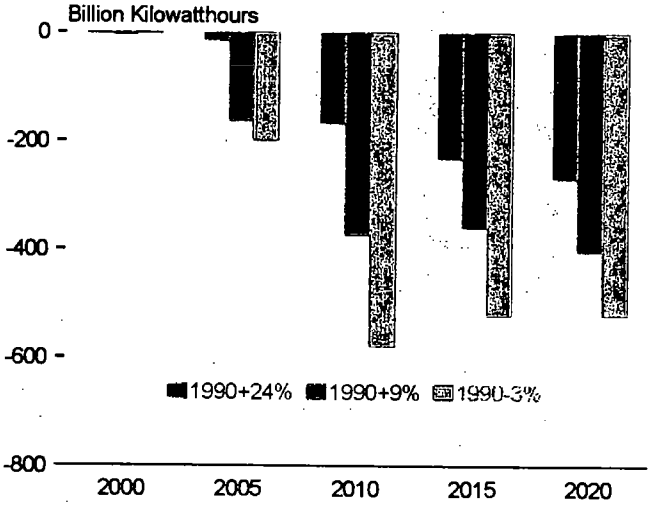
The higher projections for nuclear electricity generation in the carbon reduction cases would have implications for nuclear waste disposal. The projected impact is not significant through 2010, but in 2020 cumulative spent fuel discharges from nuclear units would be 6 percent and 9 percent higher than 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 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.

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.

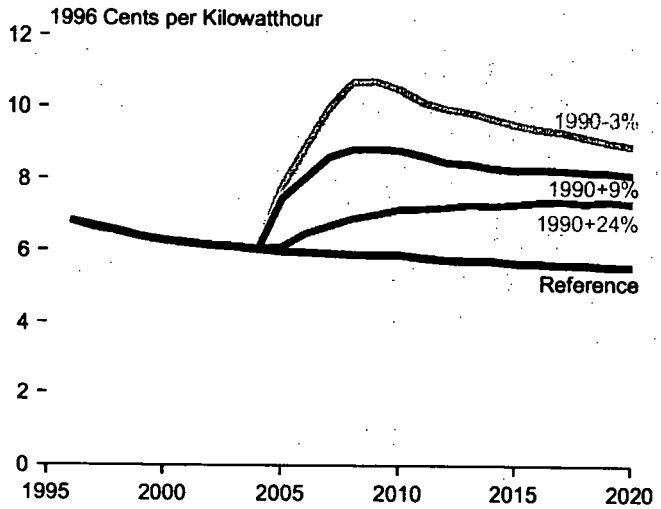
Electricity Prices

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.

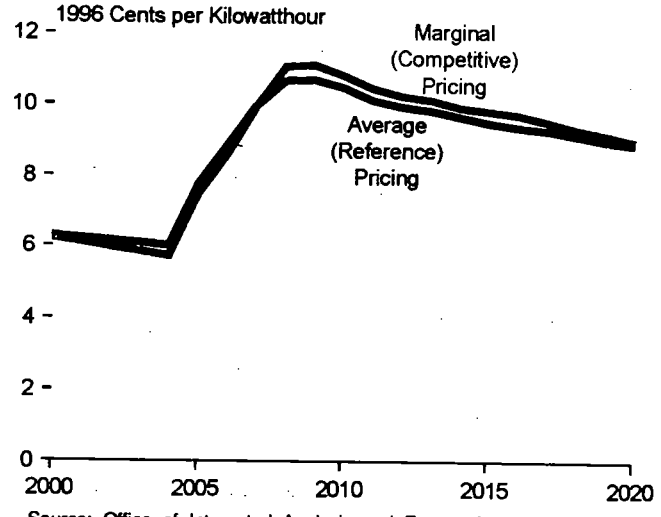
In this analysis, when higher carbon prices are projected, end-use electricity prices are higher under marginal cost (competitive) pricing than they would be under average cost (regulated) pricing (Figure 86). The effect of marginal cost pricing on electricity prices increases with the level of the carbon 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.

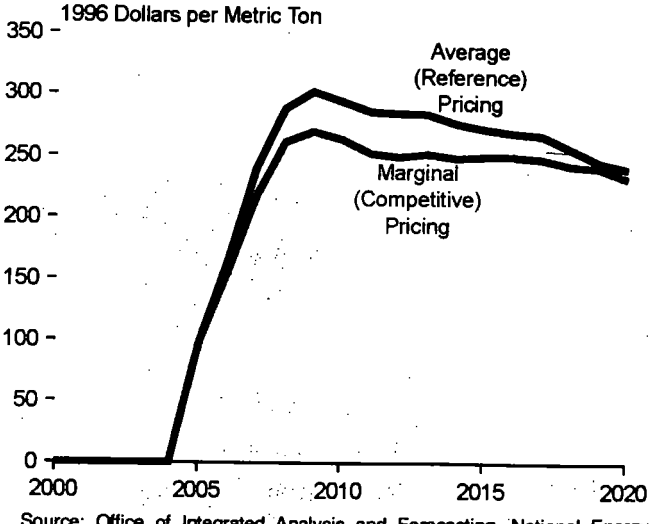
An easy way to see the impact of the carbon price is to look at the impact it has on the types of plants that will set the marginal price of power. A carbon permit system would change the plants that set the market price of electricity in a competitive pricing environment. In a carbon reduction case 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

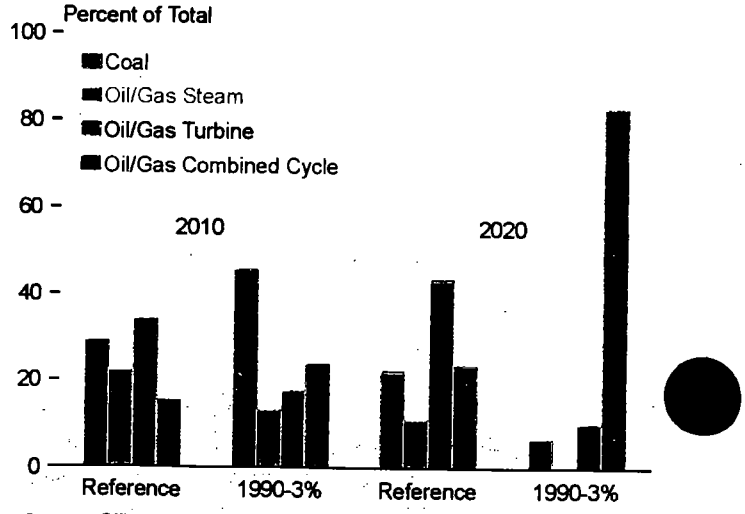


Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD03BLW.D080398B and FD03COMP.D080698C.

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

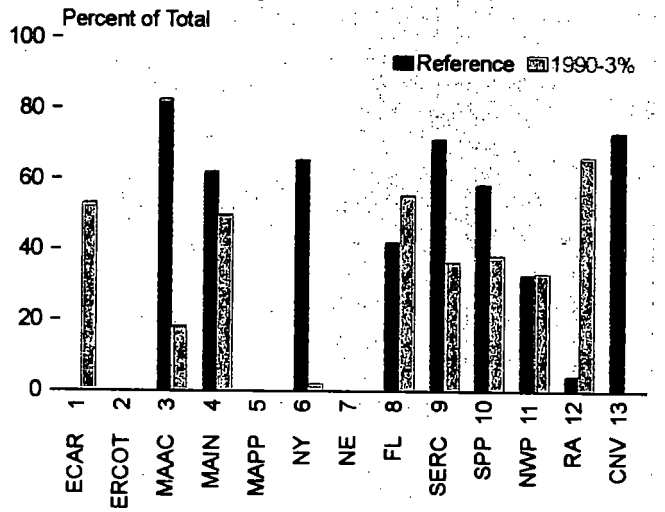
Figure 88. Projected Percentage of Time for Different Plant Types Setting National Marginal Electricity Prices, 2010 and 2020



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.

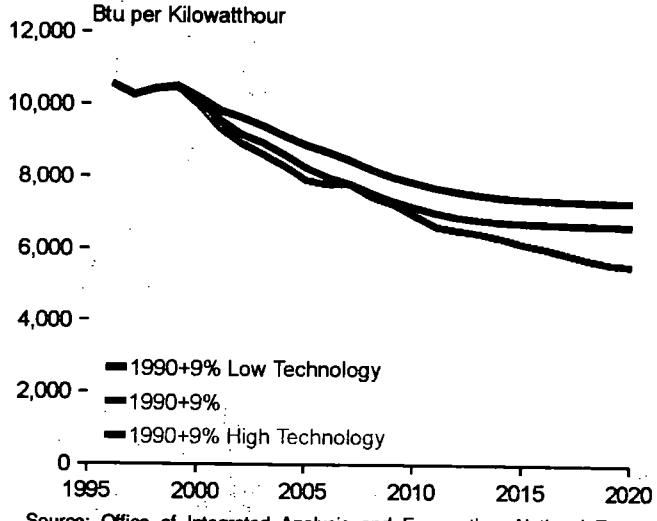
The effects of assuming lower and higher rates of technological progress on electricity prices in the carbon reduction cases are significant. For example, in 2010, projected electricity prices in the 1990+9% low technology case are more than 70 percent higher than those in the reference case (Figure 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

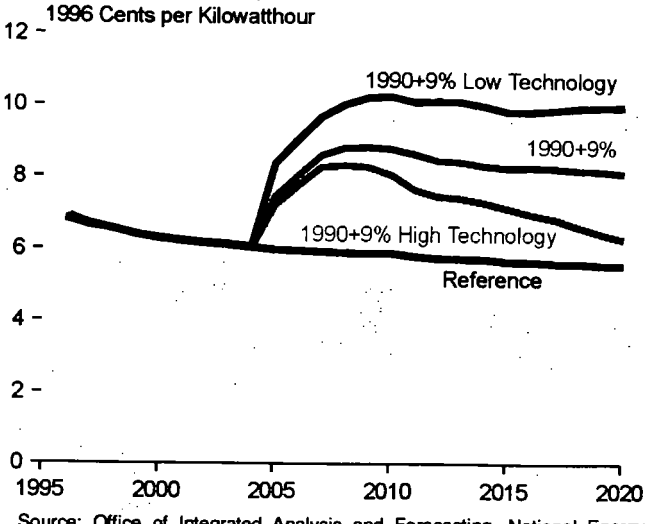
One carbon-free technology around which there is considerable uncertainty is new nuclear power plants. Currently nuclear power accounts for 20 percent of the power produced in the United States; however, no new nuclear power plants have been ordered since 1978, and the last one to come on line was Watts 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.

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



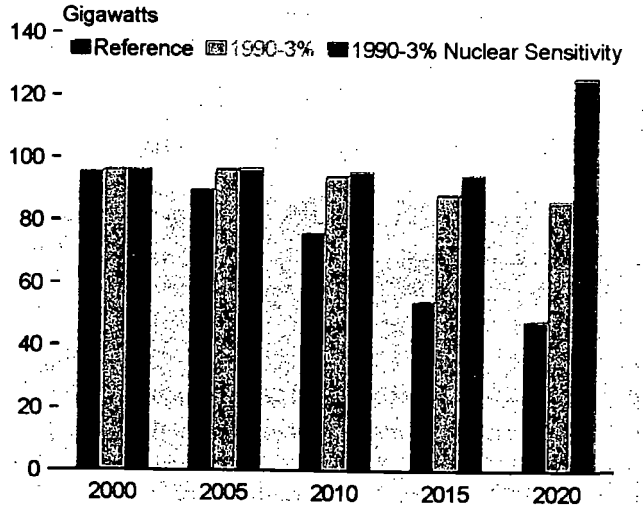
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

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 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)

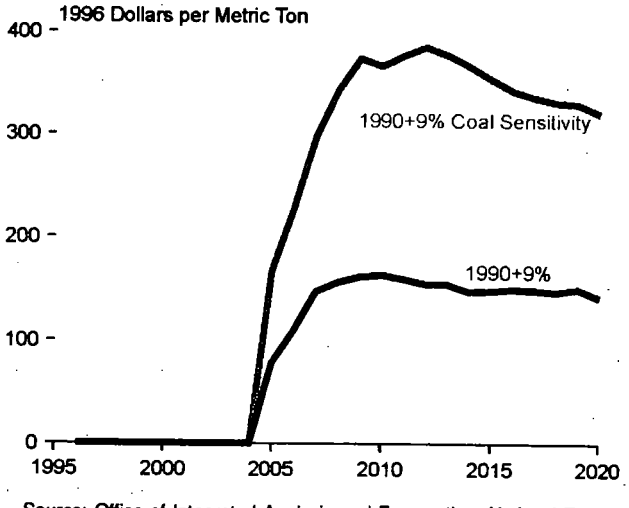
In the carbon reduction cases, the projected utilization rates for coal-fired generating capacity are much lower than the rates at which they have traditionally been operated. Many coal plants are designed as baseload capacity that operates almost continuously because they cannot be restarted quickly 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.

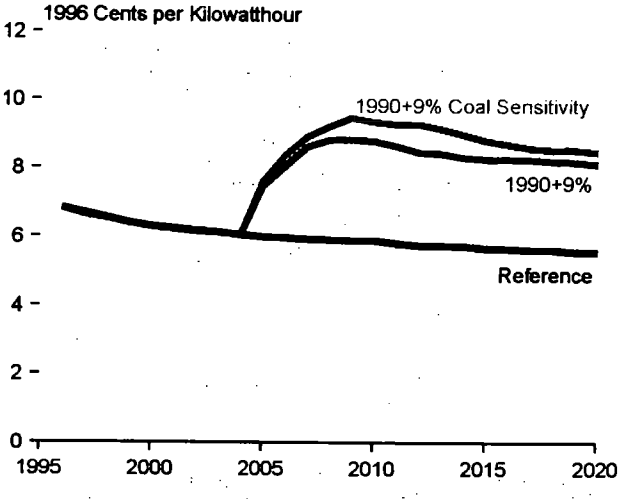
The key result of the 1990+9% coal sensitivity case is that subsidizing some portion of the coal industry would make it more difficult to reach carbon emission reduction targets, significantly raising both the carbon price and the price of electricity (see figures below). In the 1990+9% coal sensitivity 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.

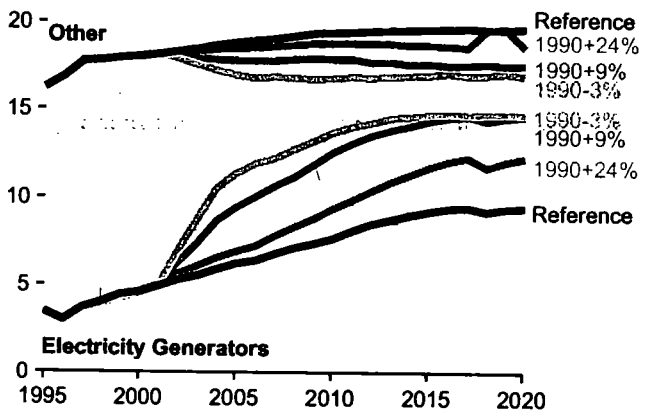
Policies designed to reduce carbon emissions would boost natural gas consumption, production, imports, and prices, principally because natural gas consumption would displace coal consumption in the electricity supply sector. In response, gas production and imports would increase, pushing up prices. In 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's, 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, lease and plant, pipeline, 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.

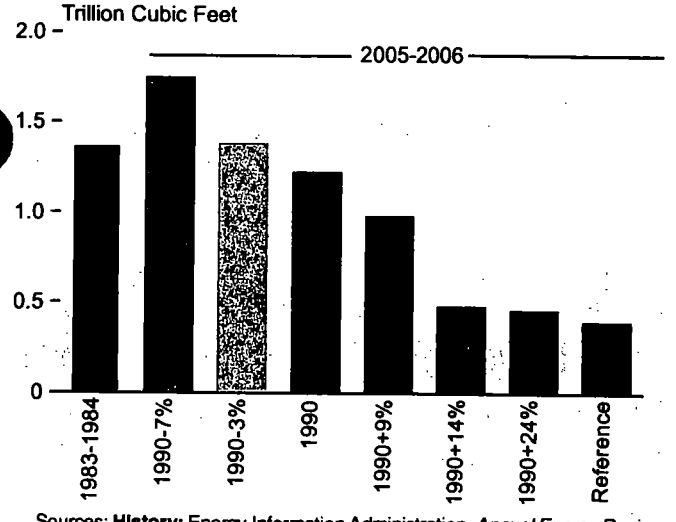
Natural Gas Production

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

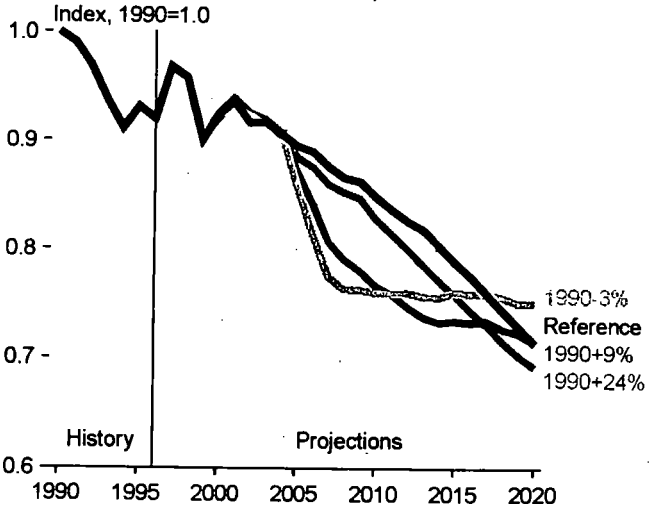
[71] T.A. Stokes and M.R. Rodriguez, "44th Annual Reed Rig Census," *World Oil* (October 1996).

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 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.

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.

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.

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]

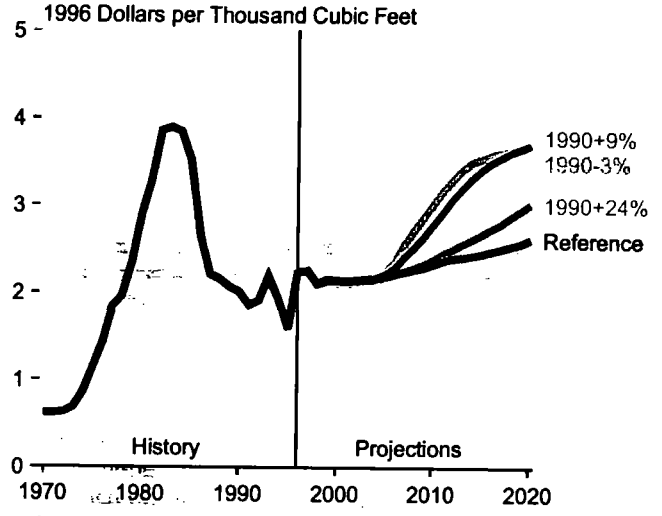
[a]Energy Information Administration, Office of Oil and Gas, *EIAGIS Natural Gas Geographic Information System Natural Gas Proposed Construction Database* (Washington, DC, preliminary as of April 1998).

[b]"NGSA: Return-on-Equity Fair Despite Protests by Pipelines," *Natural Gas Week* (March 9, 1998), p. 6.

[c]"Concerned About Prices, NGSA To Throw Shadow Over Rosy Supply Picture," *Inside F.E.R.C.* (May 11, 1998), p. 7.

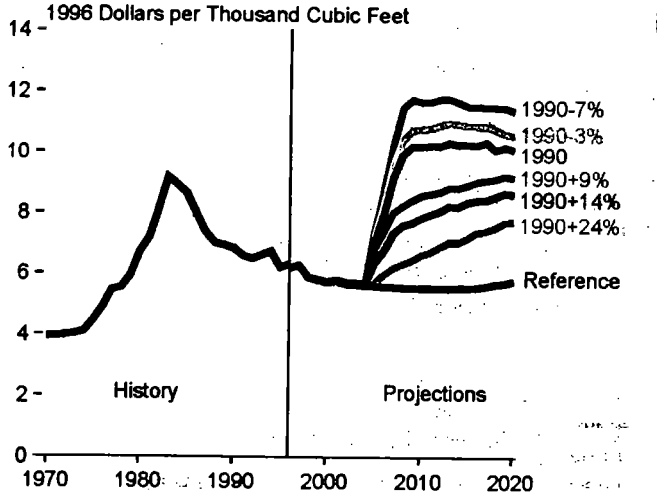
price is imposed in 2005. In the cases with higher projected carbon prices, gas prices rise more quickly, then flatten out as energy conservation on the demand side and renewable energy production on the supply side slow the overall rate of growth in natural gas consumption. When moderate carbon prices are projected, gas prices rise more steadily but ultimately reach higher levels.

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.

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.

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 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.

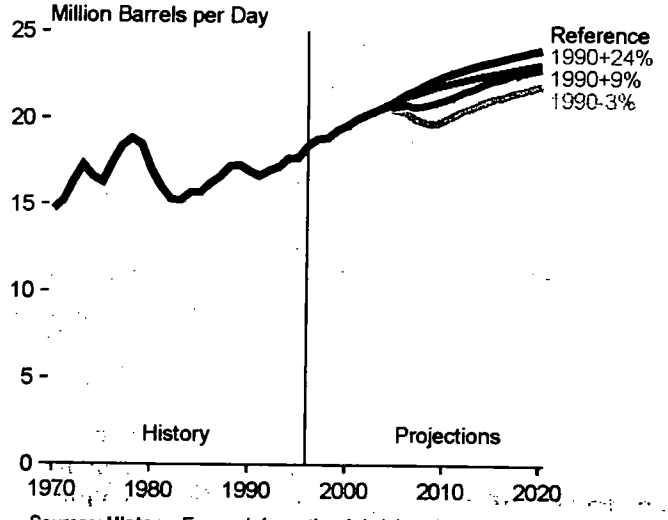
Policies aimed at reducing carbon emissions would lead to lower consumption, production, imports, and refinery margins for the U.S. oil industry. On the other hand, end-use prices and market share would be higher. Higher end-use prices—reflecting new carbon prices—would reduce consumption in the carbon 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.

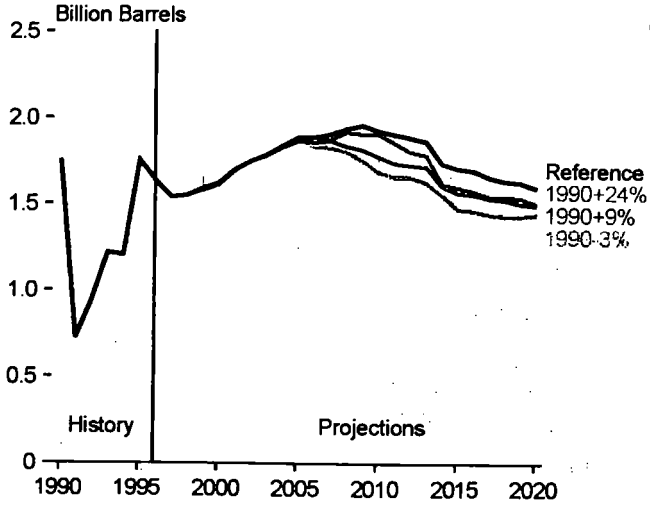
Oil use in the transportation sector is expected to absorb the largest share of the projected declines between 2005 and 2009, accounting for more than 85 percent of the total drop in oil consumption in the three most stringent carbon reduction cases, with smaller reductions in the residential, commercial, 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

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.

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.

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.

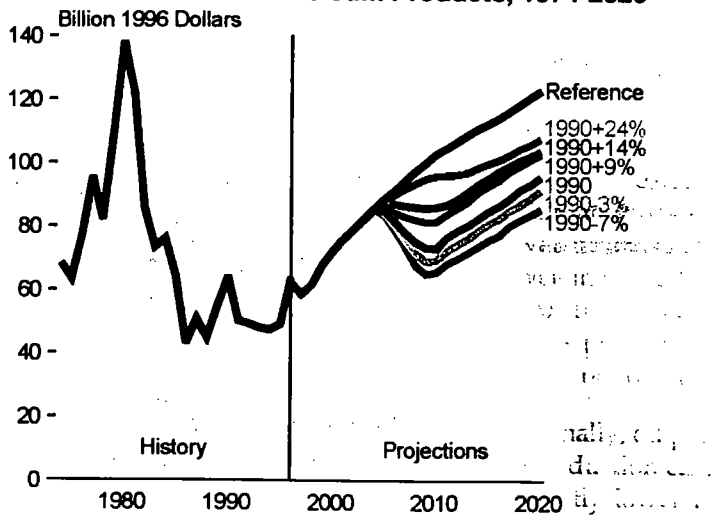
Regionally, oil production is generally lower in the carbon reduction cases than in the reference case. It is significantly lower in the Southwest (western Texas and eastern New Mexico), in the Rocky Mountains, and in the offshore Gulf Coast, which are the largest producing regions. In the 1990-3% case, 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.

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.

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.

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.

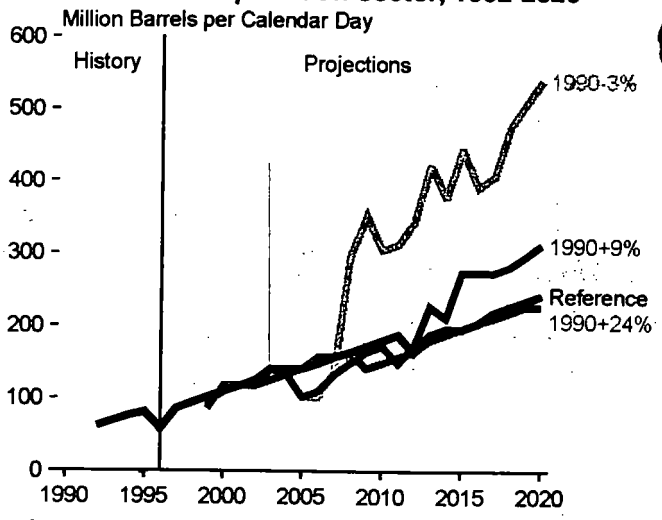
In 2010, the projected product shares of total petroleum consumption are approximately the same in the reference, 1990+24%, 1990+9%, and 1990-3% cases: 43 percent for gasoline, 18 percent for distillate, 11 percent for jet fuel, 4 percent for residual fuel, and 24 percent all other products. The gasoline 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

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.

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

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.

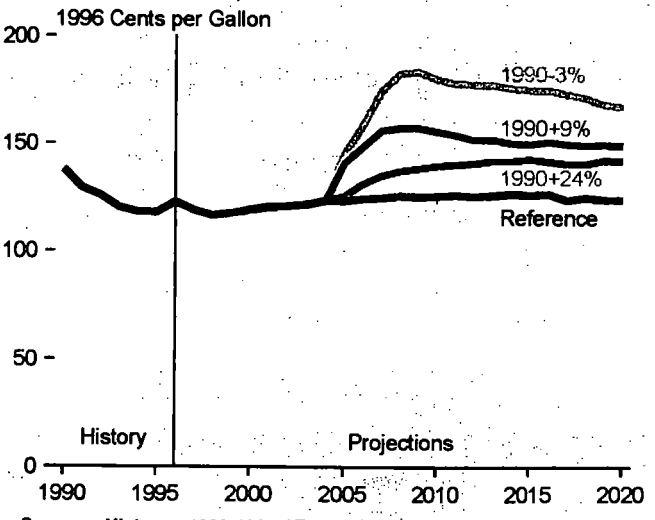
In the carbon reduction cases, ethanol consumption in some years is lower than in the reference case (Figure 101), because the carbon price causes the cost of corn-based ethanol to increase and not enough inexpensive cellulose-based ethanol is yet available. One of the costs of corn production is diesel 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 recovered 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.

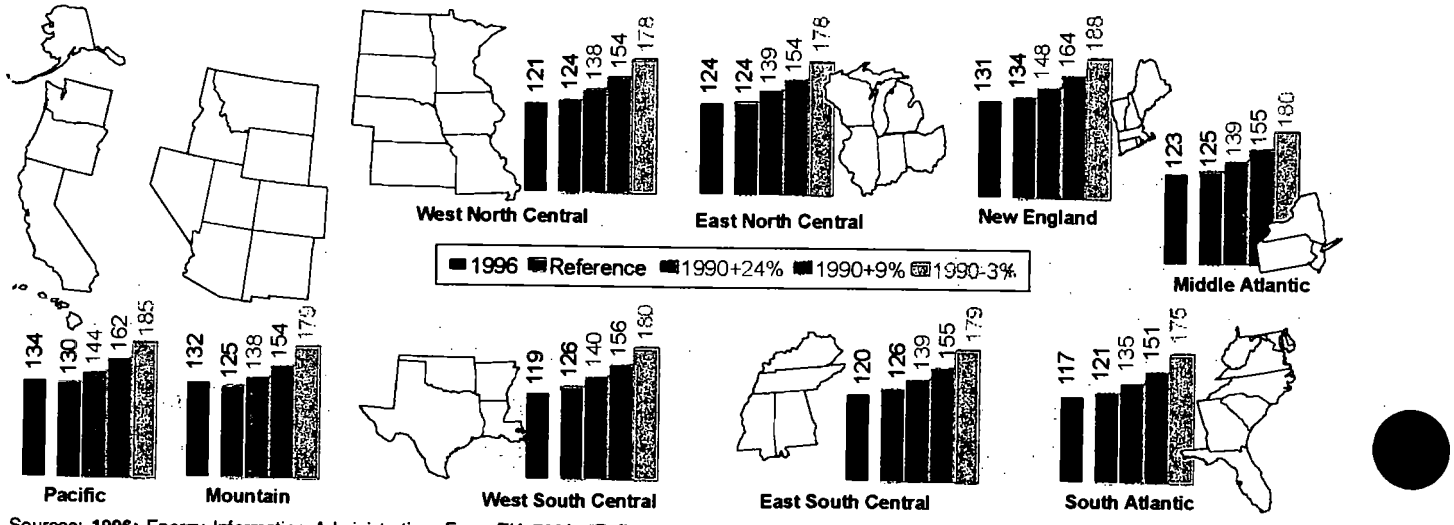
Regional petroleum product prices in the carbon reduction cases reflect many of the same market patterns that exist today. In general, the Northeast and Pacific regions continue to have the highest priced petroleum products in the reference case and the carbon reduction cases (Figure 103). Prices in 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.

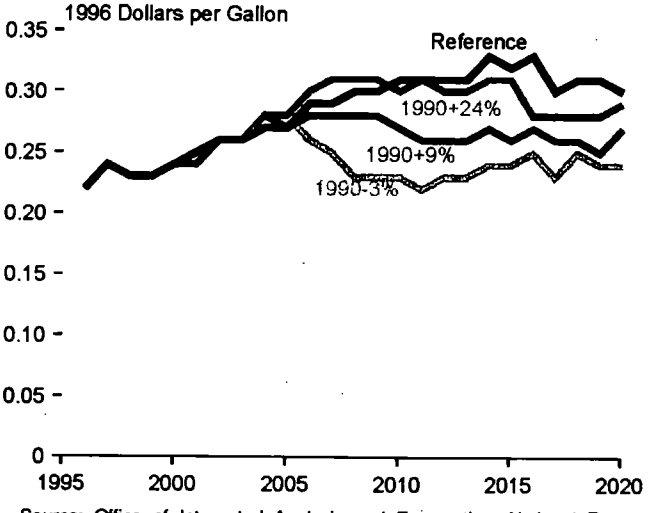
Lower demand for petroleum products is expected to slow the growth of the U.S. refinery industry. In the reference case, the combined distillation capacity of U.S. refineries is projected to be 16.9 million barrels per day in 2010, with a utilization rate of 95 percent. In comparison, in the 1990+24% 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.

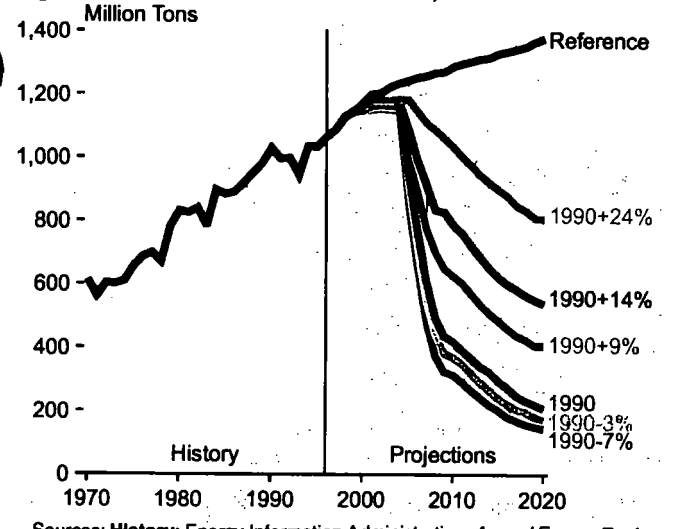
Other factors that would affect the regional impacts of carbon emission restrictions on different coalfields stem from differences in mining and transportation costs. Subbituminous coal production in the southern Powder River Basin of Wyoming had an average mine price of $6.41 per ton in 1996, as compared 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.

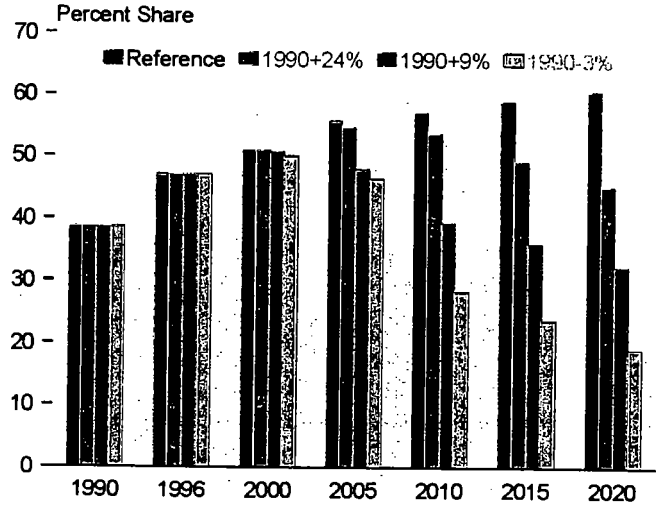
The slower decline in coal consumption in the industrial, metallurgical coal, and export sectors in the carbon reduction cases will translate into relatively less severe production cuts in regions that currently supply these markets than the reductions in those regions that depend more heavily on electricity 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

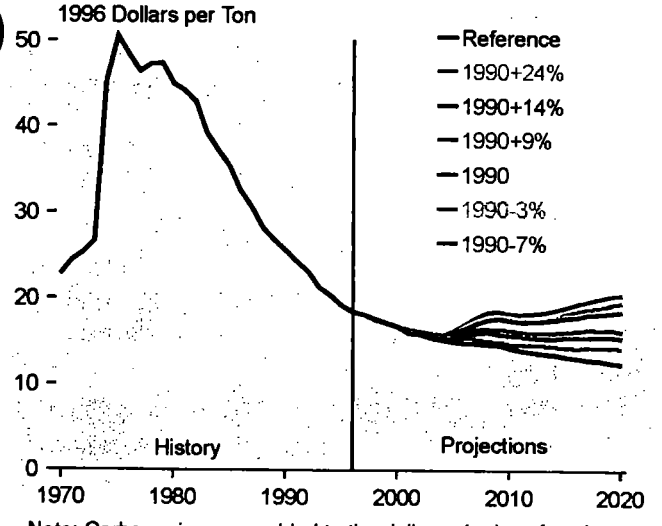
Because coal is heterogeneous in terms of heat content, sulfur level, and other physical properties, trends in national average prices are affected substantially by the relative shares of the various coal types produced and sold and by the units in which prices are reported. For example, coal from the 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.

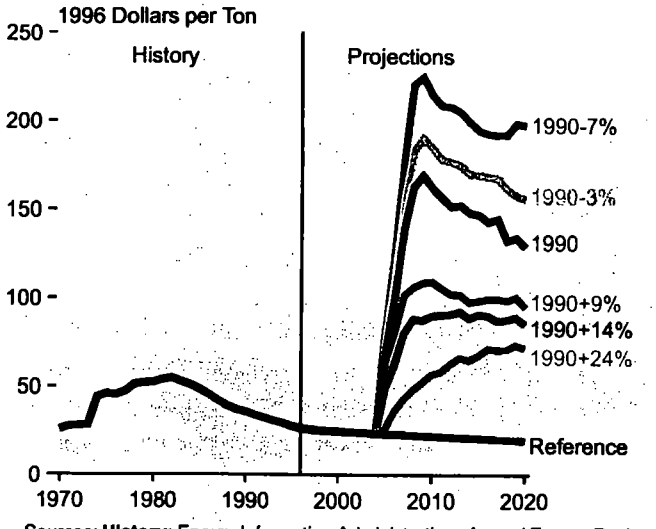
carbon reduction cases. In 2010, the carbon fee adds $1.73 per million Btu to the delivered price of coal to electricity generators in the 1990+24% case, $4.18 per million Btu in the 1990+9% case, and $7.51 per million Btu in the 1990-3% case. In 2020, the carbon price component drops to $2.55, $3.62, 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

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.

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.

[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.

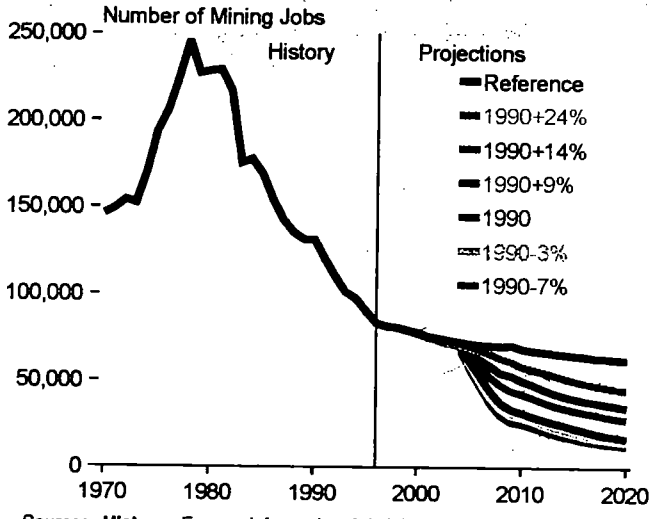
Table 23. Projected Number of Coal Mining Jobs by Region, 2010

Region	1996 Actual	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.

Production and employment are positively correlated. In 2010, the projected levels of coal production in the 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

State	Wages		Employmenta	
	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

[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.

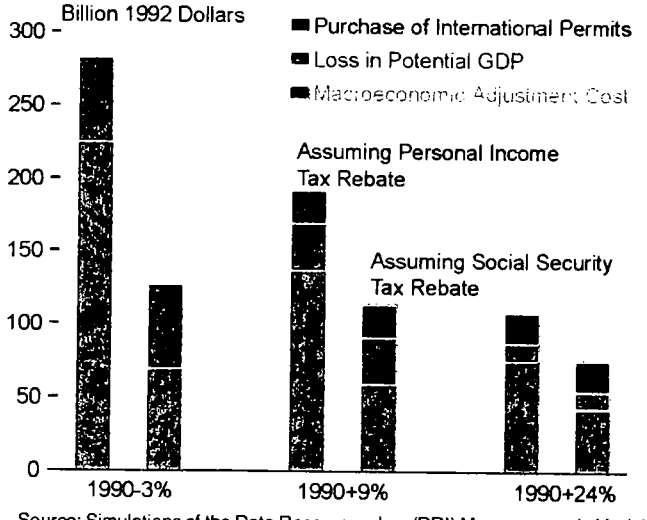
[82] The output measures presented in this chapter are expressed in constant 1992 chain-weighted dollars. The DRI macroeconomic model uses National Income and Products Accounts (NIPA) as an estimating framework. Expressing these output measures in 1992 dollars maintains consistency with the NIPA framework 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

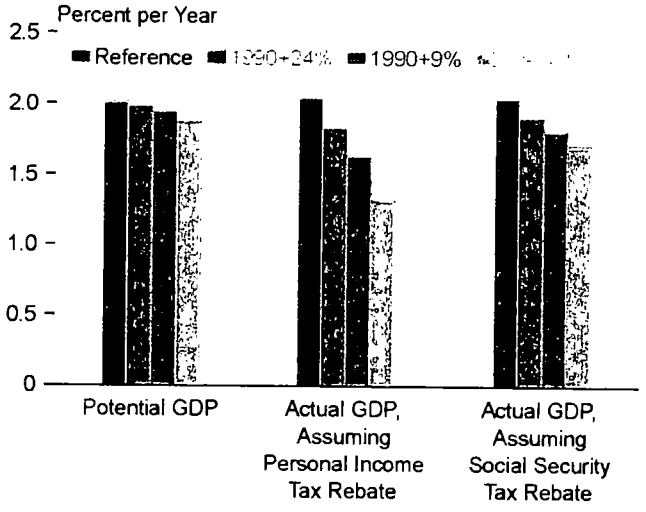
Note: Loss in potential GDP plus the macroeconomic adjustment costs equals the loss in actual GDP. The actual GDP loss plus purchases of international permits equals the total cost to the economy.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

Figure 110. Total Projected 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

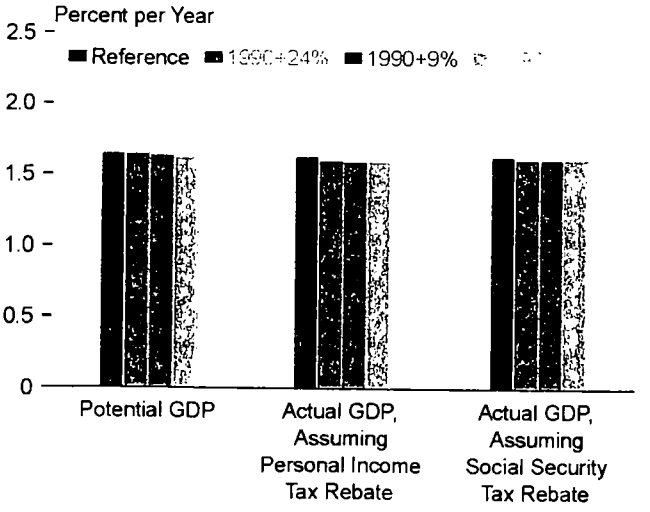


Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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 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.

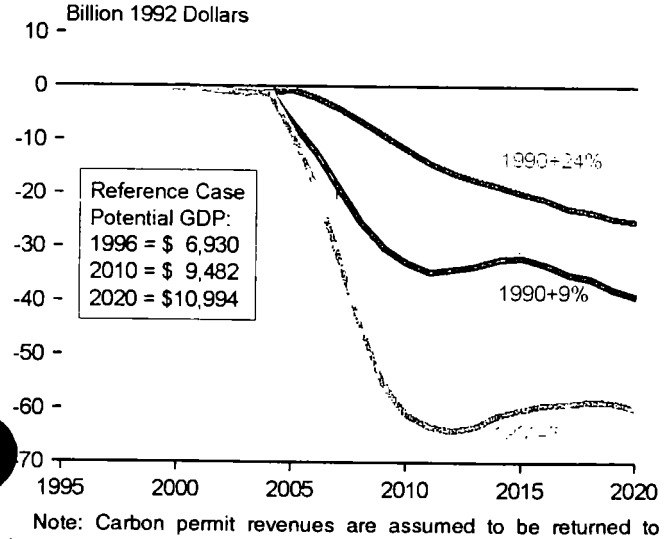
Estimating The Unavoidable Impact on the Economy

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 2008-2012. 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

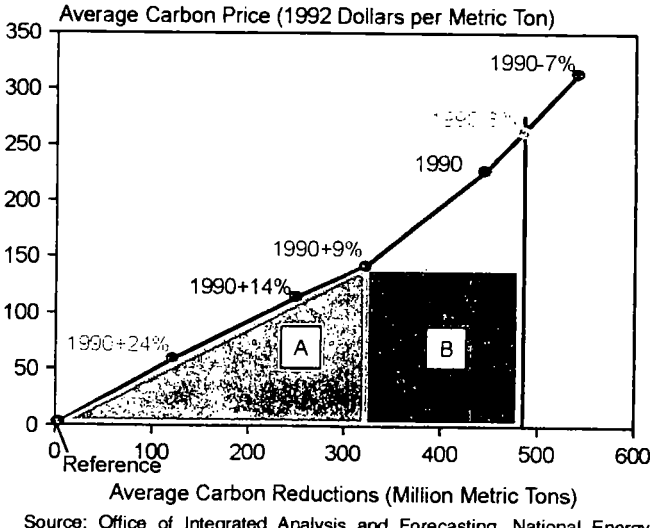
Figure 113. Projected Dollar Losses in Potential GDP Relative to the Reference Case, 1998-2020



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



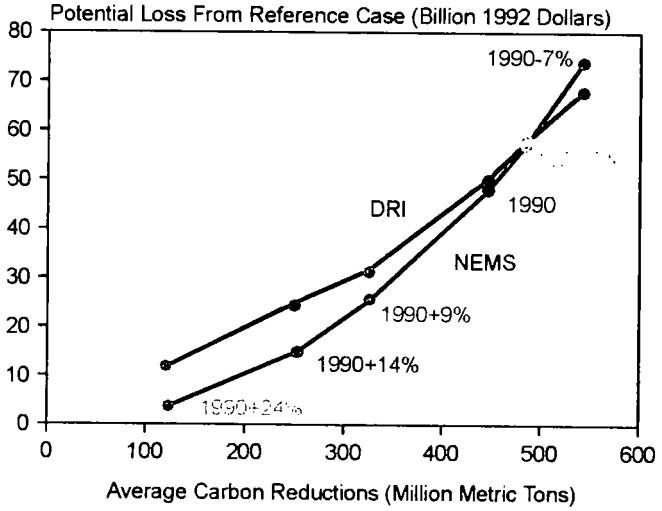
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Table 28. Average Projected Annual Losses in Economic Output, 2008-2012

Analysis Case	Value of Lost Output		U.S. Purchase of International Permits (Billion 1992 Dollars)
	NEMS Valuation (Billion 1992 Dollars)	DRI Potential GDP Loss (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.

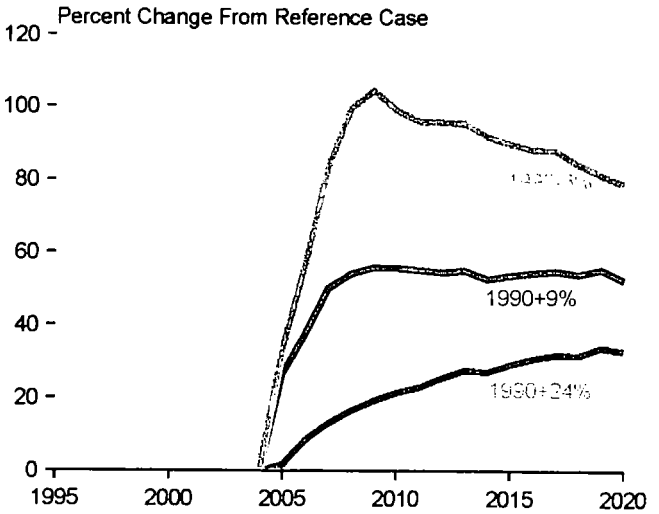
These changes can also be expressed as rates of change. In the reference case, overall energy prices rise by 3.9 percent per year between 2005 and 2010; however, in the 1990+9% case, aggregate energy prices rise at a rate of 13.5 percent per year, a difference of 9.6 percentage points. The 1990-3% case 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 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.

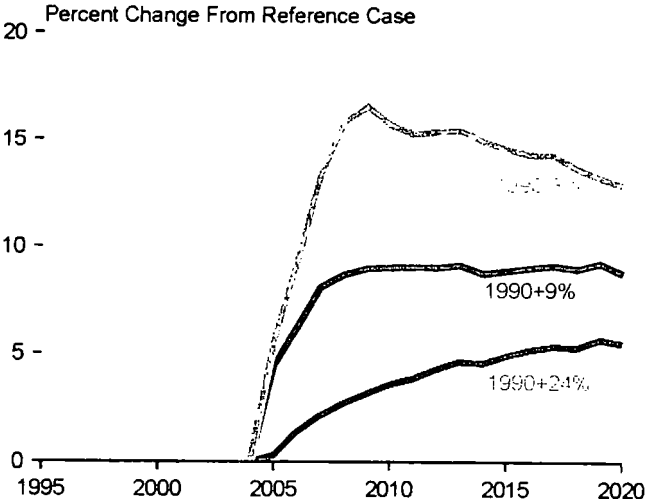
One aspect of the CPI is particularly noteworthy. The CPI measures the prices that consumers face, regardless

Figure 116. Projected Changes in Wholesale Price Index for Fuel and Power Relative to the Reference Case, 1998-2020



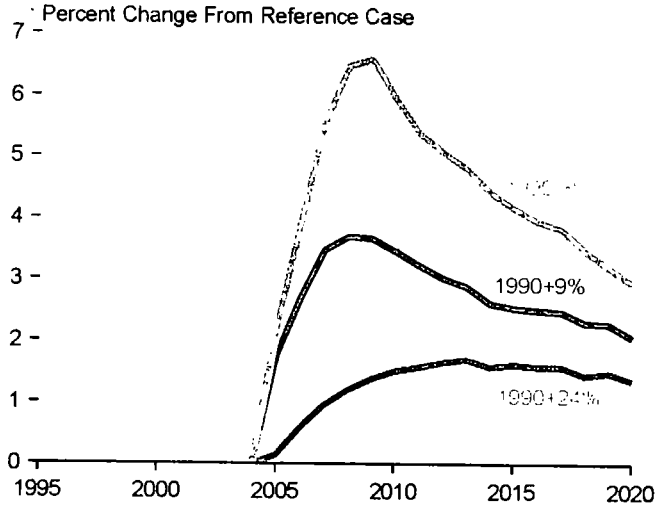
Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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.

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.

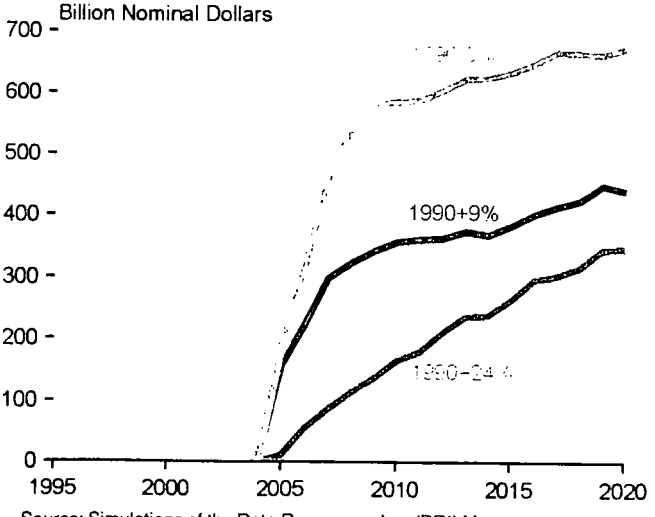
In the 1990-3% case the United States attains the binding target level, and all the funds collected are kept within U.S. borders. The revenue collected in 2010 is projected to total $585 billion nominal dollars, calculated as the level of carbon emissions (1,305 million metric tons) times the carbon 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

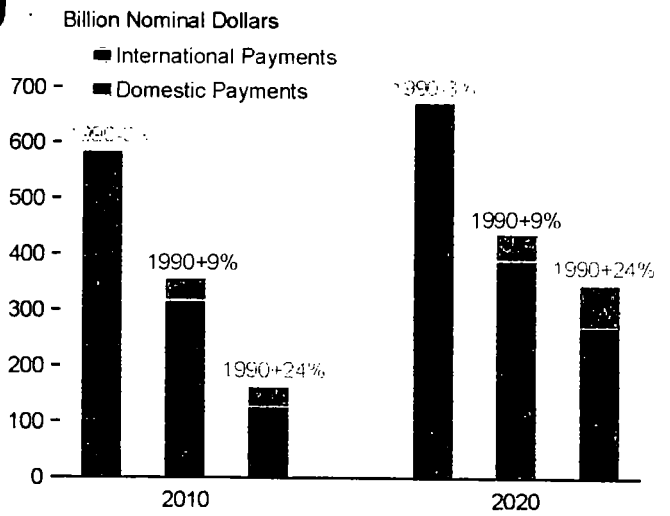
The ultimate impacts of carbon mitigation policies on the economy will be determined by complex

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

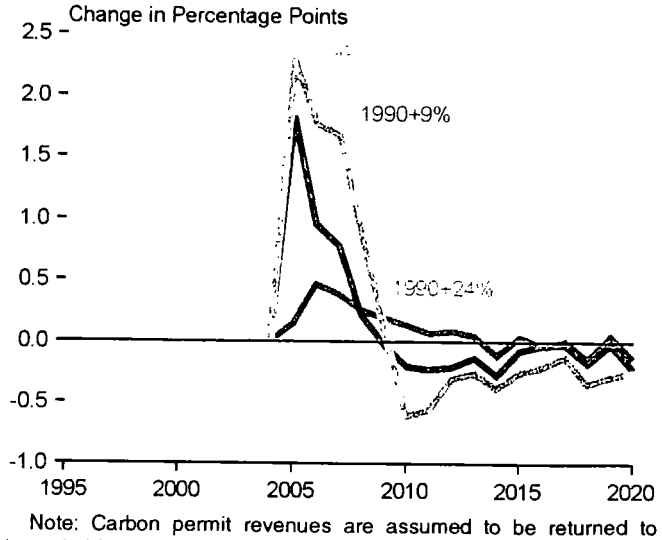
[83]The Federal funds rate is the rate charged by a depository institution on an overnight sale of Federal funds to another depository institution. This rate influences the trend in behavior for other interest rates in the economy.

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.

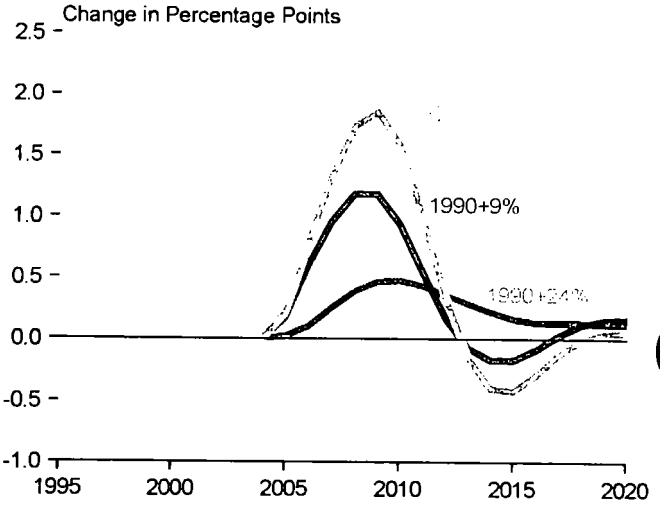
Focusing first on the 1990+9% case, the inflation rate jumps from 3.3 percent per year to 5.1 percent per year, a difference of 1.8 percentage points in 2005, the first year of the energy price rise, and continues to remain high for the first 4 years of the carbon reduction program. In the same 4-year 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



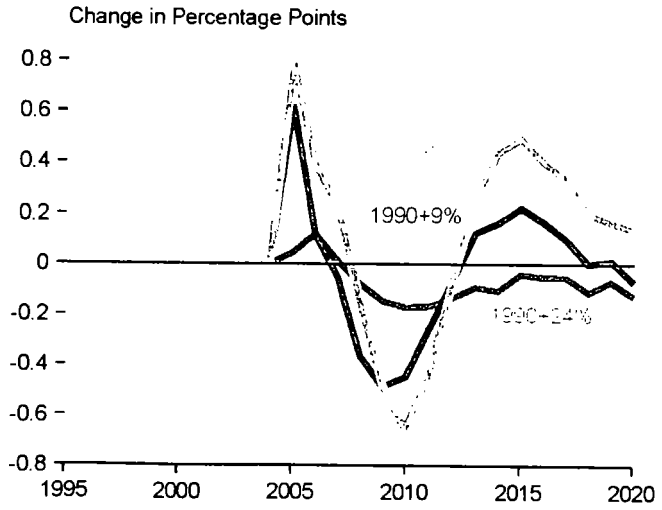
Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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



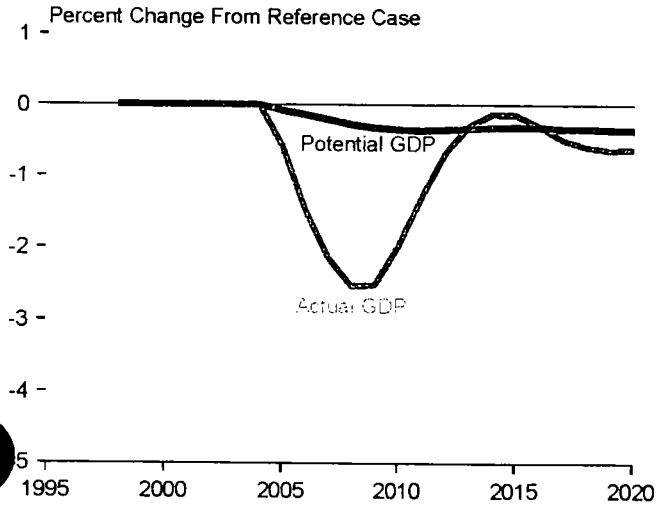
Note: Carbon permit revenues are assumed to be returned to households through personal income tax rebates.
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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.

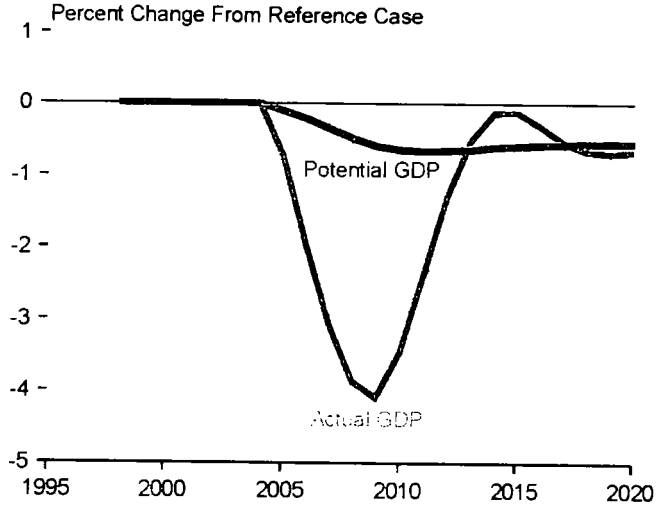
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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).

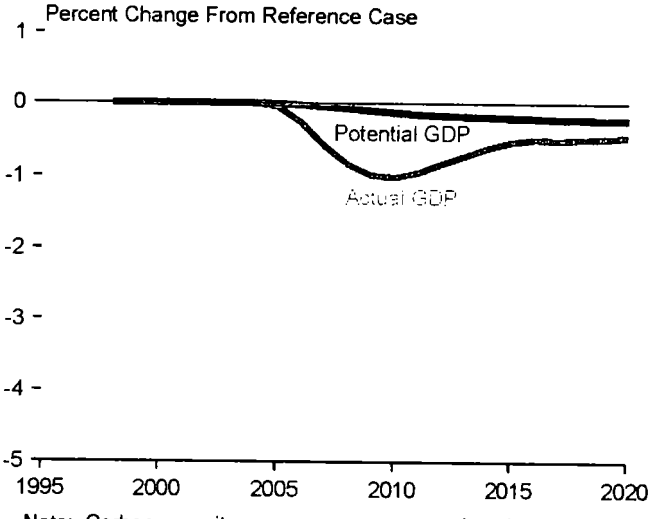
Beyond the aggregate impact on GDP, a significant change in the composition of final demand is projected in the carbon reduction cases (Table 29). In the 1990+9% case, consumption in 2009 is projected to be 1.9 percent lower than projected in the reference case (Figure 127). Returning the carbon permit 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.

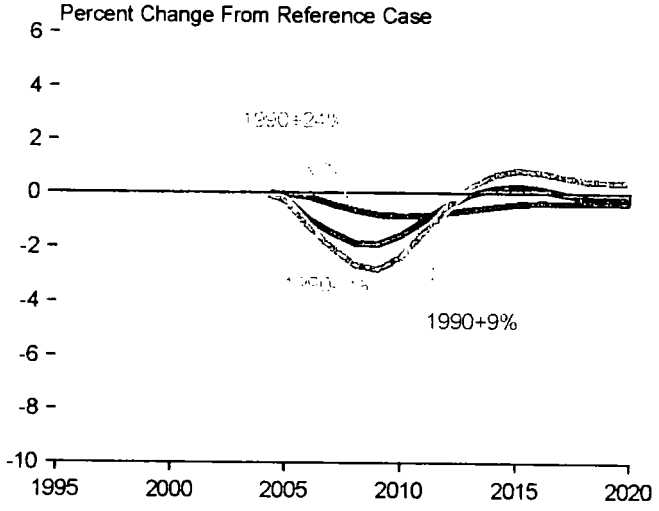
Figure 126. Projected Changes in Potential and Actual U.S. Gross Domestic Product in the 1990+24% Case Relative to the Reference Case, 1998-2020



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.

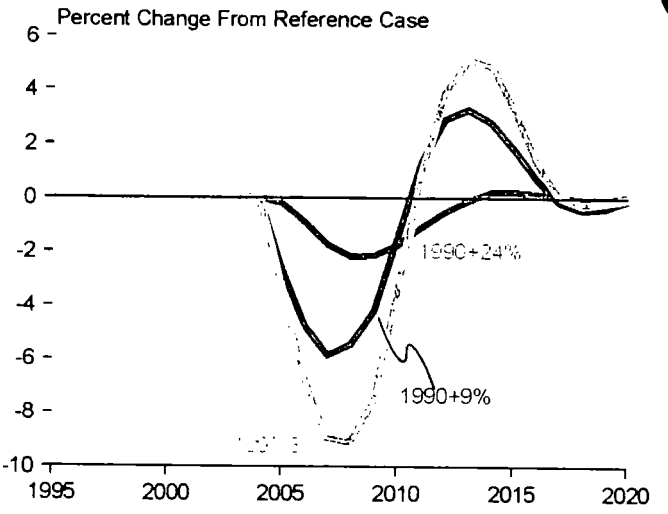
The 1990-3% case shows a pattern of adjustment similar to that projected in the 1990+9% case, except that the reaction in terms of both consumption and investment is more extreme, given the higher carbon price. Consumption reaches its lowest point in the year 2009 at 2.8 percent below the reference case. 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

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.

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

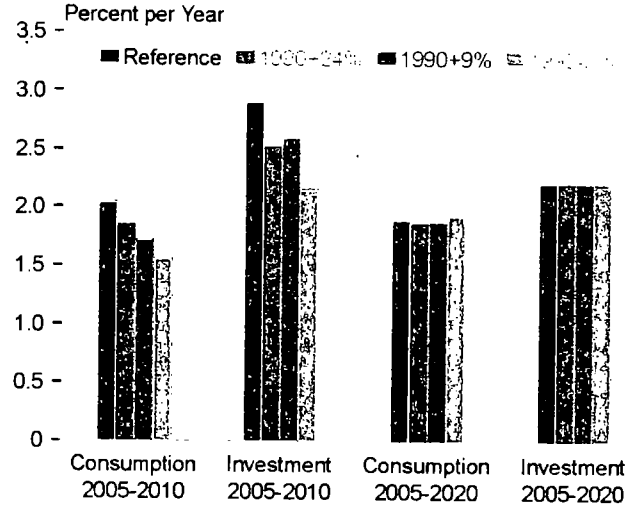
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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.

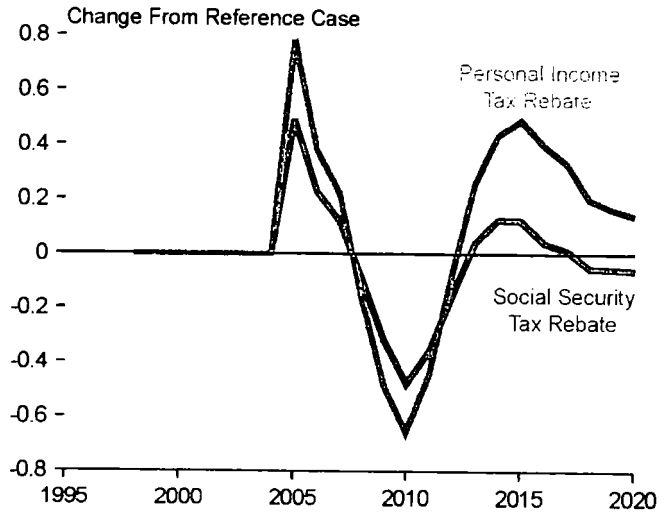
Returning the funds to consumers through personal income tax rebates or returning them to consumers and businesses through social security tax rebates would work to ameliorate the short-term impacts on the economy by bolstering disposable income. Alternative fiscal policies, such as having the Federal 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.

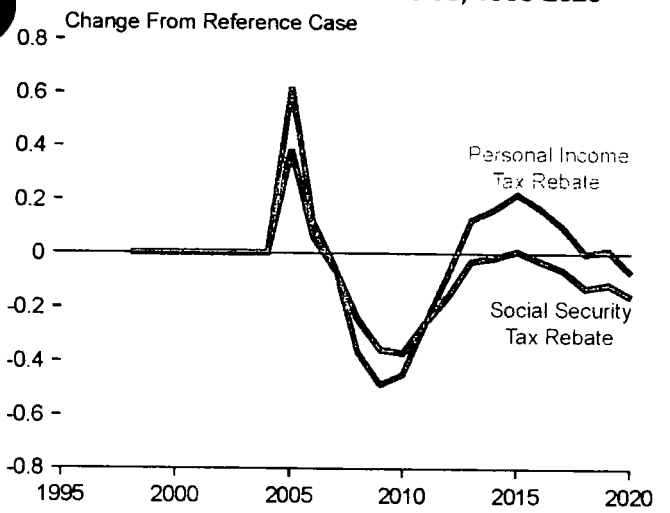
[84] In the DRI model for personal taxes only, a lump sum transfer produces the same effects as a cut in the personal income tax rate.

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



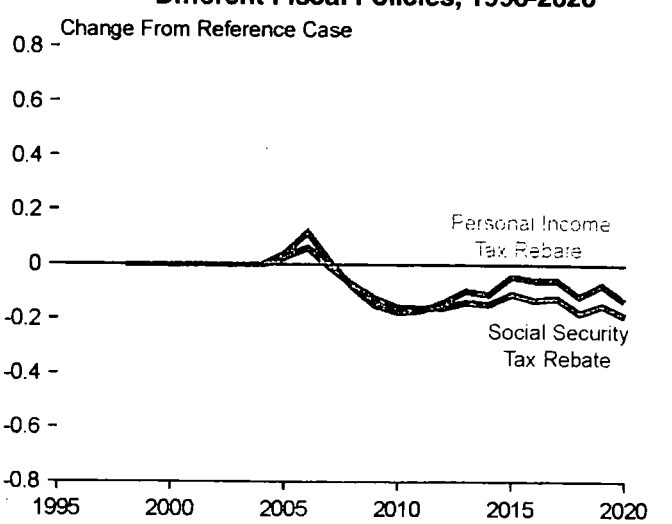
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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



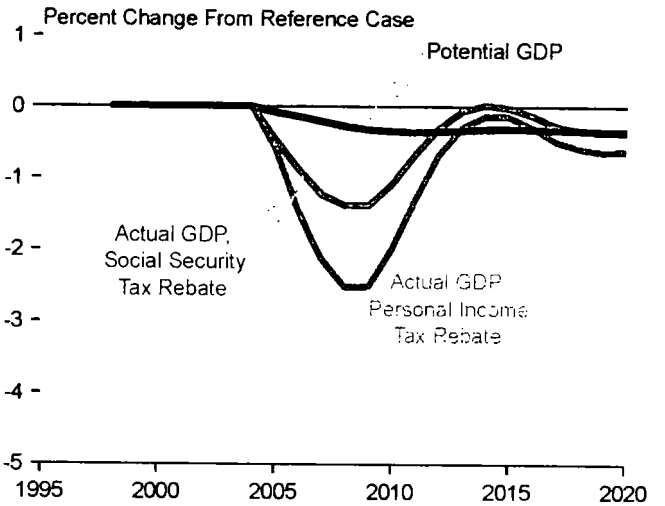
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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



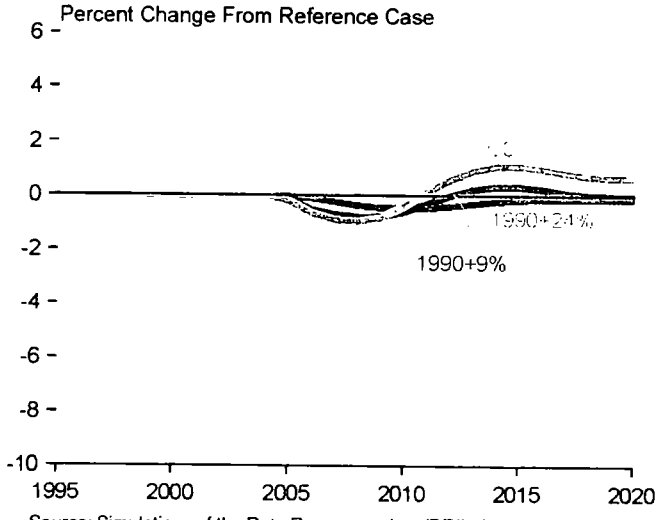
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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



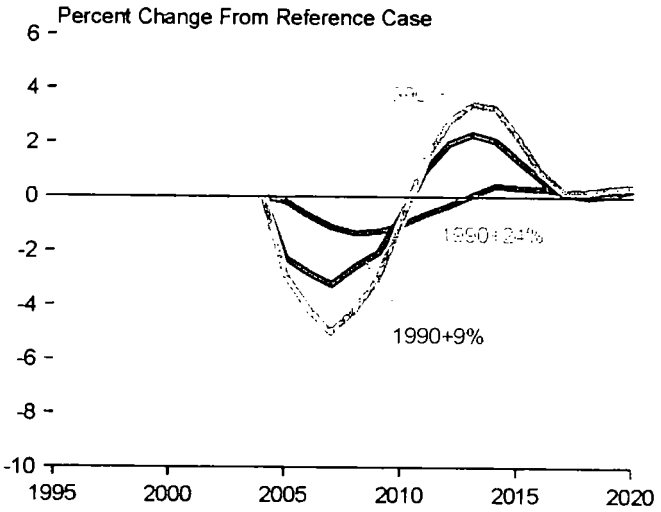
Source: Simulations of the Data Resources, Inc. (DRI) Macroeconomic Model of the U.S. Economy.

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.

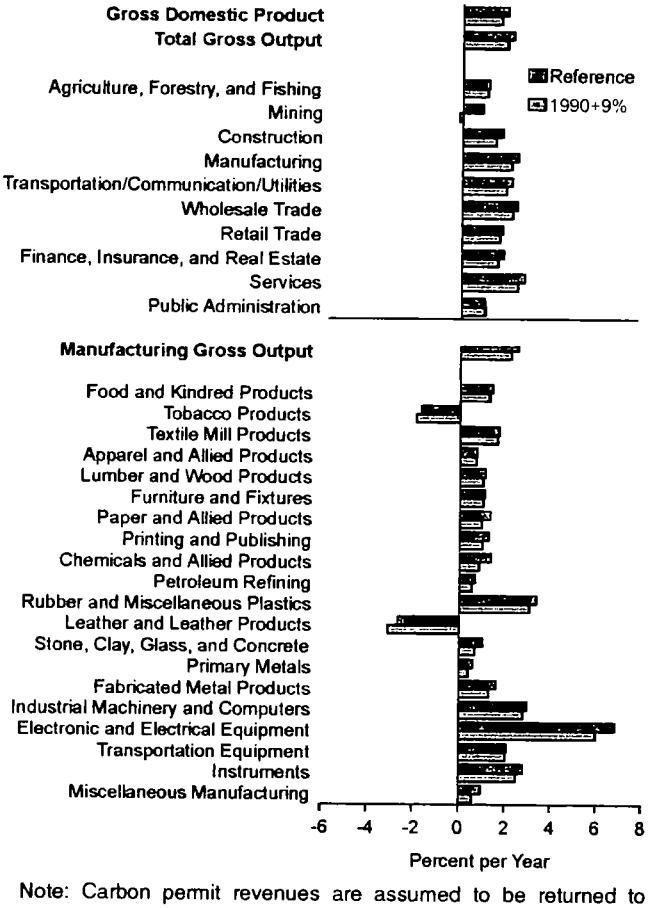
Sectoral Impacts

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.

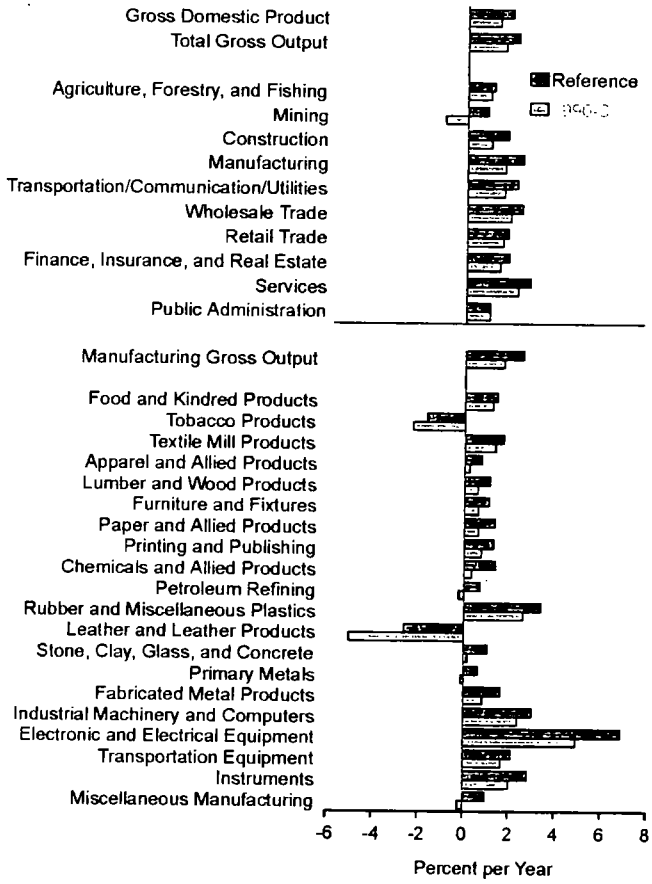
Figure 136. Projected Sectoral Growth Rates in Real Economic Output in the 1990+9% Case, 2005-2010



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.

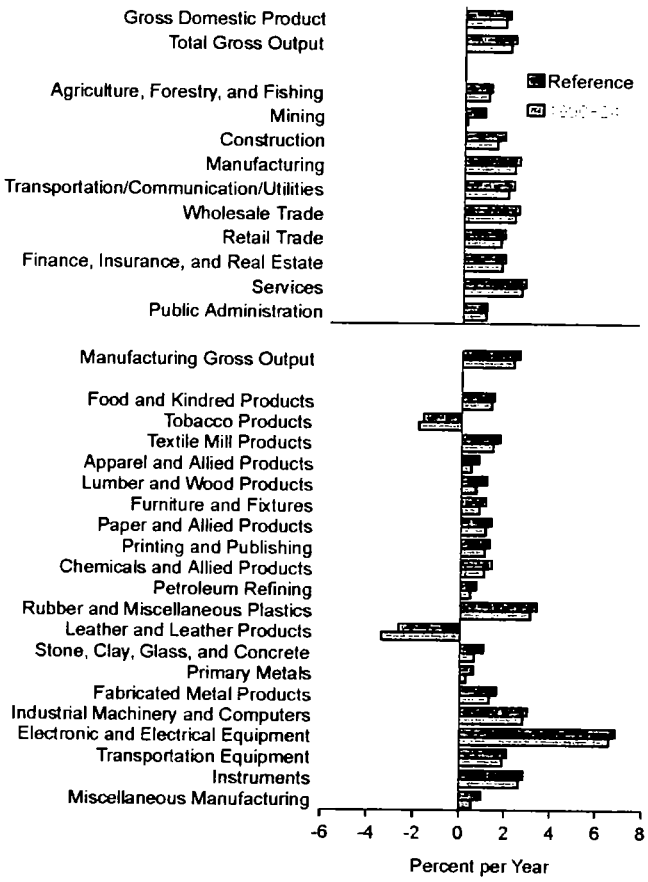
Figure 137. Projected Sectoral Growth Rates in Real Economic Output in the 1990-3% Case, 2005-2010



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.

Table 30. Comparison of Results for Reducing Carbon Emissions to 7 PercentBelow 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.

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.

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	NA	NA	-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.
NA = not available.
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)	NA	NA	—	50.00	—	67.00	163.00	121.00

[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.
NA = not available.
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 on the part of 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 the 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 Perce Belo
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	7.4
Other[9]	0.39	0.77	0.30	0.30	0.30	0.30	0.30	0.3
Total	**93.77**	**105.82**	**105.32**	**103.32**	**101.61**	**100.98**	**100.82**	**100.2**
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						
[illegible]erence [illegible]ase	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
11.18	**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 Perc 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						
erence 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 Perc Belo
Transportation								
Distillate Fuel[9]	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[5]	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						
[illegible]rence [illegible]ase	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
[illegible]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
[illegible].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
[illegible]2.06	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[16]	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

[3]Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps & solar thermal hot water heating.
[4]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[5]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.
[6]Fuel consumption includes consumption for cogeneration.
[6]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 Perc Belo
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	10.5
Petroleum Products[2]	8.76	8.61	8.76	9.52	10.02	10.21	10.37	10.5
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						
erence 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 Perc Belo
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 Perc 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	0.0
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						
ference 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 Perc 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	0.2
Lighting	1.05	1.15	1.13	1.09	1.05	1.04	1.04	1.0
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 Perc 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.
C = 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 Perc 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	4.5
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 Perc Bel
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.
Total	**24.73**	**29.81**	**29.81**	**29.64**	**29.45**	**29.35**	**29.30**	**29.**

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 Perc 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 Per 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
Combustion Turbine/Diesel	5.7	68.4	59.6	49.7	43.3	43.3	43.7	4
Nuclear Power	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						
ference 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 Pe... Belo...
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 EIA-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	2.0
Distillate Fuel[9]	3.32	3.87	3.84	3.80	3.77	3.75	3.75	3
Residual Fuel	0.90	0.83	0.84	0.82	0.81	0.80	0.79	0.
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						
erence 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						
ference 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.

ompressed natural gas used as vehicle fuel.

alancing 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 ta 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 Per 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	0.9
Total	**40.76**	**38.72**	**40.64**	**55.54**	**66.04**	**71.02**	**73.56**	**77.**

Table B14. Natural Gas Prices, Margins, and Revenue (Continued)
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Projections													
2010							2020						
ference 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 Perce Belo
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 Per 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						
ference 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 Perc 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 Perc 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						
[redacted]erence 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**
[redacted]44.3	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.
[redacted]urces: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). 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:** , 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 Perc 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**	**14.6**
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)	6,742	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)	1.08	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)	90.9	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	4.40	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)	1,069	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 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	22.4	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	79.3	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)	6,742	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)	1,069	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)	6.8	5.9	6.6	5.5	6.6
Natural Gas (Dollars per Thousand Cubic Feet)	4.26	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	22.4	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	79.3	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)	6,742	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 Consumption (Quadrillion Btu)	91	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)	6,742	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 Consumption (Quadrillion Btu)	90.9	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)	13.54	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 Consumption (Quadrillion Btu)	93.8	117.7	93.9	125.7	93.5
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.4	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	79.3	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	4.4	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)	13.5	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 Consumption (Quadrillion Btu)	93.8	117.7	101.5	125.7	103.3
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.4	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	79.3	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)	1,069	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)	13.54	11.80	10.16	10.78	9.17
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.14	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)	4.26	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)	6.8	5.9	11.0	5.6	9.3
Total Primary Energy Consumption (Quadrillion Btu)	93.8	111.2	91.7	117.0	98.8
Fossil Fuel Consumption (Quadrillion Btu)					
Natural Gas	22.4	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	79.3	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	4.4	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)	1,069	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)	13.54	11.80	10.78	11.0	10.78	9.62	9.78
Delivered Energy Intensity (Thousand Btu per 1992 Dollar of GDP)	10.14	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)	4.26	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)	6.8	5.9	8.8	8.2	5.6	8.1	7.8
Total Primary Energy Consumption (Quadrillion Btu)	93.8	111.2	99.6	101.9	117.0	103.8	105.6
Fossil Fuel Consumption (Quadrillion Btu)							
Natural Gas	22.4	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	79.3	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	7.0
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	4.4	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)	6,742	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)	90.9	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

F. JAMES SENSENBRENNER, JR., Wisconsin, CHAIRMAN
SHERWOOD L. BOEHLERT, New York
HARRIS W. FAWELL, Illinois
CONSTANCE A. MORELLA, Maryland
CURT WELDON, Pennsylvania
DANA ROHRABACHER, California
STEVEN SCHIFF, New Mexico
JOE BARTON, Texas
KEN CALVERT, California
ROSCOE G. BARTLETT, Maryland
VERNON J. EHLERS, Michigan
DAVE WELDON, Florida
MATT SALMON, Arizona
THOMAS M. DAVIS, Virginia
BILL LUTHER, Minnesota
MARK FOLEY, Florida
THOMAS W. EWING, Illinois
CHARLES W. "CHIP" PICKERING, Mississippi
BOB GRAHAM, Utah
ERNIE FLETCHER, Kentucky
MICHAEL CASTLE, Delaware
PHIL ENGLISH, Pennsylvania
GEORGE R. NETHERCUTT, JR., Washington
TOM A. COBURN, Oklahoma
PETE SESSIONS, Texas

RALPH M. HALL, Texas
MARY BONO, California
JAMES A. TRAFICANT, JR., Ohio
TIM ROEMER, Indiana
ROBERT E. (BUD) CRAMER, JR., Alabama
JAMES A. BARCIA, Michigan
PAUL MCHALE, Pennsylvania
EDDIE BERNICE JOHNSON, Texas
ALCEE L. HASTINGS, Florida
LYNN N. RIVERS, Michigan
ZOE LOFGREN, California
MICHAEL F. DOYLE, Pennsylvania
SHEILA JACKSON LEE, Texas
BILL LUTHER, Minnesota
MALCOLM M. CAPPS, California
DEBBIE STABENOW, Michigan
BOB ETHERIDGE, North Carolina
NICK LAMPSON, Texas
DARLENE HOOLEY, Oregon
ELLEN O. TAUSCHER, California

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE
SUITE 2320 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6301
(202) 225-6371
TTY: (202) 226-4410
http://www.house.gov/science/science.htm

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

F. JAMES SENSENBRENNER, JR., Wisconsin, CHAIRMAN
...
SHERWOOD L. BOEHLERT, New York
HARRIS W. FAWELL, Illinois
CONSTANCE A. MORELLA, Maryland
CURT WELDON, Pennsylvania
DANA ROHRABACHER, California
STEVEN H. SCHIFF, New Mexico
JOE BARTON, Texas
KEN CALVERT, California
ROSCOE G. BARTLETT, Maryland
VERNON J. EHLERS, Michigan
DAVE WELDON, Florida
MATT SALMON, Arizona
THOMAS M. DAVIS, Virginia
SIL SKEEN, Minnesota
MARK FOLEY, Florida
THOMAS W. EWING, Illinois
CHARLES W. "CHIP" PICKERING, Mississippi
CHRIS CANNON, Utah
KEVIN BRADY, Texas
MERRILL COOK, Utah
PHIL ENGLISH, Pennsylvania
GEORGE R. NETHERCUTT, JR., Washington
TOM A. COBURN, Oklahoma
PETE SESSIONS, Texas

GEORGE E. BROWN, JR., California
Ranking Minority Member
...
RALPH M. HALL, Texas
BART GORDON, Tennessee
JAMES A. TRAFICANT, JR., Ohio
TIM ROEMER, Indiana
ROBERT E. (BUD) CRAMER, JR., Alabama
JAMES A. BARCIA, Michigan
EDDIE BERNICE JOHNSON, Texas
ALCEE L. HASTINGS, Florida
LYNN N. RIVERS, Michigan
ZOE LOFGREN, California
MICHAEL F. DOYLE, Pennsylvania
SHEILA JACKSON LEE, Texas
BILL LUTHER, Minnesota
WALTER H. CAPPS, California
DEBBIE STABENOW, Michigan
BOB ETHERIDGE, North Carolina
NICK LAMPSON, Texas
DARLENE HOOLEY, Oregon
ELLEN O. TAUSCHER, California

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE
SUITE 2320 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6301
(202) 225-6371
TTY: (202) 226-4410
http://www.house.gov/science/welcome.htm

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),

- 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,

F. JAMES SENSENBRENNER, JR.
Chairman

GEORGE E. BROWN, JR.
Ranking Minority Member

Briefing on EIA's Kyoto Study

August 19, 1998

Kyoto Study Objective:

To determine the impact on the U.S. energy system and the economy of possible alternative target emission reduction levels that may result from the Kyoto Protocol.

Scenarios for Kyoto Study

- 34 percent above 1990 levels (AEO Base Case)
- 24 percent above 1990 levels (Substantial International Permit Trading)
- 14 percent above 1990 levels (Stabilization at 1998 Levels)
- 9 percent above 1990 levels (State Department Offsets and Sinks plus Estimate of Permits Available from FSU)
- Stabilization at 1990 Emissions Levels
- 3 percent below 1990 levels (State Department Offsets and Sinks)
- 7 percent below 1990 levels (Kyoto Protocol Target)

Assumptions

- AEO Reference Case Assumptions (including technology)
- Begin in 2005
- "Kyoto Forever"
- Nuclear Life Extension, if Economic
- No New Nuclear Construction

Major Sensitivities for Kyoto Study

- Low and high economic growth
- Low and high technology
- Nuclear plant construction

Benefits of Using NEMS

- All Energy Markets Represented
- Transitional Effects Captured/Annual Model
- Vintaged Capital Stock and Turnover Modeled
- Detailed Technology Menus
- Representation of Technological Learning
- Competitive Electricity Markets Included
- Direct Macroeconomic and World Oil Market Feedback

Issues

- Majority of Emissions Reduction from Electric Generation Sector
  - Feasibility of Plant Construction
  - Feasibility of Gas Deliverability
  - Feasibility of Renewable Supply

- Technology
  - Completeness of the NEMS Technology Menu
  - Technological Optimism/Manufacturing Incentives to Improve the Current Technology Slate
  - Consumer Behavior

Biomass Consultations

Energy Efficiency and Renewable Energy/Office of Energy Outreach
- Lynne Gillette
- Ray Costello
- Tien Nygyen

Oak Ridge National Laboratory
- Marie Walsh
- Bob Perlack
- Robin Graham
- Lynn Wright

Antares Group, Inc.
- Ed Gray
- Dan Packey
- Kevin Comer

USDA-Economic Research Service
- Roger Conway
- Hosein Shapouri
- Richard Haynes

University of Maryland
- Erik Lichtenberg

Colorado School of Mines
- Mike Graboski

Environmental Protection Agency
- Jim Turnure
- Bob Shackleton

National Renewable Energy Laboratory
- Shaine Tyson

Electric Power Research Institute
- Keith White
- Jim Burk

Examples of Other Consultations

Industrial Technology

Arthur D. Little

Buildings Technology

Arthur D. Little

Mr. James Rannels, Energy Efficiencies and Renewable Energy, Office of Photovoltaics and Wind Technologies

Mr. Lew Pratsch, Energy Efficiencies and Renewable Energy, Office of Geothermal Technologies

Transportation Technology

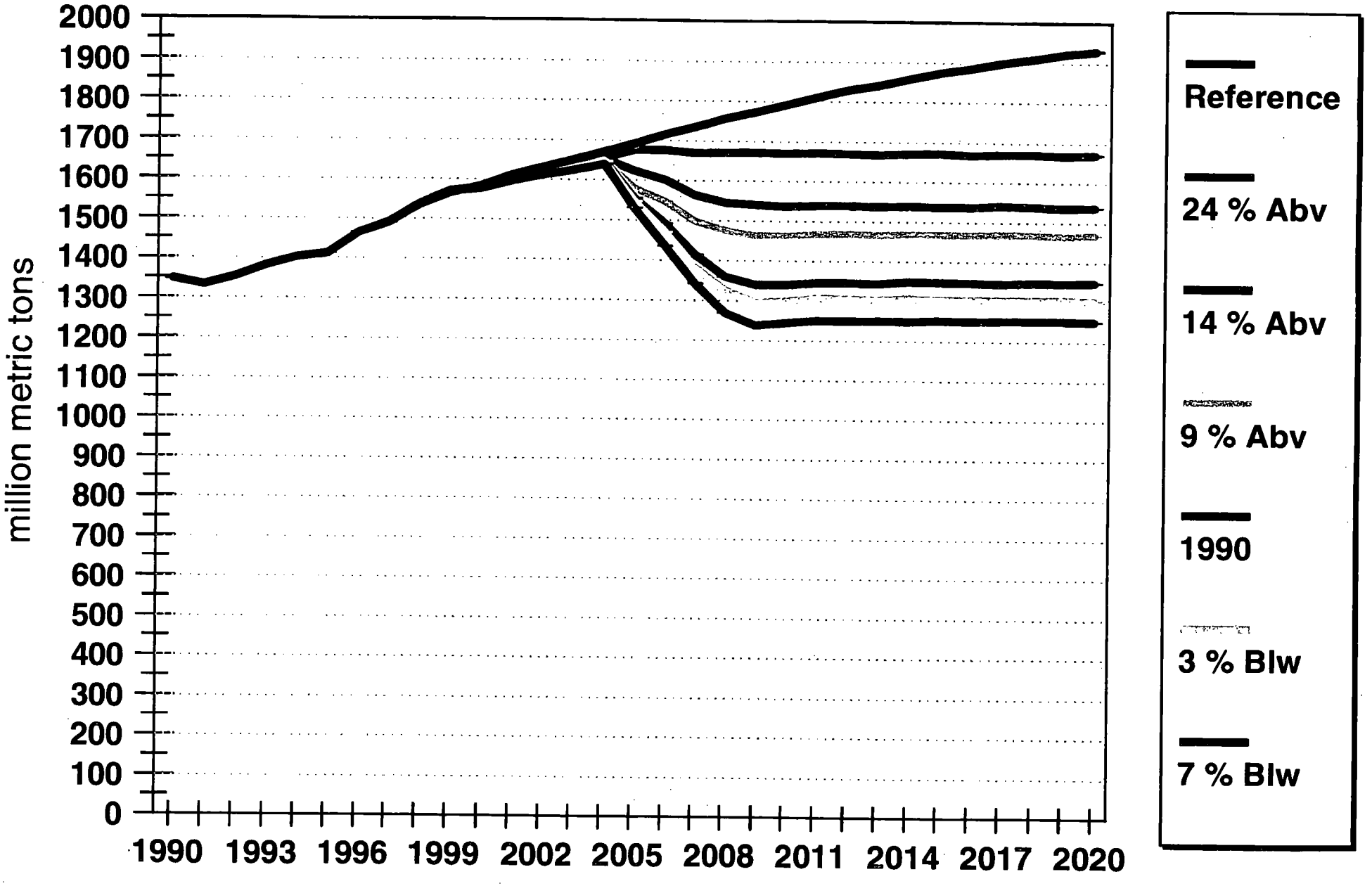
Phil Patterson, Energy Efficiency and Renewable Energy/ Transportation Technologies

Mr. Suski, American Trucking Association

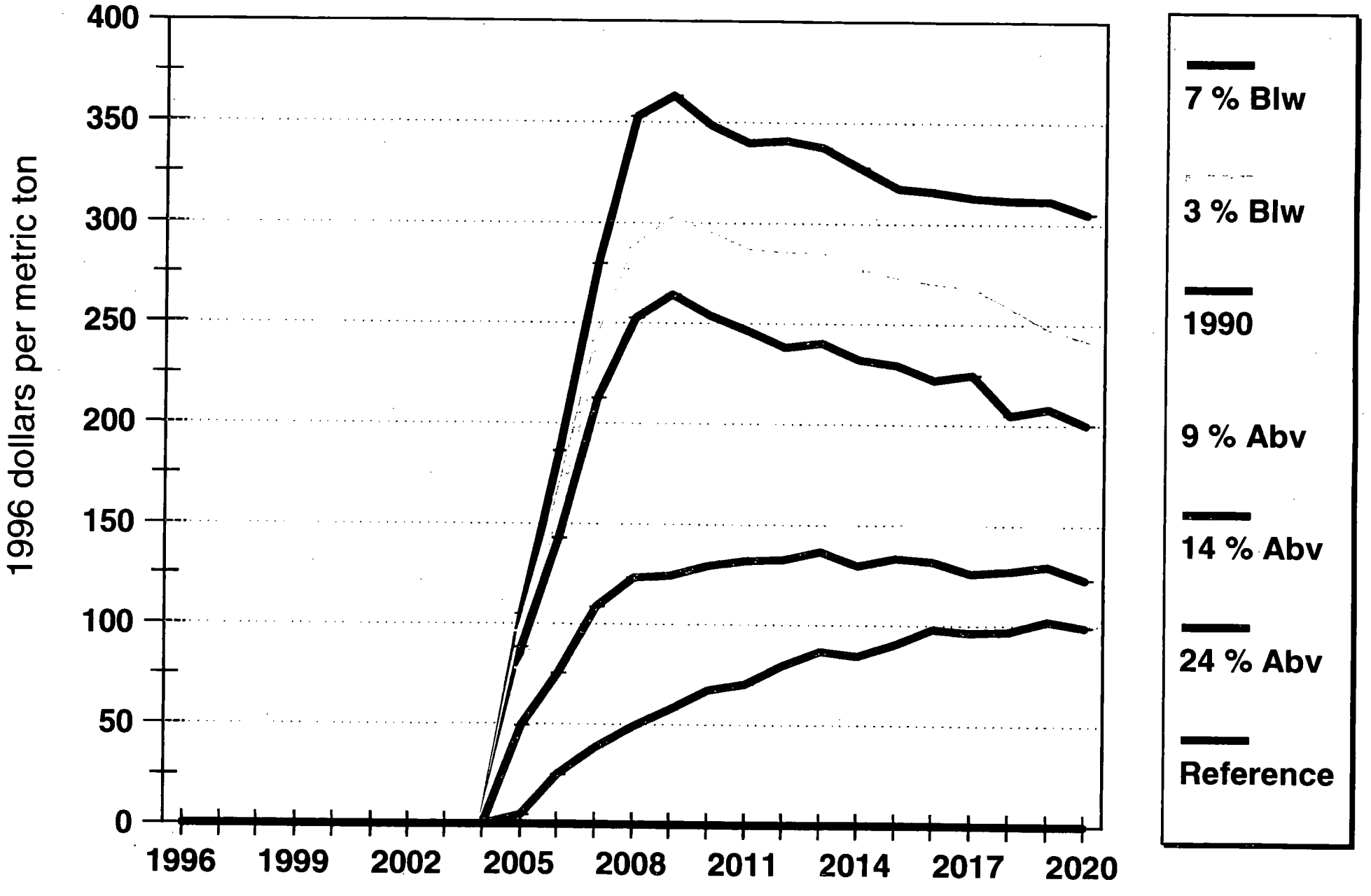
Independent Expert Reviewers

John Weyant	Energy Modeling Forum
Mike Toman	Resources for the Future
Dallas Burtraw	Resources for the Future
Billy Pizer	Resources for the Future
Richard Newell	Resources for the Future
Ray Kopp	Resources for the Future
Bill Nordhaus	Yale
Joe Boyer	Yale
Lorna Greening	Hagler Bailly
Bill Hogan	Harvard University

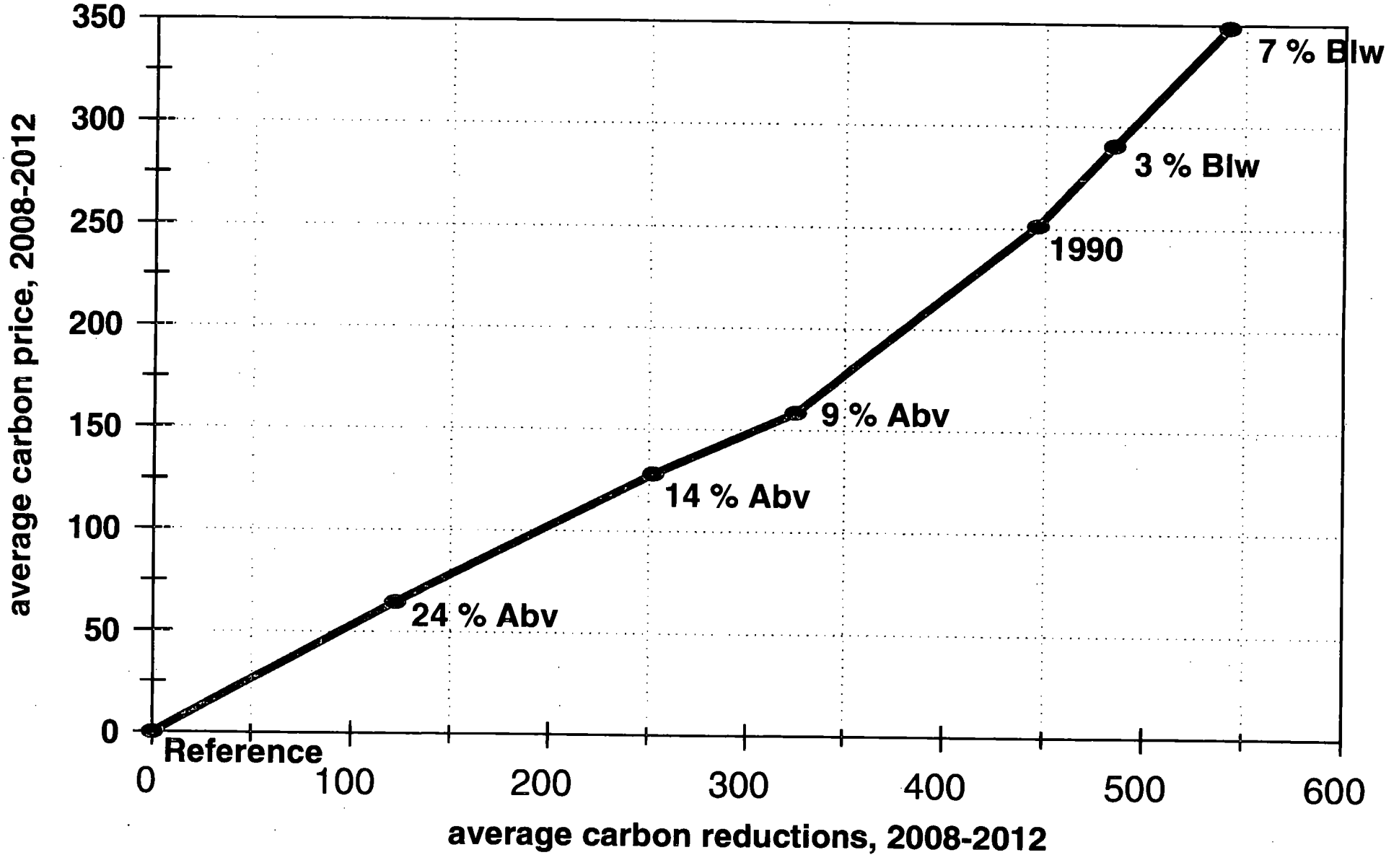
Carbon emissions in the reference and six target cases, 1990-2020



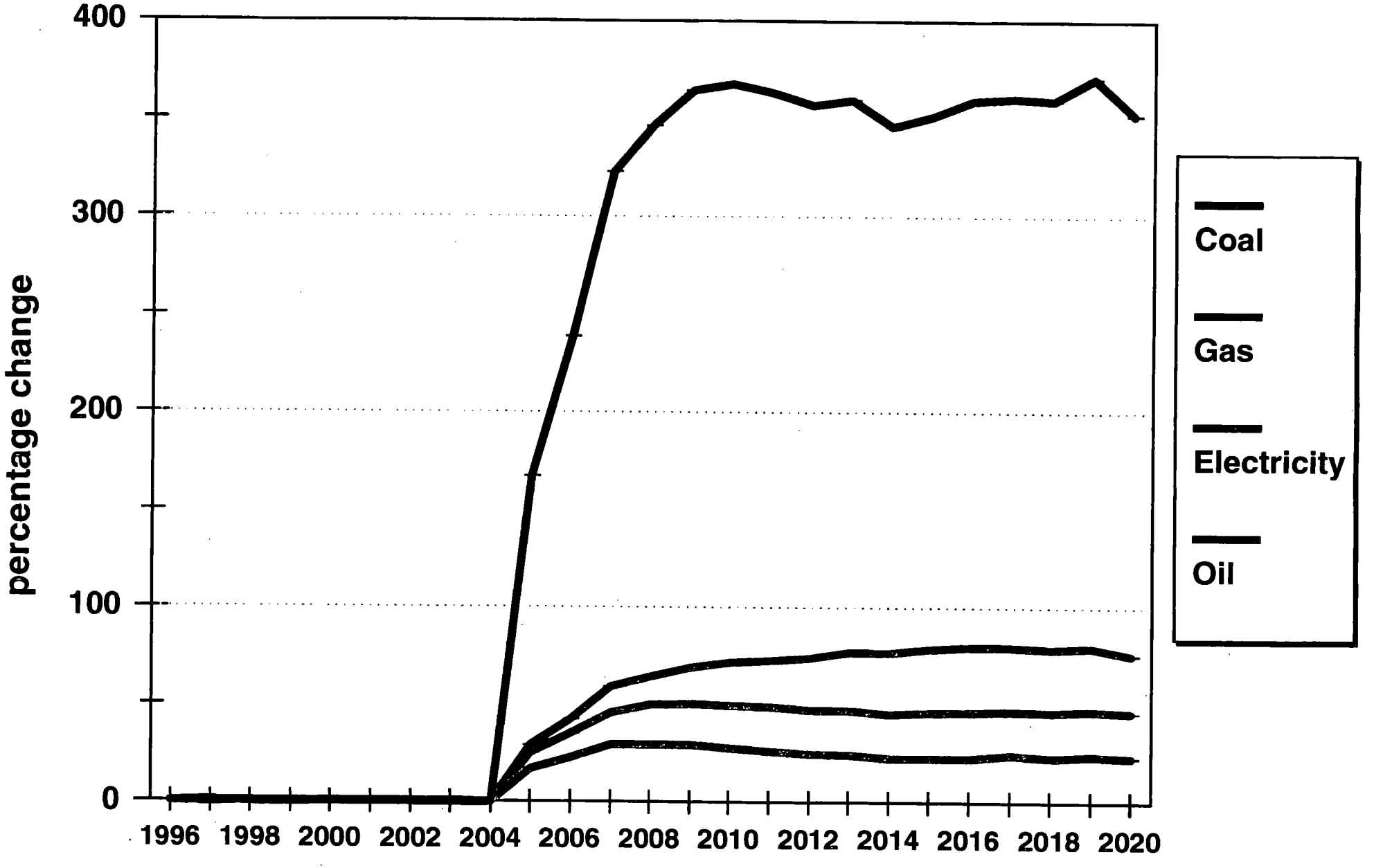
Carbon prices in the six target cases, 1996-2020



Average annual carbon reductions and carbon prices, 2008-2012

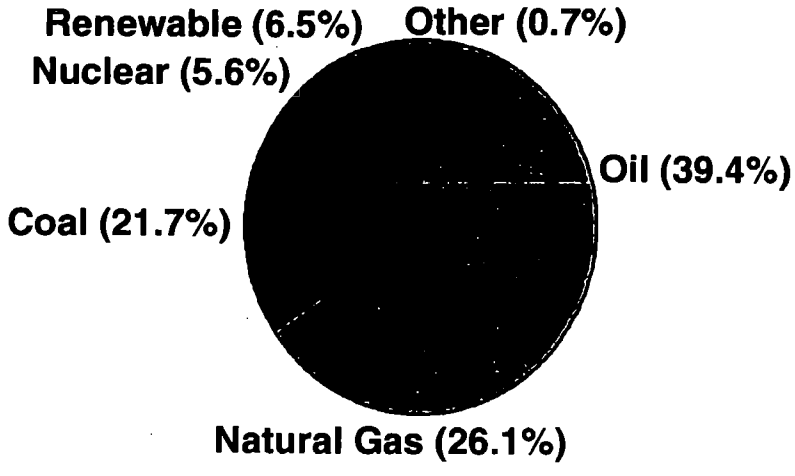


Change in delivered energy prices from reference case to 9%-above-1990 case, 1996-2020

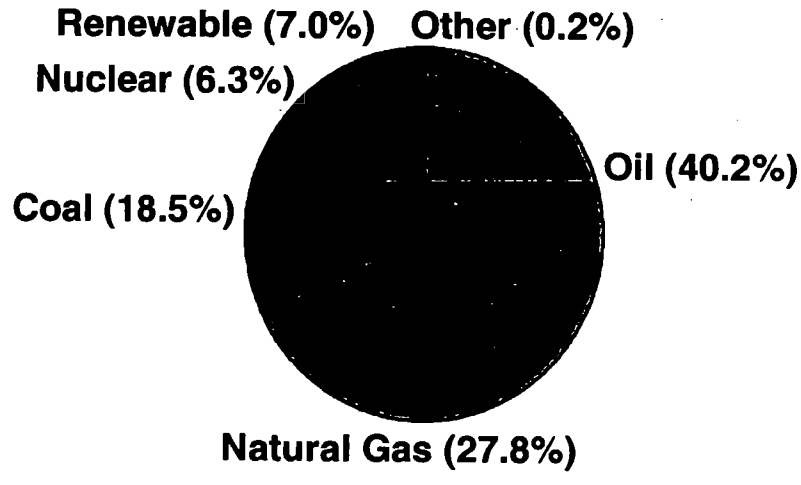


Fuel mix in the reference, 24%-above-1990,9%-above-1990, and 3%-below-1990 cases, 2010

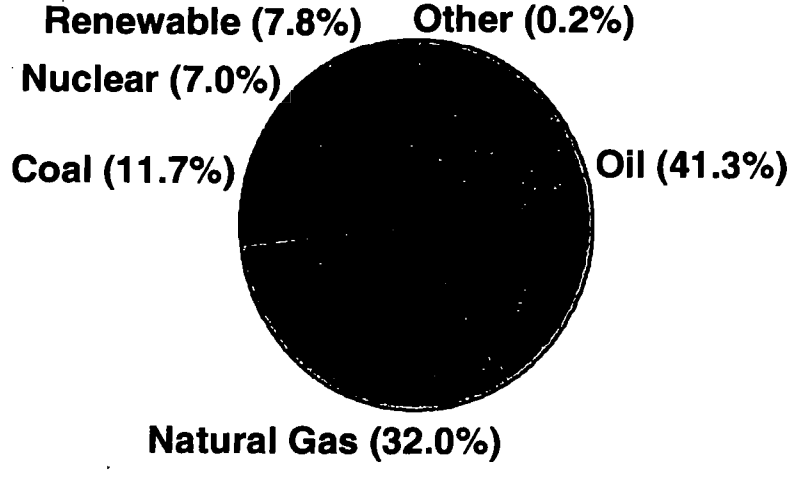
Reference



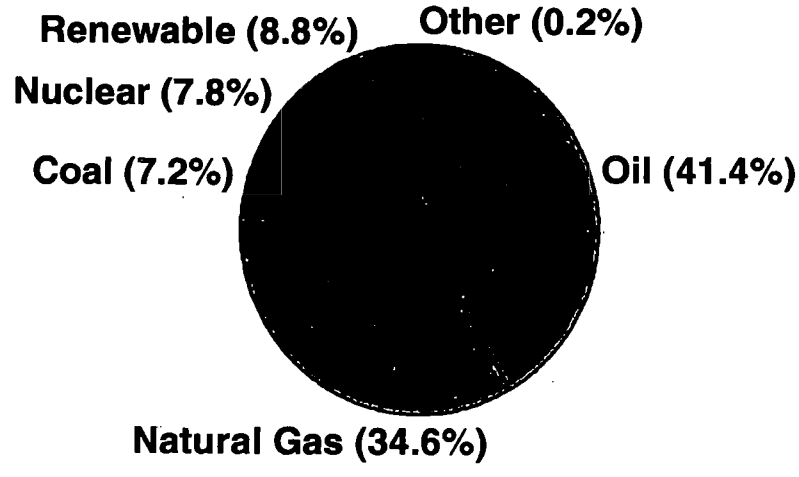
24%-Above-1990



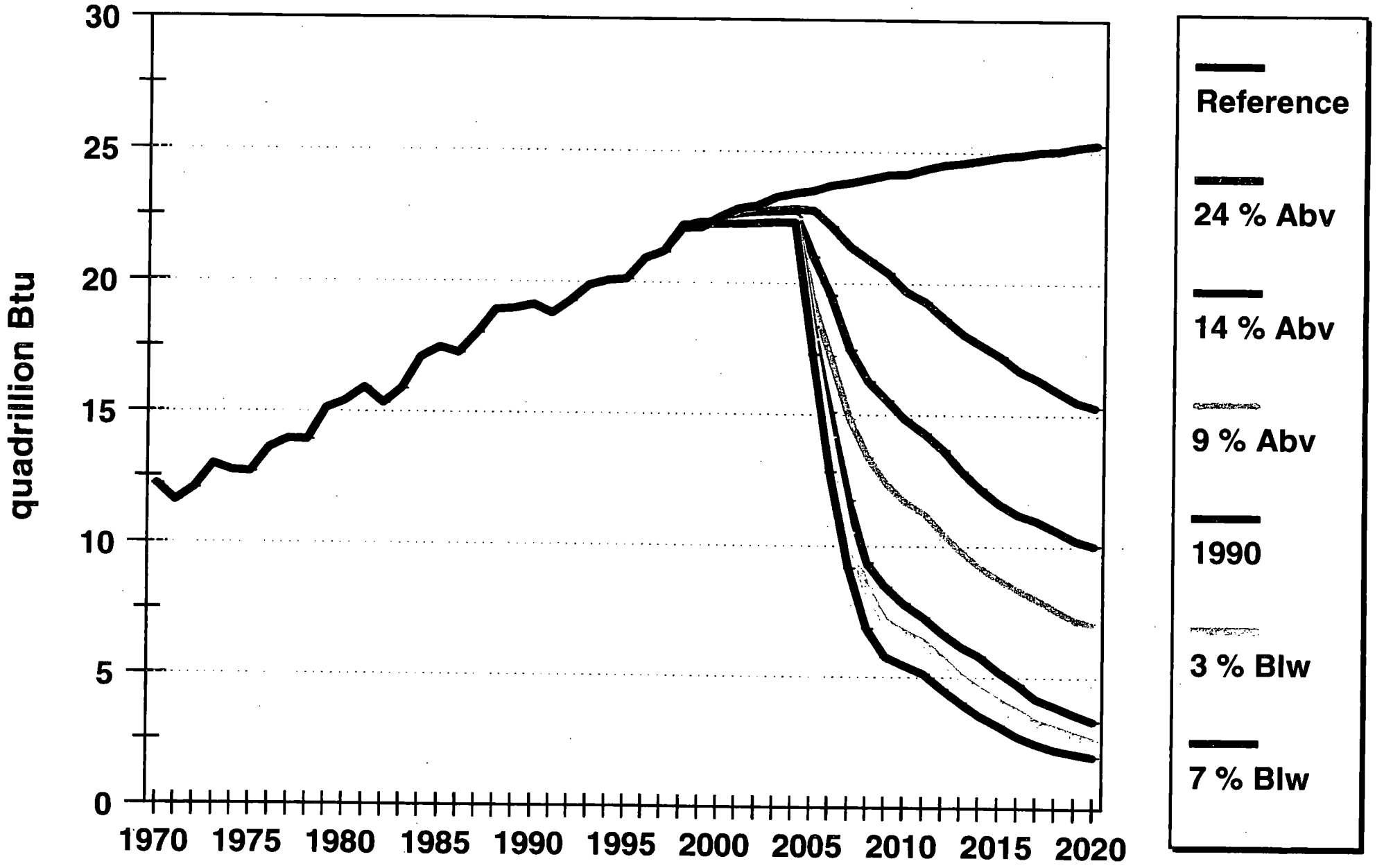
9%-Above-1990



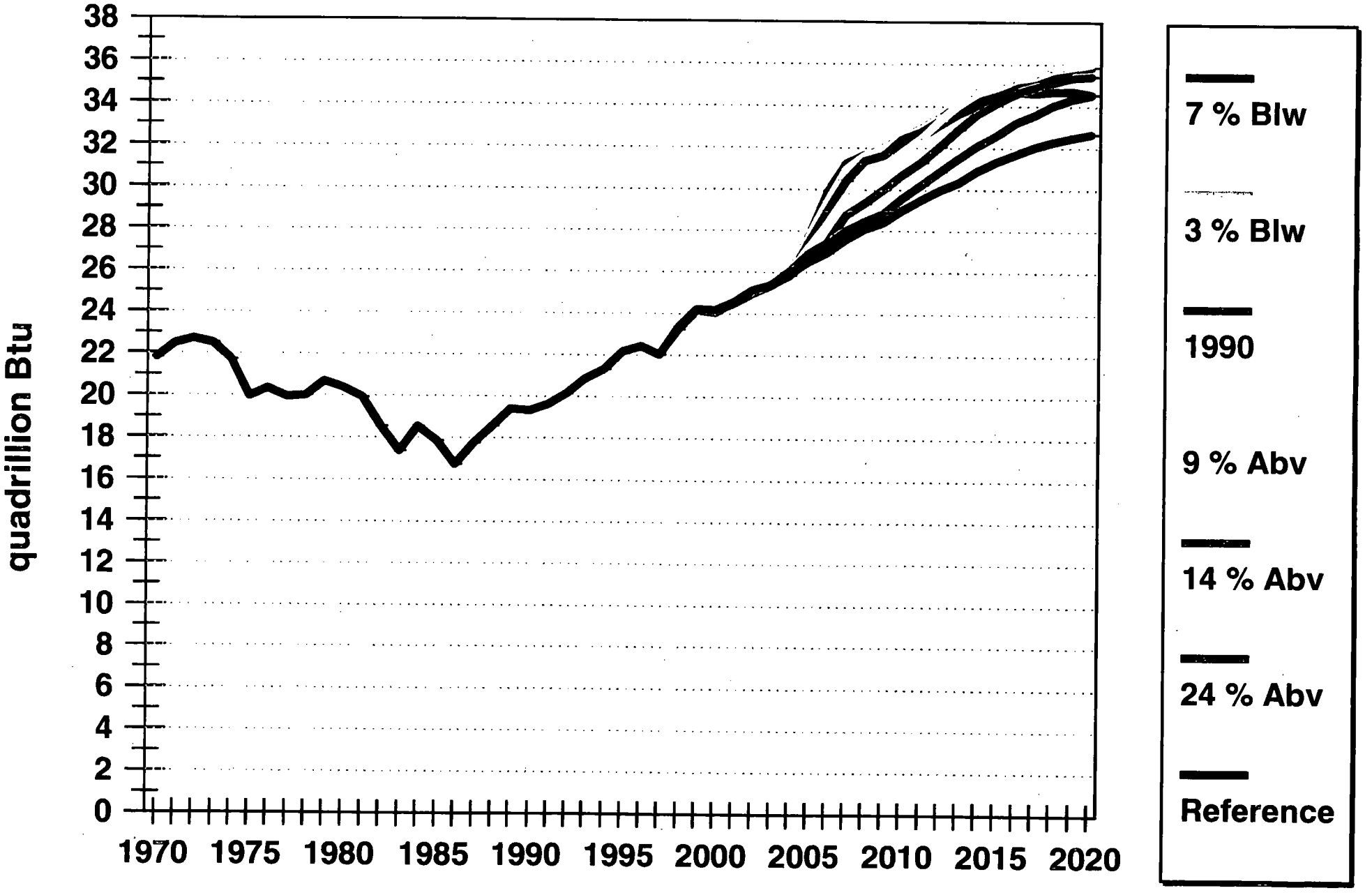
3%-Below-1990



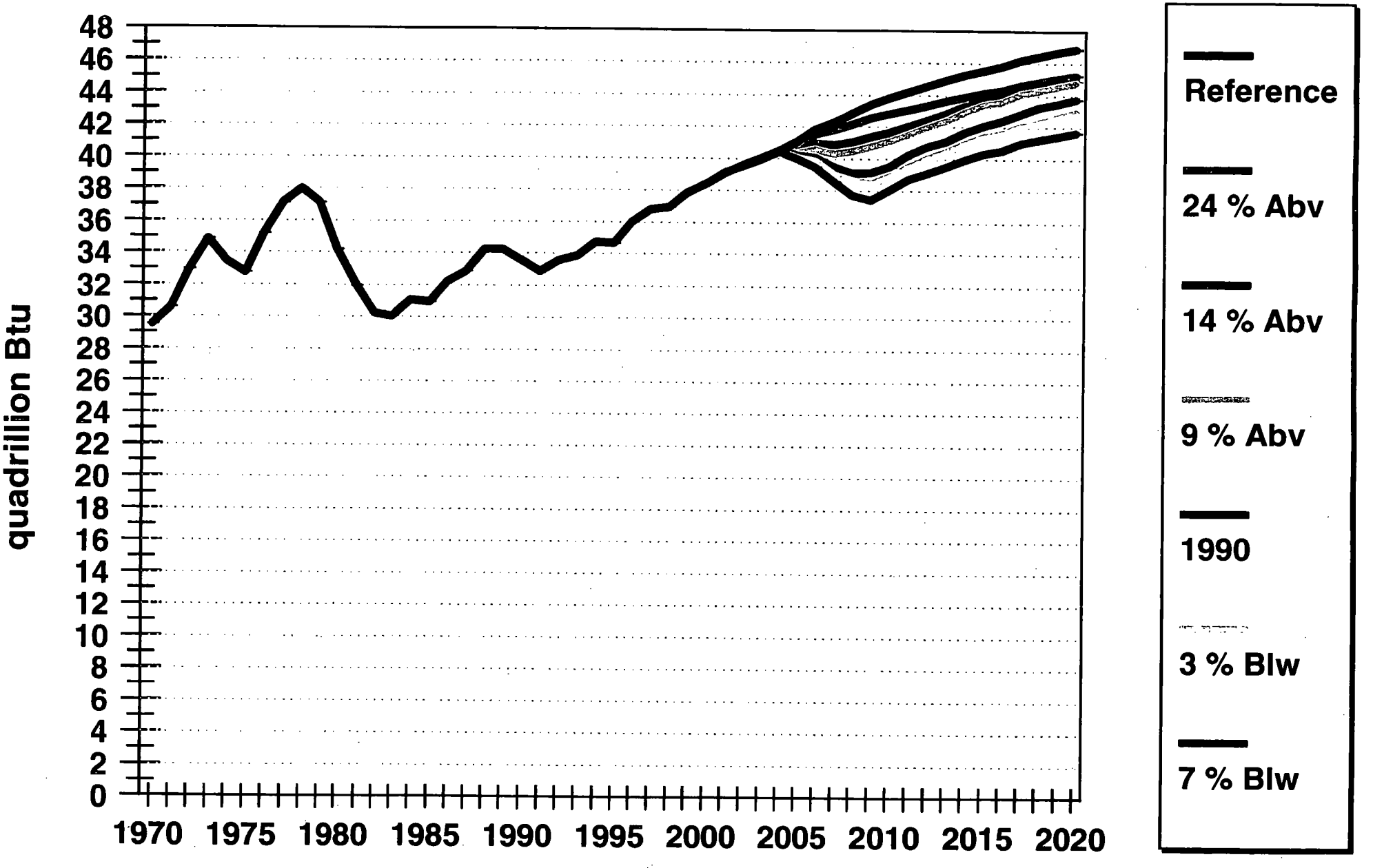
Coal Consumption in the reference and six target cases, 1970-2020



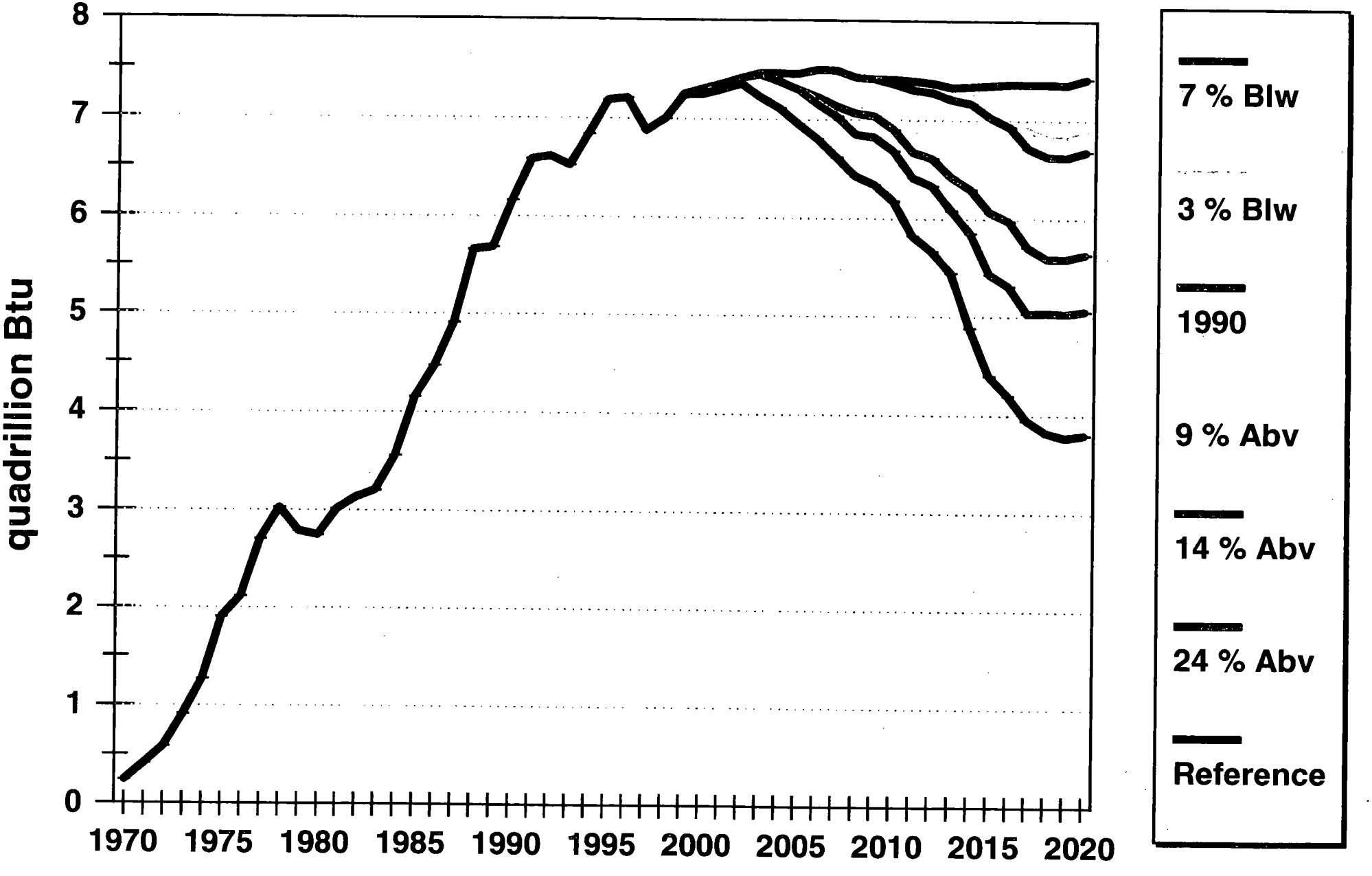
Natural gas consumption in the reference and six target cases, 1970-2020



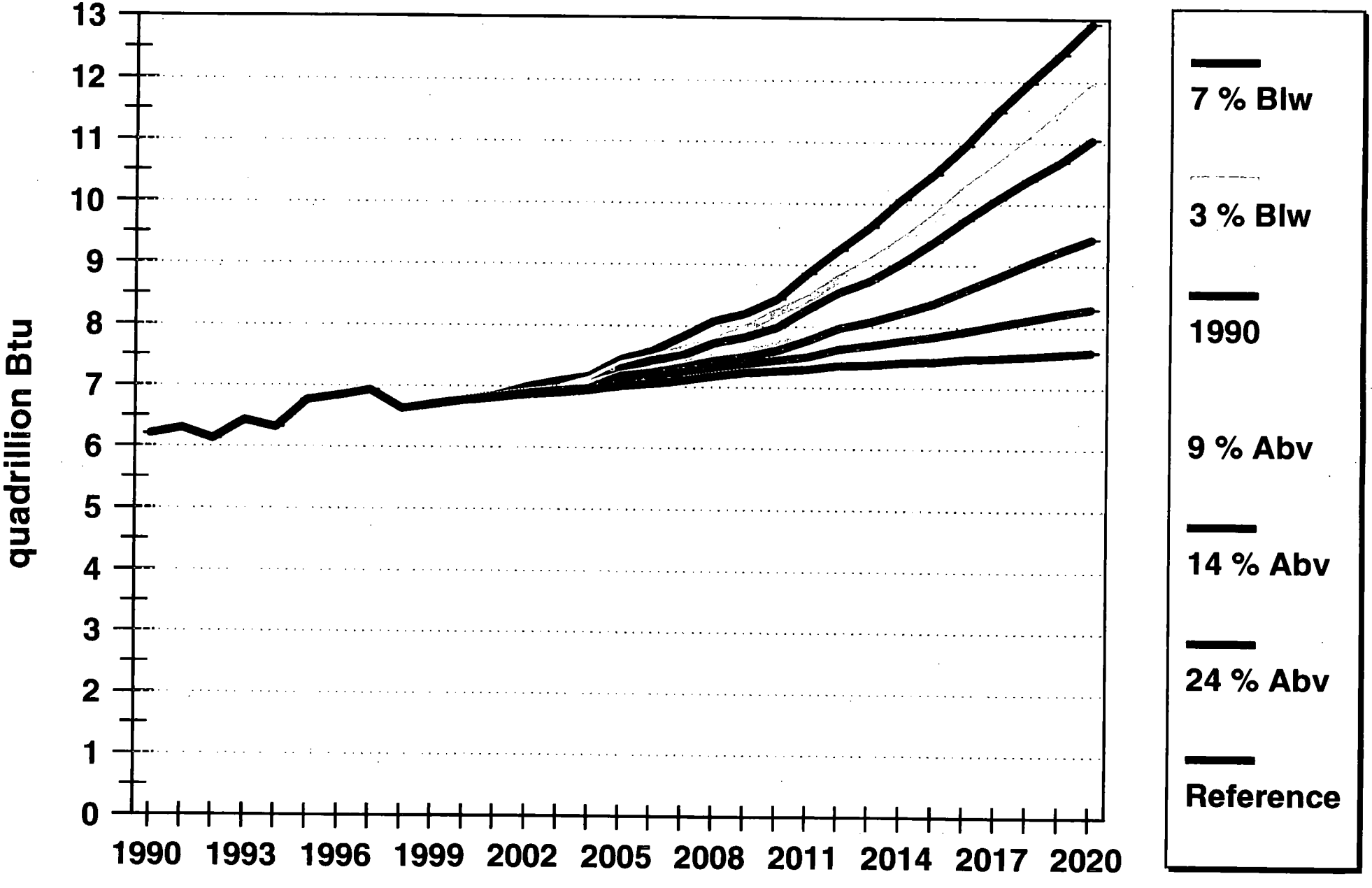
Petroleum consumption in the reference and six target cases, 1970-2020



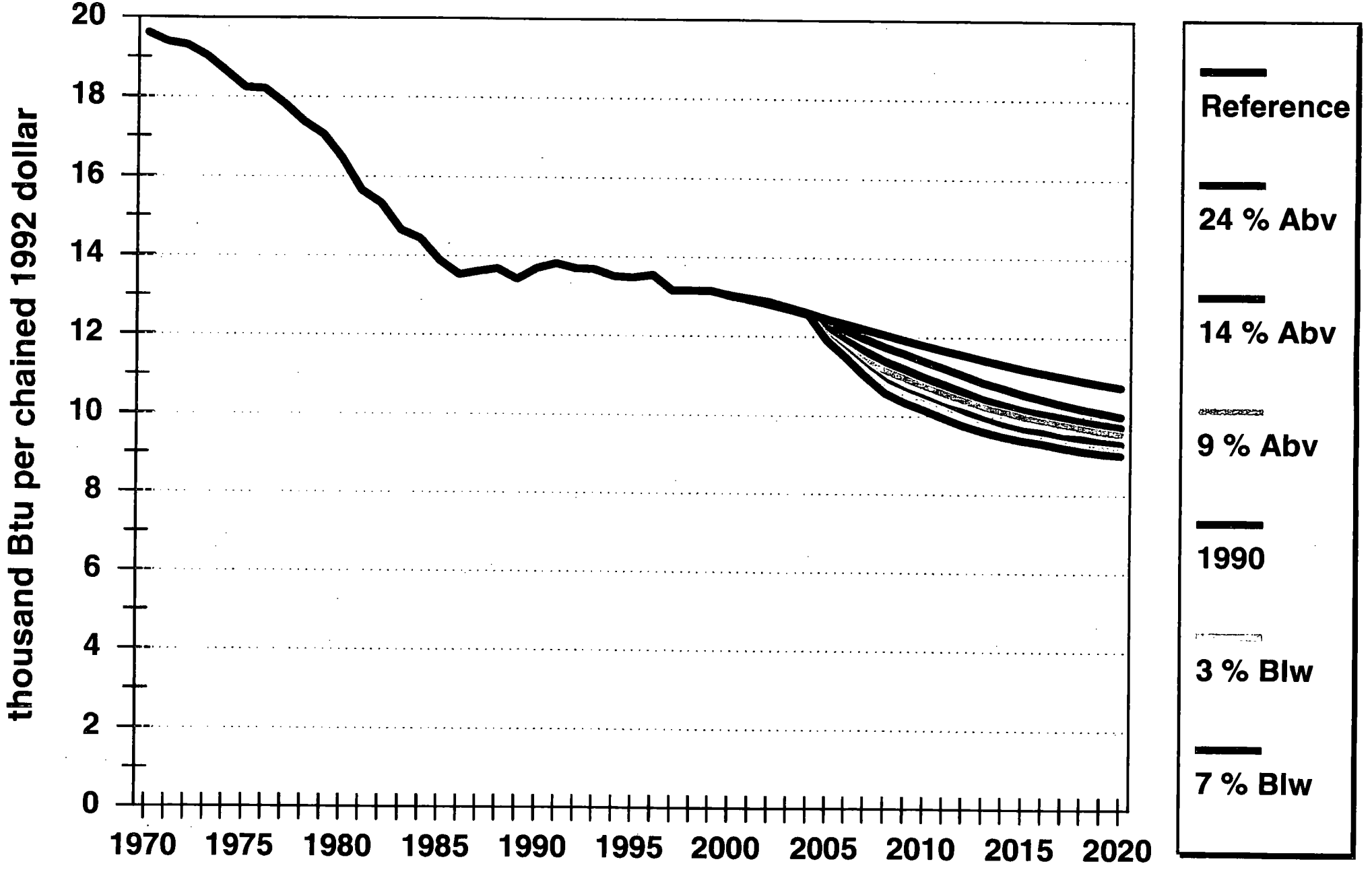
Nuclear energy consumption in the reference and six target cases, 1970-2020



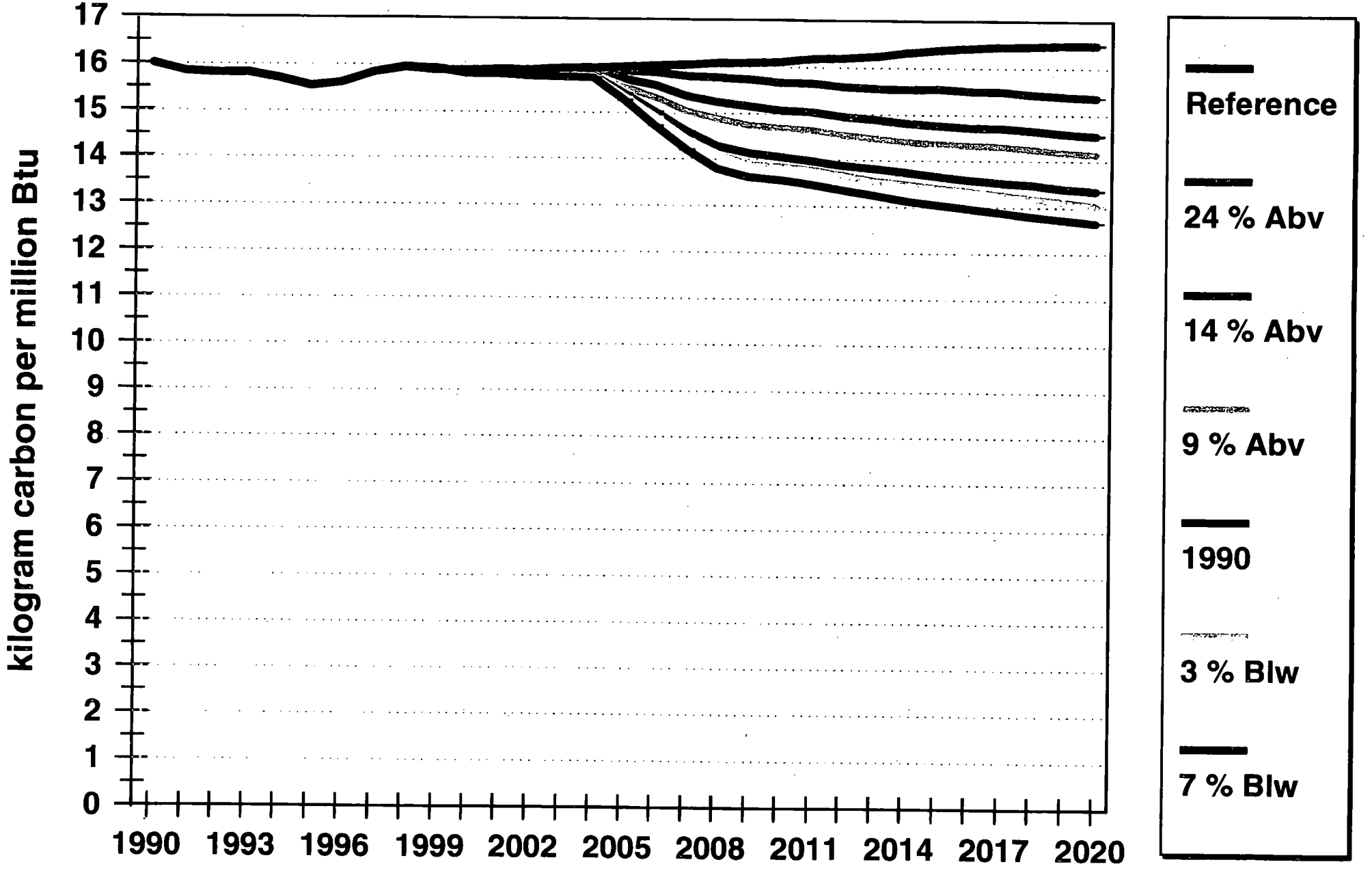
Renewable energy consumption in the reference and six target cases, 1990-2020



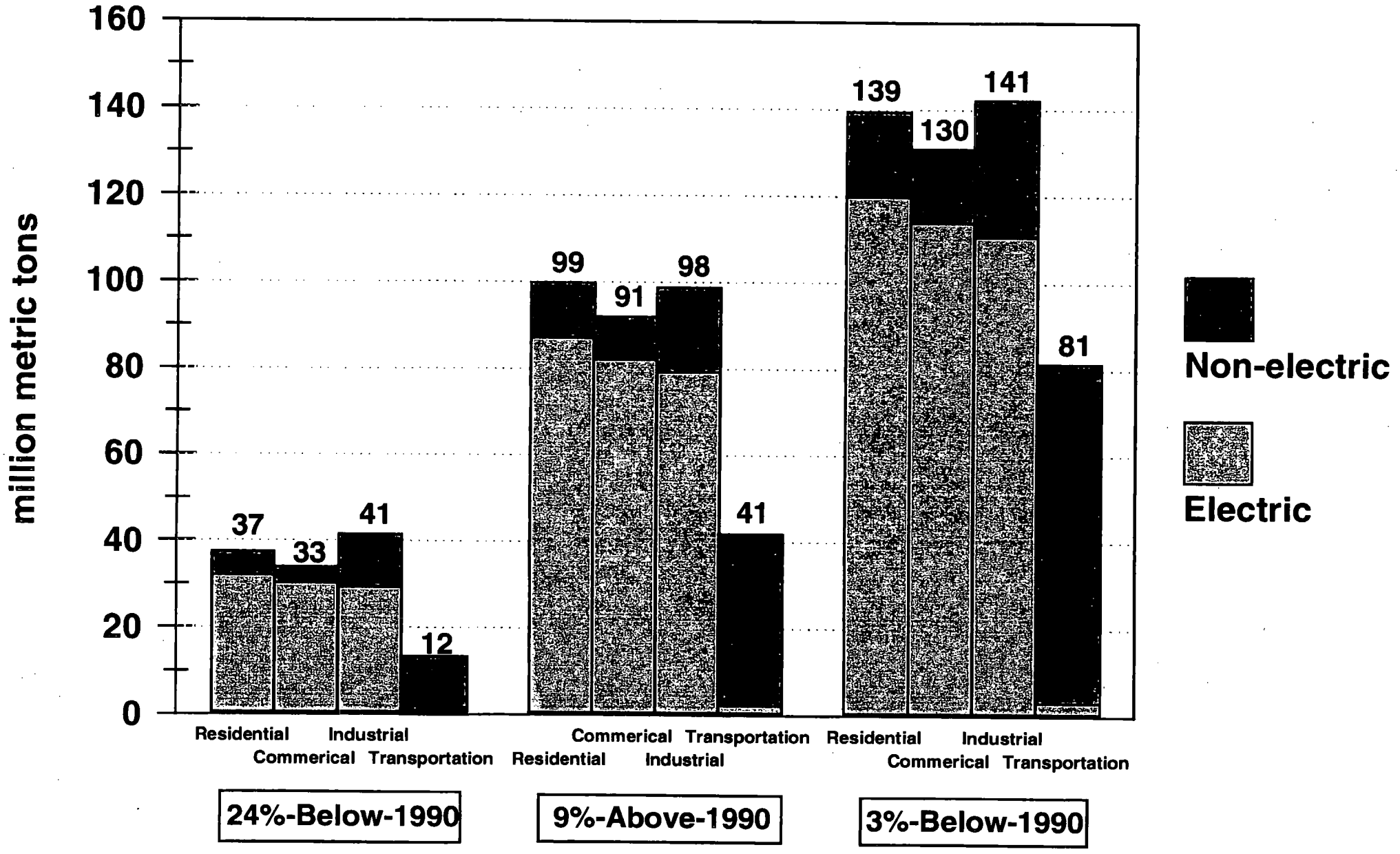
Energy consumption per unit of gross domestic product in the reference and six target cases, 1970-2020



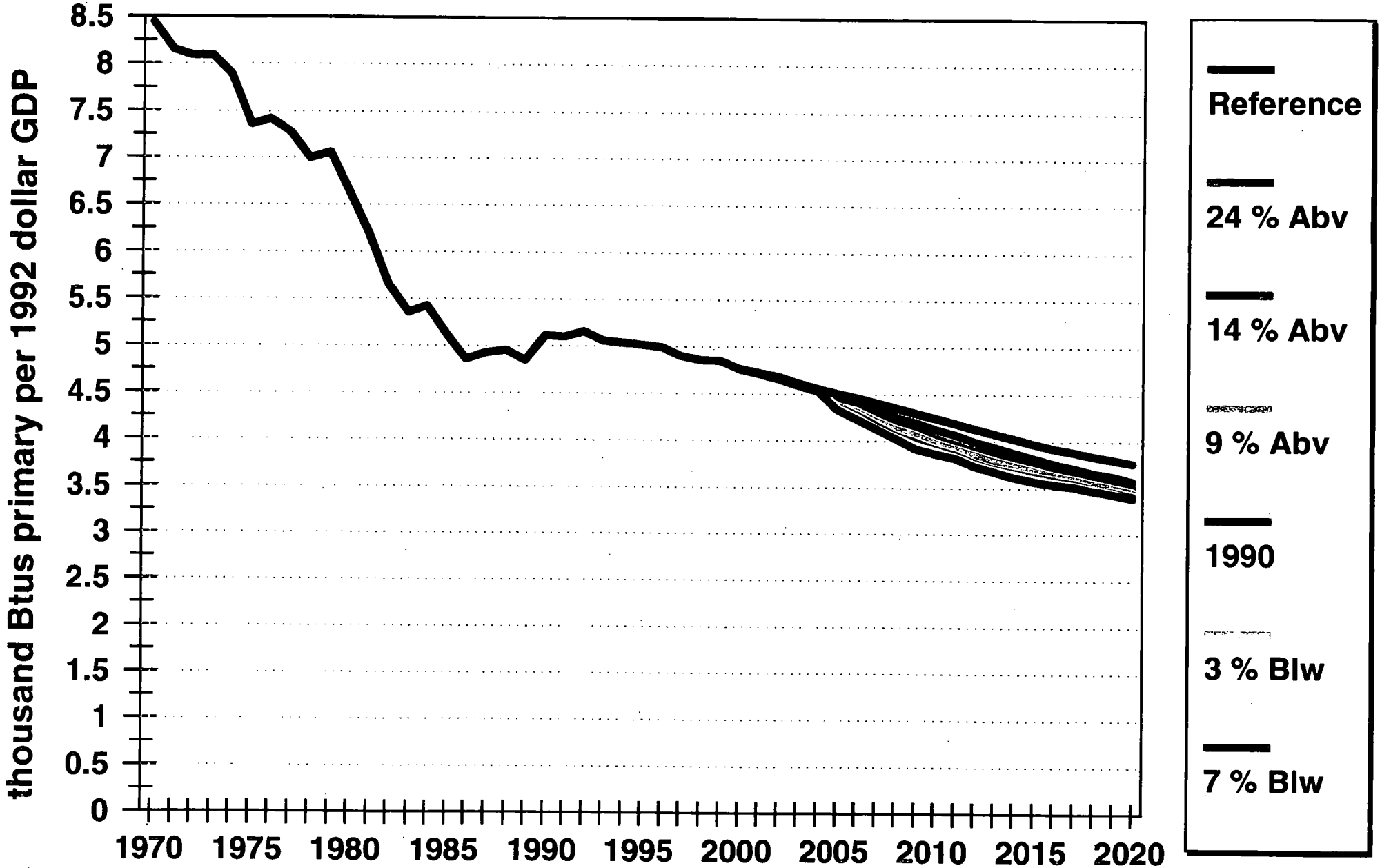
Carbon emissions per unit of primary energy consumption in the reference and six target cases, 1990-2020



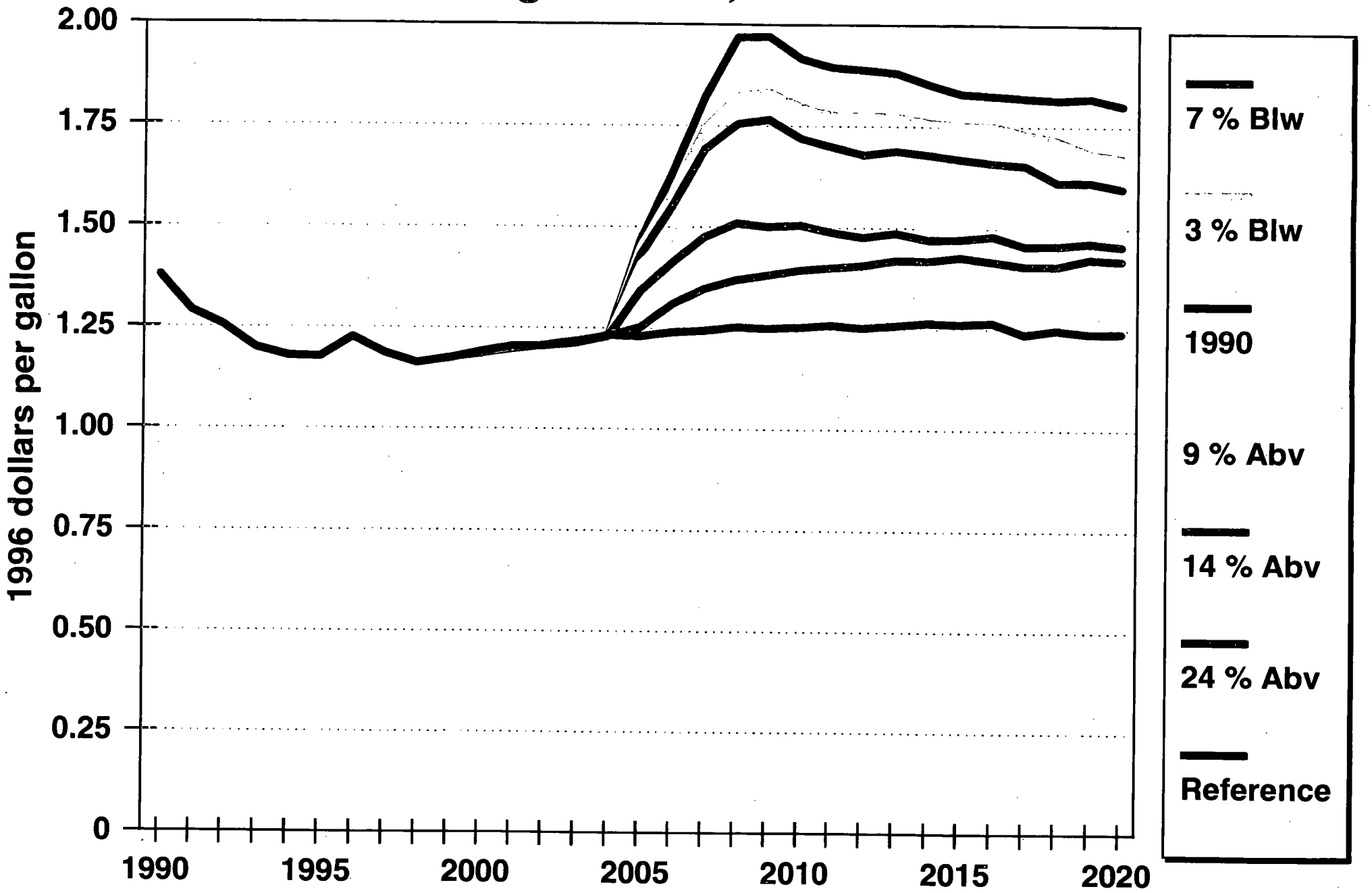
Carbon reductions by sector, 24%-above-1990, 9%-above-1990, and 3%-below-1990 cases, 2010



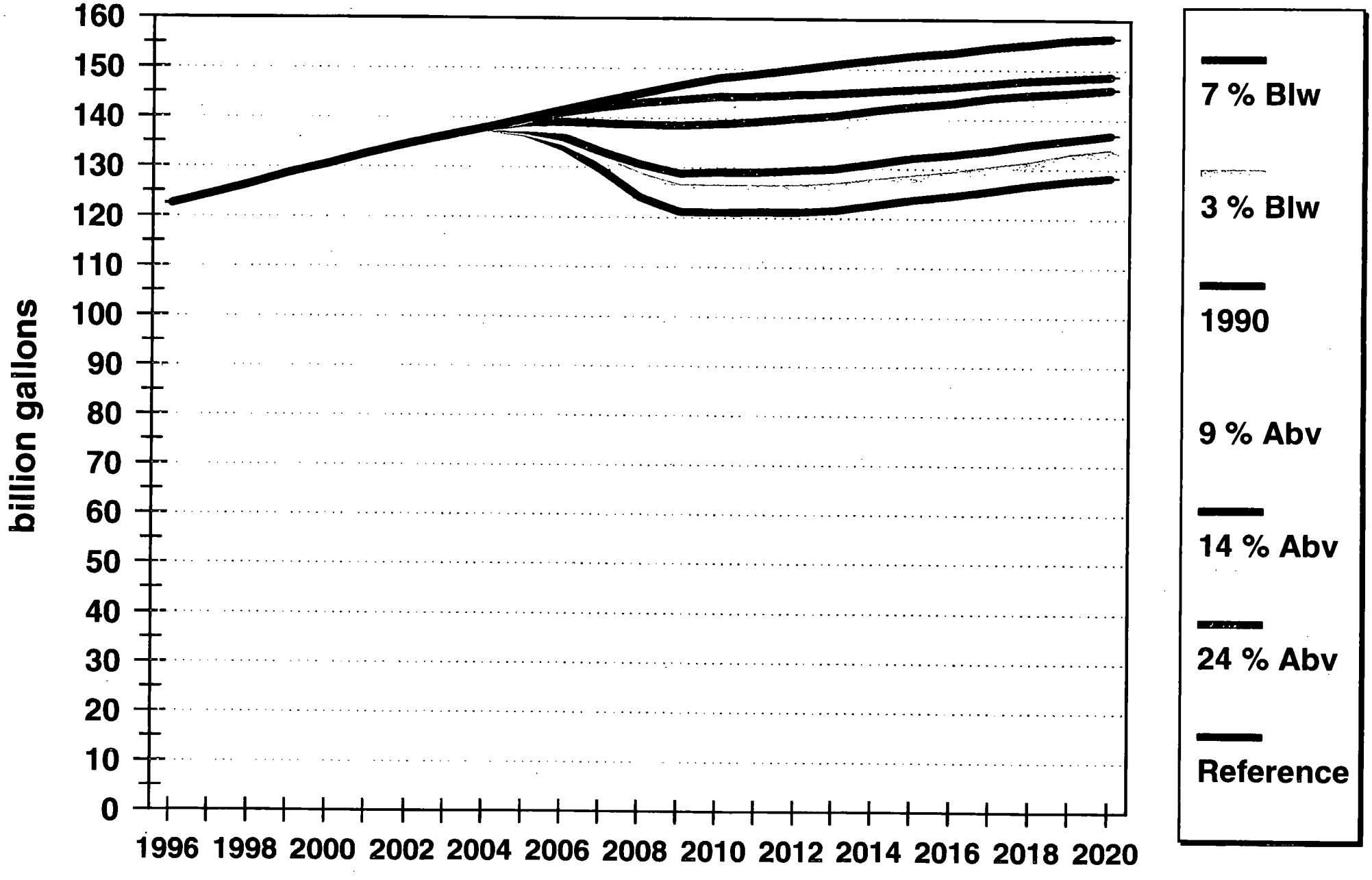
Industrial energy intensity in the reference and six target cases, 1996-2020



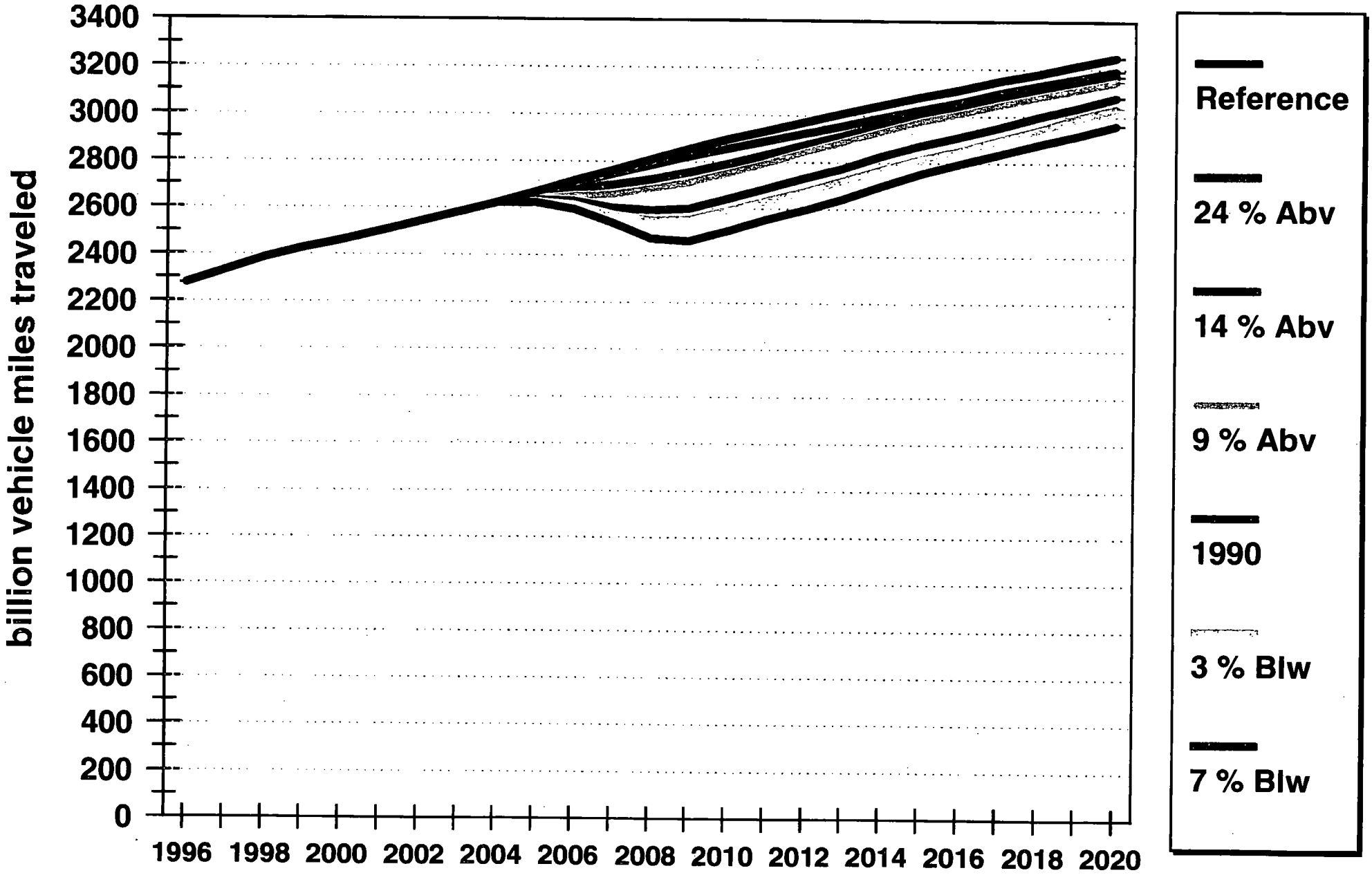
Motor gasoline price in the reference and six target cases, 1990-2020



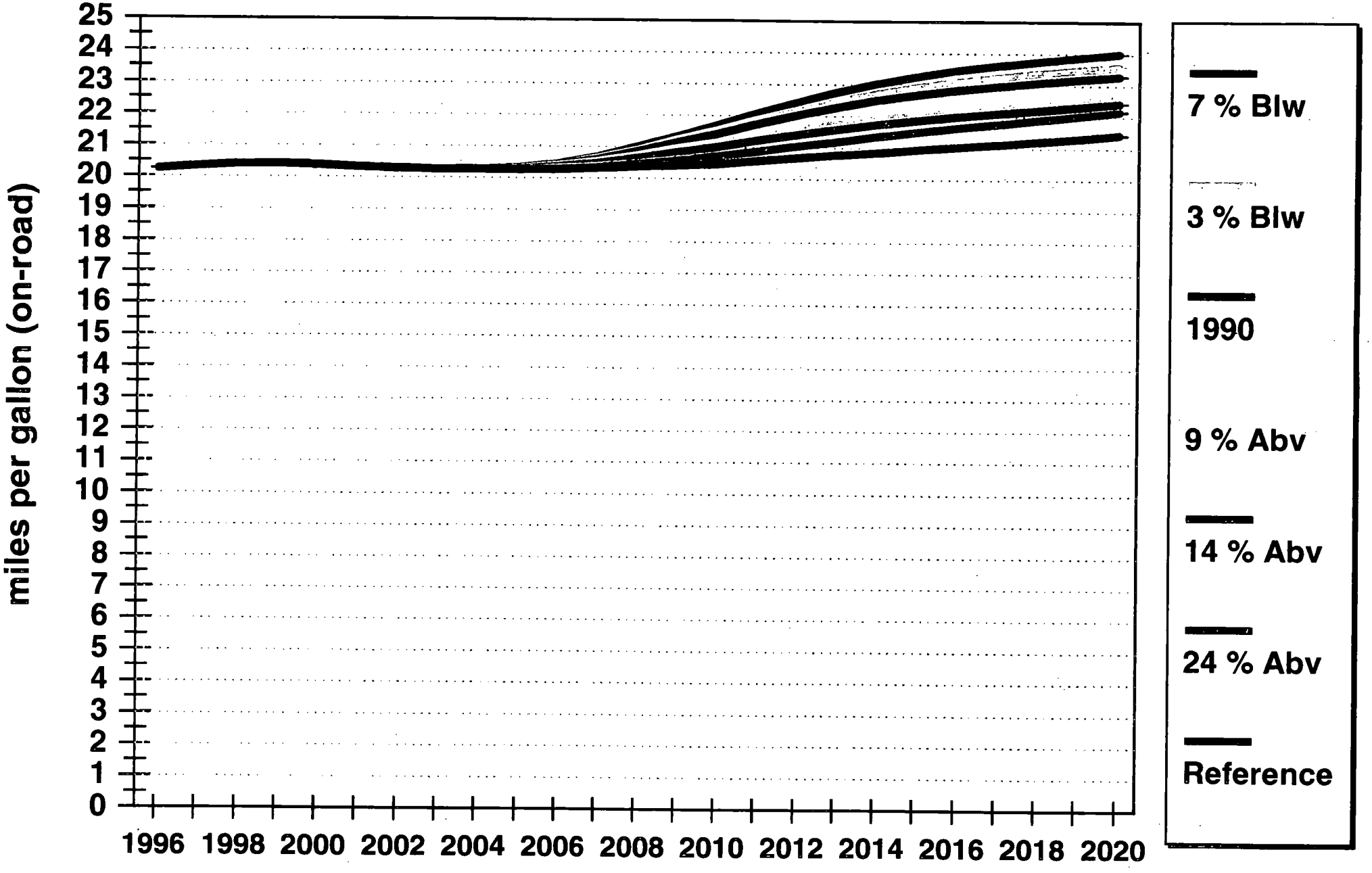
Motor gasoline consumption in the reference and six target cases, 1996-2020



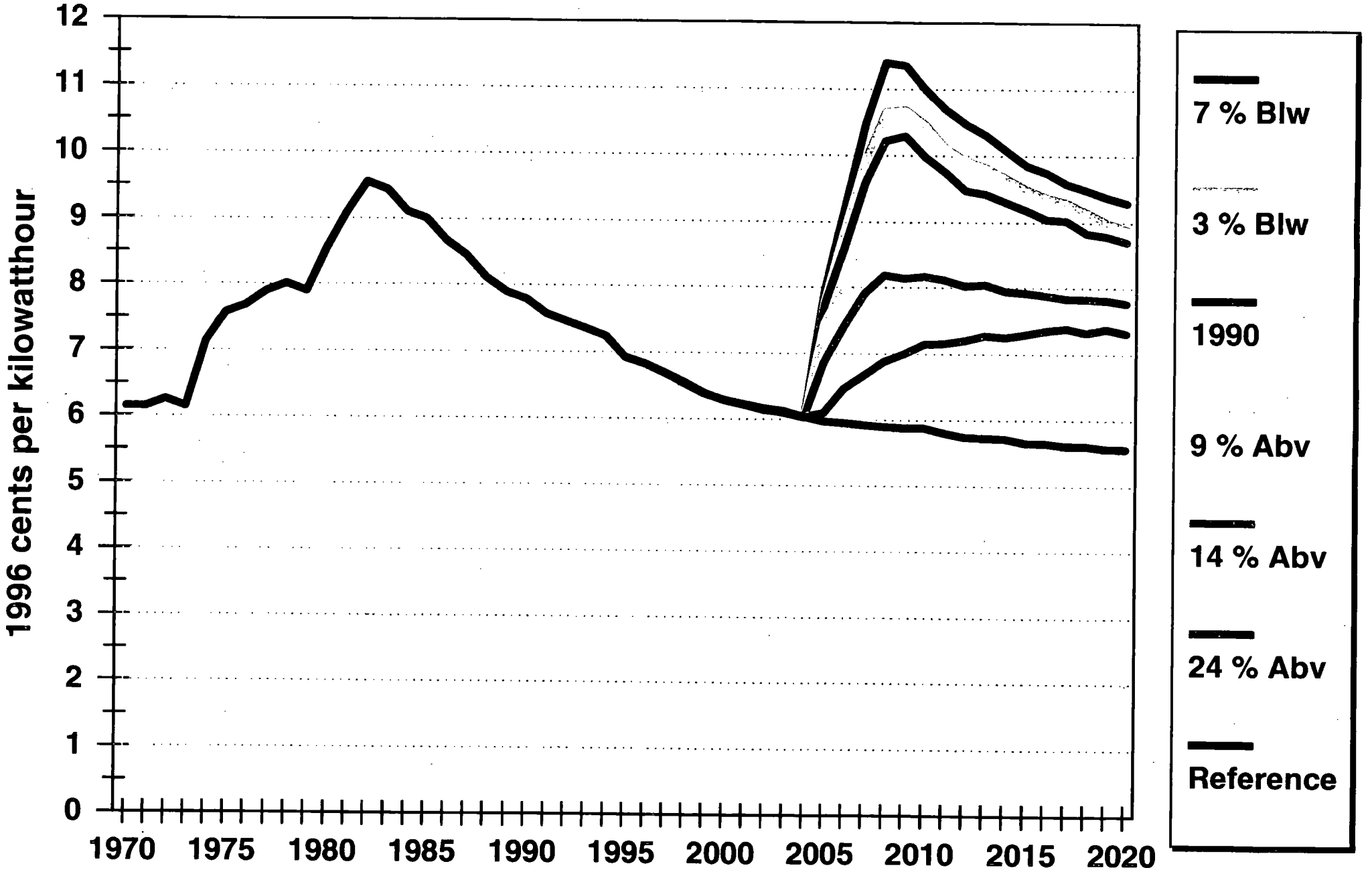
Light-Duty vehicle travel in the reference and six target cases, 1996-2020



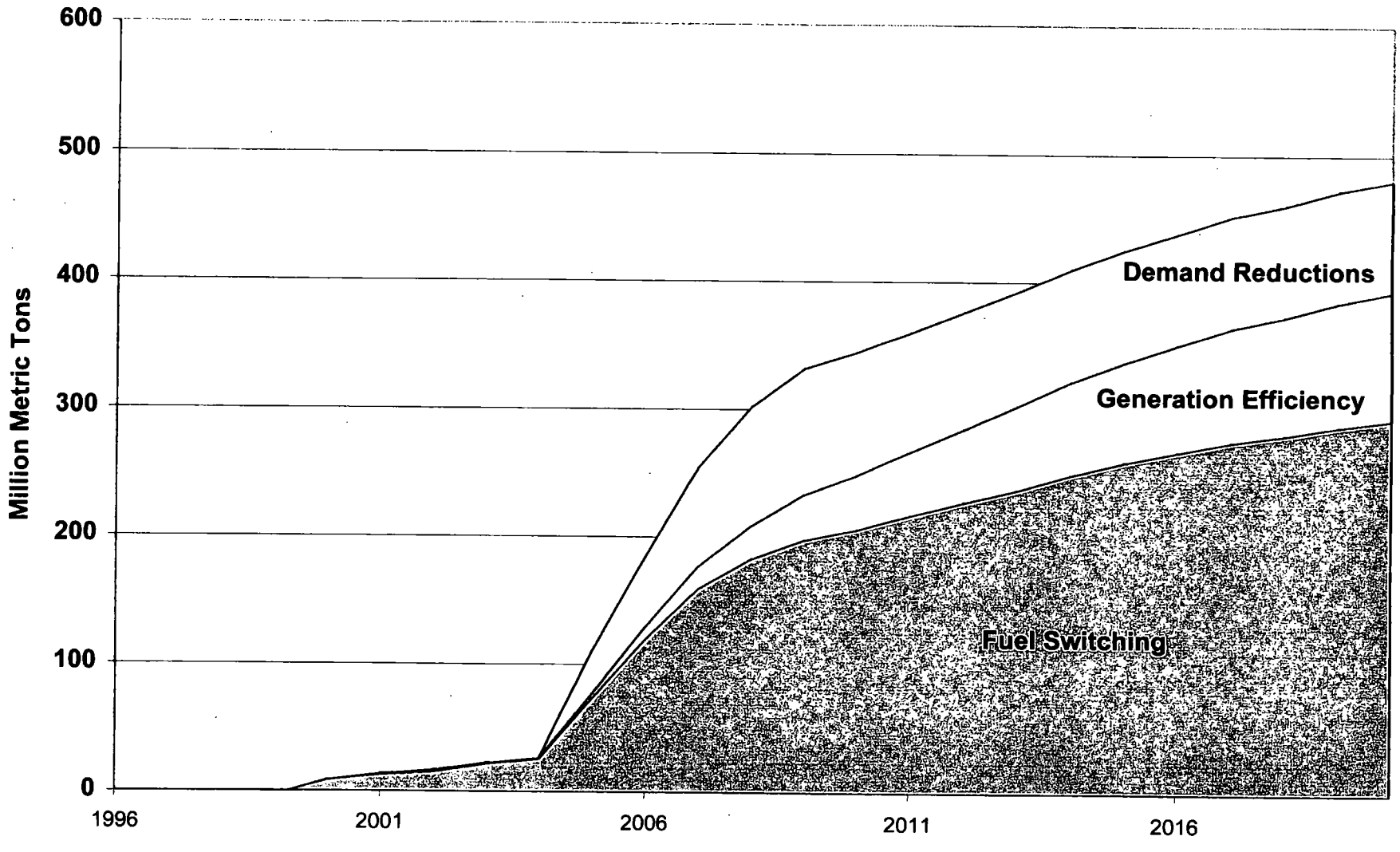
Light-Duty fleet efficiency in the reference and six target cases, 1996-2020



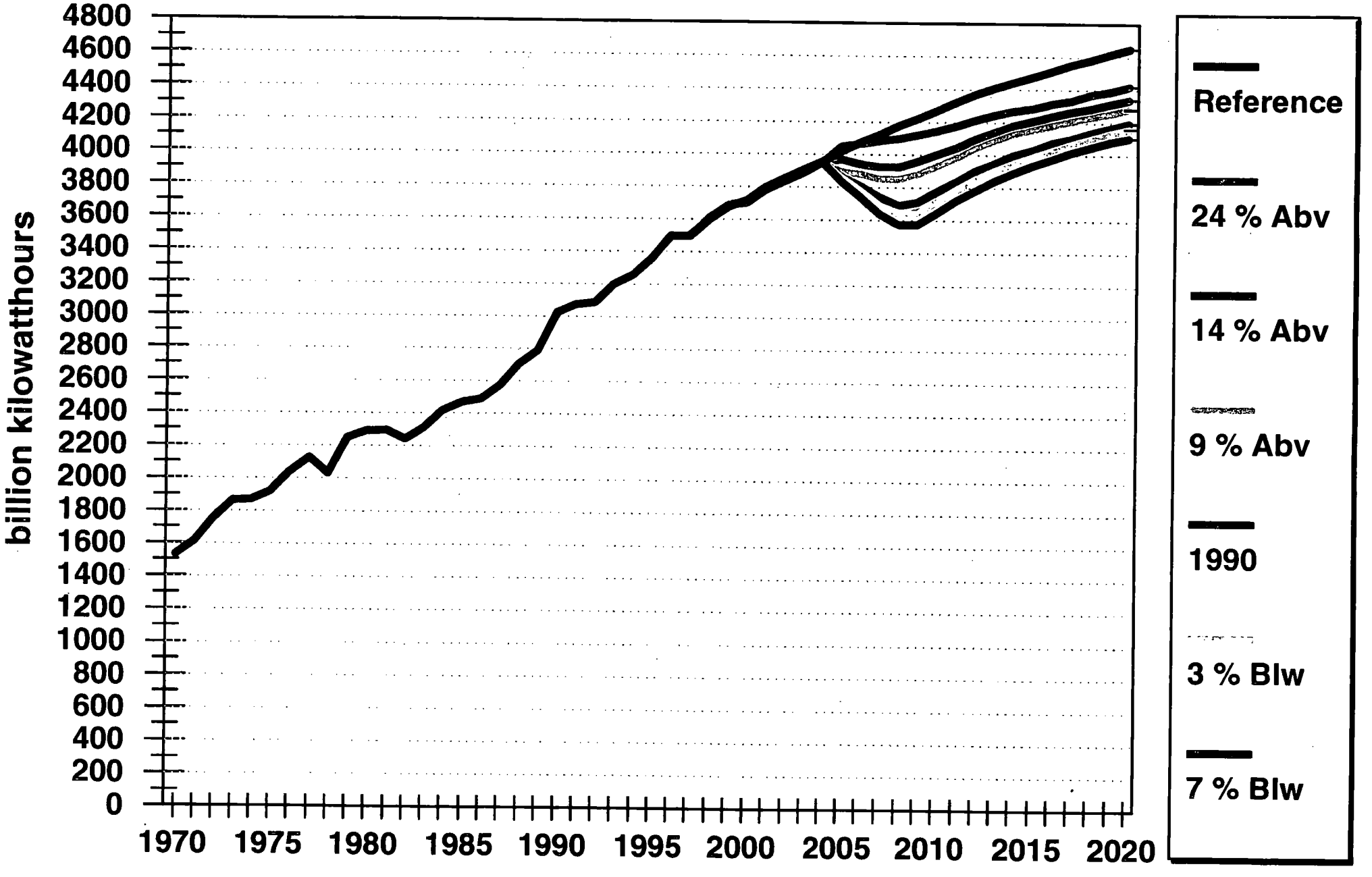
Electricity prices in the reference and six target cases, 1970-2020



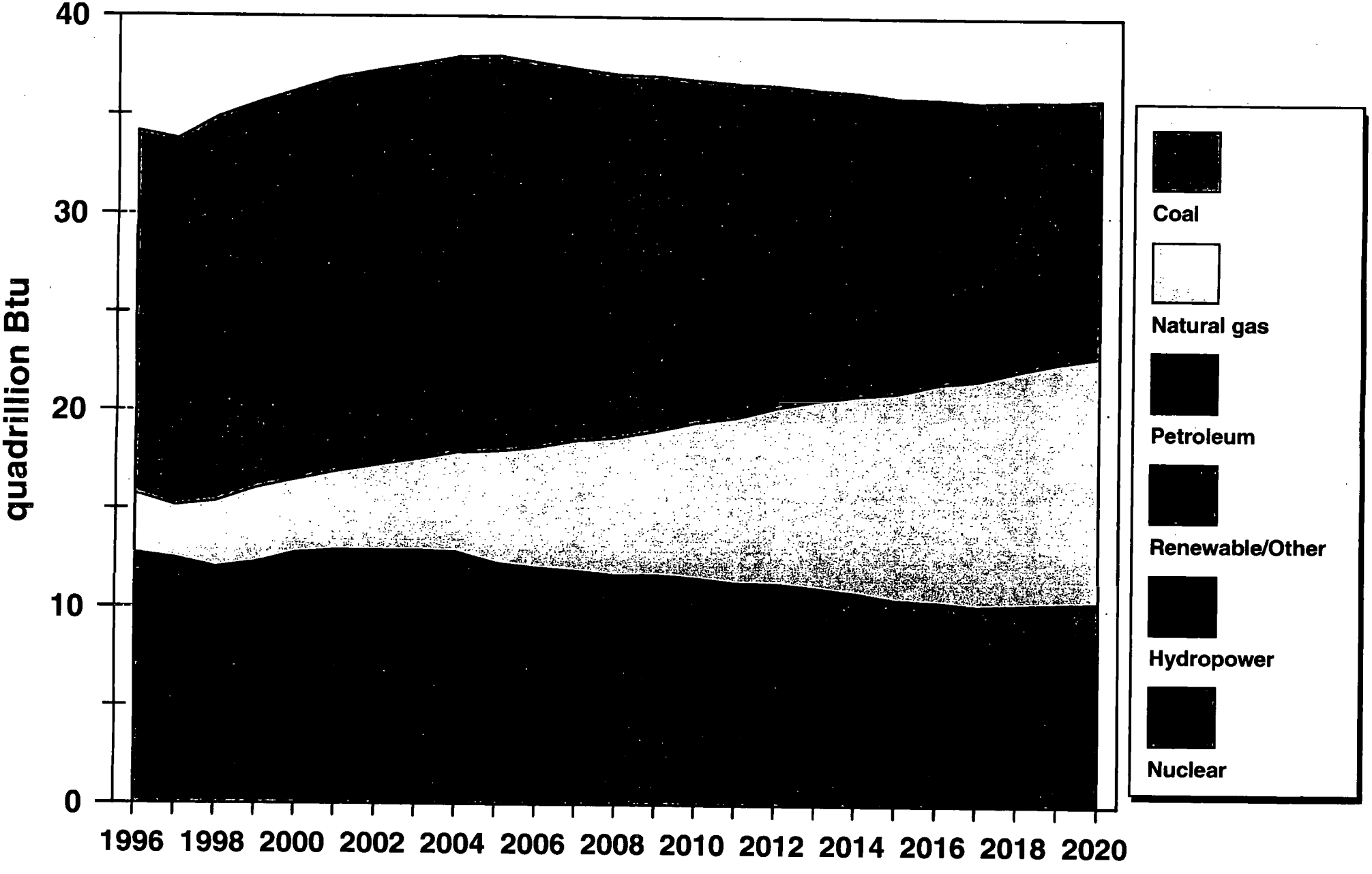
Electricity Sector Carbon Emissions Reductions by Source in the 1990-3% Case



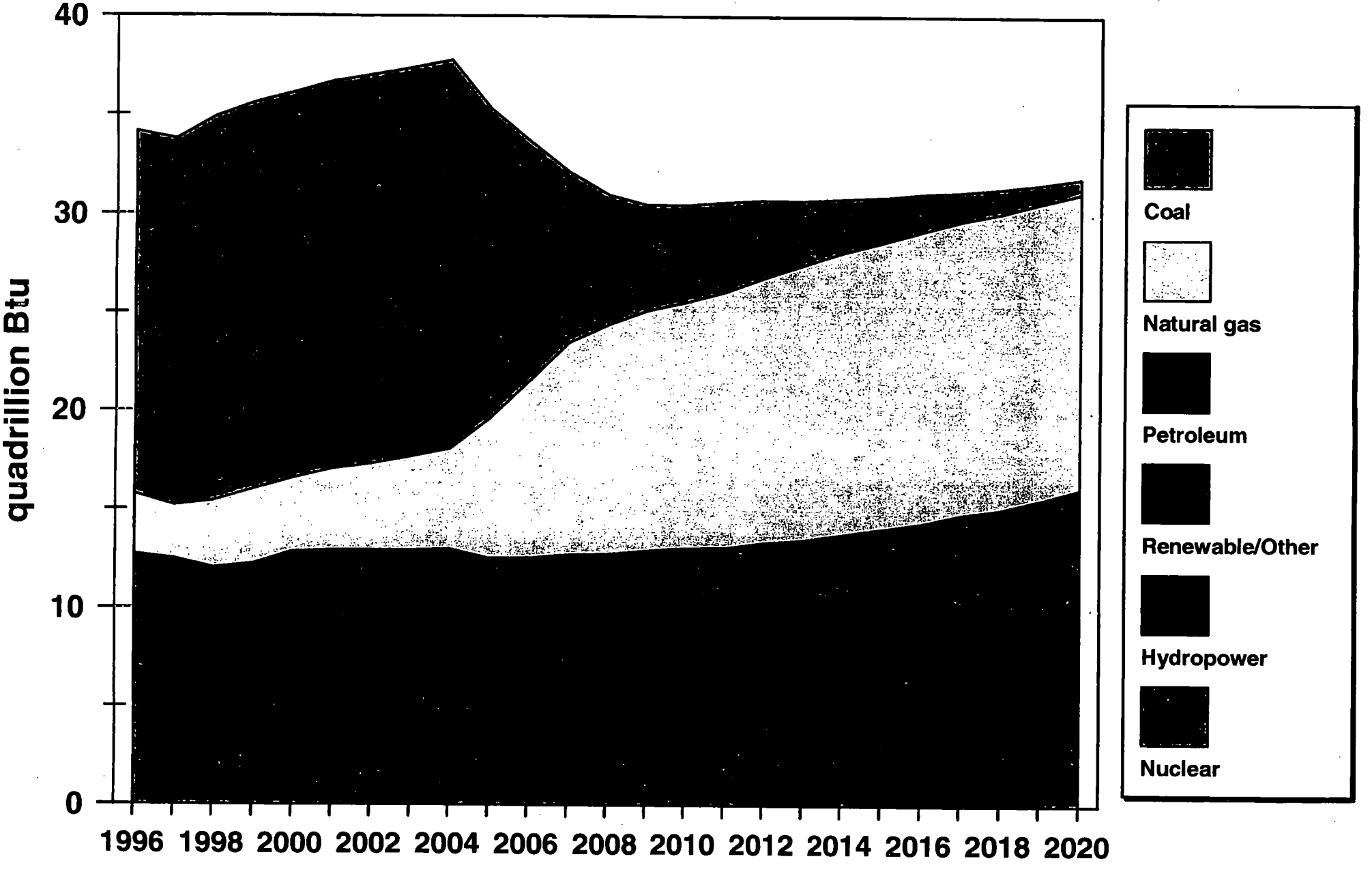
Electricity generation in the reference and six target cases, 1990-2020



Generation energy use by fuel in the 24%-above-1990 case, 1996-2020

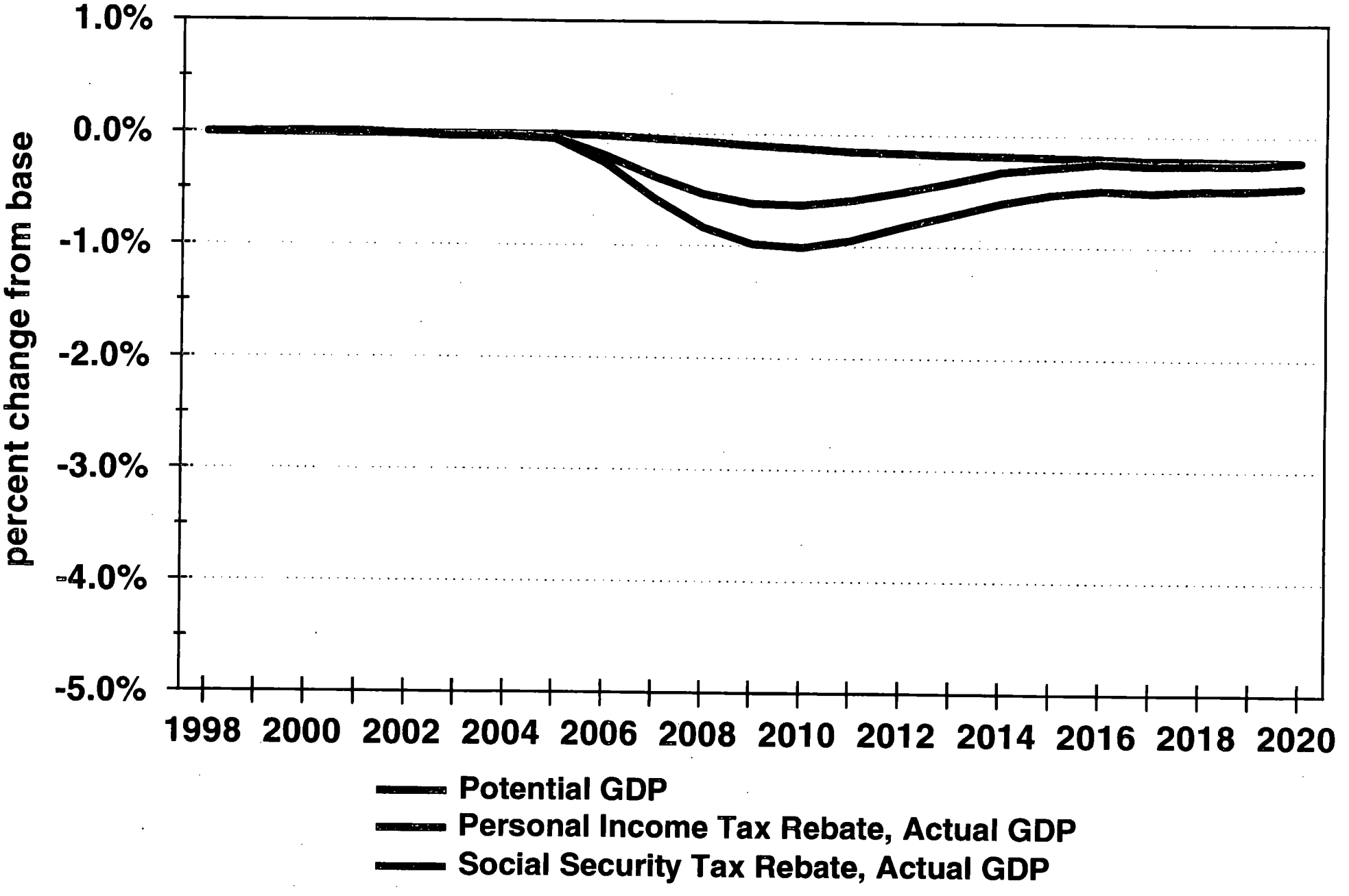


Generation energy use by fuel in the 3%-below-1990 case, 1996-2020



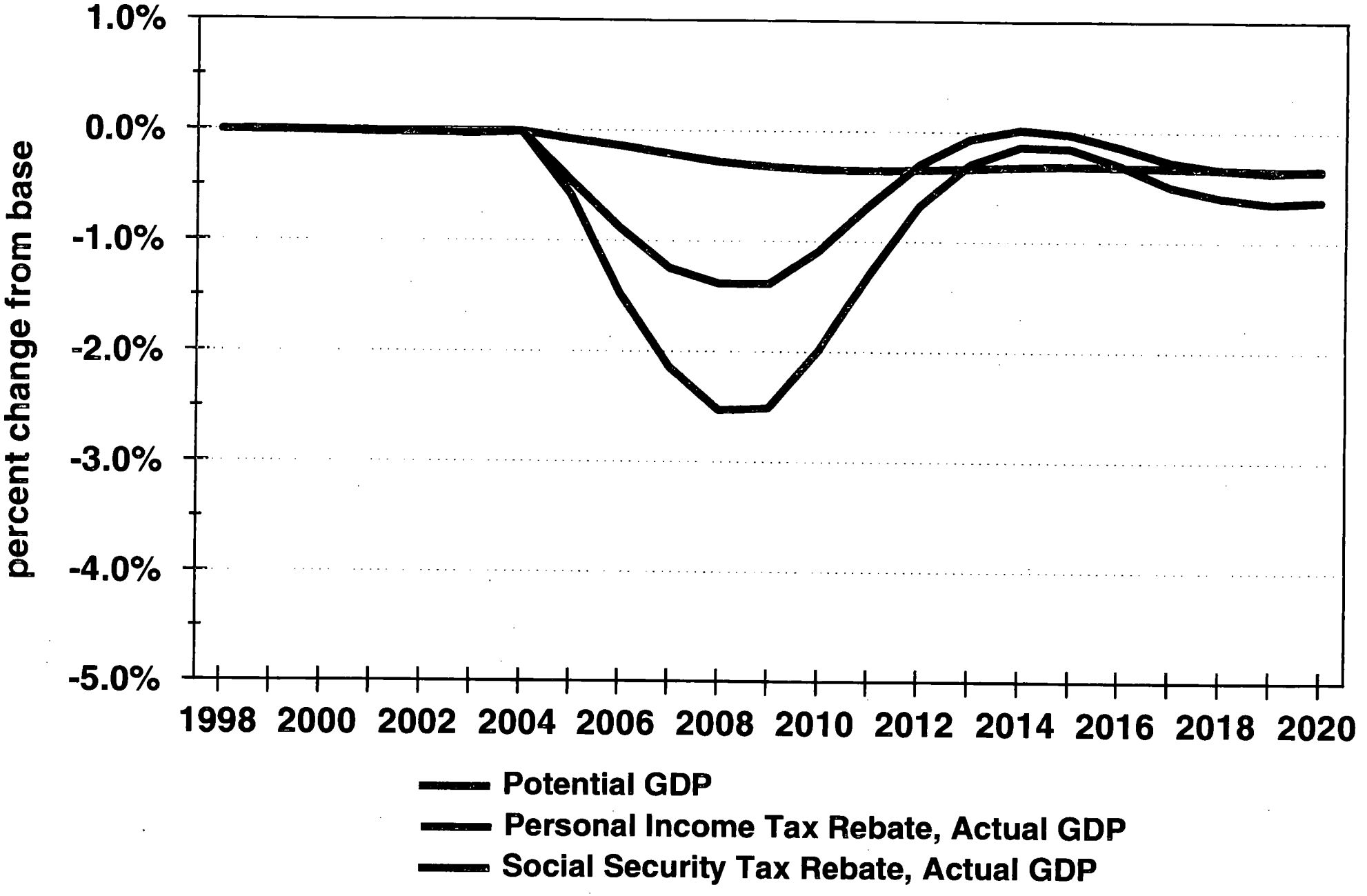
GDP with Alternative Fiscal Policies

24% Above 1990



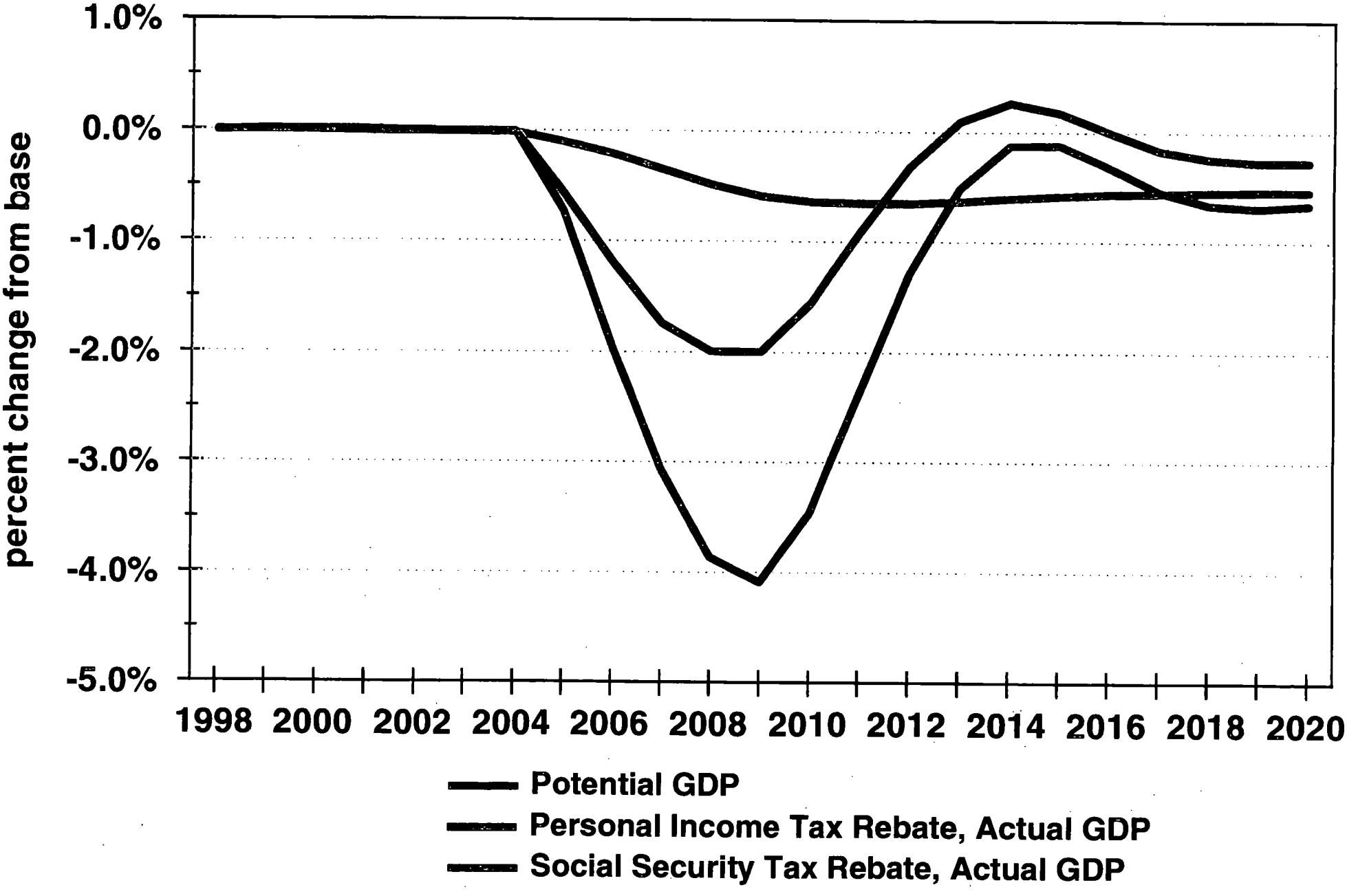
GDP with Alternative Fiscal Policies

9% Above 1990

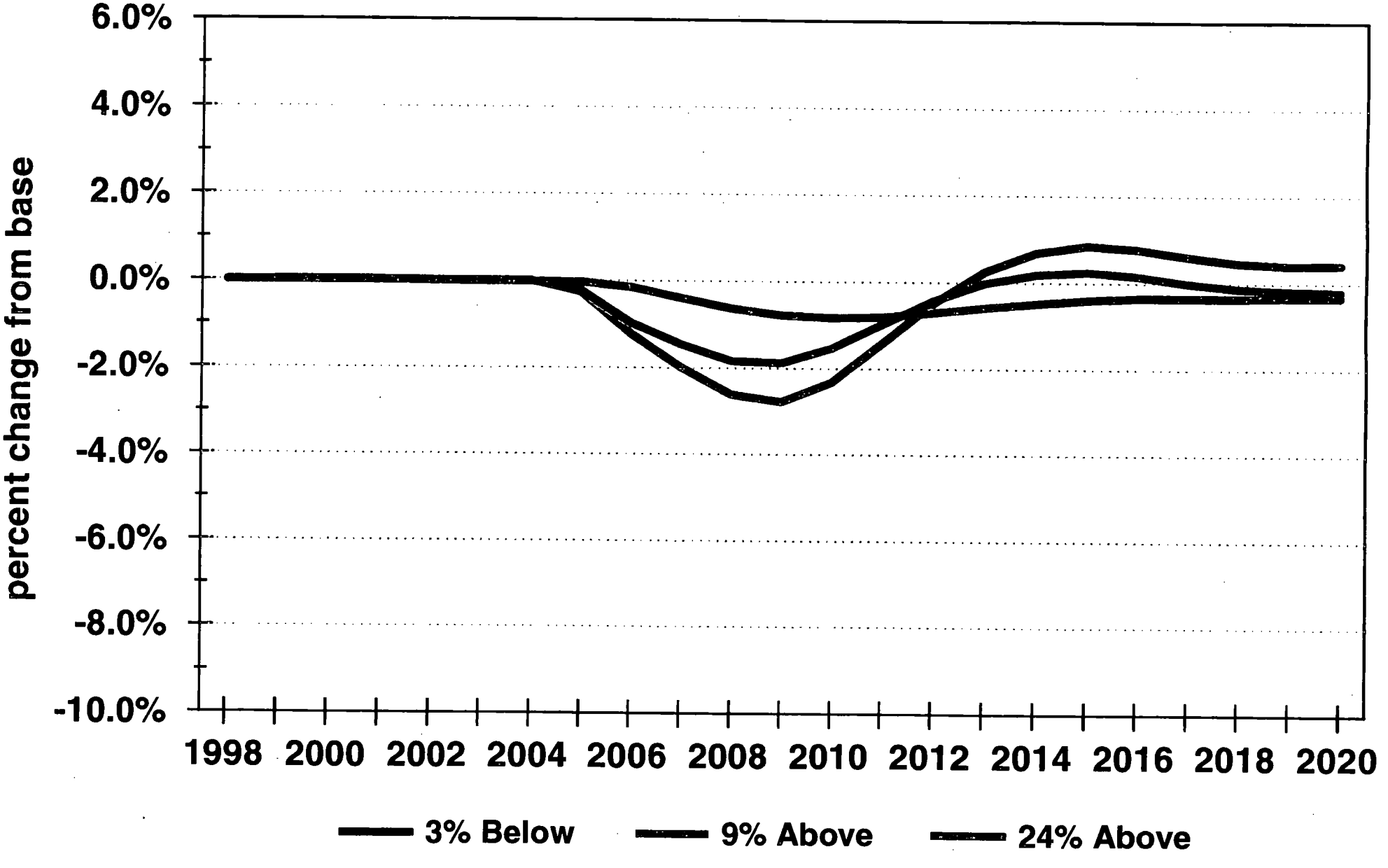


GDP with Alternative Fiscal Policies

3% Below 1990

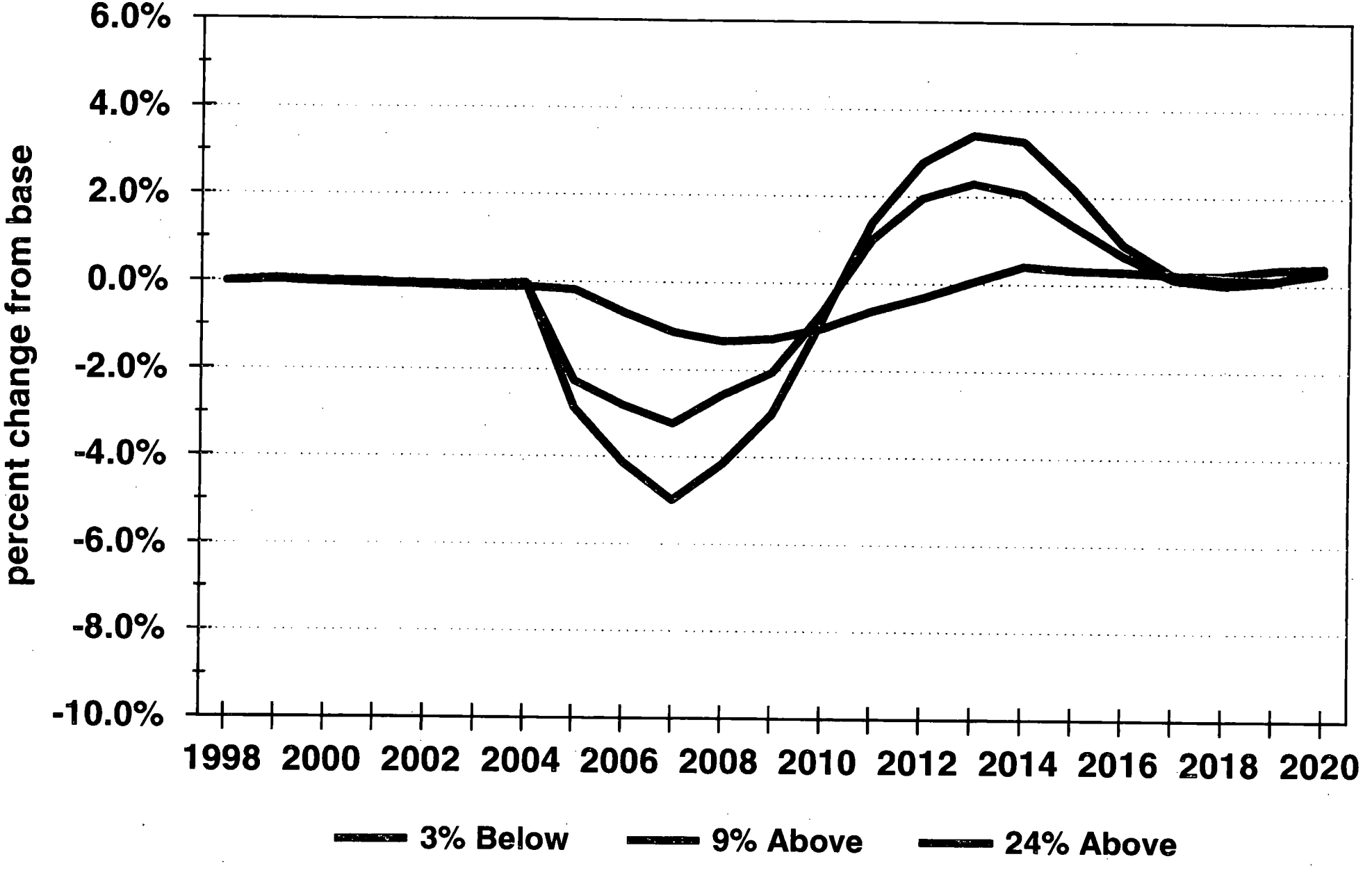


Real Consumption
Personal Income Tax Rebate

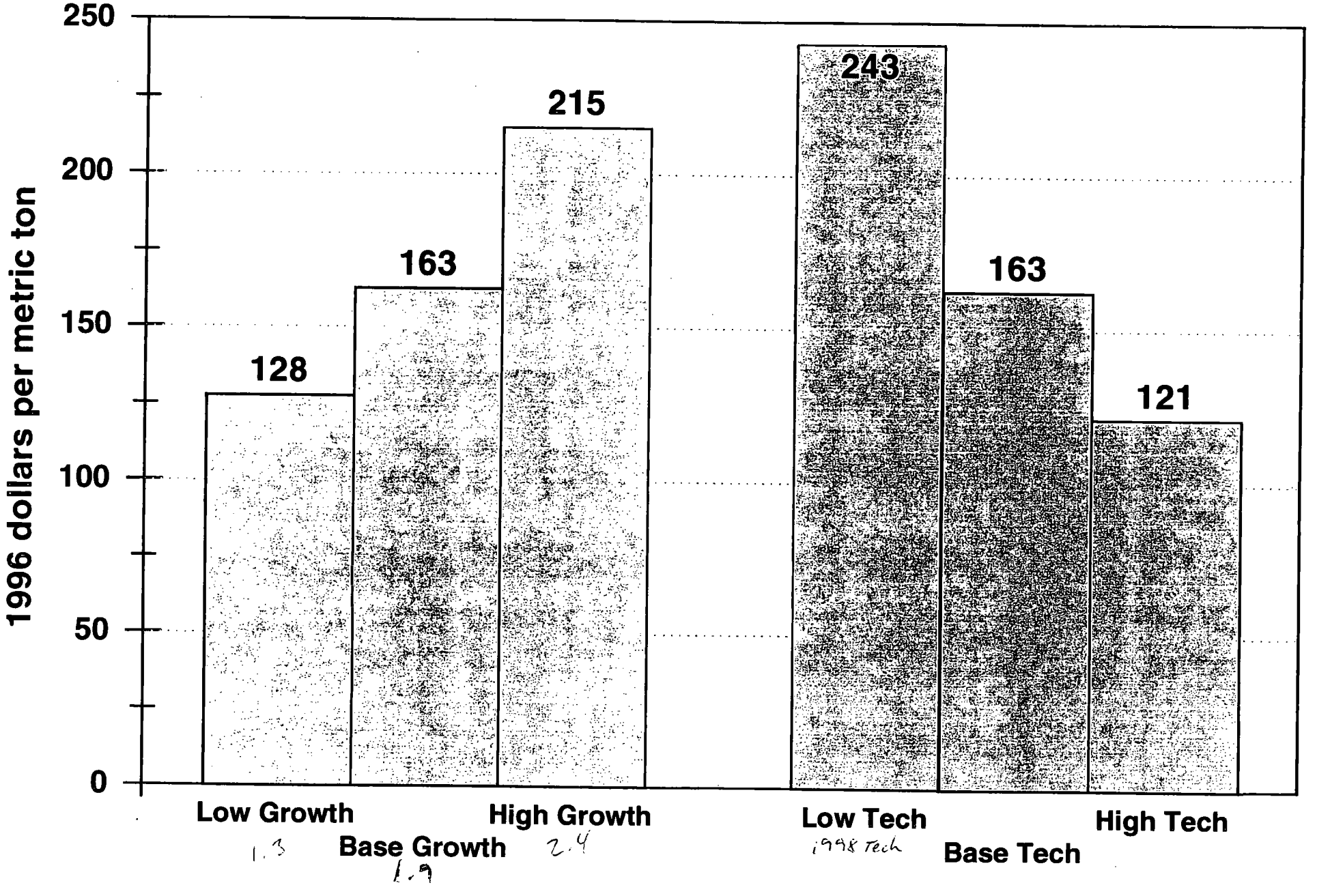


Real Investment

Social Security Tax Rebate



Carbon prices in the 9%-above-1990 sensitivity cases, 2010



Other Sensitivities

- Industrial Composition
- Competitive Pricing
- Biomass Gasification
- Reducing the Impact on the Coal Industry

Kyoto Study Objective:

To determine the impact on the U.S. energy system and the economy of possible alternative target emission reduction levels that may result from the Kyoto Protocol.

Scenarios for Kyoto Study

- 34 percent above 1990 levels (AEO Base Case)
- 24 percent above 1990 levels (Substantial International Permit Trading)
- 14 percent above 1990 levels (Stabilization at 1998 Levels)
- 9 percent above 1990 levels (State Department Offsets and Sinks plus Estimate of Permits Available from FSU)
- Stabilization at 1990 Emissions Levels
- 3 percent below 1990 levels (State Department Offsets and Sinks)
- 7 percent below 1990 levels (Kyoto Protocol Target)

Assumptions

- AEO Reference Case Assumptions (including technology)
- Begin in 2005
- "Kyoto Forever"
- Nuclear Life Extension, if Economic
- No New Nuclear Construction

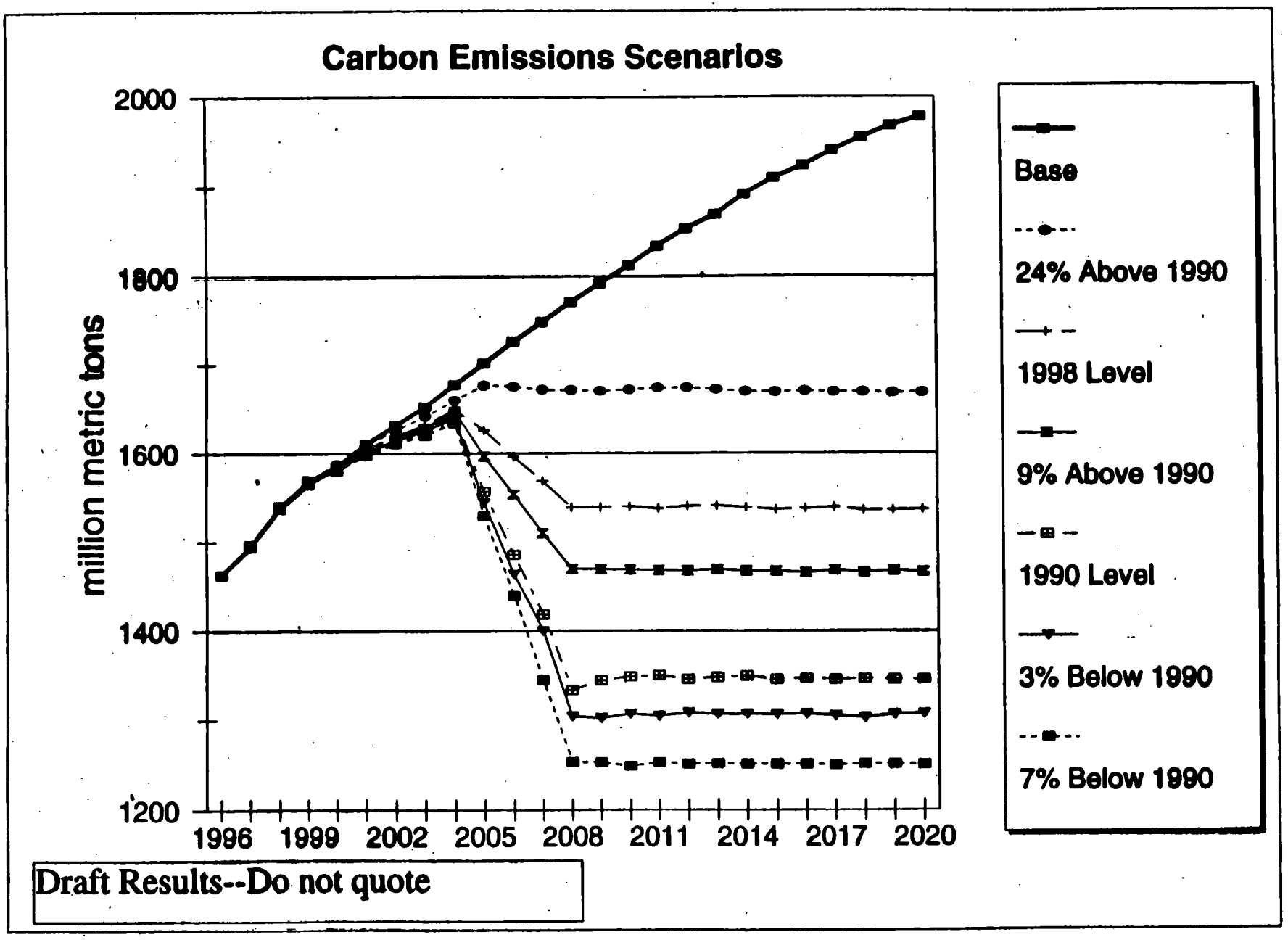
Sensitivities for Kyoto Study

- Low and high economic growth
- Low and high technology -
  └ revised w/ input from A.D. Little
- Nuclear plant construction
- Industrial Migration

Benefits of Using NEMS

- All Energy Markets Represented
- Transitional Effects Captured/Annual Model
- Vintaged Capital Stock and Turnover Modeled
- Detailed Technology Menus
- Representation of Technological Learning
- Competitive Electricity Markets Included
- Direct Macroeconomic and World Oil Market Feedback

DRI


Carbon Emissions Scenarios
2000
1800
1600
1400
1200
million metric tons
1996
1999
2002
2005
2008
2011
2014
2017
2020
Base
24% Above 1990
1998 Level
9% Above 1990
1990 Level
3% Below 1990
7% Below 1990
Draft Results--Do not quote

Issues

- Majority of Emissions Reduction from Electric Generation Sector
  - Feasibility of Plant Construction
  - Feasibility of Gas Deliverability
  - Feasibility of Renewable Supply

- Technology
  - Completeness of the NEMS Technology Menu
  - Technological Optimism/Manufacturing Incentives to Improve the Current Technology Slate
  - Consumer Behavior

- Industrial Migration

Biomass Consultations

Energy Efficiency and Renewable Energy/Office of Energy Outreach
- Lynne Gillette
- Ray Costello
- Tien Nygyen

Oak Ridge National Laboratory
- Marie Walsh
- Bob Perlack
- Robin Graham
- Lynn Wright

Antares Group, Inc.
- Ed Gray
- Dan Packey
- Kevin Comer

USDA-Economic Research Service
- Roger Conway
- Hosein Shapouri
- Richard Haynes

University of Maryland
- Erik Lichtenberg

Colorado School of Mines
- Mike Graboski

Environmental Protection Agency
- Jim Turnure
- Bob Shackleton

National Renewable Energy Laboratory
- Shaine Tyson

Electric Power Research Institute
- Keith White
- Jim Burk

Examples of Other Consultations

Industrial Technology

Arthur D. Little

Buildings Technology

Arthur D. Little

Mr. James Rannels, Energy Efficiencies and Renewable Energy, Office of Photovoltaics and Wind Technologies

Mr. Lew Pratsch, Energy Efficiencies and Renewable Energy, Office of Geothermal Technologies

Transportation Technology

Phil Patterson, Energy Efficiency and Renewable Energy/ Transportation Technologies

Mr. Suski, American Trucking Association

Independent Expert Reviewers

John Weyant	Energy Modeling Forum
Mike Toman	Resources for the Future
Dallas Burtraw	Resources for the Future
Billy Pizer	Resources for the Future
Richard Newell	Resources for the Future
Ray Kopp	Resources for the Future
Bill Nordhaus	Yale
Joe Boyer	Yale
Lorna Greening	Hagler Bailly
Bill Hogan	Harvard University

SR-OIAF/97-01

Service Report

Analysis of Carbon Stabilization Cases

October 1997

Prepared for

Office of Policy and International Affairs
U.S. Department of Energy

Prepared by

Office of Integrated Analysis and Forecasting
Energy Information Administration

This report was prepared by the Energy Information Administration (EIA), the independent statistical and analytical agency within the U.S. Department of Energy. Service Reports are prepared by EIA upon special request and are based on assumptions specified by the requester.

For Further Information . . .

An Analysis of Carbon Mitigation Cases was prepared by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, under the direction of Mary J. Hutzler (mhutzler@eia.doe.gov, 202/586-2222). General questions may be addressed to Andy S. Kydes (andy.kydes@eia. doe.gov, 202/586-2222), Senior Technical Advisor and Project Director, or Dan Skelly, (Daniel.Skelly@eia.doe.gov, 202/586-1722) Deputy Project Leader, NEMS Branch. Detailed questions about the forecasts and related model components may be addressed to the following analysts:

Residential Demand	John Cymbalsky (john.cymbalsk@eia.doe.gov, 202/586-4815)
Commercial Demand	Erin Boedecker (erin.boedecke@eia.doe.gov, 202/586-4791)
Industrial Demand	T. Crawford Honeycutt (choneycu@eia.doe.gov, 202-586-1420)
Transportation Demand	David Chien (dchien@eia.doe.gov, 202/586-3994)
Electricity Markets	Alan Beamon (abeamon@eia.doe.gov, 202/586-2025)
Electricity Markets	Jeff Jones (jjones@eia.doe.gov, 202/586-2038)
Renewable Energy	Tom Petersik (Tom.Petersik@eia.doe.gov, 202/586-6582)
Oil and Gas Production	Ted McCallister(tmccali@eia.doe.gov, 202/586-4820)
Natural Gas Markets	Joseph Benneche (jbenneche@eia.doe.gov, 202/586-6132)
Oil and Gas Markets	James Kendell (james.kendell@eia.doe.gov, 202/586-9646)
Refineries	Tom White (tom.white@eia.doe.gov, 202/586-1393)
International Oil Markets	G. Daniel Butler (george.butler@eia.doe.gov, 202/586-9503)
Coal Supply and Prices	Thanh Luong (thanh.luong@eia.doe.gov, 202/586-2165)
Economic Activity	Ronald Earley (Ronald.Earley@eia.doe.gov, 202/586-1398)
NEMS Model Runs	Paul Kondis (Paul.Kondis@eia.doe.gov, 202/586-1469)

Electronic Access and Related Reports

Model documentation reports for the National Energy Modeling System (NEMS) are available on CD-ROM. Quarterly projections of energy supply and demand for 1996 and 1997 are available in the *Short-Term Energy Outlook* (Spring 1997). For ordering information and questions on other energy statistics available from EIA, please contact EIA's National Energy Information Center. Addresses, telephone numbers, and hours are as follows:

National Energy Information Center, EI-231

Energy Information Administration
Forrestal Building, Room 1F-048
Washington, DC 20585

Telephone: 202/586-8800
TTY: For people who are deaf
or hard of hearing: 202/586-1181
9 a.m. to 5 p.m., eastern time, M-F

E-mail: *infoctr@eia.doe.gov*
World Wide Web Site: *http://www.eia.doe.gov*
Gopher Site: *gopher://gopher.eia.doe.gov*
FTP Site: *ftp://ftp.eia.doe.gov*

Contents

Preface vi

Executive Summary E-1

1. Introduction 1

2. Modeling Methodology and Assumptions 2

2.1 Description of Cases 2
2.2 Methodology 5
2.3 Modifications to AEO Reference Case Modeling Assumptions 7
2.3.1 Modifications to NEMS Demand Modules 7
2.3.2 Modifications to NEMS Supply and Conversion Modules 10
2.4 Limitations on Modeling Assumptions 12

3. Energy Model Results and Analysis 14

3.1 Comparison of the Policy Base and 1990-Level Carbon Stabilization Cases 14
3.2 Comparison of the Carbon Stabilization Cases 21
3.3 Analysis of $40 per Ton Carbon Permit Trading Fee 31

4. Macroeconomic Model Results and Analysis 34

4.1 Macroeconomic Assumptions 34
4.2 Macroeconomic Analysis 37

5. Summary of Findings 59

Appendices

A. 1/29/97 Letter from Howard Gruenspecht to Mary Hutzler requesting NEMS Climate Change Analyses

B. 4/14/97 Letter from Howard Gruenspecht to Mary Hutzler requesting NEMS Climate Change Analyses

C. NEMS Output Comparison Tables, Policy Base Case, 1344 Stabilization Case; 1344 5-Year Budget Stabilization Case

Tables

Table 2.1 Carbon Emissions Cases Examined 5
Table 2.2 Example of Effective Energy Costs for Coal, Natural Gas, and Gasoline for Various Carbon Permit Values 7
Table 3.1 Summary Comparison: Base, Announcement, and 1344 Stabilization Cases . . 15
Table 3.2 Summary Comparison: Base, $40/Ton Permit and 1344 Stabilization Cases . . 33
Table 4.1 Emission Reduction Cases Examined in Macroeconomic Analysis 36

Figures

Figure 2.1 Carbon Emissions Cases, 5-year Ramp to 2010 4
Figure 2.2 Carbon Emissions Cases, 10-Year Ramp to 2010 4
Figure 2.3 Carbon Emissions Cases, Timing Alternatives 4
Figure 3.1 Delivered Energy Prices, Percentage Change from Base to 1990-Level Carbon Stabilization Case 16
Figure 3.2 Carbon Reductions by Fuel, Base vs. 1990-Level Carbon Stabilization Case . . 16
Figure 3.3 Carbon Reductions by Primary Sector, Base vs. 1990-Level Carbon Stabilization Case 16
Figure 3.4 Carbon Reductions by End-Use Sector, Base vs. 1990-Level Carbon Stabilization Case 16
Figure 3.5 Energy Use in Selected Industries, Changes from Base to 1990-Level Carbon Stabilization Case 19
Figure 3.6 Energy Sources for Electricity Generation, Changes from Base to 1990-Level Carbon Stabilization Case 19
Figure 3.7 Generating Capability, Changes from Base to 1990-Level Carbon Stabilization Case 19
Figure 3.8 Sources of Carbon Reduction in the Electricity Sector, Base to 1990-Level Carbon Stabilization Case 19
Figure 3.9 Carbon Emissions in Various Cases, 5-Year Ramp to 2010 22
Figure 3.10 Carbon Permit Values, 5-Year Ramp to 2010 22
Figure 3.11 Carbon Emissions in Various Cases, 10-Year Ramp to 2010 22
Figure 3.12 Carbon Permit Values, 10-Year Ramp to 2010 22
Figure 3.13 Carbon Emissions in Various Cases, Alternate Timing 24
Figure 3.14 Carbon Permit Values, Alternate Timing 24
Figure 3.15 Carbon Emission in Various Cases, 1990-Level (1344) Cases 24
Figure 3.16 Carbon Permit Values, 1990-Level (1344) Cases 24
Figure 3.17 Capacity in Excess of Reserve Margin Requirements, 5-Year Ramp Cases . . . 25
Figure 3.18 Cumulative Carbon Reductions From Base, 2000-2020, All Cases 27
Figure 3.19 Cumulative Aggregate Permit Values, 2000-2020, All Cases, Discounted to 1997 @7%/Year 27
Figure 3.20 Comparison of Cases by Discounted Aggregate Permit Value (2001-2020) per Ton of Cumulative Carbon Reduction (2001-2020) 28

Figure 3.21 Comparison of Carbon by Discounted Aggregate Permit Value per Ton of Cumulative Carbon Reduction from Start of Budget Period to 2020 28
Figure 3.22 Cases Plotted by Discounted Revenue and Cumulative Carbon Reduction 30
Figure 4.1 Alternative Carbon Reduction Targets, All to Consumers, Federal Reserve Reaction Off 38
Figure 4.2 Alternative Carbon Reduction Targets, All to Consumers, Federal Reserve Reaction Off 39
Figure 4.3 GDP Impacts of Carbon Targets and Alternative Time Periods, All to Consumers Case, Federal Reserve Reaction Off 41
Figure 4.4 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, Budget: 1344 Average, 2011-15 Case 43
Figure 4.5 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, Budget: 1344 Average, 2011-15 Case 44
Figure 4.6 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, 1344 in 2010 (5-Year Ramp) Case 45
Figure 4.7 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, 1344 in 2010 (5-Year Ramp) Case 46
Figure 4.8 Federal Reserve Reaction Sensitivities, Deficit Reduction and All to Consumers, Budget: 1344 Average, 2011-15 Case 48
Figure 4.9 Federal Reserve Reaction Sensitivities, Deficit Reduction and All to Consumers, 1344 in 2010 (5-Year Ramp) Cases 49
Figure 4.10 Ramped vs. Budgeted Cases, Comparison of Sensitivities 51
Figure 4.11 Real Output, % Change from Base for the 1344 in 2010 (5-Year Ramp) Case, Deficit Neutral, Federal Reserve Reaction Function Off 54
Figure 4.12 Real Manufacturing Output, % Change from Base for the 1344 in 2010 (5-Year Ramp) Case, Deficit Neutral, Federal Reserve Reaction Function Off 55
Figure 4.13 International Emissions Trading Sensitivity, All To Consumers, Federal Reserve Reaction Off 57

Preface

The carbon stabilization analysis described in this report was produced by the Energy Information Administration (EIA), applying the National Energy Modeling System (NEMS) to assumptions specified by the U.S. Department of Energy (DOE), Office of Policy and International Affairs, consistent with analysis being undertaken in an inter-agency process to study the economic effects of carbon mitigation. NEMS is an integrated energy-economy modeling system for U.S. energy markets, developed by the EIA as a policy analysis tool to provide an integrated framework for policymakers to understand the implications of proposed policies and alternative assumptions concerning energy markets. NEMS is used annually by EIA's Office of Integrated Analysis and Forecasting (OIAF) to produce a reference case and a range of alternative projections for the midterm future, which were published most recently in the *Annual Energy Outlook 1997*.

The Energy Information Administration is an independent statistical and analytical agency within the U.S. Department of Energy. This analysis is provided by the Energy Information Administration as a service to the DOE Office of Policy and International Affairs to assess the impact of carbon stabilization goals on the U.S. energy system and economy. As such, the EIA does not advocate the policy outcomes resulting from assumptions specified by the U.S. Department of Energy for this analysis. None of the cases presented should be interpreted as an EIA forecast of the future.

Executive Summary

This study was undertaken at the request of the U.S. Department of Energy (DOE), Office of Policy and International Affairs (PO). Carbon mitigation and climate change are issues that must be addressed on a global scale by the international community. This study contributes to the analytical process by examining the impact of several carbon stabilization scenarios on the U.S. energy-economy. One set of cases extensively analyzes the impacts on the U.S. system assuming that carbon stabilization is achieved without the benefit of flexible international trading policies. The second sensitivity estimates the impacts on the U.S. energy-economy system of a much lower carbon value that may be realized under more flexible trading and other comprehensive approaches. Each potential member of the international community is expected to evaluate its options in a similar way prior to signing any international commitment to control carbon emissions. International emissions trading and a comprehensive approach to greenhouse gases are key elements of the U.S. position within the current international negotiations on climate.

The DOE Office of Policy and International Affairs was a participant in the analytical effort of the Interagency Analysis Team (IAT) studying the economic effects of global climate change policies in the United States. DOE/PO requested the analysis of several carbon policy scenarios using the National Energy Modeling System (NEMS) to examine how carbon stabilization could be achieved by 2010 and beyond.

Assumptions adopted by the IAT about domestic emissions permit trading, energy market incentives, and the effects of potential policy initiatives were implemented by EIA in the model. Alternative cases were simulated to gain some insights into the following questions:

- How might carbon reductions be achieved in U.S. energy markets? For example, what are the contributions from such factors as fuel switching, energy demand reductions, coal power plant retirements, and nuclear plant life extensions? What are the effects on individual energy sectors?
- How could technologies and capital stock turnover contribute to carbon stabilization?
- How does the starting date for achieving carbon stabilization influence the projected cost to the U.S. energy system?
- How does the length of time available for compliance influence the cost to the U.S. energy system?
- How are the marginal costs of carbon reduction affected with increasingly more stringent carbon goals?
- If a comprehensive and flexible emissions trading system resulted in carbon permit values of $40 per ton, with no Federal Reserve Bank accommodation, how many permits would

the U.S. have to purchase annually to meet 1990 levels of carbon? At what total cost? What are the fuel mix implications and what are the expected impacts on the U.S. economy?

This analysis relies on the NEMS for estimates of the implied costs of carbon stabilization, both as reflected in revenues from possible sales of carbon permits, as well as the effect on energy prices and quantities. The macroeconomic impacts of the primary carbon stabilization cases were analyzed by EIA using the in-house capability with the Data Resources, Inc. (DRI) Macroeconomic model. The macroeconomic analysis considered different options for allocating and financing the carbon stabilization costs and alternative central bank behavior.

Findings

All of the findings indicated in this report are based on the IAT assumptions and additional assumptions provided by the client in order to implement IAT assumptions. The client's assumptions and guidance were implemented within the NEMS/DRI system. These assumptions have not been assessed by the Energy Information Administration.

Carbon Stabilization Without International Carbon Emissions Trading

Meeting carbon stabilization targets solely within U.S. borders will impose significant changes on the energy markets and have long term consequences for the economy as a whole.

Carbon stabilization by 2010 at 1990 levels, if achieved through a marketable emissions permit system, would result in a carbon emissions permit value on the order of $130 to $150 per metric ton of carbon (1995 dollars). These permit values are projected to induce major changes in fuel use, with the electricity industry achieving the greatest share of the carbon reductions to over 25 percent below the 1990 level of 477 million metric tons of carbon.

By 2020, the use of coal would be curtailed to levels over half of current consumption levels. This change is induced by carbon permit values that triple the effective price of coal, eliminating the competitive edge it may have had over natural gas in existing generation capacity after 2010 under base case assumptions.

Consumption of natural gas, with a lower carbon content per unit of energy, increases relative to baseline projections in most of the stabilization scenarios. The moderate increase in natural gas use (about 3% in 2010, significantly more in earlier years) occurs with increased natural gas for generation more than offsetting decreases in gas use in the end-use sectors.

About 70 percent of carbon reductions in the electricity sector are achieved through fuel substitution away from higher carbon energy sources and from efficiency improvements, only about 30 percent of carbon reductions in electricity are attributed to reductions in electricity sales. A significant share of the carbon reductions come from substitution of renewables for fossil fuels, with additional generating capacity from wind, wood, and other renewables of over 100 gigawatts by 2010.

compared to the reference case.

Petroleum use is also projected to decline significantly in the stabilization scenario, primarily as a result of improved efficiency in transportation and an increased penetration of alternative-fuel vehicles. By 2020, oil import dependence is reduced from 62 percent in the base case to 55 percent in the 1990-level carbon stabilization case.

Capital stock turnover and technologies are important factors for carbon mitigation. The availability, cost and performance characteristics of new technologies, consumer preferences and ultimately consumer acceptance and adoption, current and expected market prices and the physical lifetime of equipment are critical factors in determining the U.S.'ability and cost to achieve carbon stabilization.

In the residential and commercial markets, consumer preferences limit premature capital stock turnover and the rate at which new technologies can contribute to carbon stabilization. Consequently, the residential and commercial markets are projected to respond the least to carbon limits using marketable emissions permits while electricity generation markets respond the most because of the cost minimizing behavior assumed in those markets. Increased economic retirements of generation equipment in a cost-of-service system result in excess capacity (candidates for early retirement) of about 100 gigawatts (12 percent) above the reference case by 2010 when stabilizing at 1990 carbon levels by 2010.

It is by no means clear what implementation mechanism will be adopted to achieve carbon stabilization and how and where any price signal will be communicated to the market. In this report, we use the term "revenues" instead of the more accurate but cumbersome phrase "cumulative aggregate permit values." In some potential implementation strategies, the government may not see or manage any revenues from carbon permits, much like the sulfur trading system now in place for electric utilities. In other cases, the government may need to collect the carbon permit values and decide how to recycle the revenues later.

The macroeconomic adjustments to carbon stabilization policy changes are complex, as various segments of the economy gradually adjust to the disequilibrium originating in the energy markets caused by implementing a "cap and trade"[1] system that places a value on carbon emissions. Four factors heavily influence the ultimate outcome of the aggregate economy:

---

[1] A "cap and trade" system is a market-based system that attempts to limit a specific emission (like sulfur) to a specific maximum level (e.g., 9 million metric tons in the utility industry) each year by pricing the permit value of an emission at the marginal cost necessary to meet the constraint. A "cap and trade" system can apply to a single region, multiple regions or different sectors (e.g., utilities, industrial). The permit acquisition process, "grandfathering" of permit rights at some historical year, initial permit values and allocation, the compliance monitoring system, and how the system is managed and operated are details of the implementation that must be worked out.

- The timing, magnitude, and flexibility of the carbon emissions reduction target and the associated increase in energy prices;
- What the Federal government does with carbon permit "revenues;"
- The reaction of the Federal Reserve in response to the macroeconomic consequences of the carbon stabilization policy; and
- The impacts of industrial competitiveness on energy-intensive industries and how it might impact the industrial output mix.

Carbon Emissions Reduction Target. The more stringent the carbon emissions reduction target, the higher the GDP loss. Shortening the ramp-in period results in greater energy price increases and greater loss in peak economic output; however, the economy returns to its baseline level in approximately the same period of time as a case with a longer ramp-in period. Extending and delaying the time frame over which carbon reduction targets are achieved ameliorates the GDP losses because the energy transition in the economy is more gradual, giving the energy market more time to adjust to permit value changes; the delay also allows advanced technologies to play a greater role in reducing the permit value of carbon.

Fiscal Policy. In the near-term, returning carbon permit proceeds to consumers via a reduction in personal income taxes cuts the loss in GDP in half relative to using the funds to reduce the deficit. However, in the long-run, the policy of using the carbon permit funds to reduce the deficit will act to lower Federal borrowing and therefore lower interest rates. In the DRI macroeconomic model, the increase in the economy's overall savings rate will ultimately spur capital formation, leading to higher GDP relative to the policy baselines.

Federal Reserve Policy. The DRI reaction function attempts to capture the likely responses of the Federal Reserve Board to changes in unemployment and the rate of inflation. EIA's general practice, outside of the IAT process, and followed in this report, is to use the DRI model with the Federal reaction function "off." EIA has prepared sensitivity cases to evaluate the impact of turning "on" the reaction functions. If the DRI reaction function is used, the negative impacts on GDP are projected by the DRI model to be roughly halved, with recovery in the later years coming much faster and stronger.

Industrial Competitiveness. If the price of carbon intensive energy inputs increases considerably, the whole cost structure of energy-intensive industries is altered. Faced with much higher costs of production in [illegible] countries, the competitiveness of domestically-operated energy-intensive industries may [illegible]. However, U.S. goods that are not carbon-intensive may emerge as potential winners, and may offset any negative impact of the carbon stabilization policy on the aggregate trade balance. Nonetheless, there is likely to be a significant shift in the composition of industrial output in the economy away from the production of energy-intensive goods to non-energy-intensive goods production.

Carbon Stabilization With Flexible International Carbon Emissions Trading

The explicit assumption in this case is that carbon permit values can be purchased internationally at $40 per ton (1995 dollars) to offset any U.S. emissions in excess of 1990 levels from 2010 to 2020.

Relative to the reference case, a $40 per ton carbon permit value (with the other assumptions of the case) is projected to decrease carbon emissions by 132 million metric tons in 2010 (35% toward stabilization) and by 237 million metric tons in 2020-electricity generation accounts for approximately 63 percent of the reduction in 2020, transportation for 22.5 percent, industrial for 12.5 percent and the rest (2 percent) by the building sector. Unlike the stabilization cases without international trading, overbuilding of electricity capacity was not required to achieve these reductions.

Despite the carbon reduction relative to the reference case, 240 million metric tons of additional carbon permit credits will have to be purchased internationally in 2010 and 298 million metric tons will have to be purchased in 2020 for carbon emissions above 1990 levels. Annual expenditures to foreign countries to purchase those carbon permits (in constant 1995 dollars) range from $9.6 billion to $11.9 billion.

By 2020, the use of coal falls by 25 percent relative to the reference case to approximately 1995 levels of consumption. Relative to the reference case, the $40 per ton carbon permit value in 2020 effectively doubles the delivered coal cost to utilities while the effective natural gas costs increase 24 percent. The carbon reductions are achieved, in part, through assumed nuclear life extensions through 2020. If nuclear life extensions with a $40 per ton carbon permit fee are not economically viable, the carbon reductions achieved for this case would be about 30-100 million metric tons higher, depending on whether gas combined cycle or coal units are used to substitute for retired nuclear units.

In 2010, about 84 percent of the carbon reductions in the electricity sector is achieved through fuel substitution away from higher carbon energy sources and from efficiency improvements; only about 16 percent of carbon reductions in electricity are attributed to reductions in electricity sales. Almost all of the fuel-switching reductions come from fuel-switching from coal generation to gas generation with some increase in renewable generation (about 22 billion kilowatt-hours and 5 gigawatts of total renewable incremental capacity from wind, biomass and geothermal).

Petroleum consumption is projected to decline by 4% in the $40 per ton case primarily from improved efficiency in transportation and an increased penetration of alternative-fuel vehicles. By 2020, oil import dependence is reduced from 62 percent in the reference case to 58 percent.

The price paid for energy goods and services is substantially lower in the $40 per ton case than in the five-year average stabilization case to 1990 levels between 2010 and 2015 ("the 5-year budget case"). The aggregate wholesale price of purchased fuel rose approximately 50 percent in the 5-year

budget case, while in the in the $40 per ton case the wholesale price rose only by roughly 15 percent. As a result, the peak loss in GDP is $50 billion in the $40 per ton case, in contrast to the $85 billion loss occurring in the stabilization case. Over the entire period through 2020, emissions trading lowers the net present value of the GDP loss from $416 billion to $202 billion. Through 2020, the positive effects of lowering the price of carbon permits dominates any adverse consequences associated with an outflow of funds overseas.

Additional Uncertainties and Issues With a $40 per Ton Carbon Trading Fee

Major additional uncertainties that occur with the $40 per ton carbon trading fee case include the economic feasibility of life extensions of nuclear units and the early retirement of approximately 35 gigawatts of coal plants whose operating and maintenance costs are between 2.5 and 4.0 cents/kilowatt-hour.

It may be uneconomic to life-extent, beyond their normal 40-year life, all or even some of the nuclear power plants at a $40 per ton carbon permit value. If technological costs to life-extend nuclear plants are too high to be economic, an additional 330 billion kilowatt-hours of electricity will have to be generated almost entirely by fossil fuel units and could result in approximately 30 - 100 million metric tons of additional carbon permits that must be purchased in 2020.

It was assumed that approximately 35 gigawatts of coal plants whose operating and maintenance costs were between 2.5 - 4.0 cents per kilowatt-hour were retired because they were assumed not to be economic. If $40 per ton does not make these plants uneconomic to dispatch, over 50 million metric tons of additional carbon credits would need to be purchased from the international market.

1. Introduction

This study was undertaken at the request of the U.S. Department of Energy, Office of Policy and International Affairs (PO). Its purpose is to analyze the impact of several carbon stabilization scenarios on the U.S. energy economy. Appendix A provides a copy of the original request made in January, 1997, along with an updated request from April, 1997.

The DOE Policy Office was a participant in the analytical effort of the Interagency Analysis Team (IAT) studying the economic effects of global climate change policies in the United States. The Policy Office requested the analysis of eleven carbon policy scenarios using the National Energy Modeling System (NEMS) to examine how limits on U.S. carbon emissions to be achieved by 2010 and beyond might affect the energy sector and the overall U.S. economy. According to guidance supplied by the requesting office, assumptions adopted by the IAT about emissions permit trading, energy market incentives, and effects of potential policy initiatives were implemented by EIA in the model. Alternative scenarios were simulated to gain some insights into the following questions:

- How might carbon reductions be achieved in U.S. energy markets? For example, what are the contributions from such factors as fuel switching, energy demand reductions, coal power plant retirements, and nuclear plant life extensions? What are the effects on individual energy sectors?

- How could technologies and capital stock turnover contribute to carbon stabilization?

- How does the starting date for achieving carbon stabilization influence the projected cost to the U.S. energy system?

- How does the length of time available for compliance influence the cost to the U.S. energy system?

- How are the marginal costs of carbon reduction affected with increasingly more stringent carbon goals?

This analysis relies on the NEMS for estimates of the implied costs of carbon stabilization, both as reflected in revenues from possible sales of carbon permits, as well as the effect on energy prices and quantities. The macroeconomic impacts of the primary carbon stabilization cases were analyzed by EIA using the in-house capability with the Data Resources, Inc. (DRI) Macroeconomic model. The macroeconomic analysis considered the different options for allocating and financing the carbon stabilization costs and alternative central bank behavior.

Section 2 describes the scenarios developed, the modeling approach, and the specific assumptions. Section 3 presents the NEMS results and an analysis of the cases examined. Section 4 presents the macroeconomic results and analysis. Section 5 summarizes the key findings of the study.

2. Modeling Methodology and Assumptions

2.1 Description of Cases

The NEMS forecast horizon was extended from 2015 to 2020 for this project, and an initial scenario was developed as an update to the *Annual Energy Outlook 1997* (AEO97) reference case. This **"Policy Base Case"** incorporates some changes in baseline assumptions and some minor model and data updates compared to the AEO97 reference case.

A second reference case, the **"Policy Announcement Case,"** was designed to represent the effect of the announcement of a carbon reduction agreement without any "price signals." This second case was designed to be similar to one evaluated by the Inter-Agency Task-force (IAT) studying the economic effects of global climate change policies. The **"Policy Announcement Case"** assumes that consumer choices and manufacturer actions will be taken to prepare for an announced, time-specific agreement on carbon stabilization. The announcement effect was assumed to lead to declines in energy intensity and carbon emissions. Intensity declines could be attributed to, for example, increased social awareness of the need to reduce carbon emissions and investment decisions made in expectation of higher future energy costs. By IAT assumption, the Policy Announcement Case was intended to result in declines in aggregate energy intensity of as much as 1.25 percent a year by 2015. This compares to an approximately 0.9 percent average annual decline in U.S. energy intensity from 1995 to 2015 in the AEO97 reference case.

In addition to the Policy Base and Announcement cases, various cases were run in which different carbon stabilization goals were met. The cases examined included the stabilization of carbon emissions at one of four levels (expressed in million metric tons of carbon):

- 1344: A level equal to U.S. carbon emissions from energy in 1990. The 1344 (million metric tons) figure for 1990 is the current estimate for carbon emissions from fossil energy consumption as reported in *Emissions of Greenhouse Gases in the United States 1995* (Energy Information Administration, DOE/EIA-0573(95), October 1996, Table 6, pg. 16). A figure of 1340 million metric tons of carbon is often cited as the value for U.S. energy-related carbon emissions, but the estimate has been revised upward to 1344.

- 1400: Slightly above the level of U.S. carbon emissions from energy in 1990, resulting from IAT assumption that "credits" reductions from non-energy greenhouse emissions and an accounting allowance to adjust for emissions associated with growth in international transportation energy use. Emissions from international transportation fuel use is not attributed to any one country's emissions target. A breakout of transportation fuel between domestic and international uses is not available in NEMS, but some portion of the growth in jet and shipping fuel would be for international use. Several other different interpretations could be attached to

stabilization at or near this level.[2]

- 1210: 10 percent below 1990 emissions
- 1142: 15 percent below 1990 emissions
- $40 : flexible emissions trading to reach 1990 carbon permit levels. All permits required to achieve 1990 carbon emissions levels are assumed available through the international market at $40 per ton

The stabilization cases also included variations on when, and how gradually, the stabilization goal would be phased in. One set of cases assumes a 2010 target date for stabilization in which emissions reductions policies would be ramped in over a 5-year period beginning in 2005, reaching their target levels in 2010. The four cases defined above with 5-year ramps are plotted in Figure 2.1 and compared to the emissions trajectories in the Policy Base and Announcement cases.

Another set of cases, plotted in Figure 2.2, examines a 10-year ramp period to eventually achieve stabilization by 2010. For this set, three carbon levels were examined: 1400, 1344, and 1210 million metric tons. Although the 1344 and 1400 cases formally paralleled the IAT cases, a comparable 1210 target was also examined as a sensitivity to provide information on the marginal value of carbon reduction at lower targets. The 1210 reduction target is 10 percent lower than 1990 carbon emission levels. The ten-year ramp period is included to permit comparison with other model structures, such as the DRI energy model, which do not easily allow investigation of 5-year ramp periods. The inclusion of three 10-year ramp cases should not be construed as being equally important or likely as the 5-year cases. The reader is encouraged to focus on the 5-year ramp cases since these cases are the principle focus of our analysis and attention and of greatest interest to our client.

Four other cases, plotted in Figure 2.3, vary the timing and flexibility of the stabilization. These include two cases in which an average annual emissions target equal to the 1990-level of 1344 million metric tons annually is attained over longer periods, and the flexibility to "budget" the reductions over time is assumed. The two budget periods tested were from 2010 to 2015 and 2010 to 2020 (ranges inclusive). These cases achieve an average emissions over their budget periods of 1344 tons a year, each assuming that smaller emissions reductions early in the budget period are balanced by larger emissions reductions later. Two other timing cases move the effective date for stabilization to 2015 with targets of 1210 and 1142 million metric tons, using the 5-year ramp period. The final sensitivity examines the impact of a $40 per ton carbon fee. Table 2.1 summarizes the cases examined.

---

[2] Specifically, it could represent a target level for carbon stabilization deliberately set above the 1990 level under a comprehensive greenhouse gas stabilization plan under the assumption that reductions in other greenhouse gases beyond levels that are required for their individual stabilization and the exclusion of international fuel use would allow for comprehensive stabilization despite the modest growth in carbon emissions.

Figure 2.1 Carbon Emissions Stabilization Cases in 2010 (5-Year Ramp)

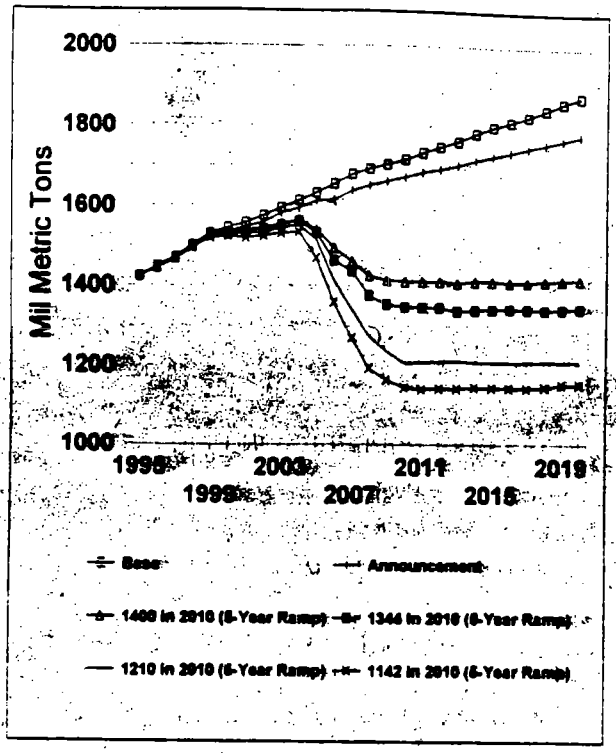


Figure 2.2 Carbon Emissions Stabilization Cases in 2010 (10-Year Ramp)

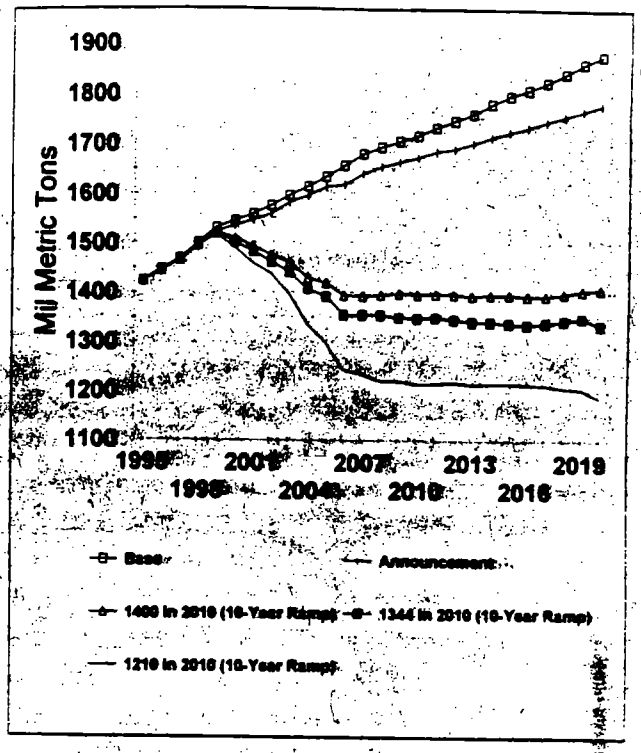


Figure 2.3 Carbon Emissions Stabilization Cases, Timing Alternatives

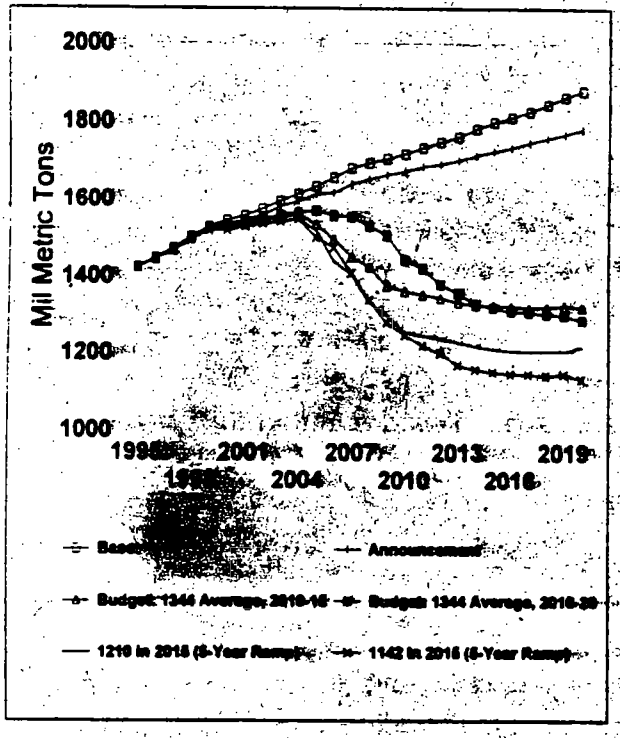


Table 2.1 Carbon Emission Cases Examined

Stabilization Target*	Compliance Period		
	1-Year Budget in 2010	5-Year Budget Average 2011-2015	10-Year Budget Average 2011-2020
1344 mmt/year (1990 Level)	●	●	●
1400 mmt/year (1990 level)	●		
1210 mmt/year (10% below 1990 level)	●	●	
1142 mmt/year (15% below 1990 level)	●	●	
$40 per ton, international emissions trading to reach 1990 carbon emissions	●		

* The carbon stabilization targets are achieved within a tolerance of about 10 million tons.

2.2 Methodology

Two types of modeling changes were implemented to simulate the emissions stabilization cases. First, alternative assumptions regarding technology cost, performance, and adoption rates were implemented in the model. These assumptions are described in detail in Sections 2.3 and 2.4. Once these technological assumptions were incorporated into the modeling system, a marketable carbon permit trading system within the United States was simulated. That is, to meet the carbon goals in the stabilization cases, a sufficient carbon emissions permit value was added to energy prices in proportion to each fuel's carbon emissions content until the goal was reached. The approach simulates a marketable emissions permit system in which permit trading determines a market-clearing price for a given number of carbon permits each year. The cost of a carbon permit is added to the energy price seen by the fossil fuel consumers. That is, the carbon value is added to all carbonaceous fuels and represents the marginal cost to remove the last unit of carbon from the system. With electricity, the carbon values are assumed to be paid by electric generators on purchases of fossil fuel and then passed along to ratepayers like other operating expenses. It should be noted that for utilities operating under cost-of-service regulation, it is likely that Public Service Commissions would adopt a "share-the-costs" or "share-the-benefits" policy between rate payers and shareholders. In this study, all consumers are assumed to incur the marginal cost of carbon when they purchase their fuels.

The cost of a carbon permit is expressed in dollars per metric ton (a thousand kilograms) of carbon emissions content. Table 2.2 displays an example of hypothetical energy costs for the year 1995 associated with various carbon permit values for each fossil fuel, based on average carbon contents. The carbon emissions permit value represents the incremental cost of constraining the last ton of emitted carbon in the energy system and thus provides the price signal necessary to induce cost-

effective reductions in carbon emissions. The size of the carbon values required to induce carbon reduction generally increases with the targeted level of reduction. However, other factors, such as the timing of reductions and technology availability can also affect permit values.

The alternative carbon stabilization cases are simulated with both carbon permits as well as with alternative technological and behavioral assumptions. Theses assumptions are described in the next two sections.

2.3 Modifications to AEO Reference Case Modeling Assumptions

This section describes the modifications to the NEMS AEO97 reference case model assumptions made by EIA under the guidance of the DOE Office of Policy and International Affairs. The modifications are based on DOE's interpretation of IAT discussions on the modeling of carbon stabilization cases. In addition, because the prices required for carbon stabilization to 1990 levels are well outside the historical price and consumption data series used to develop NEMS, EIA modified some NEMS behavioral parameters (elasticities) to reflect potentially greater demand responsiveness with high prices.

2.3.1 Modifications to NEMS Demand Modules

Residential

- In the residential sector, a price elasticity (-0.15) was applied to all end-use services. In AEO97, the elasticity was only applied to space conditioning and the rest of the elasticities were zero.

- The residential hurdle rates for energy investments were reduced. Every technology has its own hurdle rate which can vary from 15 percent (e.g., gas space heaters) to over 250 percent (e.g., ground source heat pump water heater). The first 15 percent is assumed to be the cost of money and the remainder, called the non-financial hurdle rate, represents a combination of institutional and physical constraints as well as consumer preferences. Consequently, the non-financial hurdle rates vary by technology from 0 percent to over 235 percent. The non-financial component was reduced by 20 percent which resulted in a total reduction of *up to* 45 percent of the hurdle rates — (that is, 47 percent is 20 percent of 235 percent).

- The assumed rate of growth for miscellaneous residential electricity use was reduced 15 percent starting in 2010 from the 2 percent per year assumed in AEO97. In addition, the rate of growth of miscellaneous residential electric plug load was assumed to decline by another 10 percent whenever electricity prices exceeded 30 percent of 1993[3] price levels. The AEO97 miscellaneous plug load was not price-sensitive.

[3]The residential module data is based in 1993, the latest data year available for the Residential Energy Consumption Survey.

Table 2.2 **Example of effective energy costs for coal, natural gas, and gasoline for various carbon permit values**

	Steam Coal	Gasoline	Natural Gas
Carbon Emissions Factor			
(kilograms carbon per million Btu)	25.46	19.20	14.40
Average Delivered Energy Price, 1995			
Energy Units ($/million Btu)	1.30	9.63	3.60
Physical Units ($/short ton, $/gallon, $/mcf)	27.09	1.21	3.70
Implied Cost with Carbon Permit Value Included:			
Energy Units ($/million Btu)			
$ 50/ton carbon value	2.57	10.59	4.32
$100/ton	3.85	11.55	5.04
$150/ton	5.12	12.51	5.76
$200/ton	6.39	13.47	6.48
Physical Units ($/short ton, $/gallon, $/mcf)			
$ 50/ton carbon value	53.63	1.33	4.44
$100/ton	80.18	1.45	5.18
$150/ton	106.72	1.57	5.92
$200/ton	133.27	1.69	6.66
Percentage Increase in Price of Delivered Energy			
$ 50/ton carbon value	98%	10%	20%
$100/ton	196%	20%	40%
$150/ton	294%	30%	60%
$200/ton	392%	40%	80%

Notes: **This is an example of how hypothetical carbon permit values would increase the price of delivered energy based on 1995 data. Refer to Table 3.1 for a summary comparison of results for the years 2010 and 2020.**

Carbon emissions factors are adjusted to reflect assumed fractions of fuel combusted: .99 for coal and gasoline; .995 for natural gas.

Sources: 1995 energy prices in physical units and Btu conversion factors from Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95). Carbon emissions factors derived from: Energy Information Administration, Emissions of Greenhouse Gases in the United States 1995, DOE/EIA-0573(95), Table B1, Carbon Emissions Coefficients at Full Combustion (pg 98), and Table A2, Rates of Sequestration of U.S. Fossil Fuel Consumption (pg 70).

- The sensitivity of residential shell efficiency for existing homes to energy prices was increased. In AEO97, a 5 percent increase in prices relative to 1993 resulted in a 1 percent increase in shell efficiency. In the carbon stabilization runs, a 5 percent increase in prices relative to 1993 resulted in a 2 percent increase in shell efficiency.

Commercial

- In the commercial sector, a short-run price elasticity (-0.15) was applied to refrigeration, office equipment and miscellaneous electric end uses if fuel prices differ from 1993 prices by more than 30 percent. The AEO97 assumed zero price elasticity for these end uses. The elasticities for electric space heating and space cooling in AEO97 were -0.10 and they were changed to -0.15.

- In the commercial sector, all new-equipment purchase decisions and all appropriate replacement decisions allowed consumers to consider all technologies for the selected fuel. In the AEO97, a proportion of consumers - varying for each end-use (e.g., space heating), building type and decision type - were limited to purchasing the same type of technology as previously owned based on historical decision-making in that sector. For example, for most end uses, for replacement decisions, the proportion ranges from 42 percent to 60 percent.

- Commercial building shell efficiency was assumed to improve 20 percent faster than the AEO97 rate of improvement. In the AEO97, the average shell efficiency improved 5% for existing buildings and 8% for new buildings by 2015. In the carbon stabilization runs, average building shell efficiency improved 6% for existing buildings and 9.6% for new buildings by 2015.

- Commercial sector hurdle rates were decreased to reflect an increased importance given to investments in energy efficient equipment; the hurdle rate component in excess of the cost-of-money was reduced by 20 percent. Like the residential sector, the hurdle rates are defined as the sum of a financial component plus a non-financial component and range from about 18 percent to well over 200 percent. Unlike the residential market, the commercial market is divided equally into six customer groups with six different hurdle rates to distinguish consumers with different propensities to purchase innovations. The hurdle rates typically range from about 23 percent for innovators with the lowest hurdle rate, to laggards with hurdle rates over several hundred percent. The last consumer category represents a combination of physical and institutional constraints such as the absence of gas lines which may prohibit adoption of an otherwise attractive technology or fuel choice.

- Starting in 2010, the rate of growth for miscellaneous commercial electricity use was reduced 15% from AEO97 levels. In addition, the purchase costs of advanced, more efficient technologies was assumed to start declining over time starting in 2010 at an average annual rate of 3.6 percent.

Industrial

- DOE assumed the Administration estimates for the effects of the Climate Change Action Plan (CCAP). The industrial CCAP programs are assumed to result in reductions in fossil fuel consumption and electricity sales from 2000 to 2010. The revised estimates are as follows, with the assumptions from the AEO97 provided for reference:

		Administration Assumption	AEO97 Assumption
Reduction in industrial fossil fuel consumption (trillion Btu):	2000:	196	90
	2010:	410	190
Reduction in industrial electricity consumption (billion kWh):	2000:	19.8	16.3
	2010:	78.0	47.4

- "Leakage" of a portion of the U.S. energy-intensive industries was assumed for the stabilization cases to reflect decreased competitiveness vis-a-vis non-Annex I countries. This assumption was implemented by reducing projected manufacturing output by up to 25 percent from their baseline levels by 2020 in selected energy-intensive industries. In the final sensitivity which imposes a $40 per ton carbon trading fee, "leakage" was assumed not to occur from the United States.

Transportation

- In the transportation sector, the combined market share of light trucks (pickup trucks, vans, and sports utility vehicles) as a percent of total vehicle sales was modified to respond to higher gasoline prices. When gasoline prices increase relative to the AEO97 reference case, the proportion of new vehicle sales that are light trucks declines relative to the AEO97 reference case. The modified price response is assumed to occur in any year in which the average gasoline price is above $1.22/gallon (1995 dollars), a price equal to the maximum in any year in the AEO97 reference case. At prices above $1.22, a market sharing equation shifts a portion of light truck sales back to automobile sales. In the AEO97 reference case, the market share of new light trucks, vans and utilities sales as a percentage of new vehicle sales was 42.7 percent in 2015 while in the 1344 case with a five-year ramp, the market share of new light trucks, vans and utility vehicles was 36.8 percent.

- In the cases with more stringent carbon stabilization goals of 10 to 15 percent below 1990 levels (1210 and 1142 million metric tons), it was assumed that E85 (a mixture of 85 percent ethanol and 15 percent gasoline) would become competitive with motor gasoline after 2010, as ethanol would not be subject to carbon emissions permits. For these cases (the 1210 and 1142 cases only), the alternative-fuel vehicle market shares were adjusted to favor the selection of E85/gasoline hybrid vehicles. These cases resulted in a substitution of about 2 quads of E85 for gasoline, saving about 30 million tons of carbon.

- The IAT assumption for advanced transportation success was used to imply that the PNGV vehicle (Partnership for a New Generation of Vehicles) would capture 5 percent of the new light duty vehicle sales by 2015 and 20 percent by 2020, per Administration goal. The NEMS was adapted to incorporate the client's interpretation of the IAT assumption.

- An American Council for an Energy-Efficient Economy (ACEEE) technology characterization list was used which assumed approximately a 50 percent reduction in the marginal technology costs and a 33 percent higher marginal fuel efficiency improvement above AEO97 levels.

- The Administration's 1996 estimate for CAFE reductions in vehicle miles traveled of 2.6 percent was assumed, changed from the AEO97 estimate of 1.13 percent.

2.3.2 Modifications to the NEMS Supply and Conversion Modules

Nuclear Life Extension: In the carbon stabilization cases, the operating licenses of nuclear units were assumed by the DOE client to be extended by 20 years. This assumption implies the continued use of existing nuclear plants through 2020, a significant source of carbon reductions (30 - 100 million metric tons, assuming it substitutes for either advanced gas combined cycle or existing coal-based generation) compared to the AEO97 assumptions.

"Nuclear" Plant Additions: The DOE client assumed that, after 2015, nuclear plants, or some carbon-free generating technology of equivalent cost and performance, would become available. Post-2015, these plant additions were allowed to compete with other generating technologies in the capacity planning model on the basis of economics.

Early Plant Retirements: All steam units with operating, maintenance and G&A costs in excess of 2.5 cents per kilowatt-hour were assumed to be retired prematurely (after 35 years in service rather than 40 years) in the carbon stabilization cases. In AEO97, early retirements occurred at operating costs of 4 cents per kilowatthour. By 2020, approximately 40 additional gigawatts of plant retirements occur in the stabilization cases, compared to the base case. About 35 gigawatts of these plant retirements are coal units.

Foresight: It was assumed that electricity providers would have full price knowledge of future carbon permit values and incorporate these values into their capacity planning decisions. This modeling assumption is particularly important in the electricity sector, as capacity choices influence future carbon values required to meet a particular carbon stabilization goals. While significant carbon reductions in the electricity sector can be obtained in the short term through alternative dispatching and other forms of fuel substitution, investments in renewables or low-carbon generating capacity have a potentially greater and long-lived impact. Such investment decisions are based in part on expectations about future energy costs, including the cost of any carbon permits.

Capacity in Excess of Reserve Margin Requirements: In the carbon stabilization cases, the electricity industry was allowed to build capacity in excess of reserve margin requirements if projected energy costs made

it economical to do so. That is, at some levels of carbon values, it becomes economical to invest in lower-carbon or carbon-free generating capacity to avoid using existing fossil-plants. The capacity left idle as a result could be considered to be either excess capacity or economic plant retirements. For the AEO97, the assumption was that utilities could increase capacity to a level 2 percent above reserve margin requirements. For this analysis, DOE assumed utilities could add significantly more, provided the economic retirements occurred gradually. The excess capacity limit for each of the 13 electricity supply regions was set to 10 percent above the prior year's capacity level, beginning in 2006 (for the 5-year ramp cases) or 2001 (for the 10-year ramp cases). For example, if the excess capacity level for a region reached 5 percent in a given year, the allowable excess capacity would be permitted to increase to 15 percent in that region in the next year.

Fuel Substitution in Coal Plants: The assumed maximum fraction of natural gas used in predominately coal-fired plants was increased. For those coal plants recently burning some natural gas, the maximum share of gas use was increased by 5 percentage points over the current percentage used. The AEO97 assumption was that each coal plant's maximum gas share was equal to its current fraction of gas use.

Renewables Limits on New Capacity: The AEO97 assumes upper and lower bounds to the annual amounts of new renewable capacity that can be added in each region. For the stabilization cases, the annual upper bounds assumed in each region are 500 MW per year for wind, 400 MW per year for solar thermal capacity, and 200 MW per year (East) and 100 MW per year (West) for biomass. These regional limits are higher than those assumed in the AEO97 (100 to 200 MW per year in selected regions, depending on the technology). In addition, the lower bounds, or floors, on both solar thermal and solar PV were doubled (for a combined, National total floor of about 1.5 GW by 2015) to reflect the expansion of demonstration programs and niche markets that may result from higher sectoral electricity prices.

Natural Gas Pricing: In the AEO97 reference case, intraregional natural gas price markups to electric generators are held constant throughout the forecast. Given the increased demand for natural gas for generation in the carbon stabilization scenarios, these markups were adjusted to account for the increased cost of infrastructure necessary to accommodate the added loads. The amount of the markup adjustment was based on the annual change in natural gas consumption for generation.

Ethanol Supply: New ethanol supply technologies were assumed to become available beginning in 2010 at prices ranging from $0.75 to $1.02 per gallon (1995 dollars), depending on production levels. The AEO97 assumption for ethanol supply costs were from $0.97 to $1.40 per gallon in 2010. Ethanol is available for blending with gasoline for gasohol, as E85 for ethanol-fueled vehicles, and for ETBE production.

2.4 Limitations on Modeling Assumptions

The discussion of modeling assumptions in the previous section suggests some of the sources of uncertainty in evaluating energy markets under carbon stabilization scenarios. The assumptions mentioned highlight uncertainty regarding the responsiveness of consumers to significant energy price changes that might occur under carbon stabilization policies, as well as a variety of factors influencing energy supply. While detailing the assumptions that changed from the AEO97 reference case is important, it is also useful to describe modeling assumptions that could represent additional uncertainties in this analysis but were not changed.

In particular, no significant changes were incorporated to international energy in this analysis. Coal exports are essentially unchanged from the AEO97 reference case, and no changes in the pattern of world oil demand have been assumed. Widespread adoption of carbon stabilization policies may lead to lower coal exports and lower world oil prices than indicated in the stabilization cases. Lower world oil prices could increase the domestic oil demand and offset some of the carbon reductions occurring in these cases.

This analysis does not reflect the adoption of unregulated pricing of electricity. In a regulatory environment with cost of service regulation, fuel and other costs have been traditionally passed through to customers. Whether Public Service Commissions would allow the extent of early retirements and replacements of coal plants to reduce total costs assumed in these runs is unclear. With unregulated pricing, early retirement and replacement decisions would be largely driven by economic considerations.

Both biomass and municipal solid waste (MSW) are considered zero net carbon emitters in this analysis, primarily because both are assumed to have earlier sequestered any carbon emitted later during combustion. Both biomass and MSW sequester carbon during the growing cycle and later emit it during combustion. If the average stock of standing forests, crops, crop wastes, or MSW is reduced more by combustion than would have occurred without combustion, a requirement for carbon permits may need to be imposed to reflect the net carbon emissions potential.[4]

The macroeconomic impacts of the energy price increases are highly dependent on how the specific carbon reduction policies are formulated. The stabilization runs include some macroeconomic feedback due to changes in energy prices, as modeled in the reduced form Macroeconomic Activity Module of NEMS. However, the full macroeconomic impacts on the energy system, including possible economic recovery under some scenarios for recycling of revenues from possible permit

[4]Further, if a significant proportion of forecast MSW represents petroleum-based materials (like plastics) rather than biomass, then MSW combustion should be considered a positive net carbon emitter. A cursory review suggests that although the petroleum-based fraction (plastics, tires, etc.) constitutes only about 10 percent of combustible MSW by weight, emissions from that fraction are about 25 percent of total carbon emissions from MSW.

sales or value collections, were not integrated back into NEMS because the feedback effects were expected to be minor. These macroeconomic effects, assessed using a version of the Data Resources, Inc. (DRI) Macroeconomic model, are discussed in Chapter 4.

Additional uncertainties cloud the international emissions trading case which is assumed to result in a $40 per ton carbon permit fee.

- It may be uneconomical to life-extend, beyond a normal 40-year life, all or even some of the nuclear power plants at a $40 per ton carbon permit value. If technological costs to life-extend nuclear plants are too high to be economic, an additional 330 billion kilowatthours of electricity will have to be generated almost entirely by fossil fuel units and could result in approximately 30 - 100 million metric tons of additional carbon permits that must be purchased in 2020.

- The development of a reference case forecast of carbon emissions for developing countries from which purchase of permits is being contemplated will be difficult estimate, may be difficult to reach a meaningful agreement on, and may be susceptible to manipulation by the developing countries.

- Implementation, monitoring and enforcement of carbon emission targets could be difficult to enforce.

3. Energy Model Results and Analysis

This section presents the results of the NEMS runs in two parts. First, the Base Case is compared in detail to one of the primary carbon stabilization cases. The stabilization case selected for this more in-depth comparison has a goal of reducing carbon emissions to the 1990-level of 1344 million metric tons of carbon by 2010, after a 5-year phase-in period, or ramp, of increasing reductions. The second section compares the stabilization cases to identify the effects of variations in the timing, magnitude, or phase-in period of the stabilization goal.

3.1 Comparison of the Base and 1990-Level Carbon Stabilization Cases

The Base Case is an updated reference case, similar to the AEO97 reference case, but with the forecast horizon extended to 2020. Table 3.1 provides a summary comparison of results from the Policy Base Case and the 1990-Level (1344 million metric ton) Carbon Stabilization Case. For brevity, these cases will be referred to as the "base case" and "stabilization case" in this section.

Appendix C contains a set of detailed tables comparing the base case and two stabilization cases, the first case uses a 5-year ramp to reach 1990 levels from 2005 to 2010 while the second uses a 5-year period from 2010 - 2015 over which the average annual carbon emission equals 1990 levels.

Energy Prices

The carbon reductions in the stabilization case were achieved in part through a carbon emissions permit system. A permit value on average of $130 to $150 per metric ton (1995 dollars) achieves the emissions goal from 2010 to 2020. The permit system induces significant energy market changes, particularly in electricity generation (Table 3.1).

Carbon permit values raise the effective energy prices for fossil fuels, with the price of coal, having the highest carbon content, rising the most when compared on a dollar-per-million Btu basis (Figure 3.1). While electricity consumption does not release carbon at the point of use, limitations on carbon emissions raise the price of electricity as the cost of the fossil fuel input is passed on to consumers, along with added costs to cover differences in plant investments.

The price of E85 is lower in the stabilization case, due to a more optimistic technological supply assumption and an assumed waiver from carbon permits.[5]

[5] The ethanol supply assumption and carbon permit waiver are based upon the availability in 2010 of a technology for producing ethanol from cellulose (rather than grain). By assumption, the process emits limited greenhouse gases compared to ethanol production from corn or conventional gasoline.

Table 3.1 Summary Comparison: Base, Announcement, and 1344 Stabilization Cases

	2010				2020			
	Base Case	Announce Case	1344 Case	*Change, Base to 1344 Case*	Base Case	Announce Case	1344 Case	*Change, Base to 1344 Case*
Carbon Permit Fee (1995$/mton)	0.0	0.0	130.0	130.0	0.0	0.0	150.0	150.0
Energy Prices (1995$/mmBtu)								
Coal	1.22	1.21	4.29	252%	1.10	1.10	4.83	337%
Natural Gas	3.41	3.30	5.91	73%	3.81	3.70	6.21	63%
Motor Gasoline	9.90	9.64	12.39	25%	9.65	9.35	12.11	26%
Jet Fuel	5.53	5.41	7.90	43%	5.66	5.47	8.45	49%
Distillate Fuel	7.77	7.75	10.32	33%	7.63	7.57	10.61	39%
Electricity	19.23	19.11	26.07	36%	18.72	18.53	24.83	33%
E85	17.61	16.90	16.12	-8%	18.16	18.06	13.88	-24%
Fossil Energy Use (quads)								
Natural Gas	28.55	27.93	31.74	11%	31.14	31.28	32.10	3%
Petroleum	42.25	40.94	38.99	-8%	44.23	42.20	38.87	-12%
Coal	22.58	22.18	8.78	-61%	26.17	23.78	8.87	-66%
Total	**93.37**	**91.05**	**79.51**	**-15%**	**101.54**	**97.25**	**79.84**	**-21%**
Carbon Emissions (mmt)								
Natural Gas	409.2	400.3	455.2	11%	446.5	448.5	460.5	3%
Petroleum	729.1	704.1	667.0	-9%	762.7	723.8	655.5	-14%
Coal	576.9	566.0	223.3	-61%	667.9	605.7	224.8	-66%
Total	**1715.1**	**1670.4**	**1345.5**	**-22%**	**1877.1**	**1777.9**	**1340.7**	**-29%**
Carbon Emission by Sector (mmt)								
Residential	105.0	104.2	95.8	-9%	106.5	105.9	96.9	-9%
Commercial	64.9	64.7	61.3	-6%	68.7	68.4	64.7	-6%
Industrial	336.1	330.4	297.0	-12%	353.3	343.1	284.6	-19%
Transportation	589.2	570.2	542.7	-8%	619.6	585.9	535.9	-14%
Electricity	620.8	602.1	349.8	-44%	730.8	676.7	360.8	-51%
Total	**1716.2**	**1671.5**	**1346.7**	**-22%**	**1878.9**	**1780.0**	**1342.8**	**-29%**
Electricity Sales (billion kWh)	**3744**	**3678**	**3558**	**-5%**	**4286**	**3873**	**3751**	**-12%**
Energy Use for Electricity (quads)								
Coal	19.85	19.57	6.94	-65%	23.03	20.19	7.06	-69%
Natural Gas	6.82	6.26	11.64	71%	8.54	8.83	11.66	37%
Petroleum	0.57	0.42	0.18	-69%	0.72	0.61	0.16	-78%
Nuclear	6.55	6.55	7.22	10%	3.83	3.83	8.35	118%
Renewable/Other	4.74	5.01	7.09	50%	6.08	6.57	10.20	68%
Total	**38.53**	**37.80**	**33.07**	**-14%**	**42.21**	**40.02**	**37.43**	**-11%**
Generating Capability, excluding cogeneration (gigawatts)								
Coal Steam	303.85	302.53	262.94	-13%	346.87	311.43	254.51	-27%
Other Fossil Steam	99.90	99.90	95.64	-4%	94.97	94.97	90.71	-4%
Combined Cycle	99.14	113.93	226.95	129%	158.58	176.77	229.87	45%
Gas Turbine/Diesel	154.27	125.18	120.16	-22%	190.60	153.04	125.73	-34%
Nuclear Power	88.88	88.88	100.36	13%	48.94	48.94	112.62	130%
Hydroelectric	80.38	80.38	80.38	-0%	80.38	80.38	80.38	-0%
Geothermal	3.30	3.85	5.27	60%	4.19	4.84	8.02	91%
Muncipal Solid Waste	4.12	4.12	4.07	-1%	4.45	4.45	4.42	-1%
Wood	2.21	3.81	12.67	472%	12.13	17.33	26.71	120%
Wind	3.57	3.25	30.11	745%	14.43	10.92	68.20	373%
Solar PV and Solar Thermal	0.99	0.99	0.99	0%	2.16	2.16	2.32	7%
Other	22.00	23.60	22.80	0%	22.30	28.90	23.00	0%
Total	**862.61**	**850.43**	**962.35**	**12%**	**979.99**	**934.12**	**1026.49**	**5%**

Figure 3.1 Delivered Energy Prices, Percentage Change from Base to 1990-Level Carbon Stabilization Case

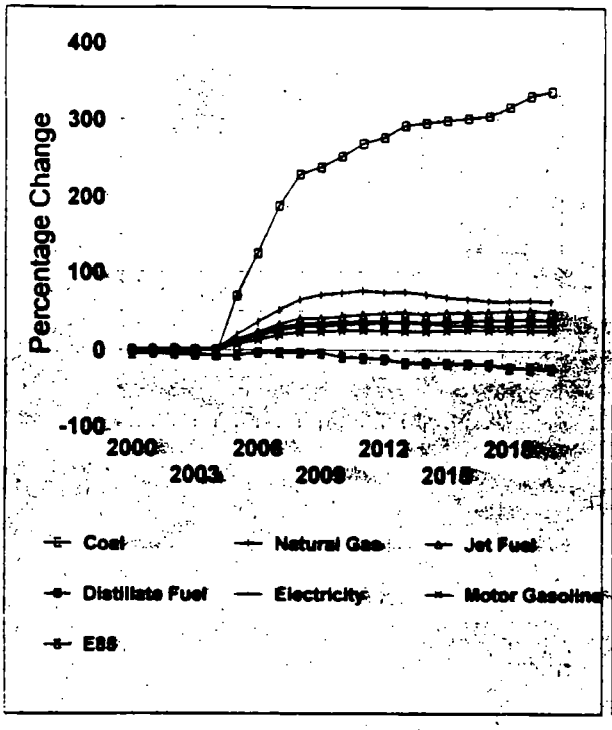


Figure 3.2 Carbon Reductions by Fuel, Base vs. 1990-Level Carbon Stabilization

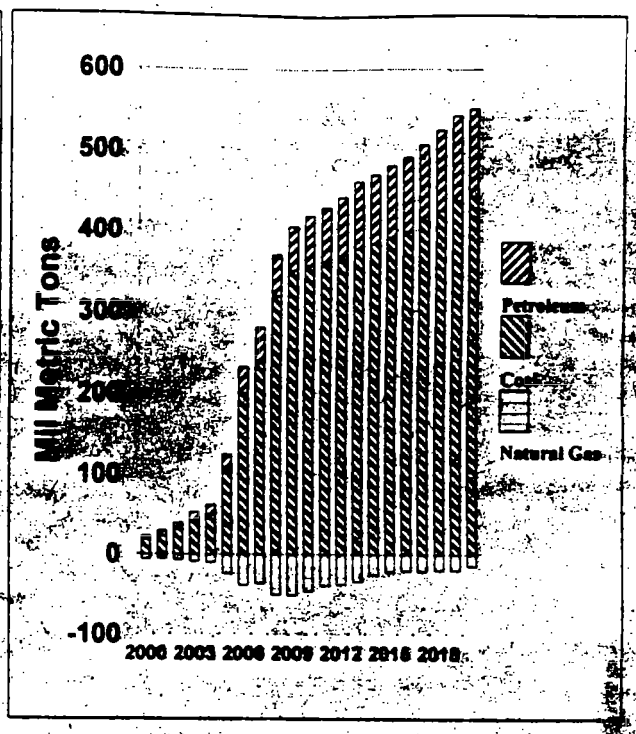


Figure 3.3 Carbon Reductions by Primary Sector, Base vs. 1990-Level Carbon Stabilization

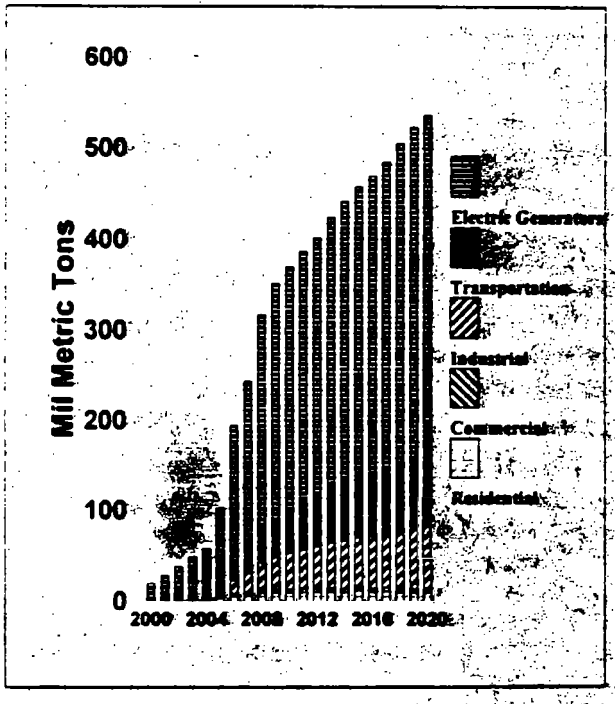
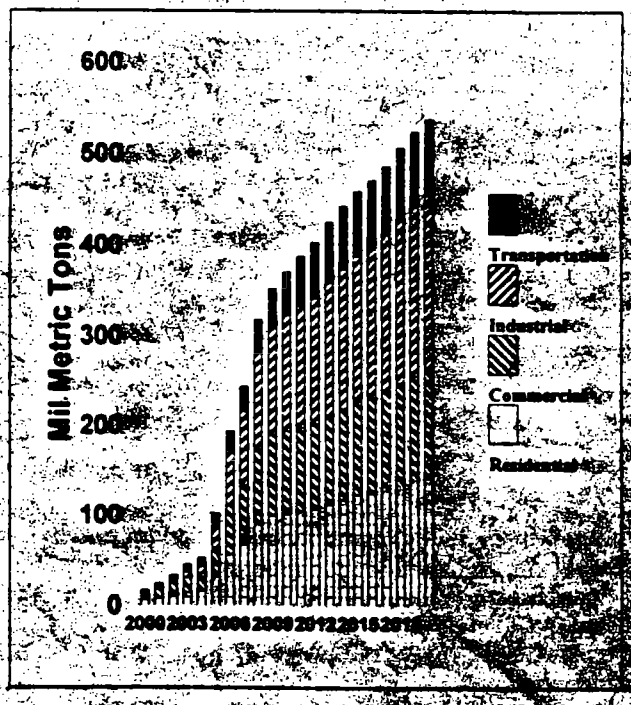


Figure 3.4 Carbon Reductions by End-Use Sector, Base vs. 1990-Level Carbon Stabilization



Carbon Reductions by Fuel

Total fossil energy consumption returns to near 1990 levels in the stabilization period, resulting in a difference of 21.7 quads between cases by 2020 (Table 3.1). While total fossil energy use declines by about 20 percent relative to the base case in 2020, natural gas use increases 3 percent in the stabilization case. The overall moderate increase in natural gas use is the result of increases in natural gas for generation accompanied by nearly offsetting reductions in natural gas in the end-use sectors. The low cost of natural gas compared to coal, once the value of carbon permits is considered, induces a 71 percent increase in gas use in electricity generation in the early portion of the stabilization period. In the end-use sectors, the use of natural gas is sharply curtailed, particularly in the industrial sector.

The most striking result of this analysis is the dramatic reduction in coal use to achieve stabilization. Coal use declines to a third of its base case level in 2020, from 26.2 quads in the base case to 8.9 quads in the stabilization case. This reduction in coal consumption results mainly from early retirement of coal plants, reductions in electricity sales, increased penetration of renewables, and assumed longer lifetimes of existing nuclear plants.

Petroleum use is reduced 5.4 quads (12 percent) relative to base by 2020. Most of this reduction, about 3.5 quads, occurs in transportation uses. The share of petroleum consumption (in barrels) met by net imports declines from 62 percent in the base case to 55 percent in the stabilization case in 2020.

The pattern of reductions in carbon emissions by fuel are similar to reductions in energy use, but magnified by the high carbon content of coal. As shown in Table 3.1 and Figure 3.2, total carbon emissions are cut 370 million metric tons in 2010 and 536 million tons by 2020, compared to the base case. The overwhelming share of reductions come from coal: 354 million metric tons in 2010 and 443 in 2020. Carbon emissions from natural gas in 2020 increase only slightly relative to the base, from 447 to 460 million metric tons.

Carbon Emissions by Sector

The carbon emissions reductions by sector in the stabilization case are displayed in Figures 3.3 and 3.4. In Figure 3.3, changes in the electricity sector are broken out. In Figure 3.4, changes in electricity are shared to the four end-use sectors based on sectoral electricity consumption.

Buildings: Fossil energy use consumed directly in the residential and commercial sectors does not change significantly in the 1344 stabilization case, and carbon emissions are reduced by less than 10 percent of base case levels. Some contribution in reducing carbon in the buildings sectors comes from electricity, as seen in Figure 3.4. When carbon emissions in the electricity generation are shared to the end-use sectors, the emissions reductions attributed to the buildings sectors are considerably higher. However, only a modest fraction of the reductions in carbon from electricity generation stem from reductions in electricity sales in the building sectors, but instead come through changes in fuels used for generation sold to the buildings sectors.

Transportation: The transportation sector reductions in carbon emissions of 84 million tons are about 16 percent of total carbon reductions from base in 2020. Transportation carbon emissions are reduced 8 percent from the base case in 2010 and 13 percent in 2020 (Table 3.1). These reductions result primarily from the increase in delivered energy prices associated with the carbon emissions permit values. The delivered price of gasoline increases about 25 percent in the stabilization case, compared to the base case, over the stabilization period. This induces an increased penetration of more fuel efficient conventional vehicle technologies, and higher penetration of alternative-fueled vehicles such as the PNGV vehicle, assumed to be an electric hybrid. By assumption, increased penetration of flex-fueled vehicles capable of burning ethanol and gasoline occurs in the more stringent stabilization cases, but not in the 1344 and 1400 level cases, where gasoline is projected to remain cheaper than E85 on a dollar per million Btu basis.

Industrial: Reductions in industrial energy use occur due to assumed improvements in technology and changes in the industrial mix away from energy intensive industries. These assumptions were implemented in the model through changes in industrial output, the principal driver of aggregate energy consumption in the industrial sector. Figure 3.5 plots the percentage changes in aggregate fossil energy consumption of the five most heavily-affected industries. These changes result in direct reductions of industrial carbon emissions of 39 to 69 million tons over the 2010 to 2020 period.

Electricity Generation: The most dramatic impact on carbon emissions occurs in the electricity sector. The reductions are partly attributed to important assumptions concerning how the industry would respond to an introduction of carbon permits. At carbon permit values of $125 to $150 per metric ton, the generation of electricity from coal becomes expensive enough to trigger major investments in coal plant replacement, modifications to boilers to burn natural gas, and rapid additions of renewable capacity and natural gas-fueled combined cycle plants (Figures 3.6 and 3.7). In addition, utilities are assumed to take the necessary actions to extend the operating lives of their existing nuclear plants through 2020. The combined effect of these actions is to economically phase out coal as the predominant energy source for electric power generation. By 2020, coal's share of electricity generation drops to 19 percent, compared to 54 percent in 1995. Coal is replaced by natural gas, renewables, and nuclear power (Figure 3.6).

To achieve economy-wide carbon stabilization by 2010 at 1990 levels, electric utilities are projected to reduce carbon emissions to about 350 million metric tons (mm), over 26 percent lower than 1990's carbon emissions (477 mm tons).

A number of elements contribute to the reduction of carbon emissions in the electricity sector.

Early Plant Retirements: By assumption, about 40 additional gigawatts of older steam plants with operating costs in excess of 2.5 cents/kWh are assumed to be retired prematurely in this stabilization case by 2020. About 35 gigawatts of these early plant retirements are coal. Additional coal plants are left idle ("retired" due to economic factors, but left in reserve) and are replaced with low-carbon capacity that is built in excess of reserve margin requirements.

Figure 3.5 Energy Use in Selected Industries, Changes from Base to 1990-Level Carbon Stabilization Case

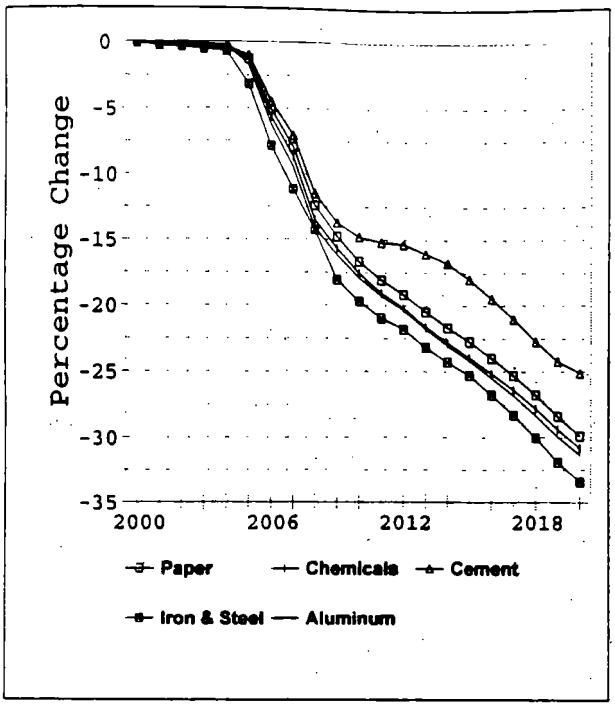


Figure 3.6 Energy Sources for Electricity Generation, Changes from Base to 1990-Level Carbon Stabilization Case

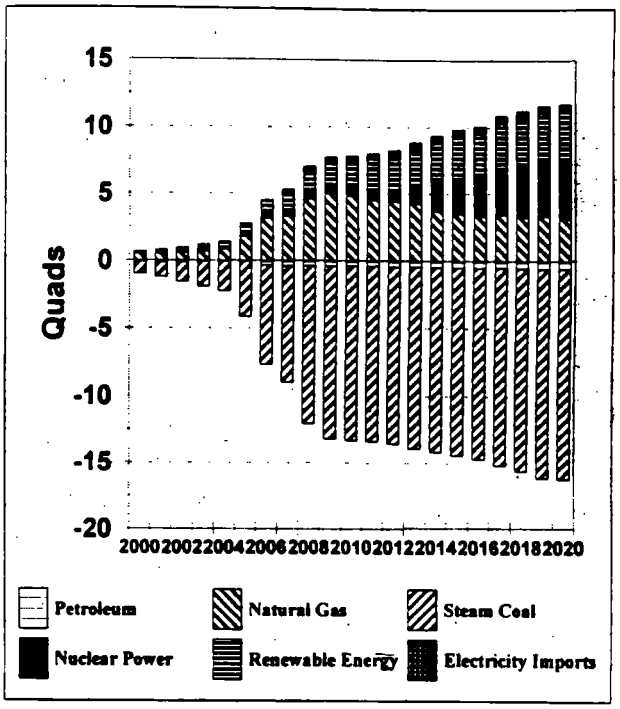


Figure 3.7 Generating Capability, Changes from Base to 1990-Level Carbon Stabilization Case

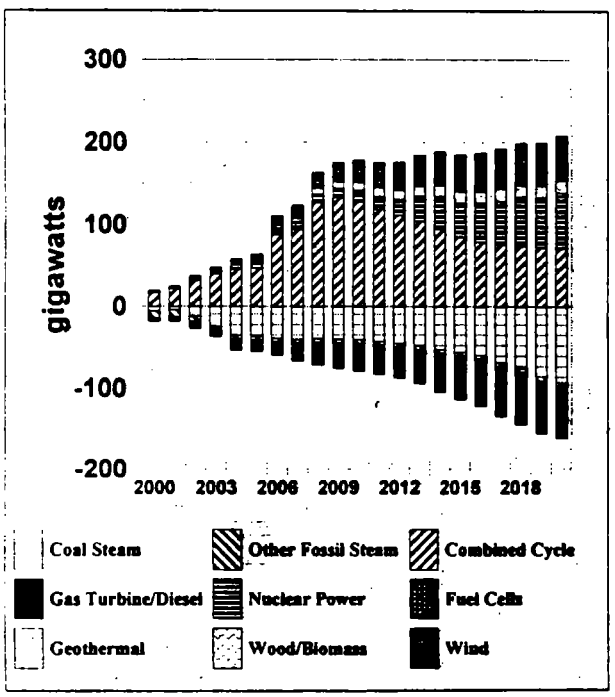
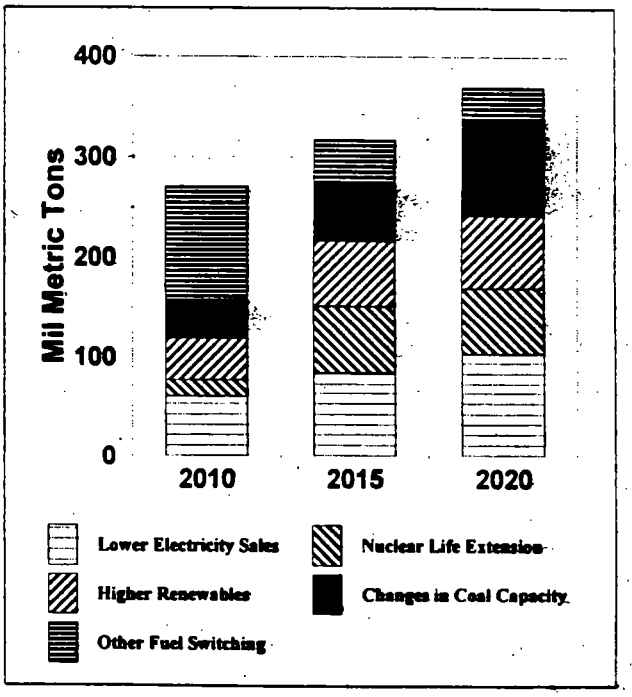


Figure 3.8 Sources of Carbon Reductions in the Electricity Sector, Base to 1990-Level Stabilization Case



Capacity in Excess of Reserve Margin Requirements: While electricity sales are lower in the carbon stabilization case, generating capacity is higher. The higher levels of capacity, relative to sales, partly reflects the economic addition of new, lower-carbon-emitting plants to avoid using existing coal plants, or economic retirements. That is, utilities are assumed to build capacity above that needed to meet reserve margins if it is economic to do so given anticipated future carbon permit values. The amount of excess capacity was limited in any single year to a level of 10 percent of existing capacity. Higher capacity, relative to electricity sales, is also due to higher wind capacity, which, because of its intermittent availability, is not assumed to be given a full capacity credit for meeting a reserve margin. Excluding wind capacity, the level of capacity in excess of reserve margin requirements in the stabilization cases is approximately 112 gigawatts in 2010 and 77 gigawatts in 2020.

Nuclear Power: After 2015, utilities are allowed to invest in either new nuclear plants or some unspecified new carbon-free base-load technology with equivalent costs. By 2020, 13.6 gigawatts of such capacity are added in the stabilization case. This, along with 50.1 gigawatts of nuclear capacity that is life-extended, accounts for 63.6 gigawatts of additional nuclear capacity in the stabilization case compared to the base case.

Renewables: Increases in wind, geothermal and biomass result in a combined capacity by 2020 of about 103 gigawatts through 2020, 72 gigawatts more than in the base case (Table 3.1). The greatest share of this renewable capacity comes from wind, which reaches 68 gigawatts in 2020.

Electricity Prices, Sales: Electricity sales decline 6 percent, relative to base, by 2020. This decline is due to higher electricity prices, as the costs of carbon permit values and capital expenses to reduce carbon emissions are passed on to electricity consumers. The average price of electricity in 2020 is 8.5 cents/kwh compared to 6.4 cents/kwh in the base case (a 33 percent increase). The largest percentage drop in electricity sales over base (11 percent in 2020) occurs in the industrial sector through a combination of technological improvements and increases in the proportion of demand for energy intensive products filled by imports.

Combustion Turbines: A large fraction of the combustion turbine plant additions in the base case are eliminated in the stabilization case. Combustion turbines become somewhat less economical in the stabilization case due to their poor fuel efficiency. The higher level of gas combined cycle plant additions to replace coal also reduces the need for combustion turbines to meet reserve requirements in some regions.

An estimate of the relative contribution of these factors in reducing carbon emissions is displayed in Figure 3.8. The breakout of the total carbon reductions by each factor is an approximation based on the following assumptions:

- Differences in total generation (due to sales changes), renewables generation, and nuclear generation offset coal generation at an average carbon savings of 0.26 kg/kwh.
- Other changes in generation are assumed to reflect a shift in generation from coal to natural gas. These changes in generation occur as new natural gas capacity is added to substitute for

either coal capacity that is retired or for coal capacity that would be built in the absence of a carbon stabilization policy. Coal capacity in the stabilization case in 2020 is about 93 gigawatts less than in the base case. This difference in capacity includes 35 gigawatts of coal capacity that is retired and 58 gigawatts of avoided coal capacity additions. It is assumed that the generation avoided from this difference in coal capacity is replaced by natural gas generation for a net carbon savings of between 0.18 and 0.19 kg/kwh.

- The remainder of carbon reductions reflects other fossil fuel switching and dispatching changes. For example, some of the substitution of natural gas generation for coal generation occurs in existing, dual-fired coal plants, which were assumed to be capable of increasing their current percentage of natural gas use by 5 percentage points. In addition, there are some reductions in oil-based generation, also assumed to reflect a switch to natural gas. Finally, the least cost dispatch of plants will tend to favor natural gas plants over coal and oil.

3.2 Comparison of the Carbon Stabilization Cases

The previous section focused on a comparison of the Base Case and the 1990-level stabilization cases. This section presents the results of the sensitivity cases run to evaluate alternative carbon stabilization cases. The alternative cases vary the level of the stabilization target as well as the timing and ramp periods for achieving the target.

Carbon Permit Values Across Cases

The stabilization cases were implemented by varying the levels and trajectories of the carbon permit values until the annual carbon targets were achieved within a tolerance of about 10 million tons per year. An initial way to evaluate the cases, then, is to examine the trajectories of carbon permit values across cases in relation to the respective carbon emissions (Figures 3.9 to 3.16).

More stringent carbon targets are associated with increasingly higher carbon permit values, holding the timing constant. This pattern is particularly evident early in the compliance period for the 5-year ramp periods (Figures 3.9 and 3.10), although by the end the of the compliance period, there is far less variation in carbon permit values.

In the cases with the most stringent stabilization goals, the highest carbon permit values occur in the first year that the carbon stabilization goal is reached (e.g., see carbon permit values in the 1142 and 1210 cases, Figures 3.10 and 3.12). Unless technologies advance faster than economic growth over the entire time horizon, one could reasonably expect that carbon permit values would eventually have to rise over time to maintain a stable carbon emissions level, given continued growth in population and economic development. With the more stringent stabilization goals, however, carbon permit values reach a peak in the first year, 2010, and then decline or remain stable. This pattern is explained by the long-term effect that most of the compliance measures have. Once investments to reduce carbon emissions are made early in the compliance period, the demand for carbon emission permits is reduced thereafter, holding down the market value of carbon permits in subsequent years.

Figure 3.9 Carbon Emission Stabilization in Various Cases, in 2010 (5-Year Ramp)

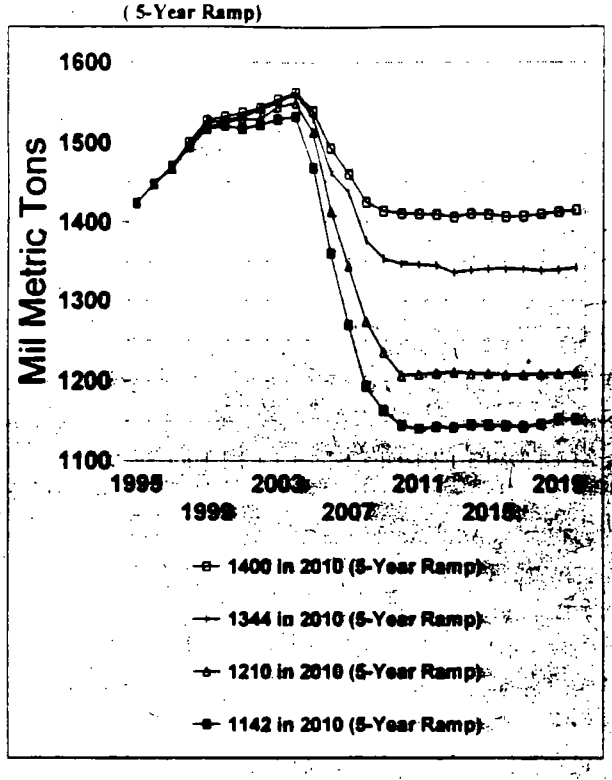


Figure 3.10 Carbon Permit Values, Carbon Stabilization in 2010 (5-Year Ramp)

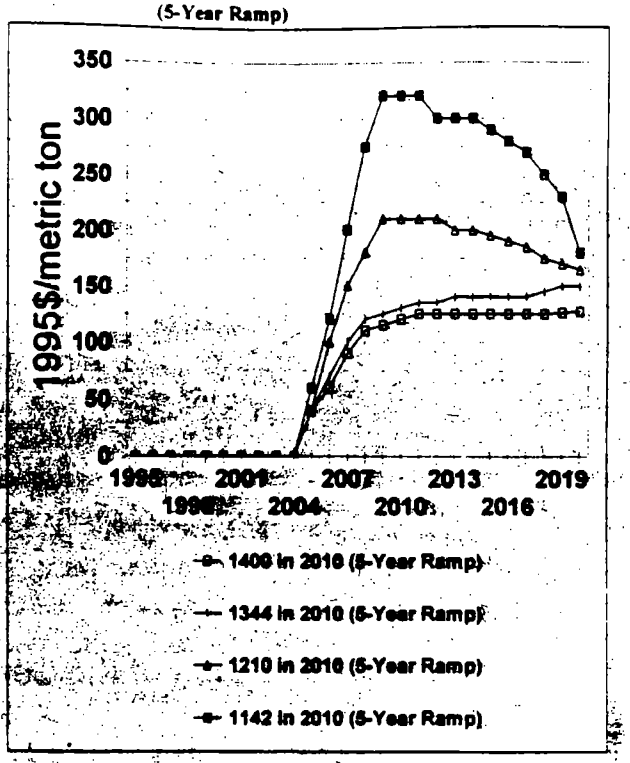


Figure 3. 11 Carbon Emission Stabilization in Various Cases in 2010 (10-Year Ramp)

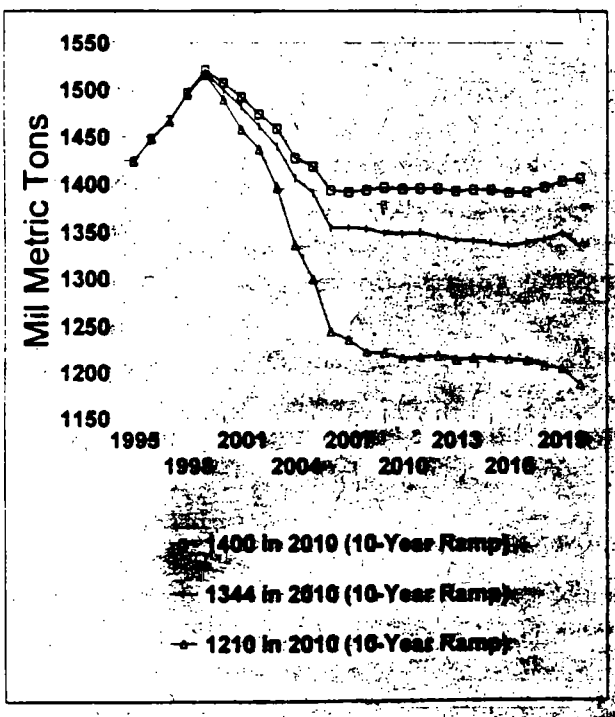
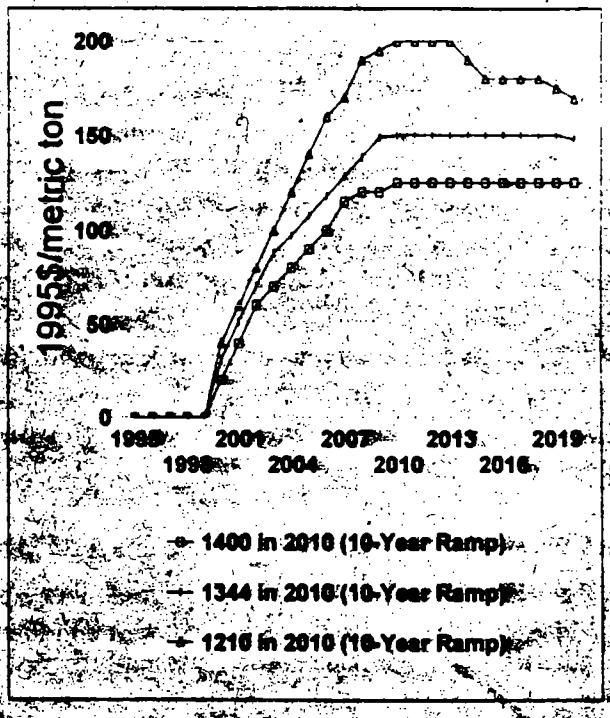


Figure 3.12 Carbon Permit Values, Carbon Stabilization in 2010 (10-Year Ramp)



In the alternate timing cases in which carbon stabilization are more flexible (averaged over 5 or 10 years rather than fixed every year) (see figures 3.13 and 3.14), carbon permit values eventually rise to higher levels than 2010 target cases, but are lower earlier on.

In the two cases in which the carbon stabilization targets (of 1210 and 1142 million tons) are delayed until 2015, the peak carbon permit values are less than in the corresponding cases with a 2010 target (eg., compare top two lines in figure 3.10 to top two lines in figure 3.14). This result may be attributed in part to the assumed availability of low-carbon-emitting technology (e.g., nuclear) available in 2015.

Figures 3.15 and 3.16 compare all of the cases tied to the 1990 carbon emissions level of 1344. Carbon permit values are generally lower (except in the last two years) in the 10-year "budget" case in which the 10-year average carbon emissions level is attained rather than a fixed level each year. In the 5-year budget case, the stabilization target was held at about 1322 after 2015 and thus represents a more stringent stabilization case than the others. As a result, the carbon permit values in the 5-year budget case are higher than the two fixed-target 1344 cases after 2015.

Influence of Generating Capacity Decisions on Carbon Permit Values

The investment decisions made in the electricity sector strongly influence the dynamics of the emissions market. By assumption, electricity providers have foresight of what the future carbon permit values will be. They incorporate these expectations into their planning decisions. The simulation of this decision making in NEMS also allows for building of low-carbon capacity (such as combined cycle plant and renewables) when economical to reduce operating cost, even though the capacity is not needed to meet peak demand and reserve requirements. When utilities build extra capacity early in the compliance period, their collective actions can lead to future reductions in carbon permit values, as their long term demand for carbon permits is reduced.

The pattern of these "economic retirements" across cases is closely related to the carbon permit values (Figure 3.17). The capacity representing economic retirements in any year is the amount of capacity in excess of that required to satisfy electricity demand and reliability, given electricity sales. In general, lower stabilization goals and higher carbon permit values are associated with greater economic retirements, and the greater the economic retirements, the greater the decline in carbon permit values in subsequent years.

Summary Measures to Evaluate Stabilization Cases

The carbon permit values used in this analysis to represent market incentives to reduce carbon are an indication of the relative costs of compliance, but should not be considered as the only cost. The permit values introduce a marginal cost of emitting carbon that is applied equally across sectors and fuels. However, the carbon permits cause consumers to alter their patterns of spending and investment. In the case of electricity generators, the introduction of carbon permits results in significantly higher levels of capacity additions, a cost reflected in electricity prices but not in the value of carbon permits.

Figure 3.13 Carbon Emission in Various Cases, Alternate Timing

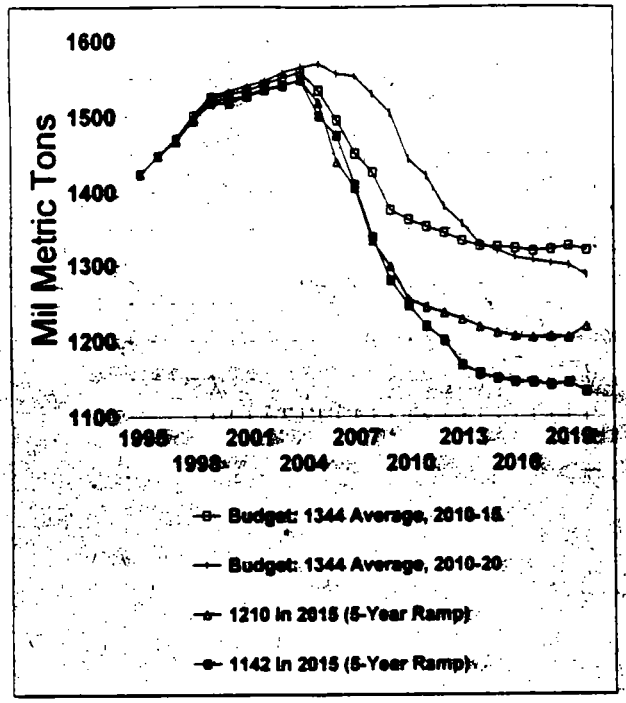


Figure 3.14 Carbon Permit Values, Alternate Timing

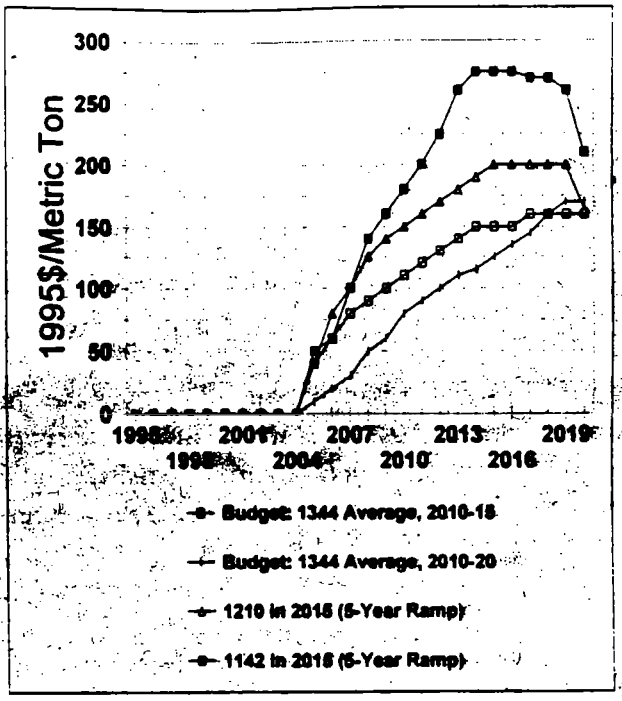


Figure 3.15 Carbon Emission in Various Cases, 1990-Level (1344) Cases

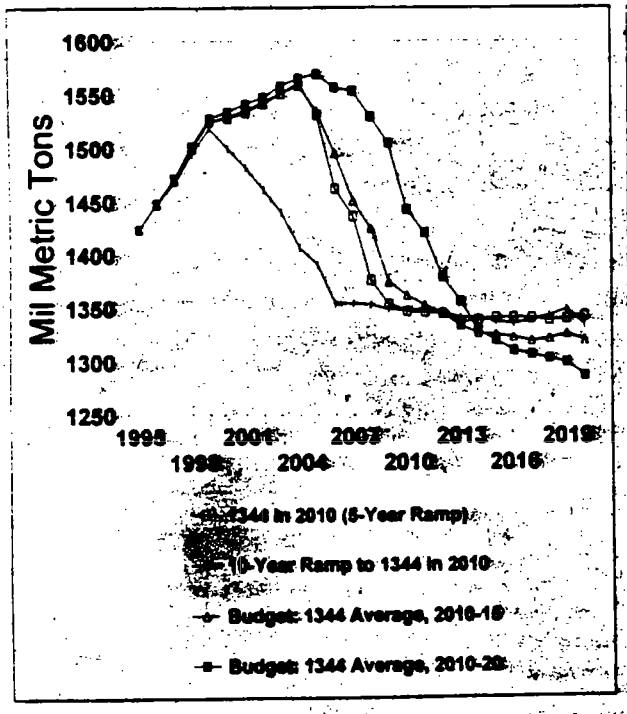


Figure 3.16 Carbon Permit Values, 1990-Level (1344) Cases

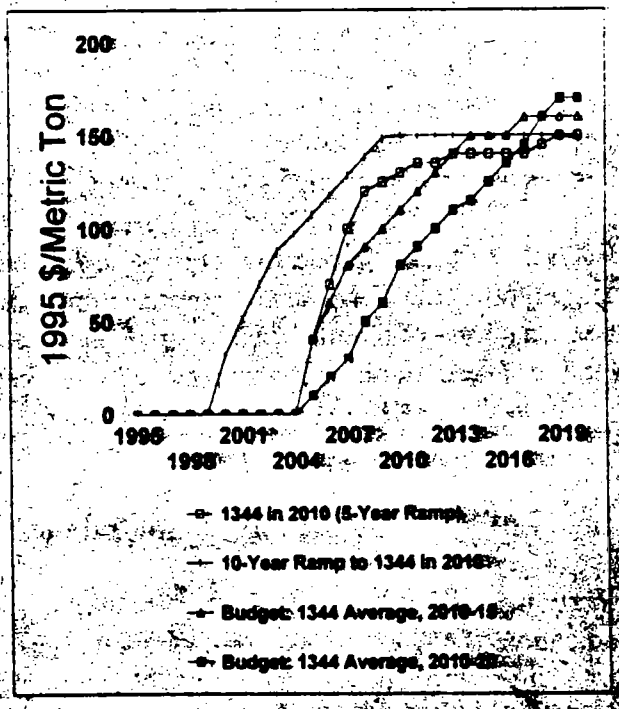
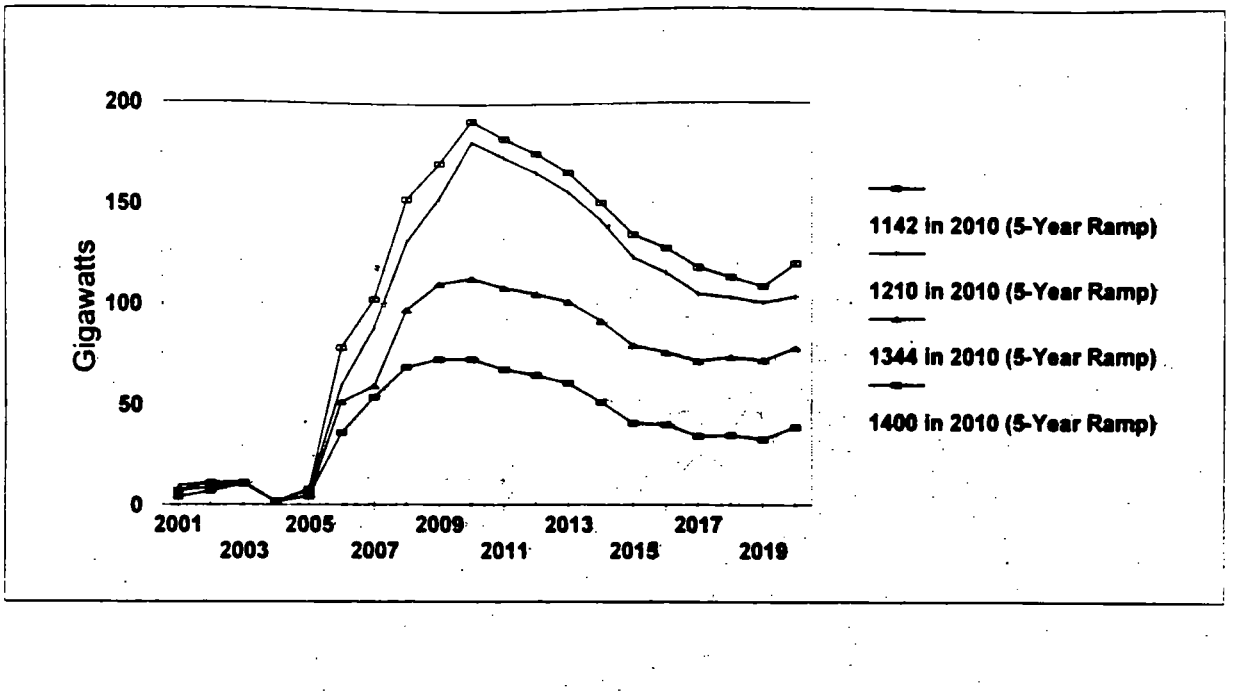


Figure 3.17 Capacity in Excess of Reserve Margin Requirements, 5-Year Ramp Cases



In addition to the incremental investment cost incurred as consumers respond to a carbon permit system, costs of compliance could include losses in output due to diversion of investments, possibly higher interest rates, lost output from energy-intensive industries, costs of shifts in employment across industries, and lower GDP. These factors illustrate the need to evaluate carbon stabilization cost on a macroeconomic basis, as is done in chapter 4, not just in terms of carbon permit values.

On the positive side, permit values for carbon emissions in fossil fuel use place a higher consumer value on energy efficient technologies, accelerate the adoption of fuel-efficient technologies, and promote a decline in energy intensity.

However, some comparative observations can be made by looking at the relative magnitude of carbon permit values across the stabilization cases. A complication in comparing the cases is that they result in different patterns of carbon emissions over time, both in the compliance periods and in the ramp periods, relative to the base case. As a result, each case results in a different level of carbon reductions.

A simple measure to compare the relative emissions control benefits across cases is the cumulative carbon reduced over the projection period (Figure 3.18). With this measure, for example, it is readily apparent that for a target of 1344, the case with a 10-year ramp period is a more stringent stabilization goal than the corresponding 5-year ramp (bars in center of plot). If the timing of the carbon emissions reduction is not critical over a 20- to 25-year time frame, then this measure of cumulative carbon emissions is an appropriate figure of merit in comparing cases. Alternatively, if there is some benefit to reducing carbon emissions at an earlier period, then a financial discounting of this measure would be a convenient way to give a greater weight to early reductions.

Similarly, the cumulative carbon "revenue" over the projections is a relatively simple measure giving an indication of *relative* costs of the cases. Taking the present value of the revenue stream adjusts for the differences in the timing of the revenues. Figure 3.19 compares the cases based on present value of real cumulative carbon revenue, discounted using a real rate of 7 percent.

Taking the ratio of these two measures yields the discounted carbon "revenue" per ton of cumulative carbon reduction (Figure 3.20). A comparison of the cases using this measure shows the 10-year ramp cases to be the most costly and the delayed implementation of the stabilization to be less costly. As indicated in the plot, the lowest cost rate occurs in the 10-year carbon budgeting case, where the target is to achieve a 10-year average carbon emission level of 1344 million tons a year between 2010 and 2020. The comparisons of costs per ton carbon reduction shown in Figure 3.20 are not entirely comparable across the cases because the values are provided over different periods. Use of a discounted present value calculation in such instances is a standard construct for making different streams of values comparable at one point in time. However, because the cases vary in timing of when they begin to implement policies for reducing emissions and when they achieve stabilization, they should also be evaluated from other perspectives, including sectoral impacts.

Figure 3.18 Cumulative Carbon Reductions From Base, 2000-2020, All Cases

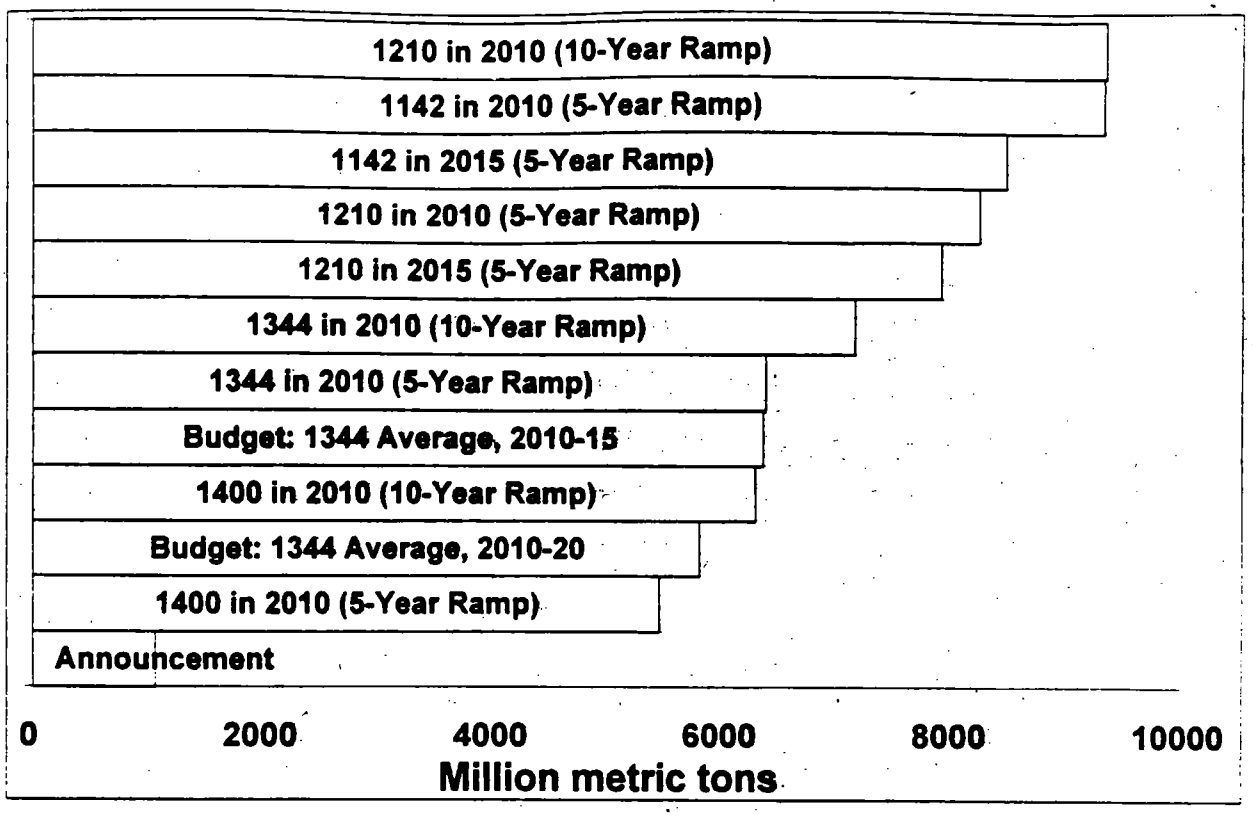


Figure 3.19 Cumulative Aggregate Permit Values, 2000-2020, All Cases, Discounted to 1997 @ 7%/year

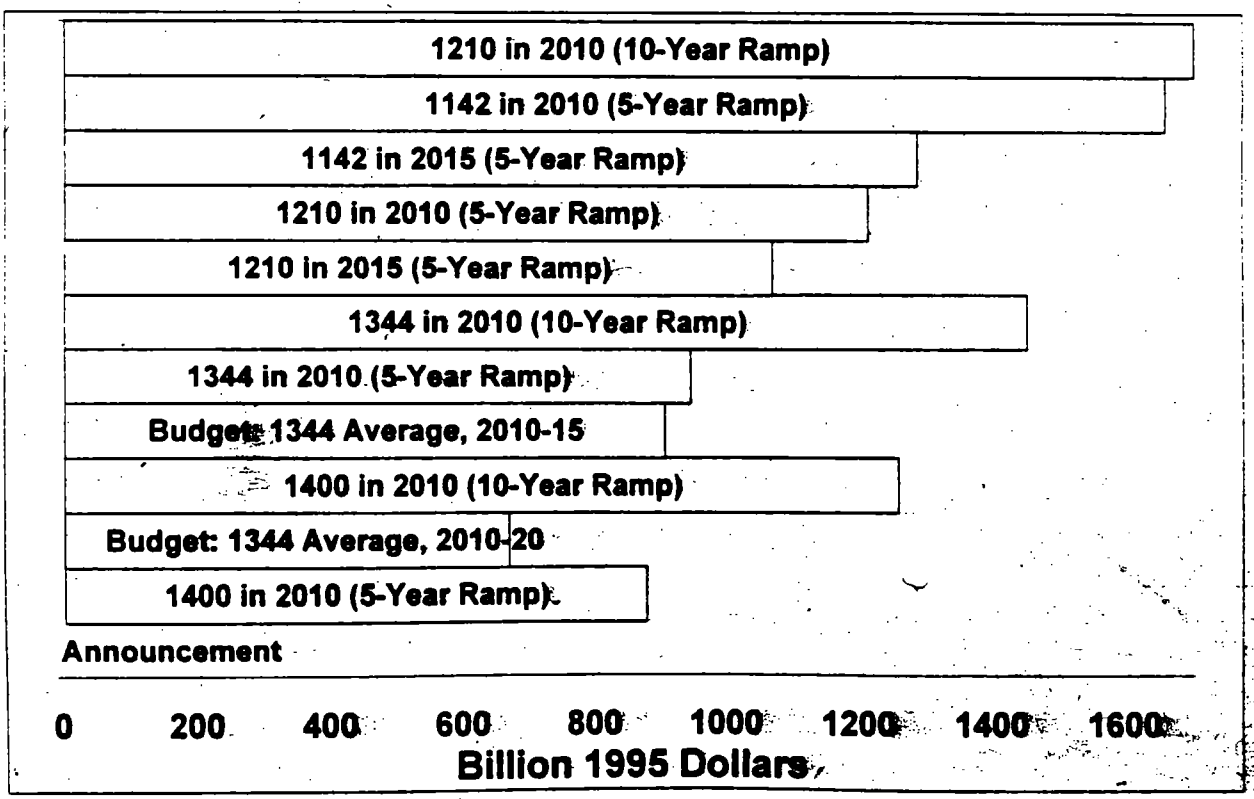


Figure 3.20 Comparison of Cases by Discounted Aggregate Permit Value (2001-2020) per Ton of Cumulative Carbon Reduction (2001-2020)

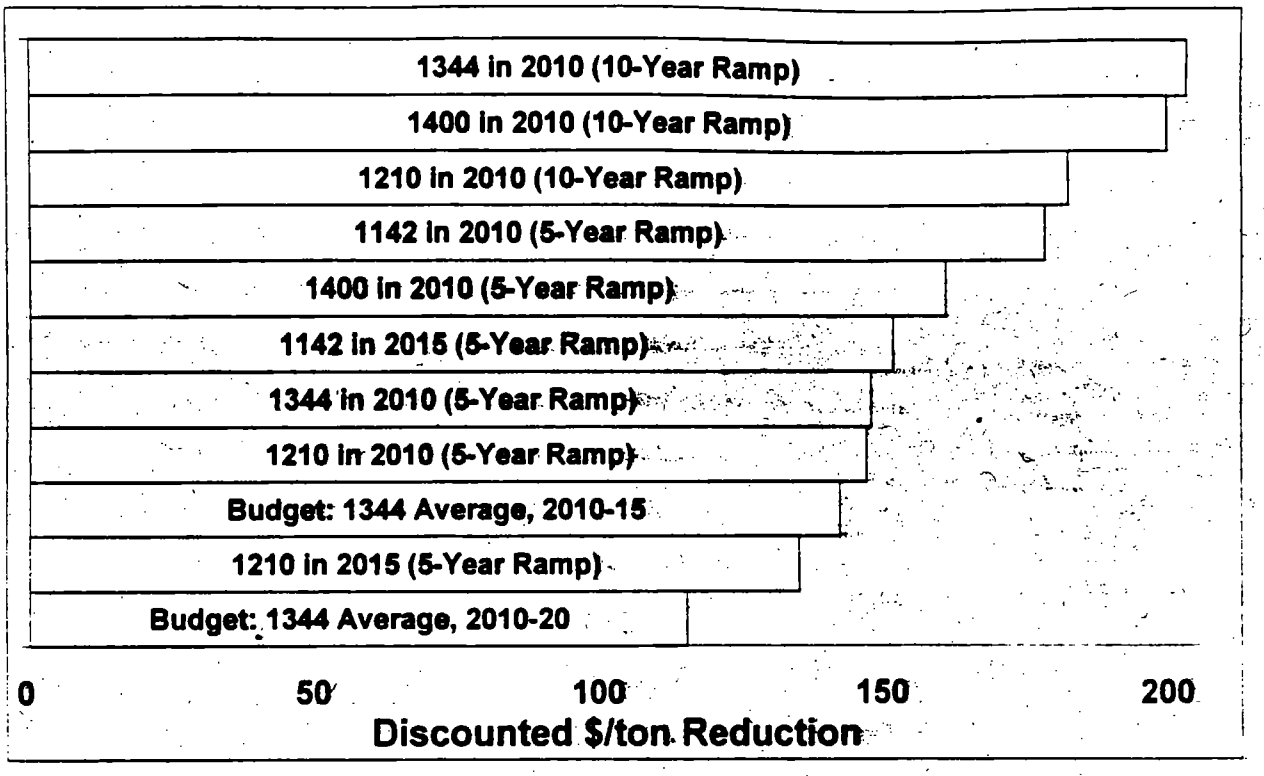
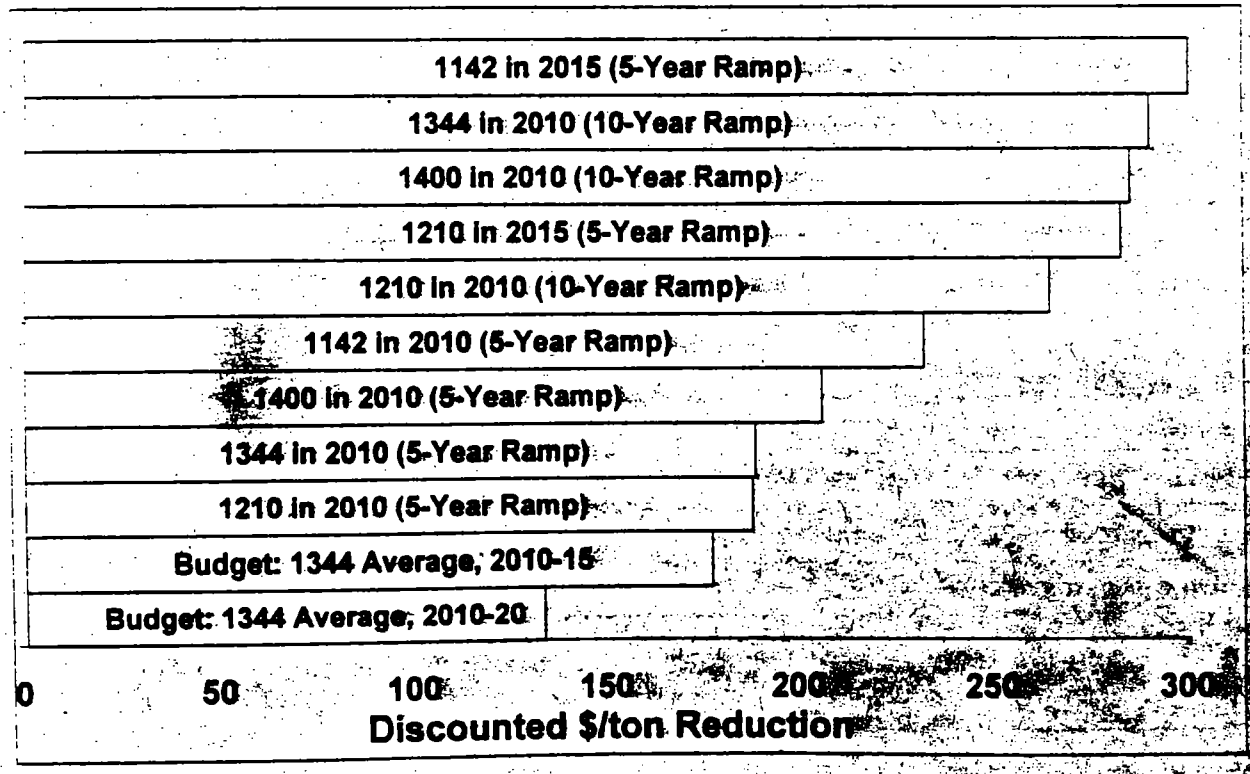


Figure 3.21 Comparison of Cases by Discounted Aggregate Permit Value (2001-2020) per Ton of Carbon Reduction from start of period to 2020



Some of the costs of carbon stabilization occur as carbon emissions are gradually reduced before the actual start of the specified carbon stabilization period. These costs to induce a gradual transition to a stabilization goal could be less than the costs required to meet a stabilization goal without any phase-in period. By this rationale, the transition costs accrued prior to the specified stabilization period were included in the above measure to compare cases. However, any carbon reductions achieved prior to a mandated stabilization period would not necessarily be credited towards meeting the specified carbon goals. In other words, carbon reductions prior to the stabilization period might not be bankable.

Without a banking credit for early reductions in carbon emissions, only the carbon reductions achieved during the stabilization period contribute to achieving compliance. If so, the comparative measure can be reformulated to include only carbon reductions achieved from the start of the compliance period through 2020. Figure 3.21 presents the comparison of cases with this alternative measure. The relative merit of alternative stabilization policies changes slightly when the banking credit for *early* reductions is removed. The two cases in which the compliance period starts in 2015 are less favorable with this measure. The rankings among the other cases are the same as in Figure 3.20.

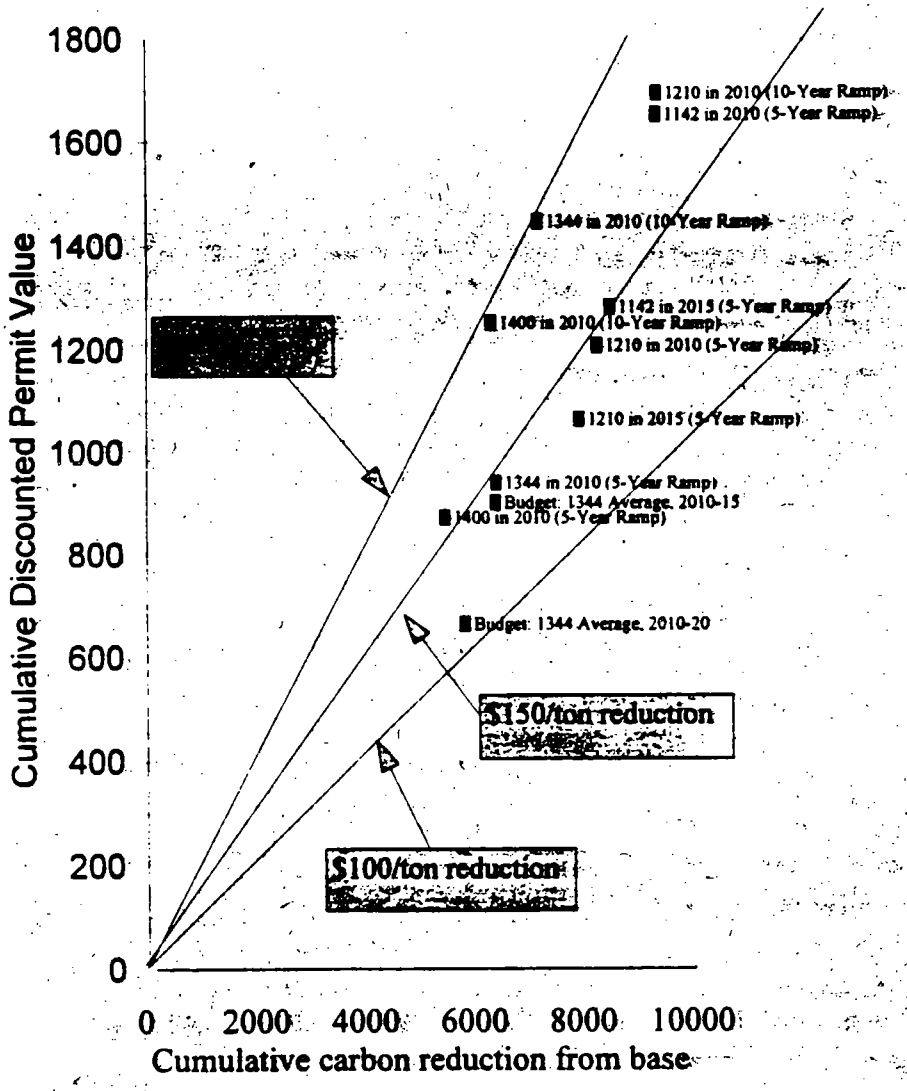
Figure 3.22 displays essentially the same information as Figures 3.18, 3.19 and 3.20 in a single scatter plot. For each case, the present value of cumulative carbon revenue is plotted against cumulative carbon reductions. The scatterplot of points falls in a reasonably narrow range between lines representing $200/ton reduction and $100/ton reduction. The following observations are offered:

- Delayed implementation of the carbon stabilization target is relatively cheap per ton of carbon reduced.

- More stringent targets are relatively more expensive, as each increment of carbon reduction requires an increasingly greater incentive.

- Flexibility in meeting the carbon stabilization target through a 5- or 10-year carbon budget period is relatively cheaper than having a fixed annual limit.

Figure 3.22 Cases Plotted by Discounted Revenue and Cumulative Carbon Reduction, 2001-2020



3.3 Analysis of $40 per Ton Carbon Permit Trading Fee

The explicit assumption in this case is that carbon permit values can be purchased internationally at $40 per ton (1995 dollars) to offset any U.S. emissions in excess of 1990 levels from 2010 to 2020. The pattern of energy impacts that a carbon permit value imposes on the U.S. energy system -- what sectors are impacted the most and which the least — are similar to the more extensively analyzed carbon cases without flexible international carbon trading. The differences reside largely in the magnitude of the projected impacts.

Relative to the reference case, a $40 per ton carbon permit value (with the other assumptions of the case) is projected to decrease carbon emissions by 132 million metric tons in 2010 (35 percent toward stabilization) and by 237 million metric tons in 2020. Electricity generation accounts for approximately 63 percent of the reduction in 2020, transportation for 22.5 percent, industrial for 12.5 percent and the rest (2 percent) by the building sector. Unlike the stabilization cases without international trading, overbuilding of electricity capacity was not required to achieve these reductions.

Despite the carbon reduction relative to the reference case, 240 million metric tons of additional carbon permit credits will have to be purchased internationally in 2010 and 298 million metric tons will have to be purchased in 2020 for carbon emissions above 1990 levels. Annual expenditures to foreign countries to purchase those carbon permits (in constant 1995 dollars) range from $9.6 billion to $11.9 billion.

By 2020, the use of coal falls by 25 percent relative to the reference case to approximately 1995 levels of consumption. Relative to the reference case, the $40 per ton carbon permit value in 2020 effectively doubles the delivered coal cost to utilities while the effective natural gas costs increase 24 percent. The carbon reductions are achieved, in part, through assumed nuclear life extensions through 2020 and early retirement of approximately 40 gigawatts of inefficient fossil units of which 35 gigawatts were coal. Since the economic viability of nuclear life extensions and early retirement of low efficiency fossil steam units facing a $40 per ton carbon permit fee are uncertain, the carbon reductions achieved for this case could be over 100 million metric tons of carbon higher.

Coal capacity utilization declines from approximately 75 percent in the reference case in 2010 to about 71 percent in the $40 per ton case. If the inefficient coal units were not retired but left in the rate base, coal utilization would have declined to about 64 percent in 2010. Approximately 13 gigawatts of new unplanned coal capacity is added between 2010 and 2020, confirming that coal generation remains economic for base-load generation in some regions of the United States despite the $40 per ton carbon fee.

In 2010, about 84 percent of carbon reductions in the electricity sector are achieved through fuel substitution away from higher carbon energy sources and from efficiency improvements; only about 16 percent of carbon reductions in electricity are attributed to reductions in electricity sales. Almost all of the fuel-switching reductions come from fuel-switching from coal generation to gas generation with some increase in renewable generation (about 22 billion kilowatt-hours and 5 gigawatts of total

renewable incremental capacity from wind, biomass and geothermal). At $40 per ton carbon permit value, renewable capacity is expected to rise significantly (e.g., to 26 gigawatts for wind and 15 gigawatts for wood and biomass in 2020) but not quickly enough to offset rising electricity demand. The carbon emissions initially stabilize around 1590 million metric tons and then increase gradually toward the end of the projection period to 1642 million metric tons.

Petroleum consumption is projected to decline significantly in the $40 per ton case primarily from improved efficiency in transportation and an increased penetration of alternative-fuel vehicles. By 2020, oil import dependence is reduced from 62 percent in the reference case to 58 percent.

Table 3.2 summarizes and compares the base case with the $40 per ton carbon permit fee case and the 1990 stabilization case for years 2010 and 2020.

Table 3.2 Summary Comparison: Base, $40/Ton Permit and 1344 Stabilization Cases

	2010				2020			
	Base Case	$40/ton Permit Case	1344 Case	*Change, Base to $40/ton*	Base Case	$40/ton Permit Case	1344 Case	*Change, Base to $40/ton*
Carbon Permit Fee (1995$/mton)	**0.0**	**40.0**	**130.0**	**40.0**	**0.0**	**40.0**	**150.0**	**40.0**
Energy Prices (1995$/mmBtu)								
Coal	1.22	2.15	4.29	76%	1.10	2.09	4.83	89%
Natural Gas	3.41	4.11	5.91	21%	3.81	4.36	6.21	14%
Motor Gasoline	9.90	10.64	12.39	7%	9.65	10.19	12.11	6%
Jet Fuel	5.53	6.29	7.90	14%	5.66	6.35	8.45	12%
Distillate Fuel	7.77	8.59	10.32	11%	7.63	8.46	10.61	11%
Electricity	19.23	21.48	26.07	12%	18.72	20.35	24.83	9%
E85	17.61	15.01	16.12	-15%	18.16	13.92	13.88	-23%
Fossil Energy Use (quads)								
Natural Gas	28.55	29.05	31.74	2%	31.14	31.09	32.10	-0%
Petroleum	42.25	40.05	38.99	-5%	44.23	41.09	38.87	-7%
Coal	22.58	18.59	8.78	-18%	26.17	19.40	8.87	-26%
Total	**93.37**	**87.69**	**79.51**	**-6%**	**101.54**	**91.58**	**79.84**	**-10%**
Carbon Emissions (mmt)								
Natural Gas	409.2	416.4	455.2	2%	446.5	445.8	460.5	-0%
Petroleum	729.1	692.8	667.0	-5%	762.7	700.6	655.5	-8%
Coal	576.9	473.8	223.3	-18%	667.9	493.1	224.8	-26%
Total	**1715.1**	**1583.0**	**1345.5**	**-8%**	**1877.1**	**1639.5**	**1340.7**	**-13%**
Carbon Emission by Sector (mmt)								
Residential	105.0	101.4	95.8	-3%	106.5	103.4	96.9	-3%
Commercial	64.9	63.6	61.3	-2%	68.7	67.4	64.7	-2%
Industrial	336.1	319.6	297.0	-5%	353.3	322.8	284.6	-9%
Transportation	589.2	557.7	542.7	-5%	619.6	566.2	535.9	-9%
Electricity	620.8	541.8	349.8	-13%	730.8	582.0	360.8	-20%
Total	**1716.2**	**1584.1**	**1346.7**	**-8%**	**1878.9**	**1641.8**	**1342.8**	**-13%**
Electricity Sales (billion kWh)	**3744**	**3667**	**3558**	**-2%**	**4286**	**4144**	**3751**	**-3%**
Energy Use for Electricity (quads)								
Coal	19.85	16.30	6.94	-18%	23.03	17.27	7.06	-25%
Natural Gas	6.82	7.74	11.64	13%	8.54	8.77	11.66	3%
Petroleum	0.57	0.51	0.18	-11%	0.72	0.53	0.16	-27%
Nuclear	6.55	7.22	7.22	10%	3.83	7.36	8.35	92%
Renewable/Other	4.74	5.17	7.09	9%	6.08	7.18	10.20	18%
Total	**38.53**	**36.94**	**33.07**	**-4%**	**42.21**	**41.11**	**37.43**	**-3%**
Generating Capability, excluding cogeneration (gigawatts)								
Coal Steam	303.85	269.20	262.94	-11%	346.87	273.60	254.51	-21%
Other Fossil Steam	99.90	95.60	95.64	-4%	94.97	90.70	90.71	-4%
Combined Cycle	99.14	125.10	226.95	26%	158.58	160.00	229.87	1%
Gas Turbine/Diesel	154.27	152.30	120.16	-1%	190.60	169.60	125.73	-11%
Nuclear Power	88.89	100.40	100.36	13%	48.94	99.10	112.62	102%
Hydroelectric	80.38	80.40	80.38	0%	80.38	80.40	80.38	0%
Geothermal	3.30	4.30	5.27	30%	4.19	6.10	8.02	45%
Muncipal Solid Waste	4.12	4.11	4.07	-0%	4.45	4.40	4.42	-1%
Wood	2.21	3.20	12.67	45%	12.13	15.20	26.71	25%
Wind	3.57	6.50	30.11	7%	14.43	26.70	68.20	85%
Solar PV and Solar Thermal	0.99	0.99	0.99	0%	2.16	2.16	2.32	0%
Other	22.00	23.50	22.80	7%	22.30	23.70	23.00	6%
Total	**862.62**	**865.60**	**962.35**	**0%**	**980.00**	**951.66**	**1026.49**	**-3%**

4. Macroeconomic Model Results and Analysis

4.1 Macroeconomic Model Methodology

The macroeconomic impacts of any carbon reduction program will depend on how energy markets respond to the mechanism imposed to achieve carbon reduction, e.g., much higher prices for carbon-intensive fuels, new efficiency standards, new information programs, or some yet-to-be-defined cap-and trade system, etc. Underlying any macroeconomic analysis is an accompanying depiction of how technology, fuel substitution, consumer behavior towards energy-using equipment, and industrial competitiveness change when, for example, energy prices are much higher. Since different energy models are likely to have different views of the workings of the energy market, the impact of carbon programs on energy markets will also vary. Consequently, estimates of the corresponding macroeconomic impacts will be different because of the different impacts on energy markets.

This chapter analyzes the impacts of varying (a) carbon targets, (b) ways in which to use the carbon-permit revenues in the economy, (c) assumptions regarding the Federal Reserve policies, and (d) alternative views about industrial energy-intensive competitiveness that result from imposing carbon permits on only Annex I nations, and (d) lowering the carbon permit value with flexible international trading. The analysis of this chapter were derived by using the NEMS energy model and DRI macroeconomic model with IAT assumptions.

Chapters 2 and 3 describe the NEMS energy model assumptions and results that provide the energy market inputs to the DRI macroeconomic model. The DRI macroeconomic model used in this analysis is based on a revised version of the US96b model.[6] This revised version was provided by DRI to be used by the Interagency Analysis Team (IAT) to analyze macroeconomic impacts of carbon emission reduction scenarios. The use of the IAT version of the macroeconomic model for this paper facilitates comparison of this analysis with results coming from the IAT efforts. This work is different from the work summarized in the draft IAT analysis paper given to Congress by the Administration in two ways. First, this analysis uses inputs from the NEMS energy model rather than the DRI energy model. Therefore, it serves to highlight differences in the results which directly result from differences in the outlook for the U.S. energy system under carbon trading schemes and protocols. Second, this analysis places additional emphasis on exploring parameters in the U.S. protocol proposal such as the length of the emissions budget periods.

The DRI macroeconomic model is a representation of the U.S. economy with detailed output, price and financial sectors incorporating gradual adjustment of the economy to policy chan

---

[6]The revised version of the US96B DRI macroeconomic model included several changes relative to the original US96B model. The changes included a respecified Federal Reserve reaction function; a revised estimation of consumer expectations; revised wage equations; inclusion of value-added taxes (which were not used in the present analysis); and a revised exchange rate equation. Complete documentation of the revised model was not provided by DRI; information regarding these changes are based on conversations with DRI personnel.

Accordingly, not all segments of the economy are in equilibrium at any given point in time. To incorporate long-run growth equilibrium conditions, DRI estimates an aggregate production function which uses capital, labor, energy, and technical progress to describe the potential output, i.e., what the economy can produce if all resources were fully employed. The aggregate production function determines the maximum GDP level achievable if all resources were ideally and fully utilized. As actual production approaches the potential production, all markets begin to tighten, leading to higher prices, labor costs, and interest rates. As the costs of the factors of production start to increase, slower rates of growth in the economy ensue.

In the DRI macroeconomic model, energy end-use demands are used to represent the energy components of the aggregate production of the economy. As shown earlier, the DOE analysis reaches carbon stabilization more through fuel switching than by energy end-use demand reductions. Since reductions in energy end-use demands reduce potential output (potential GDP), projections of a greater reduction in demand will shift back the production possibilities frontier. This means that the economic impacts of carbon stabilization depend upon whether more of the reductions in carbon use come from energy demand reductions or inter-fuel substitution for carbon-intensive fuels. The DOE analysis shows less impacts on potential GDP (or the aggregate production function) compared to an energy market analysis relying more on energy demand reductions to stabilize carbon emissions.

The economic literature that examines the economic impacts of global warming reports a wide range of economic impacts even when comparing the same carbon reduction scenario. An important reason for such a wide range of impacts result from model structure and how the following issues are addressed. How is the global economy depicted in the model? Are there ways to model alternative industrial competitiveness scenarios that might be envisioned if energy price impacts affect only a segment of the global economy? Is there an endogenous exchange rate? Is there a financial sector and what assumptions regarding Federal Reserve policy are made? Do all industries and consumers optimize behavior (either by maximizing profits or utility) or is their behavior modeled in such a way to allow for gradual response to policy changes which would imply transitional costs associated with any price change? What is the impact of flexible international trading of carbon permits? Differences in how each particular macroeconomic model can handle these issues illuminate much of the reported differences in impacts of describing carbon reduction scenarios.

Twelve macroeconomic cases are described in this chapter and focus on the sensitivity of the results to key elements (Table 4.1). There are four kinds of sensitivities: Targets for carbon emissions (T); Implementation of carbon "revenue" actions (I); Federal Reserve Policy (F); Industrial Competitiveness (C); and Emissions Trading (E). The value of carbon permits will vary across targets (the T cases). The recipient of carbon permit revenue will vary across implementation strategies (the I cases). The reaction of the monetary authorities will vary across policy sensitivities (the F cases) and, finally, the impacts on energy-intensive industries will vary across competitiveness scenarios (the C cases).

Table 4.1 Emission Reduction Cases Examined in Macroeconomic Analysis

Implementation Strategies	Stabilization at '90 Level by 2010 10-Year Ramp	Stabilization at '90 Level by 2010, 5-Year Ramp	Five-year Average at 1344, 2011-2015, at 1322 Beyond 2015	Ten-year Average at 1344, 2011-2020	Stabilization at 1210 Level by 2010, 5-Year Ramp	Stabilization at 1409 Level by 20 5-Year Ramp
Deficit Reduction		I F	I F			
Deficit Neutral, All to Consumers	T	T I F C	T I F C	T	T	

The following assumptions underlie the macroeconomic simulations unless otherwise noted for the sensitivity analyses:

- There is no Federal Reserve reaction assumed unless explicitly stated. Nominal reserves are held at baseline values. The F sensitivities relax this assumption. This approach contrasts with the IAT process where the central assumption is that the Fed automatically reacts to the increased energy prices.

- When analyzing across carbon-target scenarios, the auctioned carbon permit revenue was returned to households via reductions in personal income taxes. The revenues were returned in a lump-sum to households; marginal tax rates were not changed. The I sensitivities examine alternative ways to return the carbon permit revenue to the U.S. economy.

- The exchange rate internal to the DRI macroeconomic model was used, allowing the DRI model to estimate exchange rate impacts of alternative carbon permit scenarios. Since the carbon constraints are imposed on Annex I countries only, not all exporters to the United States experience cost increases due to impositions of carbon permits. The DRI macroeconomic model does not differentiate imports by source country. Therefore, to reflect the approximate trade share of Annex I countries, exporters to the United States are assumed to experience 55 percent of the full cost increase experienced by US producers. The C sensitivities acknowledge the uncertainty concerning the competitiveness of energy-intensive industries in response to imposing carbon limits only on Annex I countries.

- For the International Permit Trading Case (E), two sources of revenue flows are generated: carbon permit revenues remaining within U.S. borders and payments to purchase permits on the international market. The domestic revenues are recycled back to U.S. consumers and the international permits are reflected as an increase in imports of services.

- Finally, the version of the DRI model used for this analysis is identical to that developed by DRI for use in the IAT process.

This macroeconomic analysis of the various carbon target scenarios rely heavily upon price signals to simulate economic behavior in response to increasing carbon permit values. There is no engineering analysis that considers the costs of investing in new power generation capability or retiring inefficient but not economically obsolete capacity. Similarly there are no estimates of what the new technologies would cost in terms of R&D, infrastructure, and equipment purchases to achieve the potential impact of increased energy efficiency.

4.2 Macroeconomic Analysis

Alternative Carbon Targets

The values of carbon permits examined in the macroeconomic analysis range from $130 to $150 per metric ton (1995 dollars) for the 1990-level stabilization cases. The carbon permit value rises as high as $310 per metric ton in the case which achieves 15 percent below 1990 levels in 2010, $210 per metric ton in cases where the carbon constraint is tightened to 10 percent below the 1990 emission level in 2010. The 1400 million metric ton target can be achieved with a $125 per metric ton carbon value. The time path of the permit value varies substantially, depending on the time period and carbon emission levels that are implemented.

Alternative cases that examine the importance of time and carbon emission levels include:

- A more stringent emissions target of 1210 million metric tons, 10 percent below the 1990 carbon emissions level of 1344 million metric tons. Also, a less stringent case is considered, targeting emissions of 1400 million metric tons in 2010;
- Alternate ramp periods for the target: either a five-year ramp period or a ten-year period; and
- An average carbon emissions target over a 5- or 10-year period instead of a target that must be achieved in every year.

Figures 4.1 and 4.2 present economic impacts across the different carbon target reductions assuming that the carbon permit revenue is returned to households via reductions in personal income taxes. Three dimensions are highlighted.

Importance of targeted emission levels. The more stringent the target, the higher are real GDP losses. Attaining carbon emissions of 1344 million metric tons by 2010, shows a peak annual GDP loss of just over $100 billion (1.0 percent below baseline levels) and a net present (NPV) loss peak of $418 billion. The more stringent target of 1210 million metric tons (10 percent below 1990 levels) results in a peak annual GDP loss of roughly $160 billion (1.8 percent below baseline levels) and a NPV loss of $678 billion. The less stringent case of 1400 million metric tons of carbon emissions shows a peak GDP loss of $92 billion (1.0 percent below baseline levels) and a NPV loss of $391 billion.

Figure 4.1 Alternative Carbon Reduction Targets, All to Consumers, Federal Reserve Reaction Off

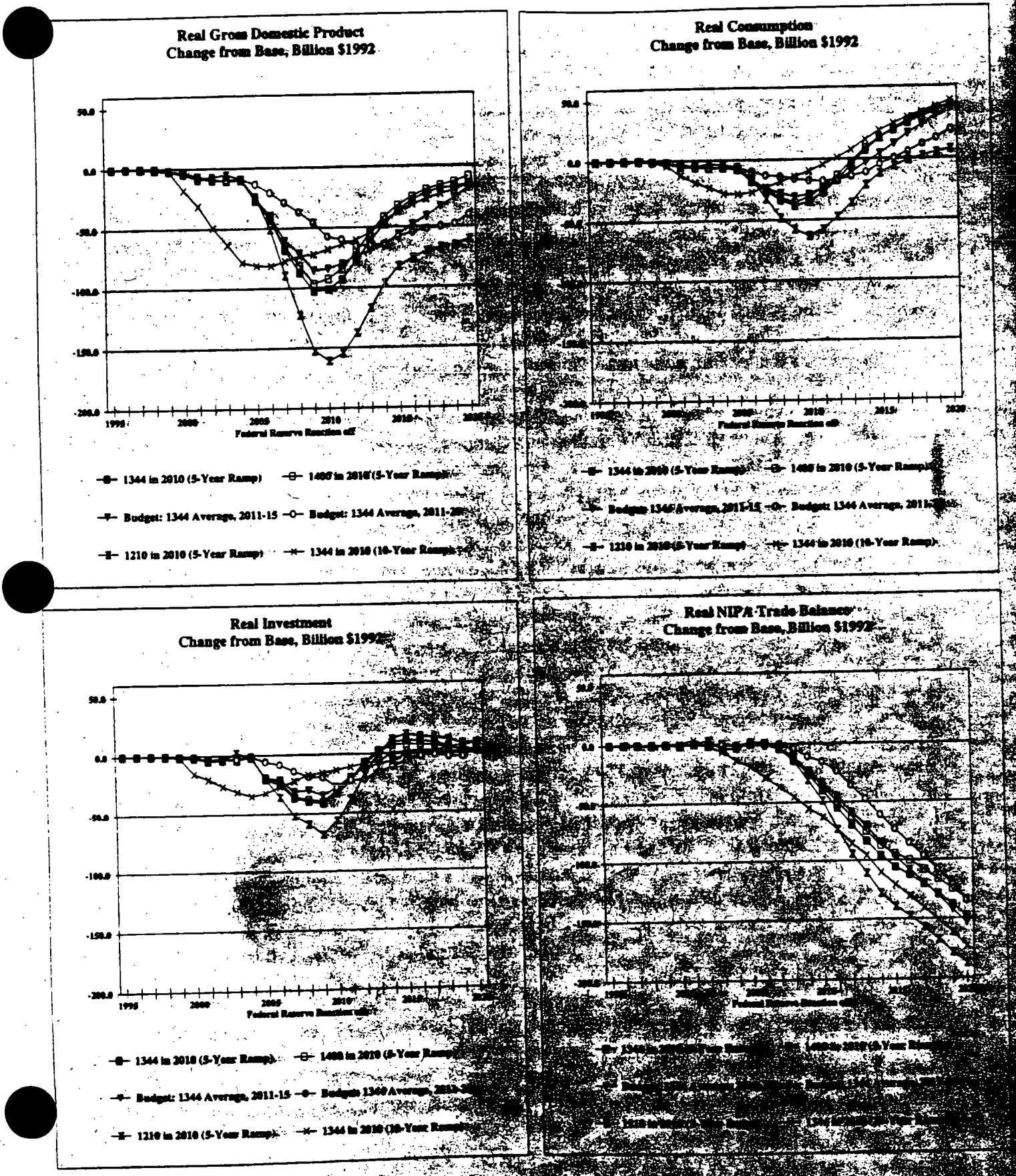
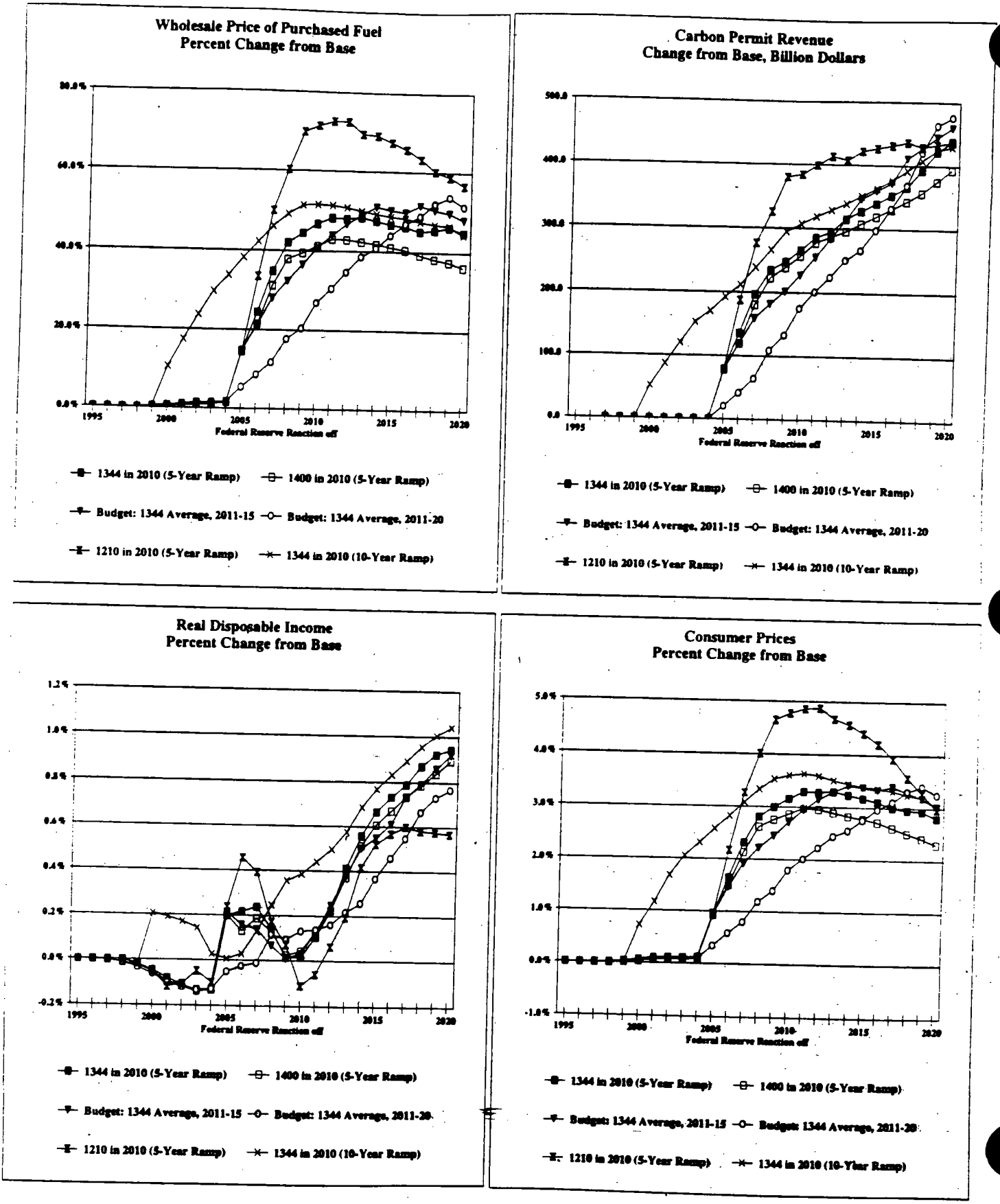


Figure 4.2 Alternative Carbon Reduction Targets, All to Consumers, Federal Reserve Reaction Off



Importance of the Ramp Period. Increasing the ramp period by five years from 5 to 10 years results in a smaller price increase over a longer period of time. Peak GDP losses are less in the 10-year ramped 1990 target case compared to the 5-year ramped 1990 target scenario because the slower rate of price increases in the 10-year ramp case gives the economy more time to adjust. Even though the increased energy prices are ramped more gradually in the 10-year case, they remain higher for a longer period of time, so it takes more time for GDP to recover back toward the baseline. However, the NPV of the 10-year ramp case is higher ($584 billion) than the 5-year ramp case ($418 billion) because the changes begin in 2000 as opposed to 2005 and the early years receive a larger weight in the NPV calculation.

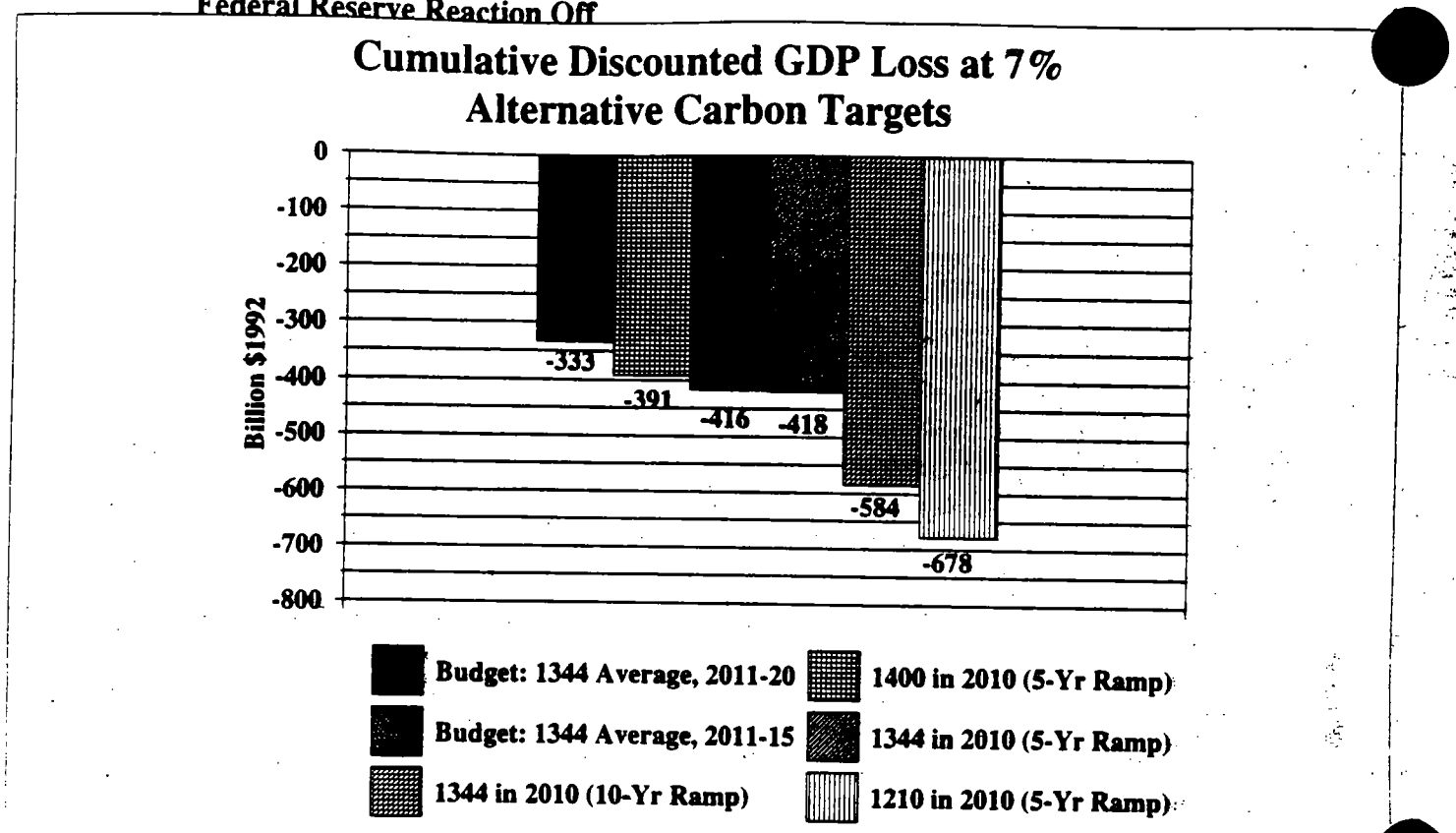
Importance of Averaging. Averaging the carbon reduction targets over 5 years ameliorates the peak GDP loss, although the NPV is the same. A longer period for averaging ameliorates the impacts even further and also lowers the NPV of the losses. Comparing a 5-year ramp in cases at 1990 levels by 2010 to a 5-year average (averaged over the 2011-2015 period) yields roughly the same overall GDP losses, but the time profile of the losses is different between the two cases. The time profile of the loss in GDP mirrors the time path of carbon permit values. The 5-year averaged scenario has slightly less output losses early in the period, but the GDP losses are greater after 2012. Averaging over a 10-year period (2011-2020) shows smaller GDP losses as the period where adjustment to higher energy prices is much longer compared to the case which ramps emissions reductions over a 5-year period.

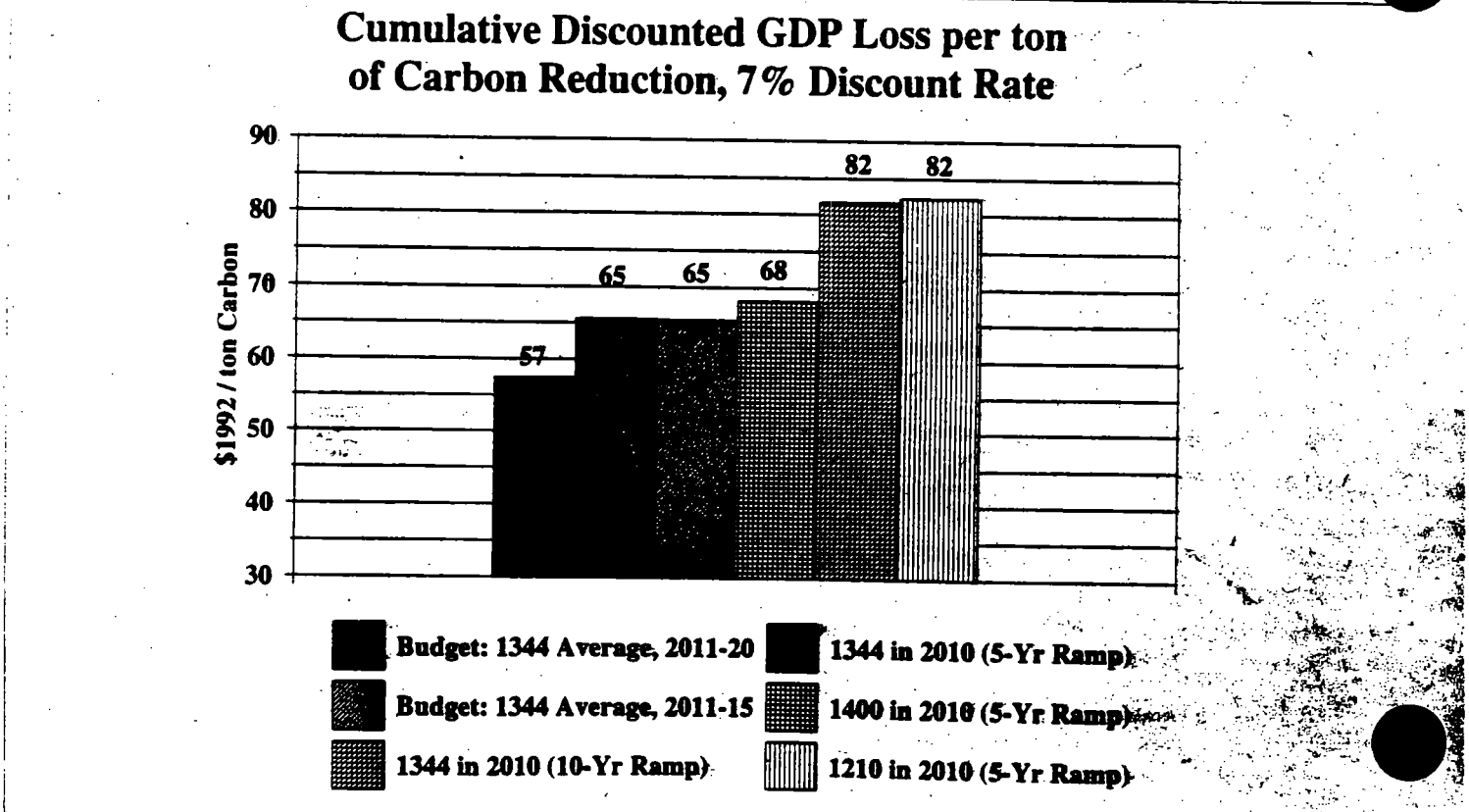
Summary of Alternative Carbon Targets

Figure 4.3 shows both the cumulative discounted GDP loss and a valuation of the GDP loss per ton of cumulative reduction of carbon. On both measures the 10-year averaged 1344 million metric tons is the least disruptive to the economy, with a loss in GDP of $385 billion and a cost of $3 per ton of carbon reduced. The 5-year ramped case targeting 1440 million metric tons is the most expensive at a loss of $678 billion and a per ton cost of $5

On a per ton basis, there is no difference for a 5-year ramp versus the 5-year average. However, there is a clear difference between the 10-year results, the averaged case and the ramped case. This is largely due to the nature of the path and when the GDP losses occur. The 10-year ramp case starts in 2000 and hits the 1344 target in 2010, thus incurring GDP losses early in the forecast period. The average case avoids early period losses by [illegible] average target which allows for flexibility in achieving the 1344 target. While the 5-year 1440 metric ton case has a smaller GDP loss ($391 billion) than the 1344 case, the per ton cost is the same.

Figure 4.3 GDP Impacts of Carbon Targets and Alternative Time Periods, All to Consumer Case
Federal Reserve Reaction Off





Implementation of Revenue Recycling Sensitivity

Two alternative methods of handling the carbon permit revenue are considered:

- Using the collected carbon permit revenues to reduce the Federal deficit; and
- Returning the carbon permit revenue to households only via reductions in personal income taxes, while ensuring that the government deficit at full employment remains at baseline levels.

Using the permit revenues to reduce the deficit could be analogous to the government keeping the revenue in a carbon emission auction, similar to what happens when radio frequencies are sold. The latter case compensates the consumer for the higher prices paid, while still maintaining the altered relative price effects of the higher energy prices. In both cases, consumers ultimately pay higher costs for all goods and services given the higher prices paid directly for energy and as the higher price of energy is passed through to the price of goods and services.

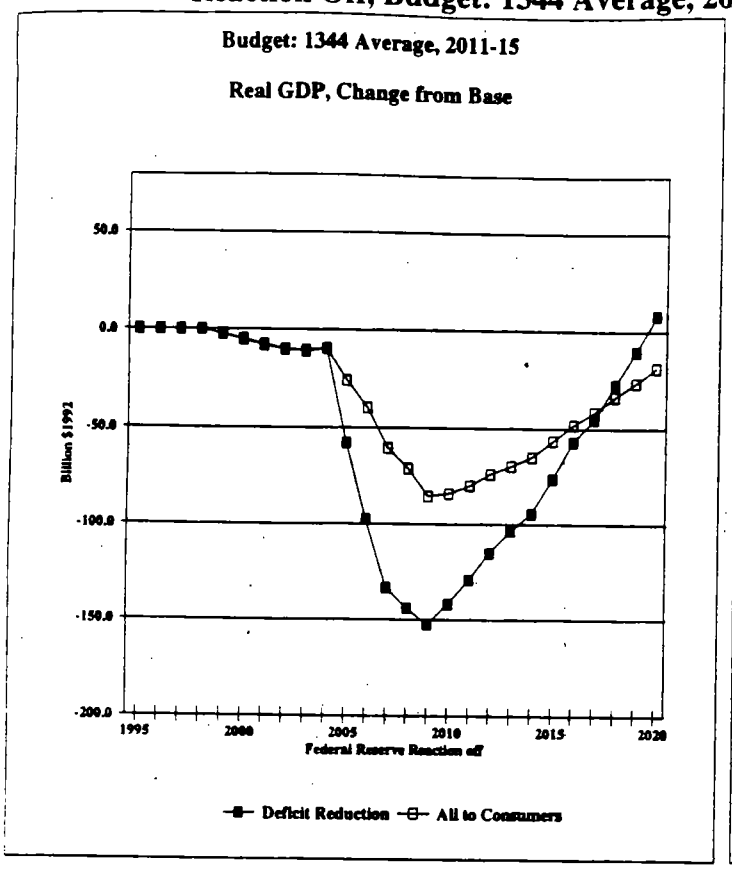
Figures 4.4 and 4.5 refer to the 5-year average cases, while 4.6 and 4.7 refer to the 5-year ramped cases. Both the averaged and ramped cases compare the macroeconomic impacts of deficit reduction and deficit neutral cases using the common assumption that the Federal Reserve does nothing in response to higher carbon permit values. The relative ordering of GDP impacts between deficit reduction and deficit neutral remains the same for all carbon emission target scenarios.

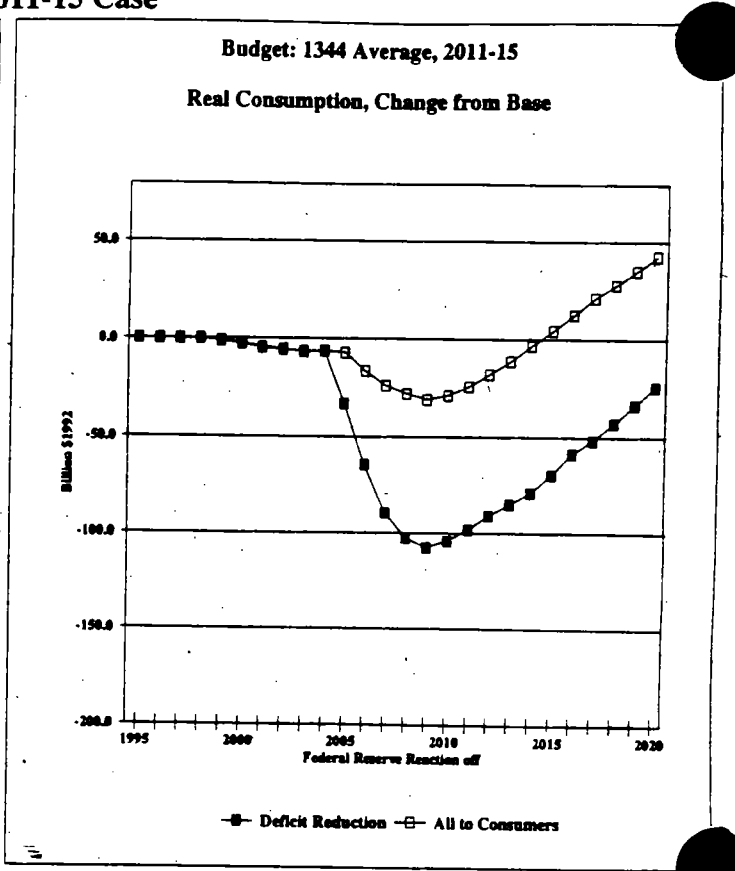
The deficit reduction case shows immediate losses in GDP. However, after about five years, this case shows a strong investment-led economic rebound as interest rates begin to fall. As investment starts to increase, consumption begins its recovery. By the end of the forecast period, consumption is almost at baseline levels as the benefits of falling prices and interest rates finally reach households.

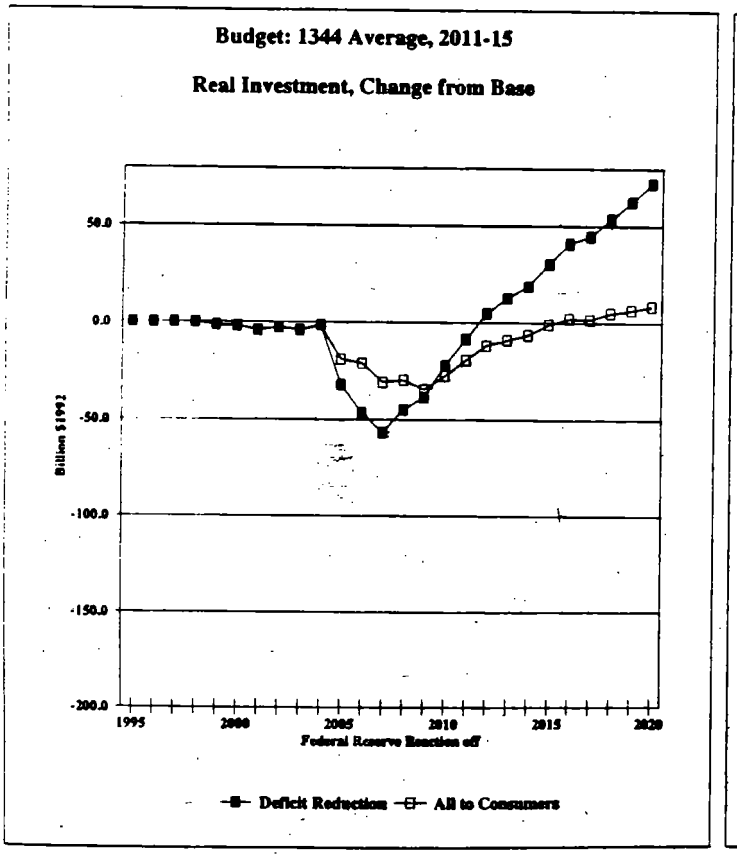
In the carbon target cases where households are compensated by reductions in personal taxes by the amount of money that ensures the full employment deficit is no different than baseline levels, consumption leads real GDP recovery, however at a cost of higher inflation. Compared to the deficit reduction cases, GDP losses are ameliorated in the short-run, but in the longer run, GDP never experiences the strong recovery since interest rates and prices remain higher. Disposable income shows much stronger growth, as the amount of revenue returned is quite substantial. Increasi disposable income maintains higher consumption levels compared to the deficit reduction cases, resulting in higher prices and labor costs. Investment levels return to reference case levels, but never really increase much above baseline throughout the forecast period.

In the long-run, any revenue recycling option favoring capital formation (such as reducing corporate income taxes or reducing the deficit and lowering interest rates) shows significantly better long-term GDP impacts than policies which compensate consumption. Returning carbon revenues all

Figure 4.4 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, Budget: 1344 Average, 2011-15 Case







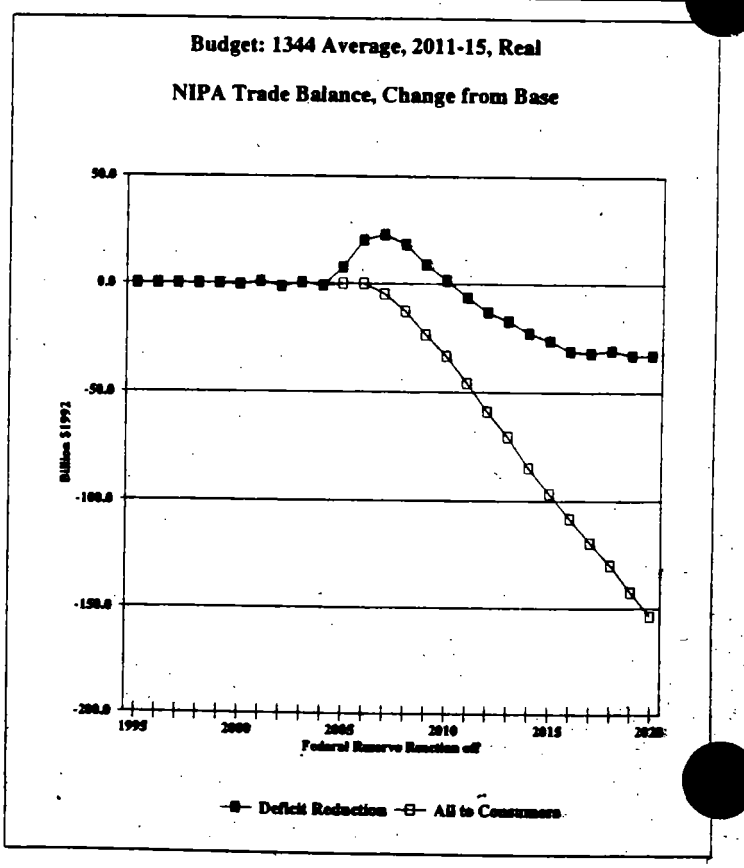
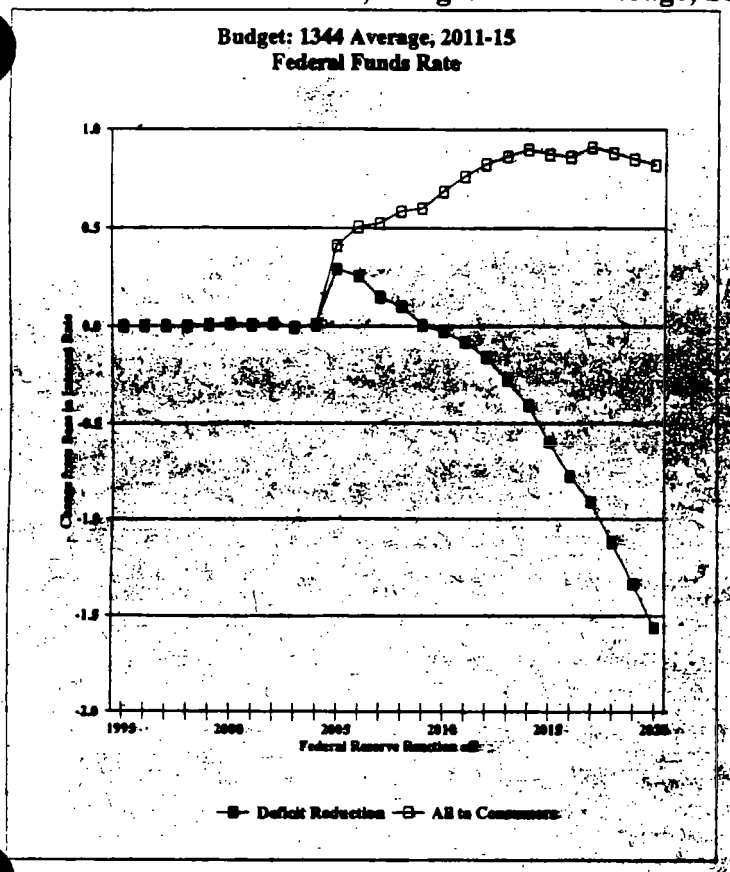
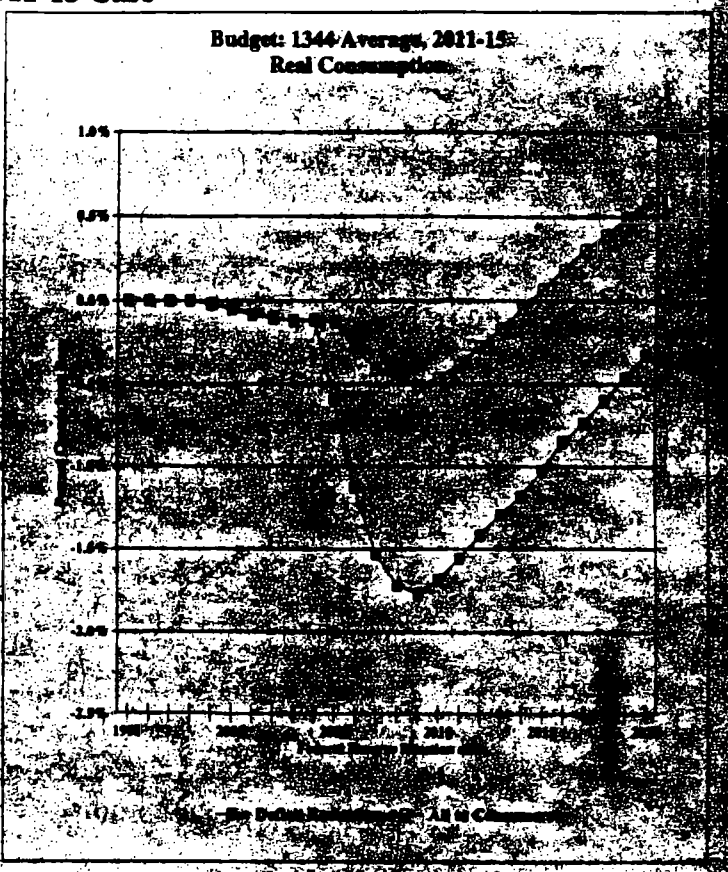


Figure 4.5 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, Budget: 1344 Average, 2011-15 Case





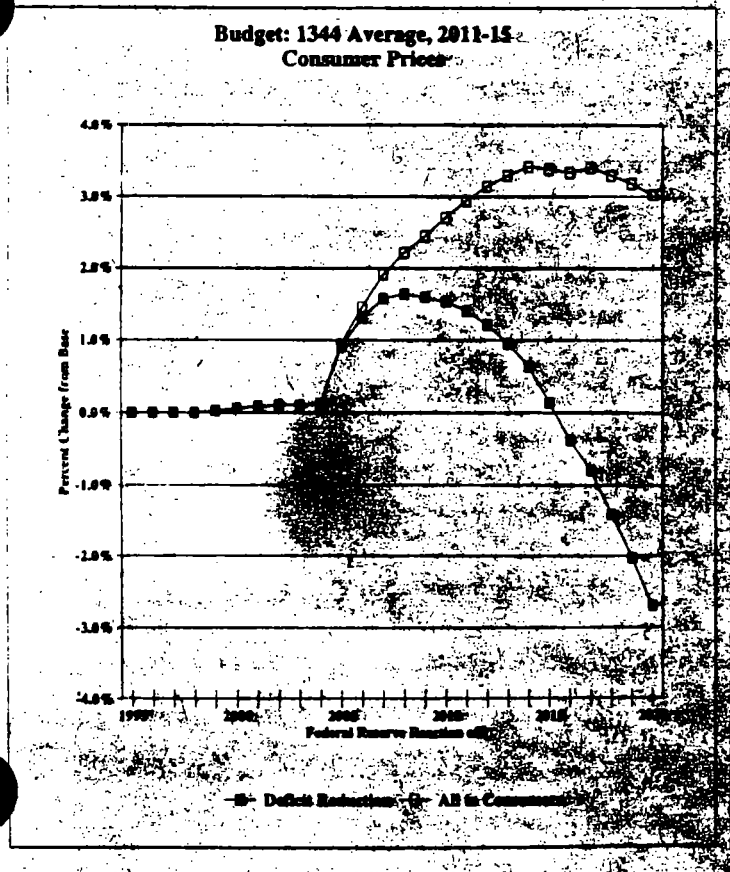
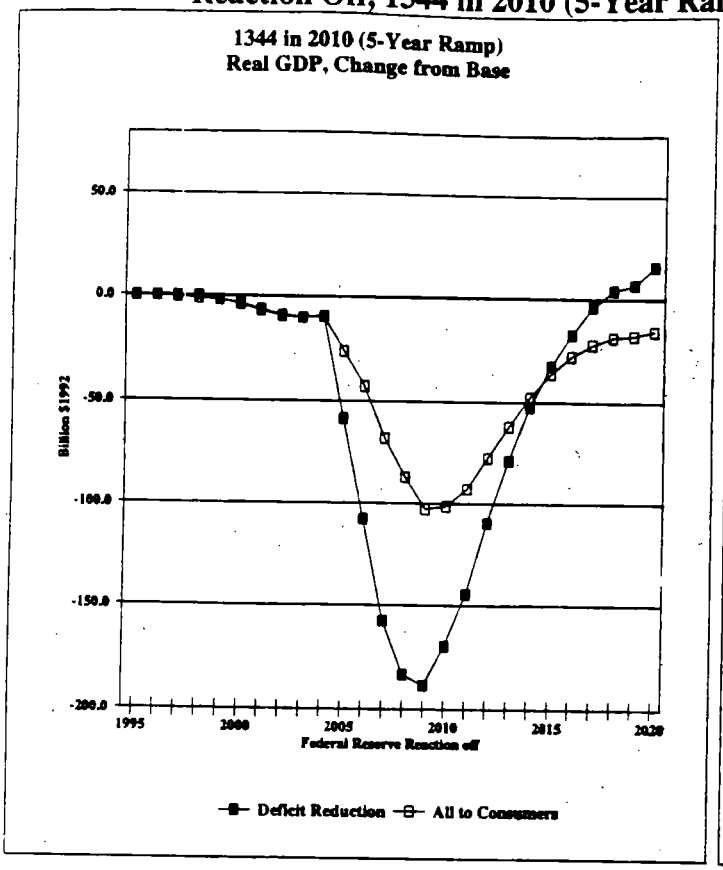
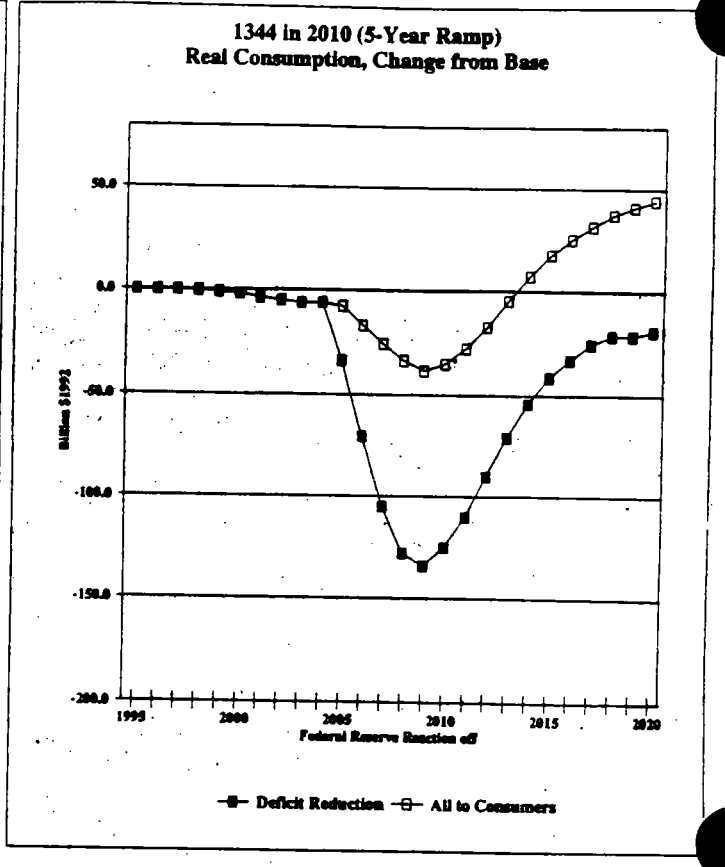
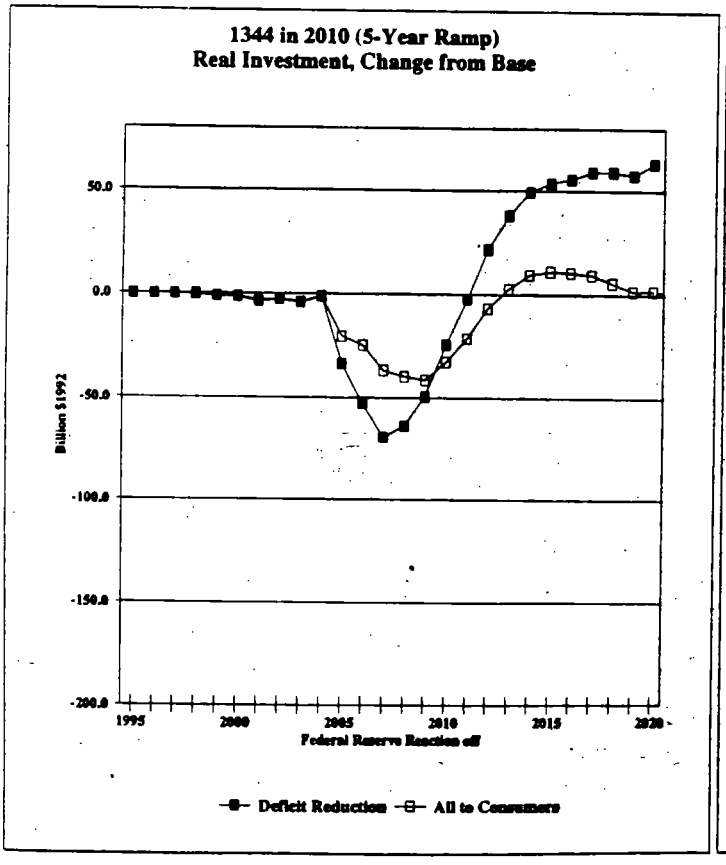




Figure 4.6 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, 1344 in 2010 (5-Year Ramp) Case







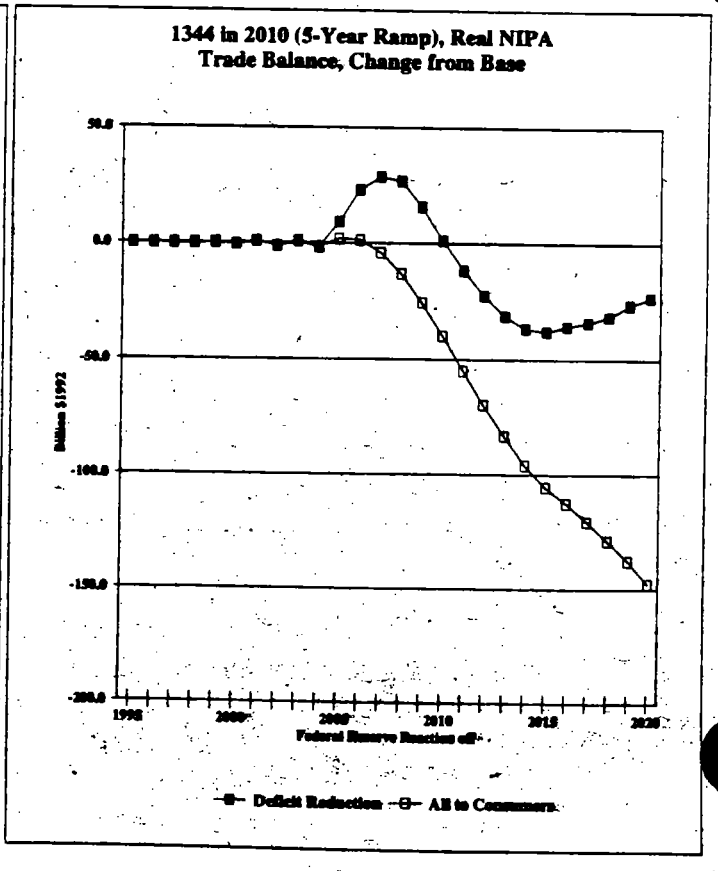
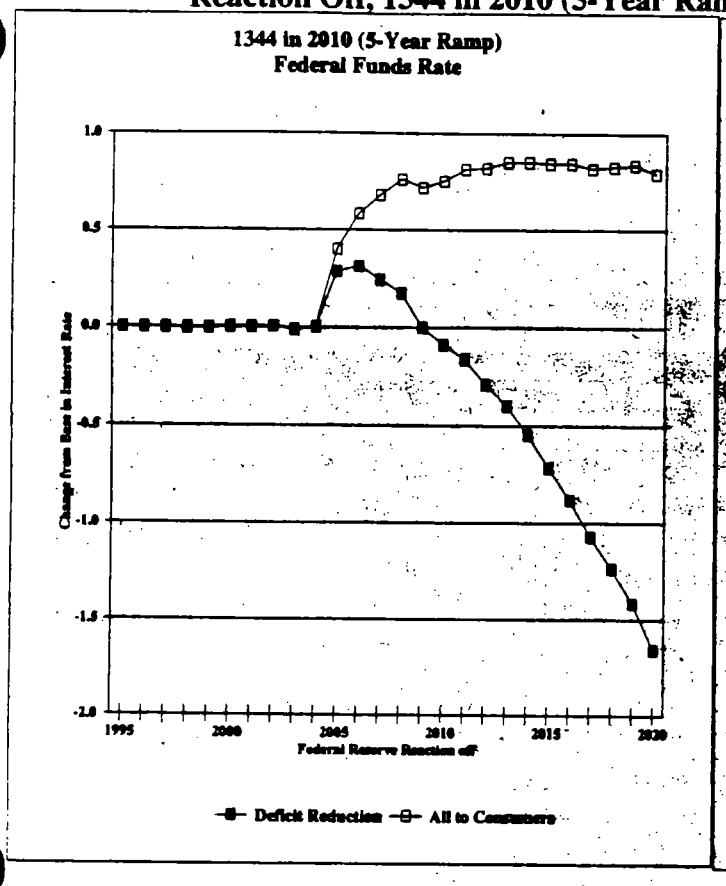
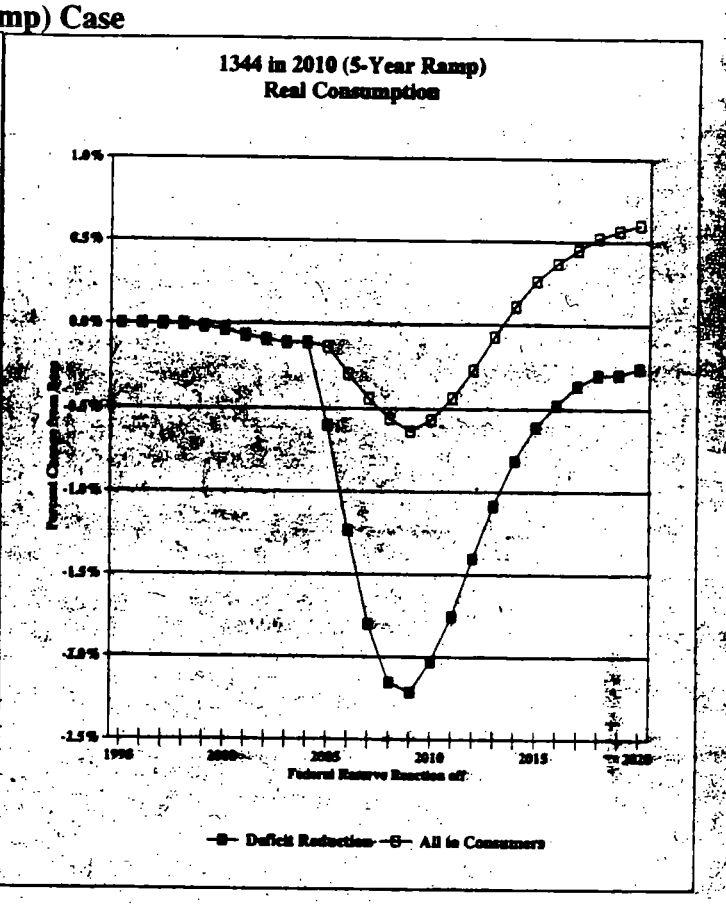
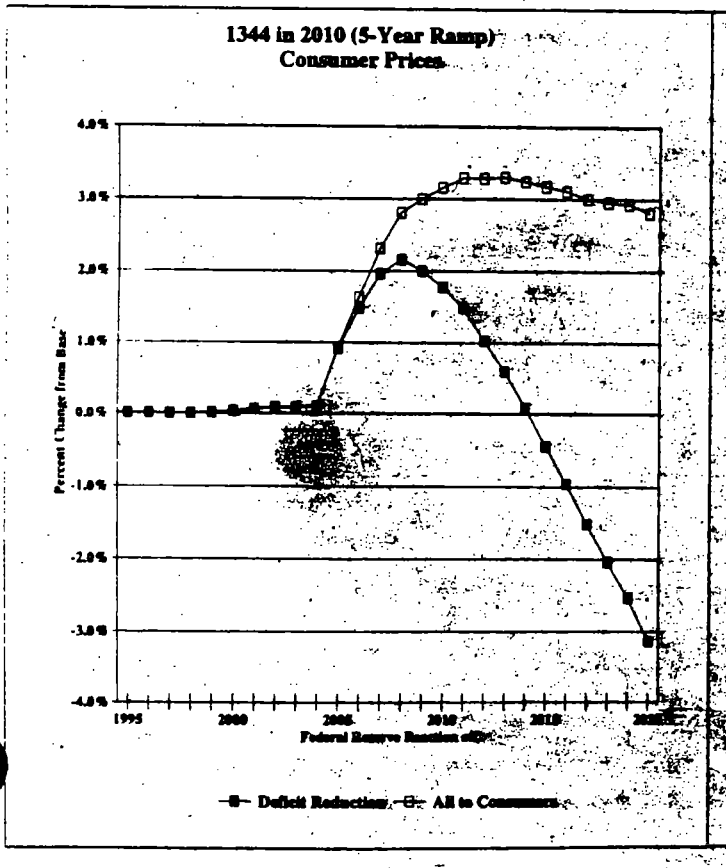
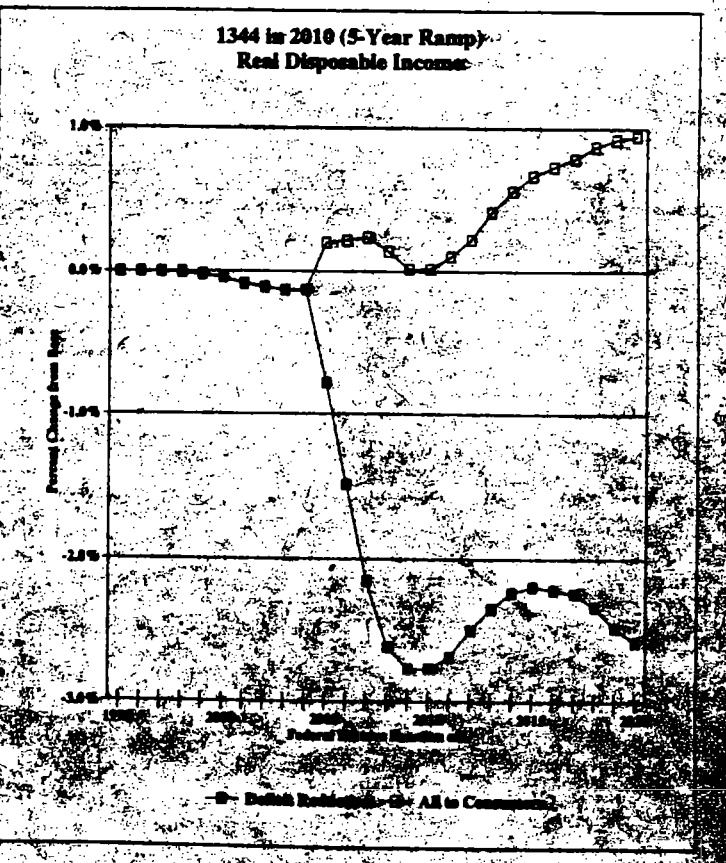


Figure 4.7 Implementation Sensitivities, Deficit Reduction and All to Consumers, Federal Reserve Reaction Off, 1344 in 2010 (5-Year Ramp) Case









households ameliorates short-run losses, but the long-term impacts are slightly worse than the deficit reduction case. Compensating consumers for increases in energy prices due to carbon permits minimizes consumption losses, keeping overall prices high throughout the forecast period.

Federal Reserve Policy Sensitivities

Historically, EIA has presented analysis using the assumption that the Federal Reserve does not react to energy events and policy changes. This approach is also followed in this report. Because of IAT interest, sensitivity analysis of the role of the Federal Reserve is presented separately to highlight how the outcomes may be altered by virtue of actions taken by the monetary authorities.

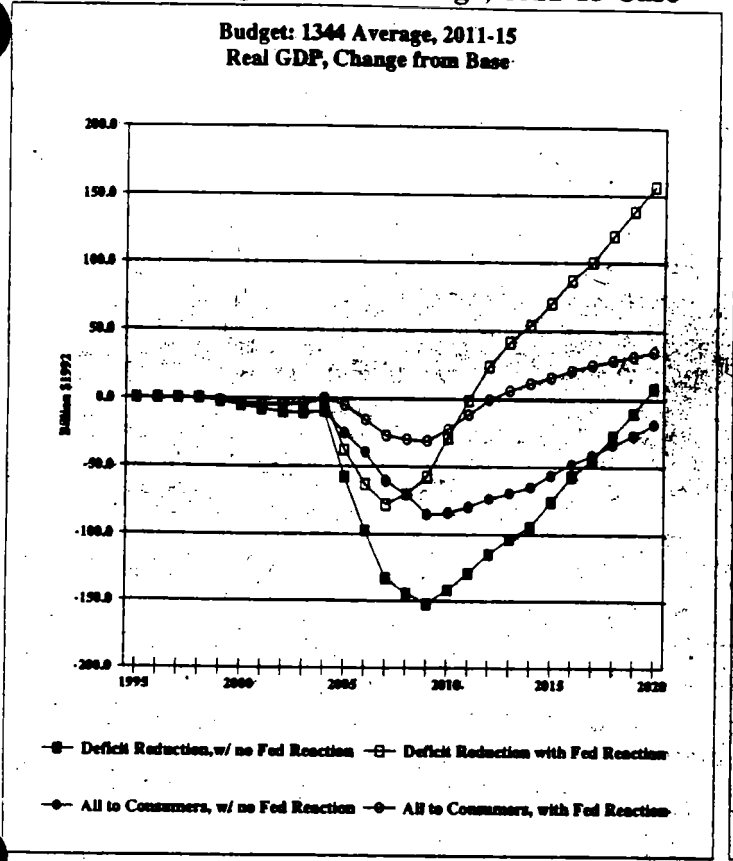
Two cases of revenue recycling (deficit reduction and deficit neutral via compensation to consumers) are examined using alternative Federal Reserve policy reactions. The DRI macroeconomic model has estimated a Federal Reserve reaction function[7] which attempts to capture possible response of the monetary authority to changes in unemployment and the rate of inflation. As unemployment increases, the Federal Reserve will start to decrease the federal funds rate (which is the rate of interest that the Federal Reserve charge banks to meet their reserve requirement) to stimulate economic expansion and the demand for labor. However, if prices remain high, the Federal Reserve will not continue to decrease rates. Turning the Federal Reserve reaction function on will alter projected impacts across all scenarios, but the extent to which the reaction function matters depends upon the path inflation and unemployment take in any particular scenario. For example, the impact of the Federal Reserve reaction is greater when unemployment losses are large and when prices and interest rates begin to abate after the initial energy price surge (the deficit reduction case). When the carbon permit revenues are given back to households, unemployment losses are not as large and inflation remains relatively high. In this case, there is less divergence between the cases where only the Federal Reserve reaction is changed.

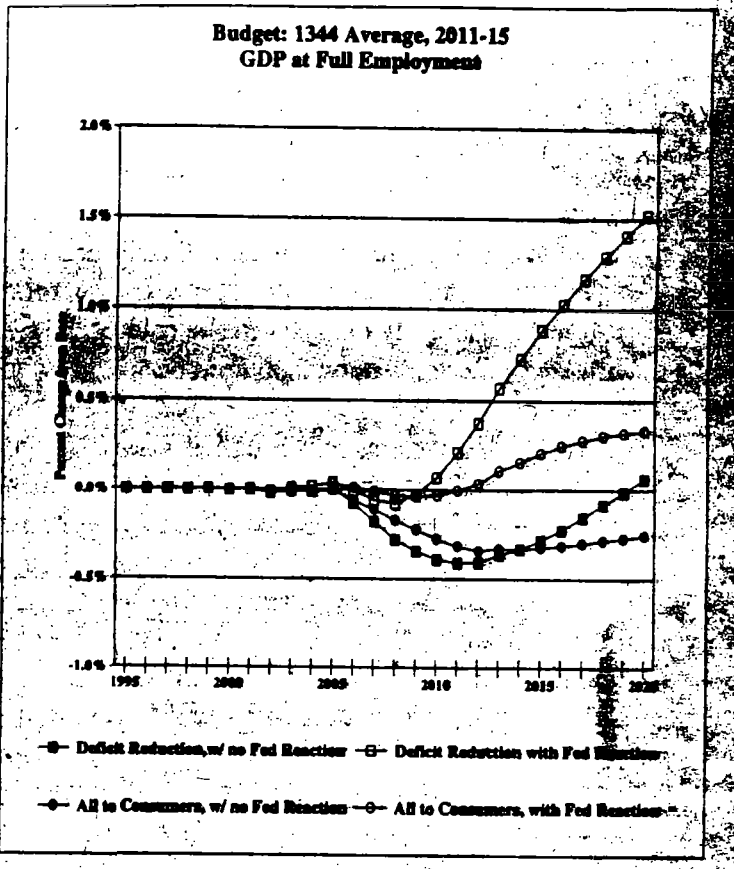
Figure 4.8 (averaged) and 4.9 (ramped) illustrate the differences in results if the estimated Federal Reserve reaction equation in the DRI macroeconomic model is used. The impact of the Federal Reserve is much larger in the deficit reduction case compared to the case where carbon permit revenue is returned to the households. In the deficit reduction case (assuming no Federal Reserve reaction), prices and interest rates initially show increases, but as reductions in aggregate demand and government's demand for borrowing continue, prices and interest rates begin to fall. In this case, the Federal Reserve has more flexibility and can lower interest rates more before worrying about increasing inflation. In response to sharp increases in the unemployment rate, the Federal Reserve is projected to decrease interest rates rapidly. Increasing capital accumulation allows potential output to increase substantially. Since potential output expands, the economy can continue to grow without experiencing increases in price and interest rates.

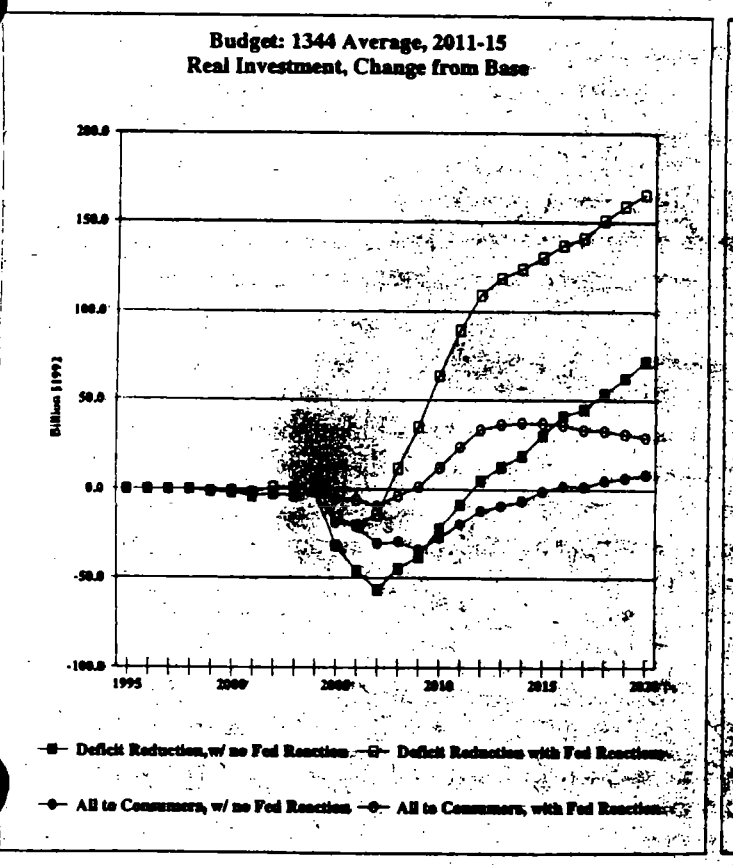
---

[7] The Federal Reserve reaction function sensitivities are based on the DRI revision to the macro-economic model identified as US96B and used as part of the Inter-Agency Task force analysis. The DRI results of the draft report released on May 30, 1997 entitled "Economic Effects of Global Climate Change Policies: Results of the Research Efforts of the Interagency Analytical Team, June 1997", are based on this revised model.

Figure 4.8 Federal Reserve Reaction Sensitivities, Deficit Reduction and All to Consumers Budget: 1344 Average, 2011-15 Case







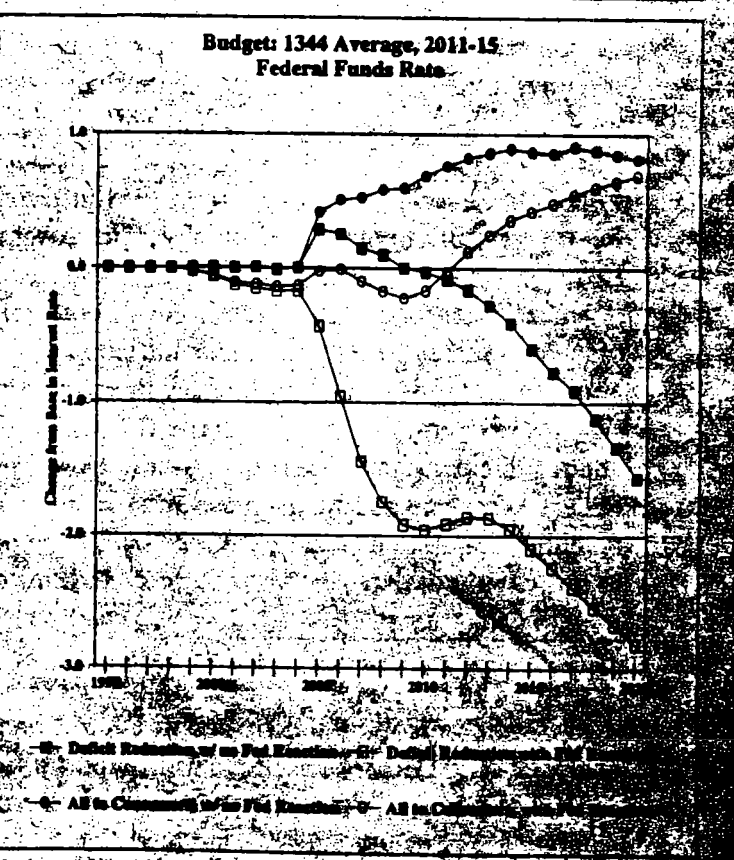
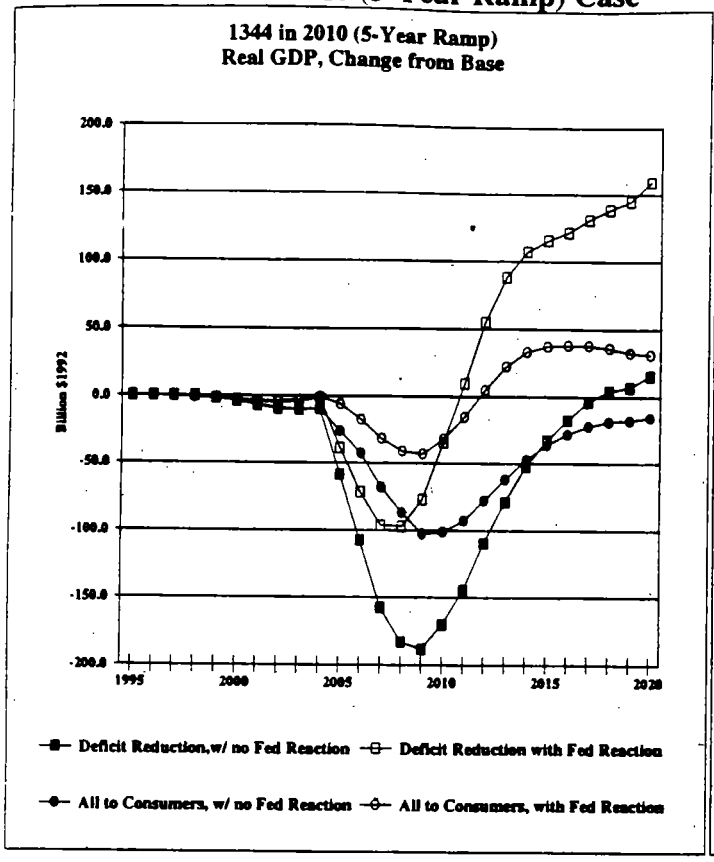
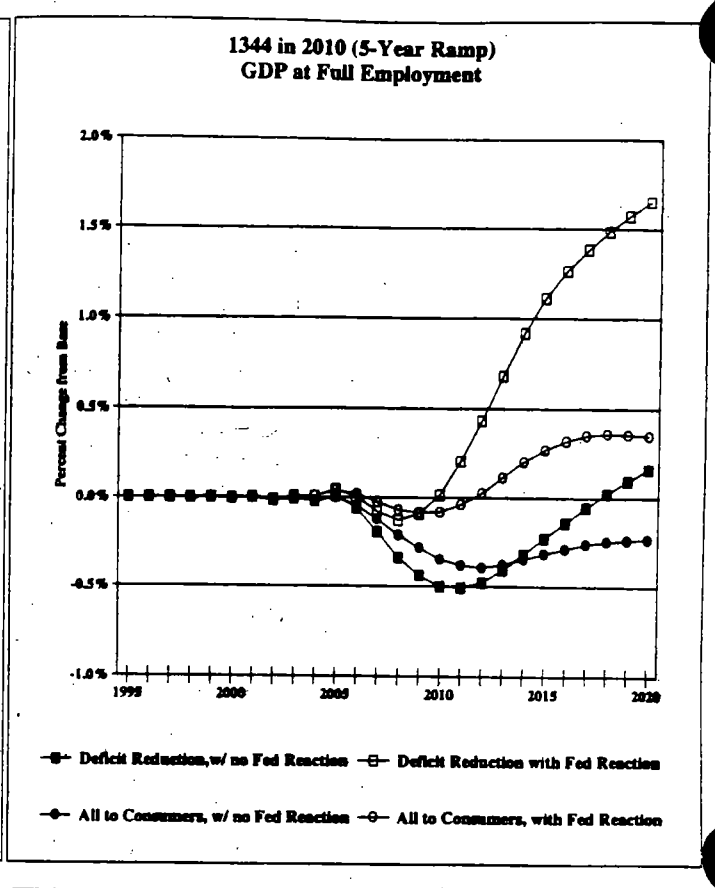
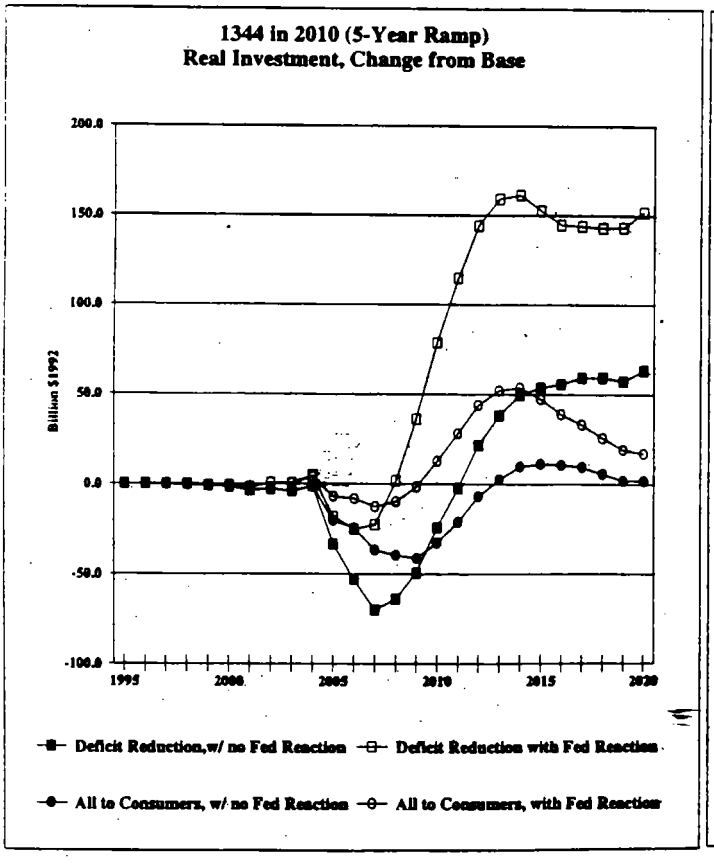
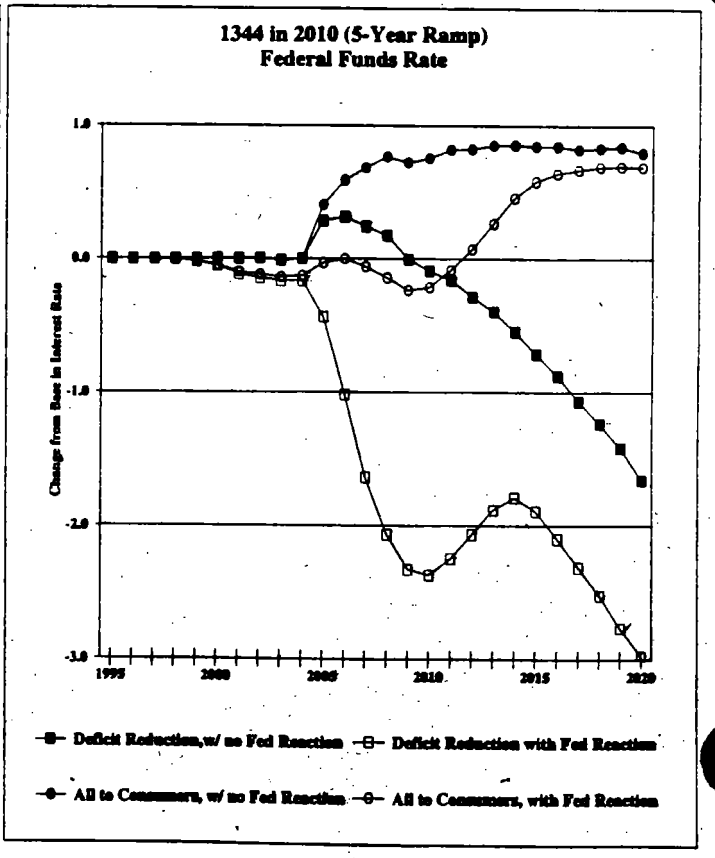


Figure 4.9 Federal Reserve Reaction Sensitivities, Deficit Reduction and All to Consumers 1344 in 2010 (5-Year Ramp) Case









If the Federal Reserve reaction is used, the peak annual GDP loss is roughly halved, with recovery in the later years coming much faster and stronger. This result is also dependent upon the price paths: the reaction function has more impact for prices that increase rapidly and then level off to higher levels compared to prices that continually rise.

In the deficit reduction case, the Federal Reserve reaction function is projected to have a large and growing impact on the economy. The difference in impacts resulting from the assumption of the Federal Reserve accommodation occurs because the Federal Reserve sharply decreases interest rates when faced with large employment losses. As the carbon permit revenue is used to reduce the deficit, and consumers have to cut back sharply on purchases leading to both falling interest rates and overall prices, the Federal Reserve has more of an opportunity to keep interest rates lower.

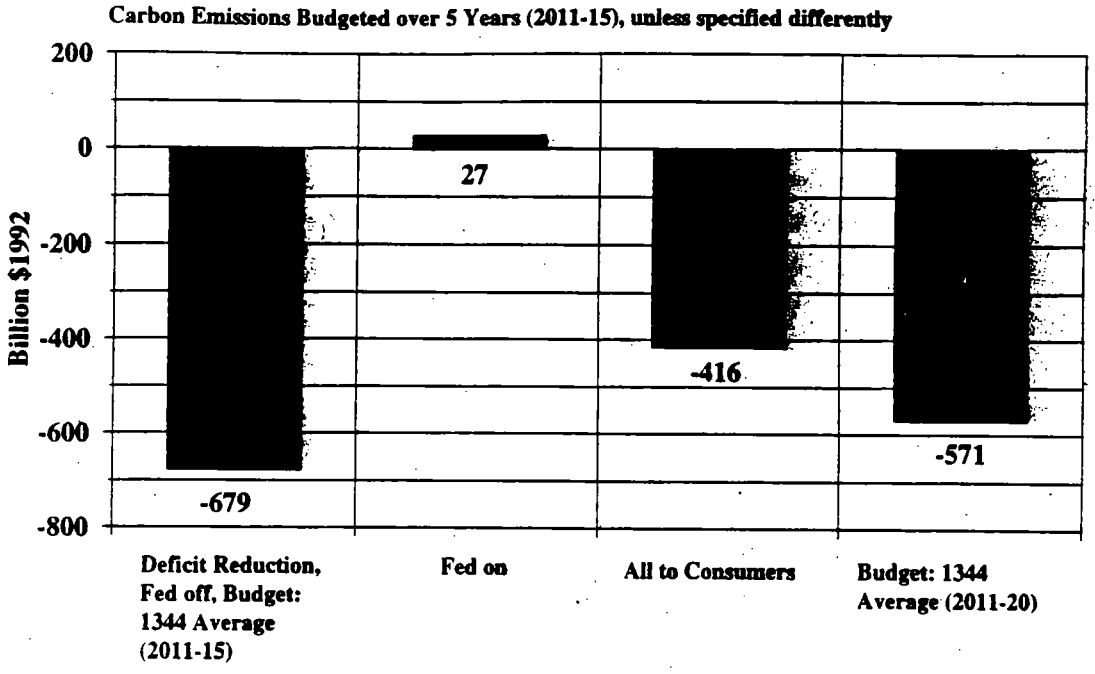
In the deficit neutral case where households are compensated for the higher energy prices, there tends to be higher inflation and less effect on aggregate demand. With higher inflation than in the deficit reduction case, the Federal Reserve reaction to reduce interest rates is less than in the deficit neutral case. With minimal reductions in aggregate demand compared to the deficit reduction case, there is less of a long term drop in interest rates and prices in general. Because consumers are compensated for higher energy prices, they maintain purchases and minimize output losses in the short run. In the long run, consumers' higher levels of aggregate demand result in higher labor costs, prices, and interest rates compared to the deficit reduction case. Hence, capital accumulation is lower in the deficit neutral case. The Federal Reserve reaction does ameliorate losses in both cases, but the improvement in GDP for the deficit neutral case is projected to be much lower.

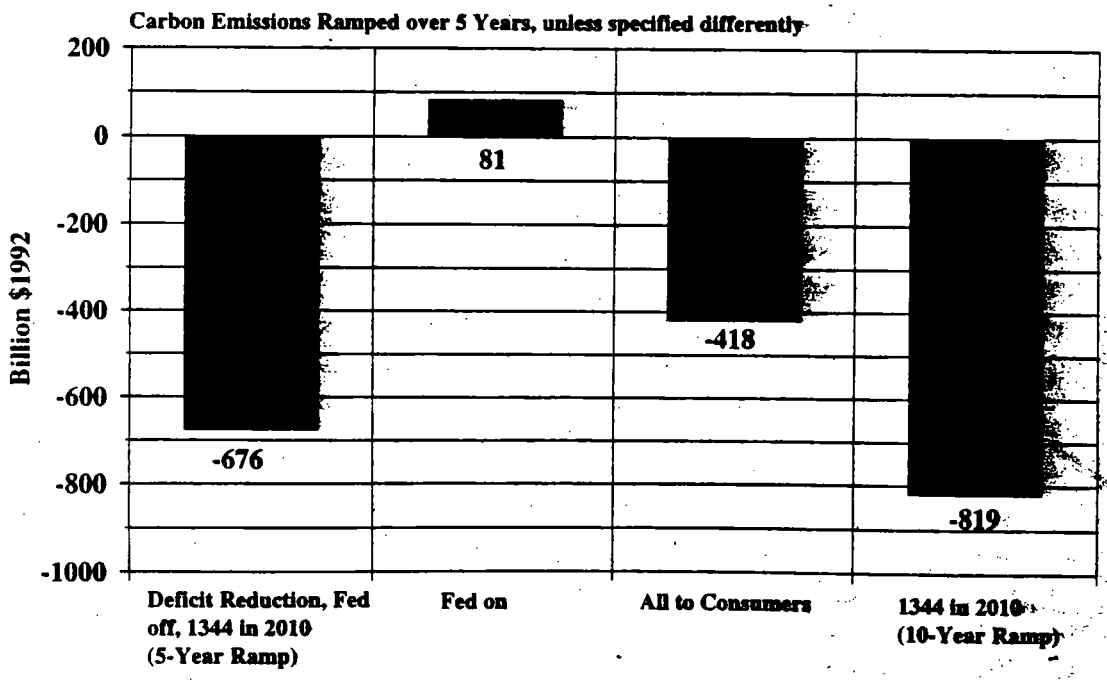
In the version of the DRI model used for this analysis, there is a greater emphasis on the part of the Federal Reserve to accommodate changes in unemployment relative to price inflation. Hence, in the deficit reduction case, where there are substantial early losses in employment, the Federal Reserve reacts immediately by substantially lowering the federal funds rate (Figures 4.8 and 4.9). Moreover, interest rates are projected to be lower relative to the case where no accommodation occurs, even in the long-run. One might expect that the two interest rate paths in the deficit reduction case would converge toward each other as they did when the collected funds were returned to the consumer. Whether the Federal Reserve will keep interest rates lower over the entire period is speculative.

Summary of Sensitivity Analyses

Figure 4.10 summarizes the GDP impacts of the sensitivity cases. The top portion of the figure focuses on the 5-year average case, and successively shows the impact of turning the (a) Federal reaction function "on", (b) returning the collected revenues to consumers, and (c) switching to a 10-year ramp. The use of the Federal reaction function has by far the largest impact, turning a loss in GDP of $679 into a net gain of $27 billion. Returning collected funds to consumers stems early GDP losses and lessens the impact to $416 billion. Switching to a 10-year period lessens the impact by the smallest margin to $571 billion. The bottom portion of the figure makes the same series of comparisons for the ramped cases. Here, the same observations can be made with one exception. The 10-year ramp has a larger GDP loss ($889 billion) than the 5-year ramp case ($679 billion). As stated earlier, this is largely due to the nature of the feedback which starts the economy in 200

Figure 4.10 Ramped vs. Budgeted Cases, Comparison of Sensitivities





Industrial Competitiveness

Even though the analysis assumes that only 55 percent of cost increases brought about by higher energy prices experienced by U.S. producers are also felt by foreign producers, this assumption is not derived from a microeconomic analysis of the carbon reduction targets at an industry level. Alternative studies have predicted that the potential impacts of imposing carbon limits might mean that energy-intensive industries located in Annex I countries would be significantly supplanted by producers located in countries not subject to the same environmental limits. A regionally and industrially disaggregated international world trade model representing both Annex I and non-Annex I countries would be needed to adequately address the issue/question of industrial "leakage". Many of the international economic models contain Annex I countries but may not have the non-Annex I countries except as regional aggregates. In addition, the industrial detail of these CGE models is usually limited to a few industries such as agriculture, manufactured goods, energy and other goods. Richness of detail along both country and sectoral dimensions is critical to analysis of the leakage issue. The risks to domestic production lay in specific product lines where individual countries may capitalize on their relatively cheaper cost structure. Aggregation along both of the lines masks the industries at risk.

The industrial impact assessment presented in this section is based on the results from an input-output model linked to the DRI macroeconomic model. The I/O model essentially asks the question, "what is the level of output required by each sector of the economy to satisfy a slate of final demands" derived in the macroeconomic model?" Thus, the impacts by industry reflect both changes in the level and the composition of final demand, or GDP. While the I/O model does have coefficients which change over time, they do not change between price scenarios.

The macroeconomic analysis presented earlier is based solely on the interactions that take place within the macroeconomic model. If leakage did not occur, output will decline at first, then increase as the economy begins to recover due to increases in investment. However, in order to investigate leakage, the final demands were altered to reflect alternative compositions of imports and exports based on the study sponsor's analysis of possible industrial impacts when only a subset of their competitors experience cost increases.

Two alternative cases are presented to discuss the industrial competitive issues. The first alternative case assumes that the reduction in domestic production by carbon-intensive industries (leakage) are offset by exports of less carbon-intensive industries by the same amount resulting in no net GDP losses. Even though aggregate GDP impacts are very similar to the case with no adjustments, the industrial impacts can be very different. The second alternative assumes that exports of less-carbon-intensive industries would not immediately or completely offset the losses in domestic production of the carbon-intensive industries.

The idea behind leakage is that if the price of carbon intensive energy inputs increases considerably, the whole cost structure of the industry would be altered. Faced with much higher costs of production in Annex I countries, these firms may decide to build new capacity in non-Annex I countries where operating costs are lower rather than continuing to operate in high cost Annex I countries. Alternatively, domestic industries may gradually switch their output and new investments

into non-energy intensive products or services. To develop detailed industrial impacts of possible reductions in industrial output, "leakage", the following reductions in output were provided by the sponsor when targeting 1990 carbon stabilization levels: a 25 percent reduction in output compared to baseline levels for the paper, chemical, aluminum, steel, and cement industries. Using these assumptions, three sensitivity cases are considered:

- The first case solved the unadjusted final demands for stabilization to 1990 levels based solely on energy prices and quantities coming from the NEMS model runs.

- The second case gradually reduced domestic production for the selected industries by 25 percent without any compensating increase in exports. Imports replace the reduced domestic production.

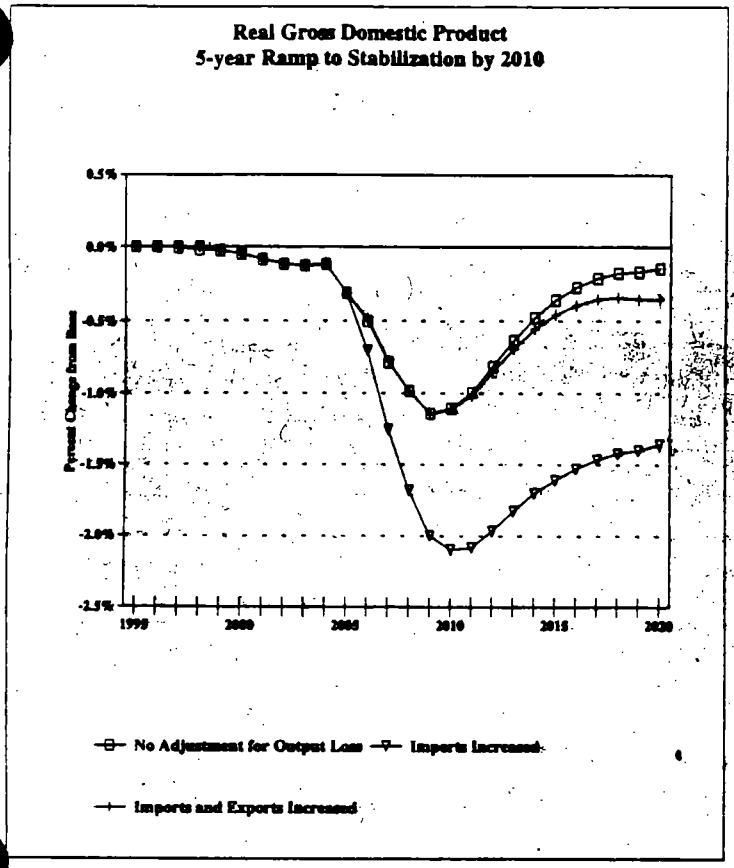
- In the third case, total exports were increased by the same dollar amount that imports from energy-intensive industries increased, implying that goods that used carbon relatively intensively would suffer competitive losses, but the U.S. goods that are not carbon intensive would emerge as potential winners.

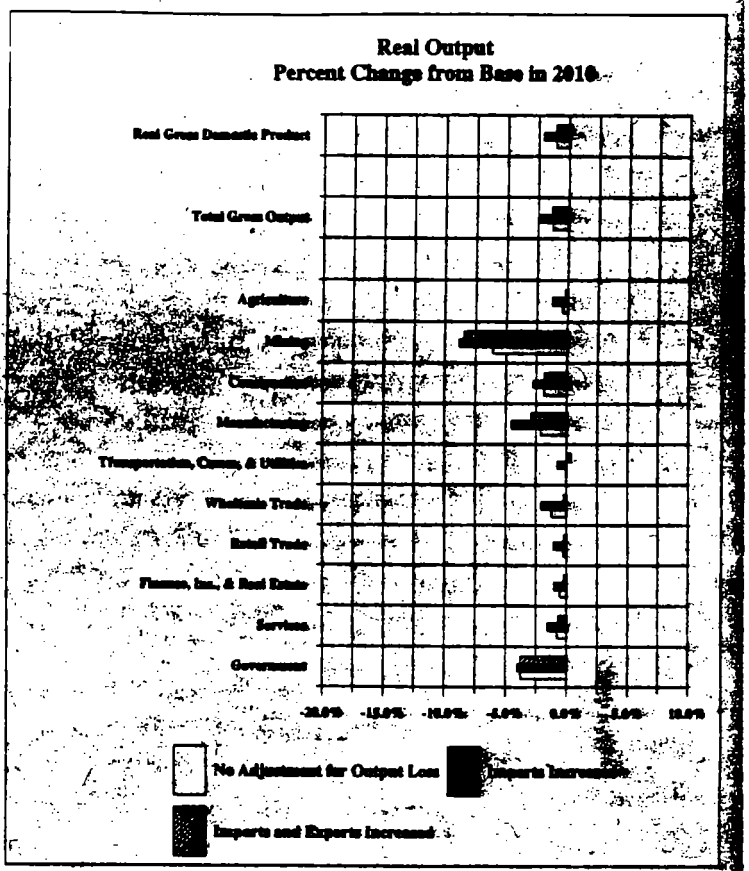
For these sensitivities, the macroeconomic model used the following assumptions. First, the exchange rate was allowed to respond. Secondly, there was no Federal Reserve accommodation. Finally, the output of energy producing sectors (such as coal, oil and gas mining and petroleum refining) is linked to the results from the NEMS energy supply modules.

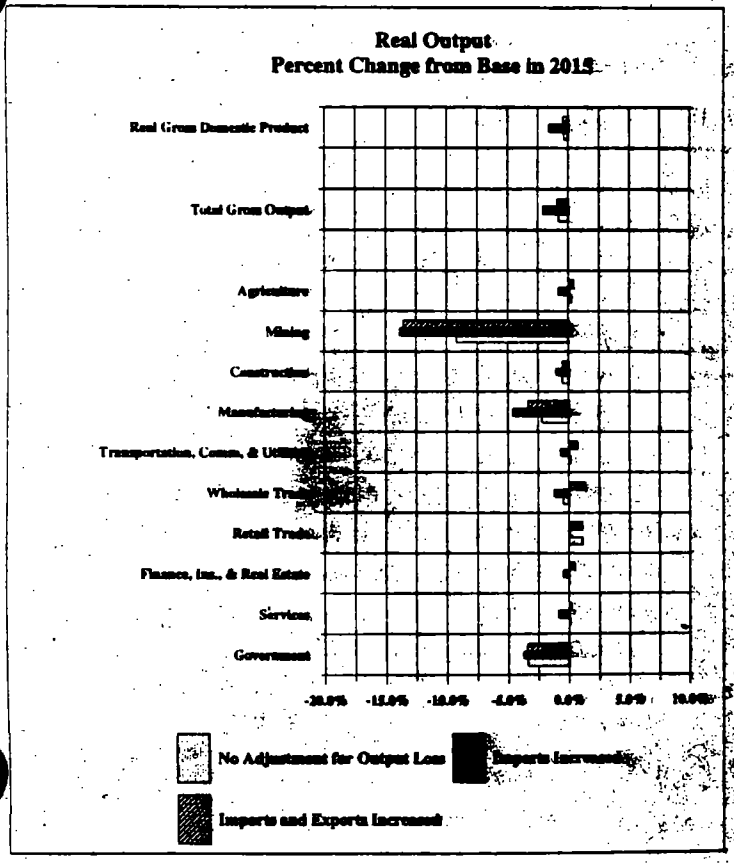
Figures 4.11 and 4.12 illustrate possible industrial impacts of alternative industrial leakage assumptions. Since the I/O model takes changes in the components of GDP as indicators of changes in the demand for industrial output, the industrial output changes predicted vary depending upon whether one assumes leakage. Figure 4.11 shows that from the aggregate economy perspective, the GDP and total gross output results are very similar when comparing the case where no adjustment to trade is made vs. the case where an equal adjustment for both exports and imports is made. Figure 4.12 examines manufacturing gross output impacts and discovers that these two cases do not show similar results. Imports of industrial materials (the import category where all of the displaced domestic production came from) impact primarily textiles, leather, chemicals, paper, primary metals, stone, clay and glass and fabricated metals. Reductions in manufacturing gross output are larger in the case where both exports and imports are adjusted compared to the case where there are no trade adjustments, because all categories of exports are increased, including exports of services.

Since many industries that use energy intensively supply industrial materials (the category of imports in the macroeconomic model that was increased), increases in those imports will displace domestic production. Energy intensive industries such as chemicals, primary metals, paper and food show much larger output losses in the leakage case than the case in which no adjustments to either exports or imports is made. Those industries relying on export markets and which are not particularly energy intensive, such as electrical machinery, show the greatest amount of improvement in output.

Figure 4.11 Real Output, Percent Change from Base for the 1344 in 2010 (5-Year Ramp) Case, Deficit Neutral, Federal Reserve Reaction Function Off







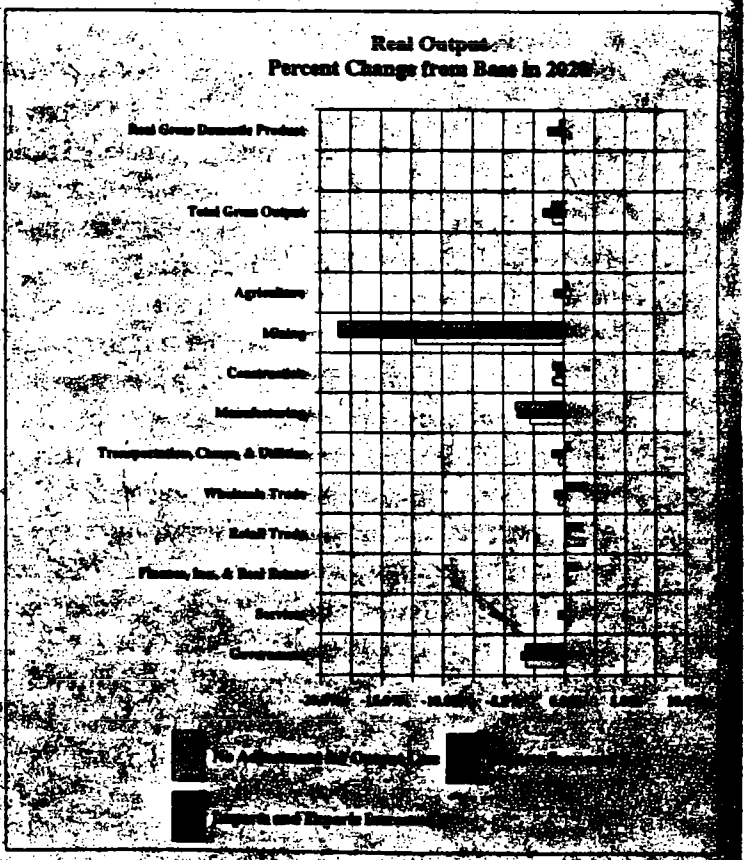
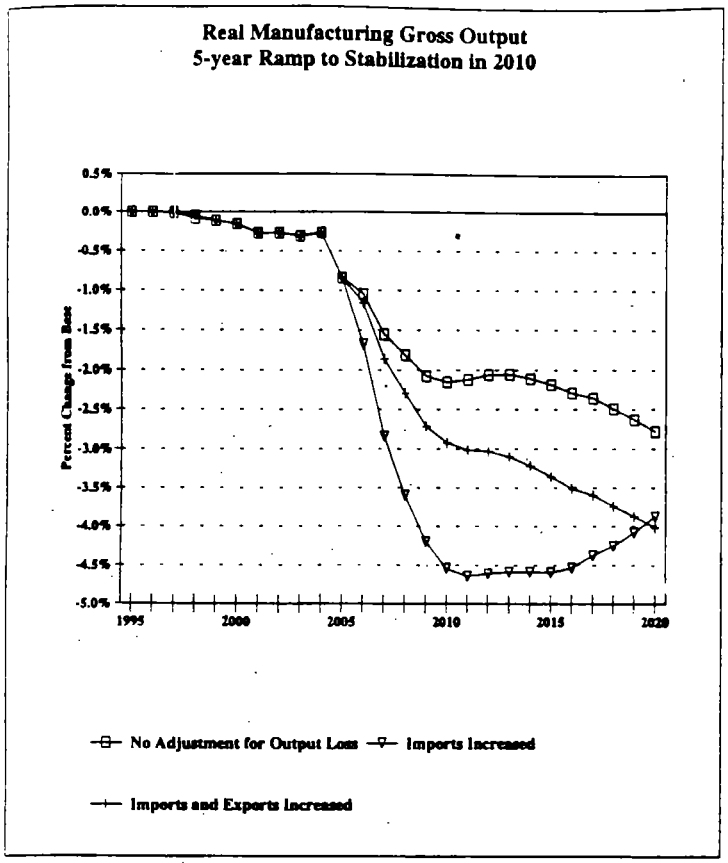
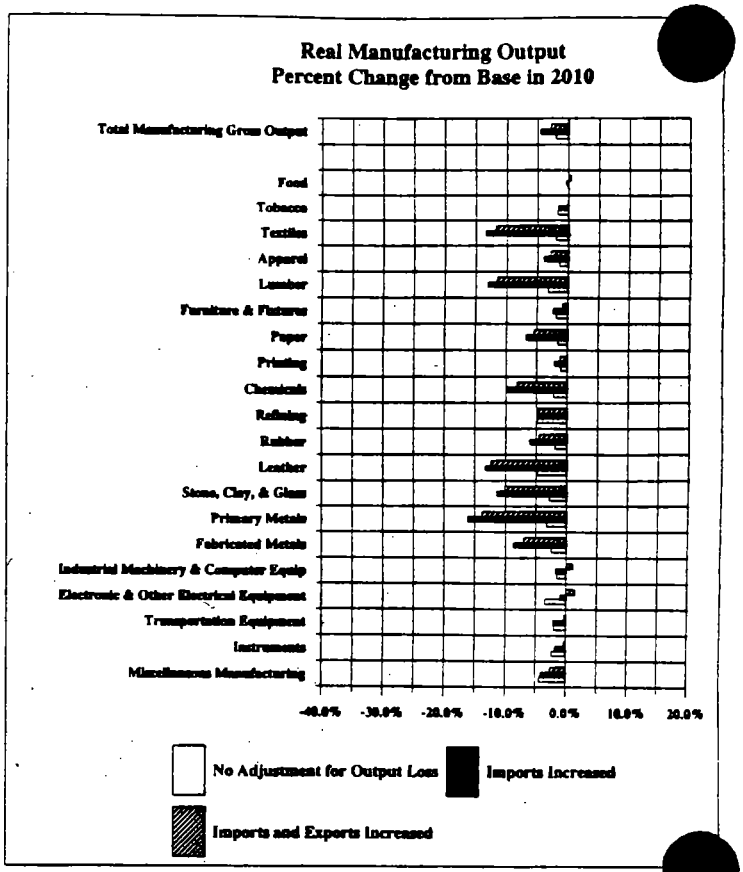
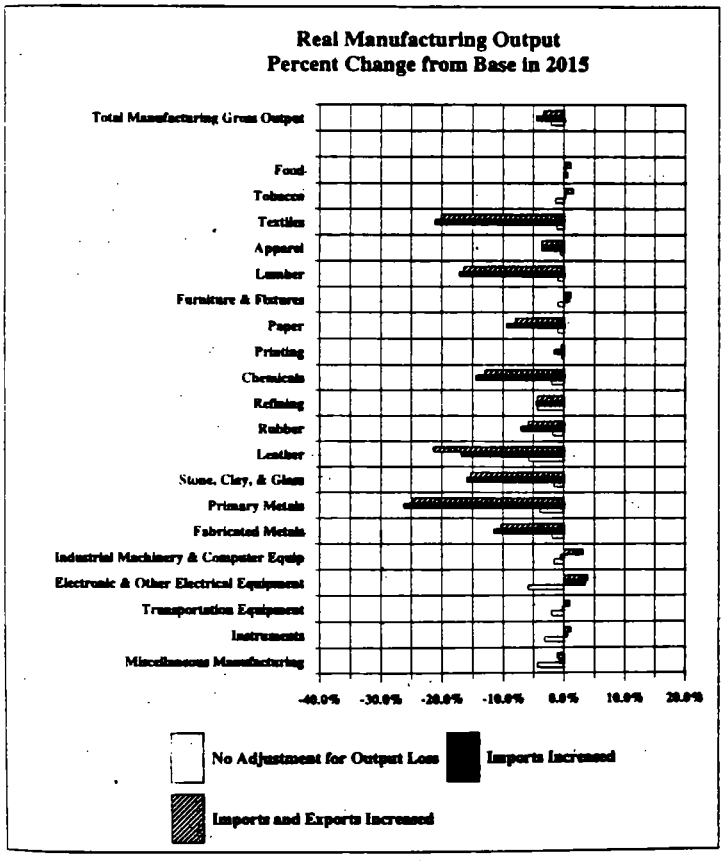
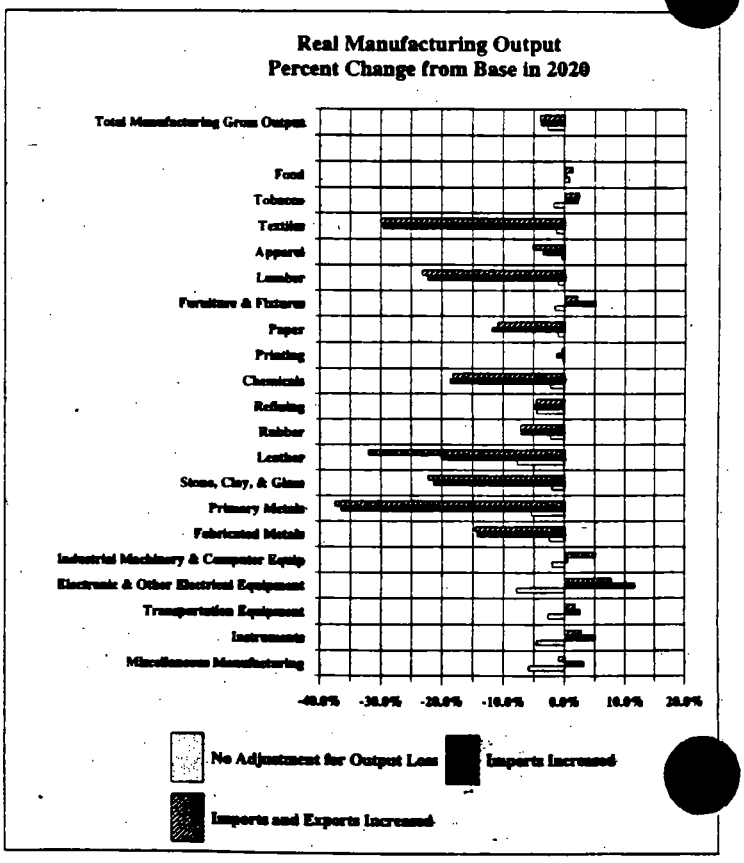


Figure 4.12 Real Manufacturing Output, Percent Change from Base for the 1344 in 2010 (5-Year Ramp) Case, Deficit Neutral, Federal Reserve Reaction Function Off









Key Uncertainties in Macroeconomic Results

The Impact of the Federal Reserve Reaction. This study emphasizes the macroeconomic impacts of reducing carbon emissions with no Federal Reserve reaction; treating the impact of alternative Federal Reserve policies as a sensitivity. Using the DRI estimated reaction function is only one alternative in modeling different actions of monetary authorities. One could easily assume that real non-borrowed reserves remained at baseline levels or that the money supply increased at the same rate as nominal GDP. As the possible reaction of monetary authorities are difficult to ascertain in response to such higher energy prices, the prudent course would be to present macroeconomic impacts with no Federal Reserve reaction and then show what differences altering this assumption would mean to the analysis.

The Loss of Industrial Output to Non-Annex I Countries. There are several sources of uncertainties in the industrial analysis. One involves the analysis of the leakage issue itself. Substantial debates ensue when permit prices are imposed for only a subset of possible competitors. In order for domestic production to be replaced by imports of non-Annex I countries, those non-Annex I economies have to be able to absorb the type of capital investment and have the required labor in order to produce the additional product demanded. Transportation costs may play a more important role in determining a product's price, implying that Annex I countries may not experience such a large competitive disadvantage compared to non-Annex I countries.

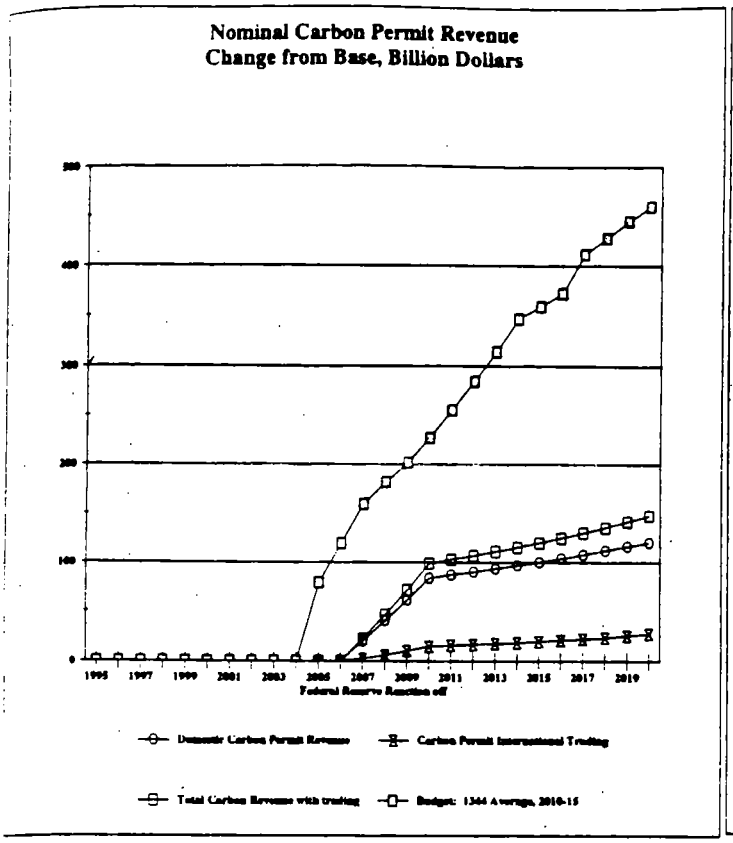
The Use of a Static I/O Model Representation. The use of an Input/Output model implies that the underlying coefficients are not price or scenario responsive and as such, may overstate industrial losses in response to changing final demand levels. Nonetheless, the relative impacts shown emphasize the relative nature of the impacts that may be disproportionately felt among the sectors of the economy.

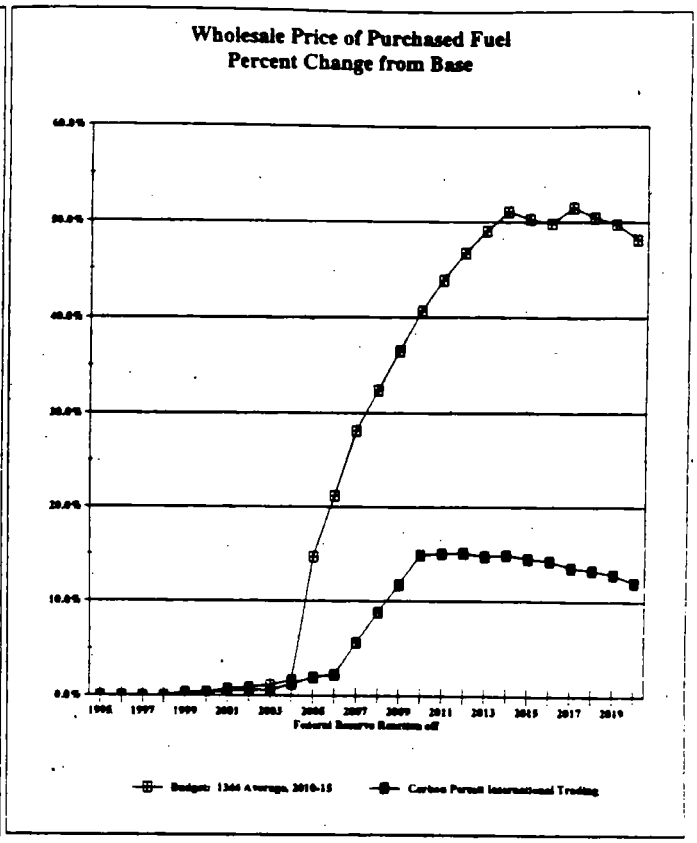
Emissions Trading.

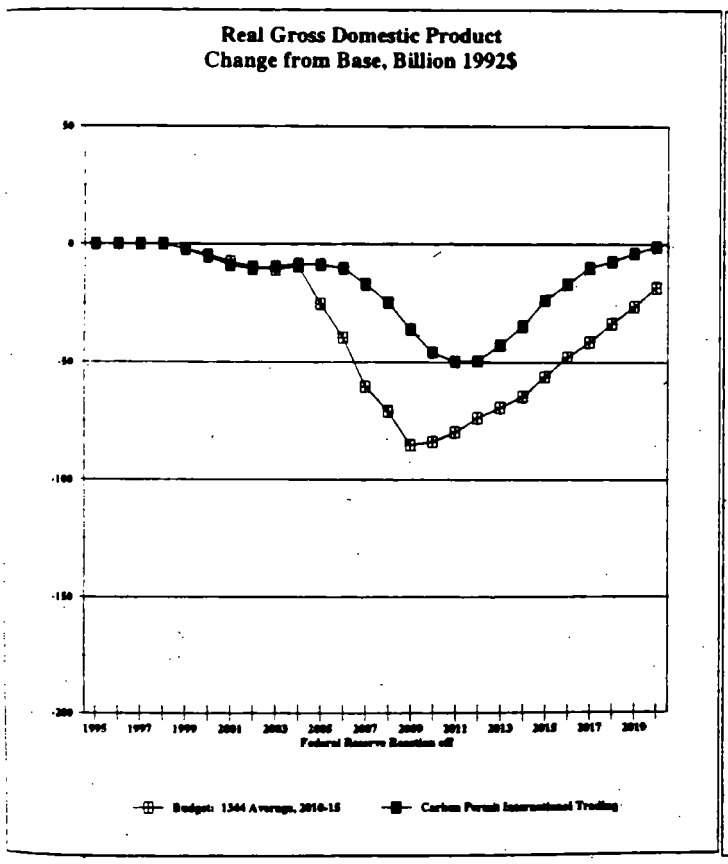
As indicated, carbon stabilization by 2010 at 1990 levels, if achieved through a marketable emissions permit system without international trading, would result in a carbon emission permit value on the order of $130 to $150 per metric ton of carbon (1995 dollars). Flexible emissions trading of permits is assumed to lower the price of the permits to $40 per ton, approximately a 70 percent reduction in the cost of the permits. The macroeconomic sensitivity case considered here looks at the effect of this lower price paid for carbon permits. An important caveat is appropriate. Much discussion has surfaced about implementation and administration issues surrounding the creation of an international emissions trading program with or without Joint Implementation. This assessment does not address that set of issues. It considers only the differential impacts associated with the lowering of the price which U.S. consumers and business must pay for carbon permits and the flow of funds to purchase the permits.

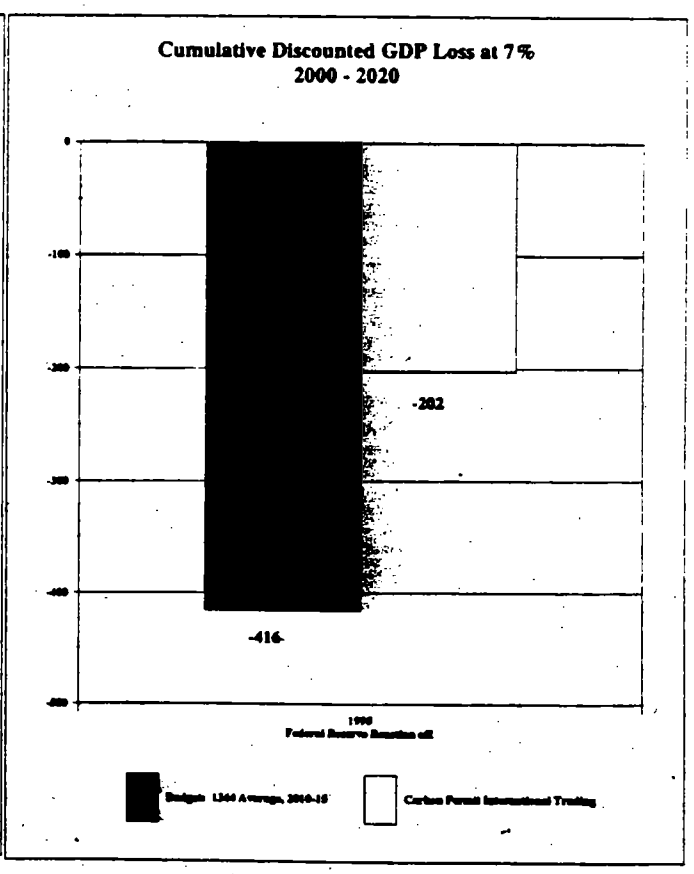
In an international setting, there are two sets of revenue flows: domestic and international. The value of the carbon permits remaining within U.S. borders is calculated as the price of the carbon permit ($40 per ton) and the emissions target, which in this case is equal to 1990 levels or 1,544 million metric tons. The value of the payments abroad is calculated based on the difference between the

Figure 4.13 International Emissions Trading Sensitivity, All to Consumers, Federal Reserve Reaction Off









level of carbon emissions consumed and the target level. Figure 4.13 contrasts the values of the carbon revenue streams with the 1344 five-year average stabilization case. In the year 2010, nominal revenues total $99 billion with $84 billion remaining within U.S. borders and $15 billion going abroad. This is in contrast to the $200 billion generated by the stabilization case. By 2020, the gap grows dramatically larger.

In assessing the economic impacts of this case, two key factors prevail: the price paid for carbon is substantially lower, but a portion of the collected funds must go overseas. When considering a domestic only program, the permits were assumed to be auctioned and that the revenue from the auctioned permits were returned to households through a reduction in income taxes such that the Federal deficit was targeted to remain at baseline. For the current emissions trading case, these domestic funds are similarly recycled back to consumers. The international flow of carbon permit revenue is considered an increase in the value of imported services.

As shown in Figure 4.13, the price paid for energy goods and services is substantially lower in the emissions trading case. In the stabilization case, the aggregate wholesale price of purchased fuel rose approximately 50 percent, while in the emissions trading case only by roughly 15 percent. As a result, the peak loss in GDP is $52 billion by the emissions trading program in contrast to the $85 billion loss occurring in the stabilization case. Over the entire period through 2020, emissions trading lowers the net present value of the GDP loss from $416 billion to $217 billion. Through 2020, the positive effects of lowering the price of carbon permits dominates any adverse consequences associated with an outflow of funds overseas.

5. Summary of Findings

This study was undertaken at the request of the U.S. Department of Energy, Office of Policy and International Affairs (PO) to analyze the impact of several carbon stabilization scenarios on the U.S. energy economy. The DOE Policy Office was a participant in the analytical effort of the Interagency Analysis Team (IAT) studying the economic effects of global climate change policies in the United States. The Policy Office requested the analysis of eleven carbon policy scenarios to examine how limits on U.S. carbon emissions to be achieved by 2010 and beyond might affect the energy sector and the overall U.S. economy. According to guidance supplied by the requesting office, assumptions adopted by the IAT about domestic emissions permit trading, energy market incentives, and effects of potential policy initiatives were implemented.

While carbon mitigation and climate change are issues that must be addressed on a global scale by the international community, this study contributes to the analytical process by examining the impact of several carbon stabilization scenarios on the U.S. energy-economy. Each potential member of the international community is expected to evaluate its options in a similar way prior to signing any international commitment to control carbon emissions. The incorporation of international emissions trading or a comprehensive approach to greenhouse gas mitigation, all of which are key elements of the U.S. position within the current international negotiations on climate, could significantly change the results presented in this report.

The analysis reveals that meeting carbon stabilization targets will involve significant changes on the energy markets and have long term consequences for the economy as a whole. The energy modeling of various emission stabilization cases demonstrates how carbon stabilization could occur, given various assumptions about market incentives and reactions to those incentives by consumers and industry.

Carbon stabilization by 2010 at 1990 levels, if achieved through a marketable emissions permit system, would result in carbon emissions permit values on the order of $130 to $150 per metric ton of carbon (1995 dollars). Permit values of this magnitude would induce major changes in fuel use, with the electricity industry achieving the greatest share of the carbon reductions.

By 2020, the use of coal would be curtailed to levels over half of current consumption levels. This change is induced by carbon permit values that triple the price of coal, eliminating its competitive edge over natural gas in generation.

Consumption of natural gas, with a lower carbon content per unit of energy, increases relative to baseline projections in most of the stabilization scenarios. The moderate increase in natural gas use (about 3% in 2020) occurs with increased natural gas for generation more than offsetting decreases in gas use in the end-use sectors.

About 70 percent of carbon reductions in the electricity sector are achieved through fuel substitution away from higher carbon energy sources; only about 30 percent of carbon reductions in electricity

are attributed to reductions in electricity sales. A significant share of the carbon reductions come from substitution of renewables for fossil fuels, with additions in generating capacity from wind, wood, and other renewables of over 100 gigawatts by 2020, compared to the reference case.

Petroleum use also declines significantly in the stabilization scenario, primarily as a result of improved efficiency in transportation and an increased penetration of alternative-fuel vehicles. By 2020, oil import dependence is reduced from 62 percent in the base case to 55 percent in the 1990-level carbon stabilization case.

The macroeconomic adjustments to carbon stabilization policy changes are complex, as various segments of the economy gradually adjust to the disequilibrium originating in the energy markets. Four factors heavily influence the ultimate outcome of the aggregate economy:

1) the timing, magnitude, and flexibility of the carbon emissions reduction target and the associated increase in energy prices,
2) what the Federal government does with carbon permit revenues,
3) the reaction of the Federal Reserve in response to the macroeconomic consequences of the carbon stabilization policy, and
4) the impacts of industrial competitiveness on energy-intensive industries and how it might impact the industrial output mix.

The influence of these four factors are addressed in turn:

Carbon Emissions Reduction Target. The more stringent the carbon emissions reduction target, the higher the GDP loss. Shortening the ramp-in period results in greater energy price increases and greater loss in peak economic output; however, the economy returns to its baseline level in approximately the same period of time as a case with a longer ramp-in period. Averaging the carbon reduction targets over a number of years ameliorates the GDP losses, with the longer averaging period reducing the impacts further.

Fiscal Policy. In the near-term, returning carbon permit proceeds to consumers via a reduction in personal income taxes cuts the loss in GDP in half relative to using the funds to reduce the deficit. However, in the long-run, the policy of using the carbon permit funds to reduce the deficit will act to lower Federal borrowing and therefore lower interest rates. This will spur capital formation, lead to higher GDP relative the policy baseline in the long run.

Federal Reserve Policy. A reaction function attempts to capture the likely responses of the Federal Reserve Board to changes in unemployment and the rate of inflation. If the reaction function is used, the negative impacts on GDP are roughly halved, with recovery in the later years coming much faster and stronger.

Industrial Competitiveness. If the price of carbon intensive energy inputs increases considerably, the whole cost structure of energy-intensive industries is altered. Faced with much higher costs of production in Annex I countries, the competitiveness of domestically operated energy-intensive industries may suffer. However, U.S. goods that are not carbon-intensive may emerge as potential

winners, and may offset any negative impact of the carbon stabilization policy on the aggregate trade balance. Nonetheless, there is likely to be a significant shift in the composition of industrial output in the economy away from the production of energy-intensive goods to non-energy-intensive goods production.

In the $40 per ton case, the price paid for energy goods and services is substantially lower than in the five-year average stabilization case to 1990 levels between 2010 and 2015 ("the 5-year budget case"). The aggregate wholesale price of purchased fuel rose approximately 50 percent in the 5-year budget case, while in the in the $40 per ton case the wholesale price rose only by roughly 15 percent. As a result, the peak loss in GDP is $50 billion in the $40 per ton case, in contrast to the $85 billion loss occurring in the stabilization case. Over the entire period through 2020, emissions trading lowers the net present value of the GDP loss from $416 billion to $202 billion. Through 2020, the positive effects of lowering the price of carbon permits dominates any adverse consequences associated with an outflow of funds overseas.

Major additional uncertainties that occur with the $40 per ton carbon trading fee case include the economic feasibility of life extensions of nuclear units and the early retirement of approximately 35 gigawatts of coal plants whose operating and maintenance costs are between 2.5 and 4.0 cents/kilowatt-hour.

It may be uneconomic to life-extent, beyond their normal 40-year life, all or even some of the nuclear power plants at a $40 per ton carbon permit value. If technological costs to life-extend nuclear plants are too high to be economic, an additional 330 billion kilowatt-hours of electricity will have to be generated almost entirely by fossil fuel units and could result in approximately 30 - 100 million metric tons of additional carbon permits that must be purchased in 2020.

It was assumed that approximately 35 gigawatts of coal plants whose operating and maintenance costs were between 2.5 - 4.0 cents per kilowatt-hour were retired because they were assumed not to be economic. If $40 per ton does not make these plants uneconomic to dispatch, over 50 million metric tons of additional carbon credits would need to be purchased from the international market.

Appendix A

1/29/97 Letter from Howard Gruenspecht to Mary Hutzler requesting NEMS Climate Change Analyses

Memorandum

To: Mary Hutzler

From: Howard Gruenspecht

Date: January 29, 1997

Subject: NEMS Climate Change Analyses

We greatly appreciate the work you have done to extend the National Energy Modeling System to 2020 in preparation for supporting DOE's analytical effort in support of the climate change policy process.

As you know, the Administration's analysis efforts are being coordinated by Undersecretary Everett Ehrlich of the Commerce Department. At last week's meeting of the interagency team, Dr. Ehrlich requested that we consider two alternative cases involving behavioral and technology changes that could accompany a U.S. commitment to carbon stabilization and expanded research and development efforts. I therefore request that the Office of Integrated Analysis and Forecasting implement and run two cases as follows: the Policy Announcement Case (PAC) and the Accelerated Technology Case (ATC). Both the PAC and ATC cases should assume that (a) a protocol on carbon stabilization will be signed by the United States in December 1997 and approved by the Senate, (b) American institutions and consumers will begin to react to the U.S. commitment in year 2000 as suggested in the attachment, (c) and some sort of carbon trading scheme will be used beginning in year 2010 and beyond to stabilize anthropogenically generated carbon emissions to 1990 levels. No other policies or legislation are to be assumed enacted. The results of the runs with and without carbon stabilization in 2010 are needed by close of business on Tuesday, January 28, 1997, including the macro economic analysis for the stabilization run.

We will also need additional runs that analyze the effects of changing the values of the key flexibility parameters included in the recent U.S. submission to the Convention Secretariat by noon February 3, 1997.

Thank you for your staff's excellent contributions to date. I look forward to working with you and you staff on the remainder of this project.

Attachment — Case Definitions

Policy Announcement Case

The PAC is assumed to gradually reach a 1.25%/ year decline rate in the energy/GDP ratio by year 2005, beginning in year 2000. The Policy Announcement Case should generally target the achievement of what impact the announcement of the signed and approved protocol might have on energy equipment decisions. Recognizing that there is considerable uncertainty on how consumers and manufacturers might respond to such an announcement, assume for this phase that, relative to the AEO97 reference case, the announcement of the protocol will result in:

- more rapid cost reductions of advanced technologies as characterized in the AEO97 "Advanced Cost Reduction" cases in the technology cases for residential, commercial and transportation sectors;
- reductions of 20% of the "non-cost-of-money" component in the effective hurdle rate for residential and commercial markets;
- the successful introduction of the PNGV vehicle which captures 5% of new light duty vehicle sales by 2015 and 30% by 2020;
- achievement of the Administration's CCAP goals;
- reduction of the energy intensity trends due to output mix shifts and technology changes as follows in the industrial sector

Indices of industrial intensity (1995 = 1.0)

	Average Existing	New	Average Existing	Average Existing	Average Existing	New
	1995	1995	2000	2010	2015	2015
Food	1.00	0.90	1.00	0.96	0.95	0.80
Paper	1.00	0.75	0.93	0.85	0.79	0.64
Bulk Chemicals	1.00	0.90	0.96	0.91	0.88	0.80
Glass	1.00	0.85	0.96	0.86	0.83	0.79
Cement	1.00	0.88	0.95	0.87	0.82	0.75
Steel	1.00	0.86	0.96	0.92	0.89	0.57
Aluminum	1.00	0.88	1.00	0.99	0.99	0.81

The average new values between 1995 and 2015 can be interpolated linearly in the reference case. Hurdle rates are not applicable in the NEMS Industrial Module.[1]

In the electricity generation market,

---

[1] Of importance to energy use in the industrial sector is the rate of equipment turnover and the change in the technological frontier.

- -- nuclear power plant will be life extended in the carbon cap cases and the accelerated technology cases outlined below;
- -- economic retirements of older generation plants are permitted.

Accelerated Technology Case

The ATC is assumed to gradually reach a 1.75%/ year decline rate in the energy/GDP ratio by the year 2005, beginning in year 2000. The Accelerated Technology Case should generally target the achievement of what impact the announcement of the signed and approved protocol might have on energy equipment decisions, and the impact of generally more effective R&D and DOE program management in bringing advanced technologies to market sooner and the elimination of non-cost-of money hurdle rates (assume 15% for the time value of money for purposes of this study). Recognizing that there is considerable uncertainty on how consumers and manufacturers might respond to such an announcement, assume for this phase that, relative to the AEO97 reference case, the announcement of the protocol will result in:

- -- more rapid cost reductions of advanced technologies as characterized in the AEO97 "Advanced Cost Reduction" cases in the technology cases for residential, commercial and transportation sectors;
- -- advancement of the initial date of availability of the most advanced technologies in the residential and commercial sectors by at least 5 years;
- -- a reduction to 85% in the "plug load" growth rate for residential and commercial electricity demand;
- -- the successful introduction of the PNGV vehicle which captures 7% of new light duty vehicle sales by 2015 and 50% by 2020;
- -- achievement of the Administration's CCAP goals;
- -- more rapid building shell efficiency improvements as specified in the moderate case of the OTA study;
- -- reductions in the rate of energy intensity in the industrial sector which are approximately consistent with the high technology case described in the AEO97.

In the electricity generation market:

- -- use the advanced technology assumptions of the AEO97 cases;
- -- nuclear power plant will be life extended in the carbon cap cases and the accelerated technology cases outlined below;
- -- economic retirements of older generation plants are permitted.

Appendix B

4/14/97 Letter from Howard Gruenspecht to Mary Hutzler requesting NEMS Climate Change Analysis and

And

9/18/97 Letter from Howard Gruenspecht to Andy S. Kydes requesting one final analysis to complete report information

Department of Energy
Washington, DC 20585

Memorandum

To: Mary Hutzler
Director, Office of Integrated Analysis and Forecasting

From: Howard Gruenspecht
Director, Office of Economic, Electricity, and Natural Gas Analysis

Date: April 14, 1997

Subject: NEMS Climate Change Analyses

We greatly appreciate your work to extend and exercise the National Energy Modeling System to 2020 to support of DOE and Administration analyses being conducted in support of the climate change policy process.

As you know, the Administration's analysis efforts are being coordinated by Undersecretary Everett Ehrlich of the Commerce Department. Although that process is considering both a Policy Announcement Case and an Accelerated Technology Case, the contribution of NEMS to the interagency process and the Department's own consideration of these issues is likely to be much more significant in the former case. Therefore, NEMS analysis should focus on the former case. As the Administration process has advanced, the number of cases needed has grown beyond the set identified in my memo of January 24. The cases of primary interest (all with 5 year ramps unless otherwise noted) are as follows:

1. stabilize at 1990 level in 2010 through 2020 (also do 10 year ramp)
2. stabilize at 1990 level in 2015 through 2020
3. stabilize at 10 percent below 1990 level in 2010
4. analyses of protocol flexibility parameters in the stabilization at 1990 levels case.
5. analyses of alternative carbon values derived from assumptions regrading the clearing price with international emissions trading.

In addition to the main body of work using the NEMS suite, there are two additional types of analyses on which we are seeking your assistance. First, there is a need for multiple runs of the macroeconomic model for the stabilization at 1990 levels case to assess the sensitivity of the results to alternative assumptions regarding fiscal policy, distribution, and the behavior of the monetary authority. This should not require additional runs of the energy models. Second, we are requesting a comparison of the results from the NEMS and DRI energy model runs, the latter to be supplied by EPA, for the stabilization case.

Finally, you should note that our technology assumptions for the policy announcement case have been slightly modified since my earlier request. An updated set of assumptions is attached to this memo.

Thank you for your staff's excellent contributions to date. I look forward to working with you and you staff on the remainder of this project.

Attachment

Assumptions: Policy Announcement Case

Chnages in AEO97 reference case assumptions to be used in carbon stabilization cases for "Policy Announcement Case"

- more rapid costs reductions of advanced technologies as characterized in the AEO97 "Advanced Cost Reduction" cases in the technology cases for residential, commercial and transportation sectors; cost reductions do not begin, however, until 2010;
- reductions of 20% of the "non-cost-of-money" components in the effective hurdle rate for residential and commercial markets;
- the successful introduction of the PNGV vehicle which capures 5% of new light-duty vehicle sales by 2015 and 30% by 2020;
- achievement of the Administration's CCAP goals;
- phased-in reductions (25% from base levels by 2020) in energy use of energy-intensive industries reflecting plant location decisions and technology advances;
- price sensitivity has been added and increased to all end-use sectors in the residential and commercial markets, including miscellaneous electricity.

In the electricity generation market:

- nuclear power plant was life extended in the carbon cap cases;
- economic retirements of older generation plants are permitted, up to 10 percent per year beginning during any ramp-up period;
- introduction of new non-carbonaceous generation system which comes on-line in 2015 and has the same characteristics as new nuclear generation systems;
- where coal plants may use a secondary fuel, the maximum share was increased from 5% in the policy announcement case to 20% in the stabilization cases.

New non carbonaceous supply added:

- introduction of new ethanol supply curves ranging in price from $0.50/gallon to $0.75/gallon; the fuel is available as E85 for ethanol driven vehicles or as a mix with gasoline (gasohol).

Department of Energy
Washington, DC 20585

To: Andy Kydes
Senior Technical Advisor
Office of Integrated Analysis and Forecasting

From: Howard Gruenspecht
Director
Office of Economic, Electricity, and Natural Gas Analysis

Subject: Effects of International Permit Trading on the U.S. Economy

Date: September 18, 1997

Thank you for the opportunity to review the September 15 draft EIA report "An Analysis of Carbon Stabilization Cases." The draft report appears to be very responsive to the interest of former Deputy Secretary Curtis in examining the implications of alternative greenhouse gas mitigation commitment parameters for the U.S. energy-economy system.

As noted at the beginning of the draft report, the National Energy Modeling System (NEMS) focuses on the U.S. energy-economy system. While the cases presented in the draft report are responsive to our request and usefully illustrate the possible implications of emissions limitations without emissions trading and Joint Implementation (JI), they are likely to overstate the implications of commitments that incorporate these features. It would be of great interest for the report to also approximate, using NEMS, the impacts of emissions trading and joint implementation (JI) with credit, two important elements of the U.S. proposal in ongoing international negotiations regarding new climate commitments.

In order to gain some insight into the possible benefits of emissions trading and JI, we would like you to prepare an additional case based on a set of assumptions from outside of NEMS regarding the effect of trading and JI on carbon permit values. An extensive literature on the role of "where" flexibility in emissions reduction suggests that such flexibility can reduce carbon permit values by an average of 70 percent as compared to a "go it alone" approach. This literature is consistent with preliminary results reported in the May 30 draft report of the Interagency Analysis Team. We are therefore requesting that you prepare a 1344 stabilization case under the assumption that carbon permits would be available on the international market at a price of $40 per metric ton (reflecting a 70 percent reduction from the 1344 stabilization case carbon permit values in the draft report) throughout the 2010 to 2020 period. The detailed specifications are as follows:

- We assume the international permit price in year 2010 and thereafter is $40 per ton.
- We assume that behavior in the U.S. energy system reflects a phase-in of the carbon permit value from $0 per ton in 2005 to $40 per ton in 2010.

Printed with soy ink on recycled paper

- The number of permits that the U.S. will purchase each year is the difference between the US carbon emissions with the $40 per ton tax and the 1990 carbon emissions.
- We adopt EIA reference case assumptions regarding industrial activity.
- We assume that the "Fed reaction function" is not implemented in the macroeconomic model.
- Carbon revenues remaining within U.S. borders should be recycled back to the consumers.

We recognize that implementation of these runs may raise modeling issues that we have not explicitly considered in the specifications outlined above. Please contact us should any questions arise.

Once again thanks for your timely and highly professional support in completing this important analysis.

Appendix C

NEMS Output Comparison Tables, Base Case, 1344 Stabilization Case, 1344 5-Year Budget Stabilization Case

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Production										
Crude Oil and Lease Condensate	13.89	12.38	12.36	12.36	11.42	11.28	11.30	11.17	10.82	10.78
Natural Gas Plant Liquids	2.37	2.66	2.71	2.72	2.99	3.36	3.36	3.46	3.56	3.56
Dry Natural Gas	19.01	20.78	21.15	21.18	24.64	27.41	27.52	26.82	27.63	27.68
Coal	22.09	23.57	22.83	22.85	25.10	11.37	11.71	28.94	11.78	10.92
Nuclear Power	7.19	7.33	7.42	7.42	6.55	7.22	7.22	3.83	8.35	8.99
Renewable Energy[1]	6.29	6.58	6.63	6.57	7.29	8.97	8.88	8.93	11.91	11.76
Other[2]	1.34	0.43	0.44	0.44	0.40	0.47	0.48	0.42	1.12	1.08
Total	72.19	73.74	73.54	73.54	78.48	70.08	70.49	83.55	75.17	74.77
Imports										
Crude Oil[3]	15.89	19.15	18.54	18.57	21.49	19.40	19.51	21.64	18.12	18.19
Petroleum Products[4]	3.19	5.08	5.46	5.41	7.99	6.14	6.22	9.97	7.08	7.05
Natural Gas	2.90	3.75	3.82	3.83	4.28	4.78	4.79	4.74	4.91	4.87
Other Imports[5]	0.60	0.68	0.68	0.68	0.69	1.02	1.02	0.69	1.17	1.17
Total	22.38	28.66	28.50	28.49	34.43	31.33	31.54	37.03	31.28	31.29
Exports										
Petroleum[6]	2.02	1.77	1.73	1.74	1.90	1.72	1.73	2.03	1.83	1.82
Natural Gas	0.16	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Coal	2.26	2.44	2.44	2.44	2.82	2.82	2.82	3.15	3.15	3.15
Total	4.45	4.42	4.38	4.39	4.94	4.77	4.78	5.41	5.21	5.20
Discrepancy[7]	0.80	-0.21	-0.24	-0.21	-0.25	-0.14	-0.12	-0.47	-0.14	-0.15
Consumption										
Petroleum Products[8]	34.92	37.83	37.69	37.67	42.25	38.99	39.21	44.23	38.87	38.84
Natural Gas	22.18	24.20	24.60	24.64	28.55	31.74	31.87	31.14	32.10	32.12
Coal	19.95	21.41	20.67	20.71	22.58	8.78	9.15	26.17	8.87	8.00
Nuclear Power	7.19	7.33	7.42	7.42	6.55	7.22	7.22	3.83	8.35	8.99
Renewable Energy[1]	6.30	6.58	6.63	6.57	7.30	8.99	8.89	8.94	11.94	11.79
Other[9]	0.39	0.41	0.41	0.41	0.40	0.80	0.78	0.40	0.98	0.98
Total	90.93	97.76	97.43	97.43	107.83	96.51	97.13	114.71	101.10	100.71
Net Imports - Petroleum	16.87	22.46	22.27	22.24	27.57	23.81	24.00	29.58	23.37	23.43
Prices (1995 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.26	18.13	18.13	18.13	20.53	20.53	20.53	22.17	22.17	22.17
Gas Wellhead Price (dollars per Mcf)[11]	1.61	1.81	1.85	1.84	1.95	2.64	2.59	2.48	2.82	2.87
Coal Minemouth Price (dollars per ton)	18.93	18.70	18.41	18.48	16.93	14.38	14.20	15.23	15.33	15.88

[1]Includes utility and nonutility grid-connected electricity from hydroelectric, wood and wood waste, 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 nonmarketed renewable energy. See Table 18 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 aequisition cost for imported crude oil.

[11]Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Mcf = Thousand cubic feet.

1344 Fixed = This 1990 Level Carbon Stabilization Case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 natural gas price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC November 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), fl344nX.d040897a (2), and avgV1344.d041297a (3).

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.83	0.82	0.82	0.75	0.67	0.68	0.69	0.60	0.60
Kerosene	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.05	0.05
Liquefied Petroleum Gas	0.40	0.43	0.43	0.43	0.45	0.43	0.43	0.45	0.43	0.43
Petroleum Subtotal	1.32	1.33	1.32	1.32	1.27	1.16	1.17	1.20	1.09	1.09
Natural Gas	5.01	5.39	5.31	5.30	5.57	5.07	5.12	5.78	5.26	5.21
Coal	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
Renewable Energy[1]	0.57	0.57	0.57	0.58	0.55	0.51	0.52	0.52	0.48	0.48
Electricity	3.58	3.88	3.87	3.87	4.45	4.31	4.33	5.30	4.99	4.98
Delivered Energy	10.61	11.16	11.11	11.10	11.85	11.10	11.18	12.83	11.84	11.79
Electricity Related Losses	7.92	8.31	8.21	8.20	8.99	7.44	7.42	9.99	8.92	8.83
Total	18.43	19.47	19.32	19.30	20.84	18.54	18.58	22.81	20.77	20.62
Commercial										
Distillate Fuel	0.41	0.37	0.37	0.37	0.35	0.33	0.33	0.33	0.31	0.31
Residual Fuel	0.17	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Petroleum Subtotal	0.67	0.60	0.60	0.60	0.59	0.57	0.58	0.58	0.57	0.57
Natural Gas	3.16	3.36	3.36	3.35	3.54	3.32	3.34	3.80	3.54	3.52
Coal	0.08	0.09	0.09	0.08	0.09	0.09	0.09	0.10	0.09	0.09
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.23	3.50	3.46	3.46	3.92	3.54	3.58	4.40	3.96	3.95
Delivered Energy	7.15	7.55	7.50	7.50	8.14	7.52	7.58	8.88	8.17	8.13
Electricity Related Losses	7.18	7.50	7.36	7.35	7.90	6.11	6.13	8.30	7.09	7.00
Total	14.33	15.04	14.86	14.84	16.04	13.63	13.72	17.18	15.25	15.13
Industrial[4]										
Distillate Fuel	1.15	1.27	1.26	1.26	1.48	1.49	1.49	1.63	1.62	1.62
Liquefied Petroleum Gas	2.01	2.09	2.09	2.09	2.30	2.13	2.12	2.45	2.08	2.09
Petrochemical Feedstocks	1.16	1.25	1.25	1.25	1.35	1.23	1.23	1.45	1.15	1.15
Residual Fuel	0.34	0.29	0.30	0.28	0.31	0.30	0.30	0.33	0.28	0.28
Motor Gasoline[2]	0.20	0.22	0.22	0.22	0.26	0.25	0.25	0.28	0.28	0.28
Other Petroleum[5]	3.83	4.20	4.28	4.27	4.51	4.33	4.35	4.55	4.19	4.17
Petroleum Subtotal	8.68	9.31	9.40	9.37	10.21	9.72	9.74	10.68	9.57	9.59
Natural Gas[6]	9.74	10.82	10.48	10.55	11.47	10.49	10.64	11.75	10.36	10.32
Metallurgical Coal	0.89	0.79	0.79	0.79	0.62	0.46	0.48	0.49	0.27	0.27
Steam Coal	1.58	1.84	1.76	1.72	1.86	1.18	1.23	2.35	0.98	0.97
Net Coal Coke Imports	0.03	0.08	0.08	0.08	0.12	0.07	0.09	0.17	0.09	0.10
Coal Subtotal	2.51	2.51	2.62	2.59	2.60	1.71	1.80	3.01	1.35	1.33
Renewable Energy[7]	1.74	1.91	1.91	1.91	2.29	2.04	2.06	2.54	2.00	1.99
Electricity	3.46	3.81	3.84	3.85	4.32	4.16	4.19	4.82	4.29	4.31
Delivered Energy	26.12	28.16	28.25	28.27	30.89	28.13	28.42	32.79	27.57	27.54
Electricity Related Losses	7.69	8.15	8.16	8.18	8.71	7.17	7.17	9.08	7.89	7.83
Total	33.81	36.31	36.41	36.45	39.60	35.30	35.59	41.88	35.26	35.17

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Transportation										
Distillate Fuel	4.42	4.96	4.95	4.95	5.76	5.53	5.55	6.19	5.76	5.76
Jet Fuel[4]	3.13	3.70	3.69	3.69	4.50	4.31	4.35	4.99	4.80	4.79
Motor Gasoline[7]	14.65	15.76	15.63	15.63	17.20	15.44	15.54	17.36	14.50	14.48
Residual Fuel	1.08	1.29	1.29	1.29	1.64	1.61	1.61	1.92	1.88	1.88
Liquefied Petroleum Gas	0.03	0.04	0.04	0.04	0.17	0.16	0.16	0.23	0.21	0.21
Other Petroleum[9]	0.26	0.29	0.29	0.29	0.33	0.31	0.31	0.34	0.33	0.33
Petroleum Subtotal	23.56	26.04	25.90	25.90	29.61	27.36	27.53	31.04	27.49	27.45
Pipeline Fuel Natural Gas	0.72	0.77	0.78	0.78	0.88	0.99	1.00	0.95	0.98	0.99
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.26	0.23	0.23	0.33	0.30	0.29
Renewable Energy (E85)[10]	0.00	0.00	0.00	0.00	0.06	0.07	0.07	0.10	0.13	0.13
Methanol[11]	0.00	0.00	0.00	0.00	0.06	0.06	0.06	0.10	0.12	0.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.02	0.03	0.03	0.08	0.12	0.12	0.11	0.29	0.29
Delivered Energy	24.32	26.89	26.77	26.77	30.96	28.83	29.01	32.63	29.30	29.27
Electricity Related Losses	0.05	0.06	0.06	0.06	0.17	0.21	0.21	0.21	0.52	0.52
Total	24.36	26.95	26.83	26.83	31.12	29.06	29.23	32.84	29.82	29.79
Delivered Energy Consumption for All										
Distillate Fuel	6.82	7.42	7.41	7.41	8.34	8.02	8.06	8.83	8.29	8.29
Kerosene	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Jet Fuel[4]	3.13	3.70	3.69	3.69	4.50	4.31	4.35	4.99	4.80	4.79
Liquefied Petroleum Gas	2.49	2.62	2.61	2.61	2.98	2.77	2.77	3.19	2.77	2.80
Motor Gasoline[7]	14.87	16.01	15.88	15.88	17.48	15.72	15.82	17.67	14.80	14.78
Petrochemical Feedstocks	1.16	1.25	1.25	1.25	1.35	1.23	1.23	1.45	1.15	1.15
Residual Fuel	1.58	1.71	1.72	1.71	2.10	2.04	2.05	2.39	2.30	2.29
Other Petroleum[12]	4.07	4.47	4.55	4.54	4.82	4.62	4.65	4.87	4.50	4.48
Petroleum Subtotal	34.24	37.29	37.21	37.19	41.68	38.81	39.03	43.50	38.71	38.69
Natural Gas[8]	18.64	20.13	19.99	20.04	21.73	20.10	20.32	22.60	20.44	20.34
Metallurgical Coal	0.88	0.79	0.79	0.79	0.82	0.46	0.48	0.49	0.27	0.27
Steam Coal	1.73	1.77	1.89	1.85	2.00	1.30	1.35	2.48	1.11	1.10
Net Coal Coke Imports	0.03	0.08	0.08	0.08	0.12	0.07	0.09	0.17	0.09	0.10
Coal Subtotal	2.64	2.64	2.75	2.72	2.73	1.84	1.92	3.14	1.48	1.46
Renewable Energy[13]	2.30	2.49	2.48	2.48	2.90	2.63	2.64	3.16	2.60	2.60
Methanol[11]	0.00	0.00	0.00	0.00	0.06	0.06	0.06	0.10	0.12	0.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.27	11.21	11.19	11.21	12.77	12.14	12.22	14.62	13.53	13.53
Delivered Energy	68.10	73.75	73.63	73.64	81.87	75.58	76.20	87.13	76.88	76.74
Electricity Related Losses	22.83	24.01	23.79	23.79	25.76	20.93	20.94	27.58	24.22	23.97
Total	90.93	97.76	97.43	97.43	107.63	96.51	97.13	114.71	101.10	100.71
Electric Generators[14]										
Distillate Fuel	0.09	0.09	0.08	0.08	0.14	0.04	0.04	0.16	0.04	0.04
Residual Fuel	0.60	0.45	0.40	0.39	0.43	0.14	0.14	0.56	0.12	0.11
Petroleum Subtotal	0.68	0.54	0.47	0.48	0.57	0.18	0.18	0.72	0.16	0.15
Natural Gas	3.54	4.07	4.61	4.60	6.82	11.64	11.55	8.54	11.66	11.78
Steam Coal	17.31	18.77	17.92	17.99	19.85	6.94	7.23	23.03	7.39	6.54
Nuclear Power	7.19	7.33	7.42	7.42	6.55	7.22	7.22	3.83	8.35	8.99
Renewable Energy[15]	3.99	4.09	4.15	4.09	4.40	6.36	6.25	5.78	9.34	9.19
Electricity Imports	0.39	0.41	0.41	0.41	0.34	0.73	0.72	0.30	0.86	0.86
Total	33.10	35.22	34.98	35.09	38.53	33.07	33.15	42.21	37.75	37.50

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Total Energy Consumption										
Distillate Fuel	6.91	7.51	7.48	7.49	8.48	8.08	8.10	8.99	8.34	8.39
Kerosene	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Jet Fuel[a]	3.13	3.70	3.69	3.69	4.50	4.31	4.35	4.99	4.80	4.79
Liquefied Petroleum Gas	2.49	2.62	2.61	2.61	2.98	2.77	2.77	3.19	2.77	2.80
Motor Gasoline[b]	14.67	16.01	15.86	15.88	17.49	15.72	15.82	17.67	14.80	14.78
Petrochemical Feedstocks	1.16	1.25	1.25	1.25	1.35	1.23	1.23	1.45	1.15	1.15
Residual Fuel	2.18	2.16	2.12	2.10	2.52	2.18	2.19	2.96	2.41	2.46
Other Petroleum[c]	4.07	4.47	4.55	4.54	4.82	4.82	4.85	4.87	4.50	4.48
Petroleum Subtotal	34.82	37.83	37.69	37.67	42.25	38.99	39.21	44.23	38.87	38.84
Natural Gas	22.18	24.20	24.60	24.64	28.58	31.74	31.87	31.14	32.10	32.12
Metallurgical Coal	0.88	0.79	0.79	0.79	0.62	0.46	0.46	0.49	0.27	0.27
Steam Coal	19.04	20.55	19.81	19.85	21.84	8.25	8.59	25.51	8.50	7.63
Net Coal Coke Imports	0.03	0.08	0.08	0.08	0.12	0.07	0.09	0.17	0.09	0.10
Coal Subtotal	19.95	21.41	20.67	20.71	22.58	8.78	9.15	26.17	8.87	8.00
Nuclear Power	7.19	7.33	7.42	7.42	6.55	7.22	7.22	3.83	8.35	8.99
Renewable Energy[d]	6.30	6.58	6.63	6.57	7.30	8.99	8.89	8.94	11.94	11.79
Methanol[e]	0.00	0.00	0.00	0.00	0.08	0.08	0.08	0.10	0.12	0.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.39	0.41	0.41	0.41	0.34	0.73	0.72	0.30	0.86	0.86
Total	90.93	97.76	97.43	97.43	107.63	96.51	97.13	114.71	101.10	100.71
Energy Use and Related Statistics										
Delivered Energy Use	68.10	73.75	73.63	73.64	81.87	75.58	76.20	87.13	76.88	76.74
Total Energy Use	90.93	97.77	97.43	97.43	107.80	96.49	97.11	114.65	101.04	100.65
Population (millions)	263.58	275.62	275.62	275.62	298.92	298.92	298.92	323.47	323.47	323.47
Gross Domestic Product (billion 1992 dollars)	6738.95	7544.62	7539.82	7539.82	9182.30	8943.31	8988.79	10555.29	10346.70	10349.74
Total Carbon Emissions (million metric ton)	1423.47	1543.89	1527.53	1528.63	1716.16	1346.65	1361.64	1878.87	1342.79	1319.69

[a]Includes wood use for residential heating. See Table 18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps & solar thermal hot water heating.
[b]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[c]Includes commercial sector electricity cogenerated by using wood and wood waste, municipal solid waste, and other biomass. See Table 18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[d]Fuel consumption includes consumption for cogeneration.
[e]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[f]Includes lease and plant fuel.
[g]Includes consumption of energy from hydroelectric, wood & wood waste, municipal solid waste, & other biomass, including for cogeneration, both for sale to electric & own use.
[h]Includes naphtha and kerosene type.
[i]Includes aviation gas and lubricants.
[j]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[k]Only M85 (85 percent methanol).
[l]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous pet products.
[m]Includes electricity generated for sale to electric utilities and for self 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.
[n]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity as a by product of other processes.
[o]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Excludes cogeneration.
[p]Includes hydroelectric, geothermal, wood & wood waste, municipal solid waste, other biomass, wind, photovoltaic & solar thermal sources. Includes ethanol components of E excludes ethanol blends (10 percent or less) in motor gasoline. Excludes nonmarketed renewable energy consumption for geothermal heat pumps & solar thermal hot water heaters.

Btu = British thermal unit.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a fi year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors. Consump values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 1995 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, D October 1996). 1995 transportation sector compressed natural gas consumption: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2 and avgV1344.d041297a (3). 1995 electric utility fuel consumption: EIA, *Electric Power Annual, Volume I*, DOE/EIA-0348(95)/1 (Washington, DC, July 1996). 1 nonutil consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, D October 1996). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C3. Energy Prices by Sector and Source
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Residential	12.87	12.76	12.81	12.87	12.70	17.72	17.16	13.17	17.85	18.17
Primary Energy	6.28	6.12	6.13	6.20	5.90	8.49	8.18	6.07	8.64	8.91
Petroleum Products	7.51	8.41	8.54	8.56	9.01	11.41	11.02	9.21	11.91	12.10
Distillate Fuel	6.24	7.00	7.09	7.09	7.40	9.98	9.56	7.56	10.51	10.70
Liquefied Petroleum Gas	10.29	11.16	11.37	11.40	11.77	13.71	13.38	11.77	13.87	14.04
Natural Gas	6.01	5.59	5.57	5.86	5.23	7.86	7.56	5.45	7.99	8.27
Electricity	24.68	24.25	24.36	24.37	23.21	31.12	30.32	22.57	29.64	29.93
Commercial	13.24	12.90	12.92	12.99	12.84	17.59	17.09	12.79	17.29	17.58
Primary Energy	4.82	4.67	4.65	4.72	4.55	7.12	6.80	4.78	7.33	7.60
Petroleum Products	4.58	5.12	5.20	5.20	5.49	8.01	7.62	5.60	8.48	8.68
Distillate Fuel	4.39	5.03	5.12	5.12	5.40	7.93	7.54	5.53	8.50	8.69
Residual Fuel	2.99	2.75	2.72	2.72	3.00	5.72	5.29	3.07	6.24	6.45
Natural Gas[1]	4.96	4.66	4.63	4.71	4.47	7.03	6.73	4.74	7.21	7.48
Electricity	23.46	22.41	22.57	22.60	21.35	29.33	28.41	20.77	27.87	28.14
Industrial[2]	5.05	4.87	4.96	4.97	5.02	7.84	7.48	5.22	8.04	8.24
Primary Energy	3.36	3.18	3.25	3.25	3.43	5.67	5.35	3.69	6.04	6.23
Petroleum Products	4.92	4.36	4.49	4.51	4.76	6.36	6.11	4.91	6.64	6.80
Distillate Fuel	4.61	4.94	5.04	5.04	5.35	7.90	7.51	5.52	8.54	8.73
Liquefied Petroleum Gas	6.53	5.82	6.04	6.08	6.13	8.23	7.86	6.04	8.18	8.41
Residual Fuel	2.55	2.74	2.78	2.77	3.04	5.79	5.37	3.14	6.20	6.42
Natural Gas[3]	2.28	2.40	2.45	2.44	2.56	5.11	4.78	3.08	5.52	5.73
Metallurgical Coal	1.76	1.76	1.74	1.73	1.59	4.82	4.32	1.42	5.25	5.52
Steam Coal	1.49	1.50	1.49	1.49	1.38	4.48	3.97	1.26	4.98	5.24
Electricity	14.71	14.19	14.30	14.33	13.31	18.34	17.79	12.72	17.06	17.26
Transportation	7.92	8.44	8.50	8.50	8.61	11.02	10.63	8.38	10.93	11.14
Primary Energy	7.92	8.44	8.49	8.49	8.59	11.00	10.61	8.36	10.89	11.09
Petroleum Products	7.92	8.44	8.50	8.50	8.58	11.00	10.60	8.31	10.86	11.06
Distillate Fuel[4]	8.03	8.67	8.71	8.72	8.66	11.17	10.78	8.37	11.33	11.53
Jet Fuel[5]	3.85	5.09	5.17	5.16	5.53	7.90	7.54	5.66	8.45	8.66
Motor Gasoline[6]	9.23	9.71	9.78	9.78	9.92	12.41	12.00	9.66	12.13	12.33
Residual Fuel	2.44	2.67	2.64	2.64	3.17	5.88	5.46	3.16	6.31	6.52
Liqued Petroleum Gas	8.61	13.06	13.27	13.30	13.06	14.97	14.64	12.55	14.57	14.74
Natural Gas[7]	5.77	5.87	5.83	5.92	6.62	9.28	8.99	7.48	9.92	10.20
E85[8]	11.95	16.02	15.13	15.19	17.81	16.12	15.79	18.16	13.88	13.88
M85[9]	15.11	11.81	11.70	11.58	13.43	14.43	14.12	14.06	17.35	17.67
Electricity	15.26	15.12	15.19	15.21	14.35	15.88	15.82	13.87	15.32	15.43
Total End-Use Energy	8.24	8.31	8.36	8.38	8.38	11.63	11.20	8.47	11.80	12.02
Primary Energy	7.84	7.96	8.01	8.03	8.04	11.09	10.68	8.06	11.19	11.40
Electricity	20.92	20.24	20.33	20.35	19.23	26.07	25.32	18.72	24.83	25.06
Electric Generators[10]										
Fossil Fuel Average	1.48	1.51	1.52	1.52	1.57	4.92	4.52	1.68	5.27	5.53
Petroleum Products	2.78	3.07	3.11	3.14	3.62	8.60	8.15	3.63	7.34	7.61
Distillate Fuel	3.93	4.51	4.63	4.61	4.89	7.51	7.12	5.06	8.15	8.34
Residual Fuel	2.62	2.80	2.82	2.83	3.19	8.35	5.89	3.22	7.06	7.35
Natural Gas	2.01	2.22	2.24	2.24	2.48	5.28	4.98	3.02	5.53	5.77
Steam Coal	1.32	1.31	1.29	1.30	1.20	4.25	3.72	1.09	4.80	5.06

Table C3. Energy Prices by Sector and Source (Continued)
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Average Price to All Users[11]										
Petroleum Products	7.07	7.38	7.48	7.47	7.63	9.86	9.51	7.47	9.87	10.06
Distillate Fuel[4]	6.99	7.63	7.69	7.70	7.77	10.32	9.93	7.63	10.61	10.81
Jet Fuel	3.86	5.09	5.17	5.16	5.53	7.90	7.54	5.66	8.45	8.69
Liquefied Petroleum Gas	7.20	6.89	7.11	7.14	7.46	9.53	9.19	7.39	9.64	9.84
Motor Gasoline[5]	9.23	9.69	9.76	9.76	9.99	12.39	11.99	9.65	12.11	12.32
Residual Fuel	2.55	2.71	2.70	2.70	3.15	5.89	5.46	3.16	6.33	6.54
Natural Gas	3.57	3.48	3.48	3.50	3.41	5.91	5.61	3.61	6.21	6.46
Coal	1.36	1.33	1.31	1.31	1.22	4.29	3.76	1.10	4.83	5.09
E85[6]	11.98	16.02	15.13	15.19	17.61	16.12	15.78	18.16	13.89	13.89
M85[6]	15.11	11.61	11.70	11.58	13.49	14.43	14.12	14.06	17.35	17.57
Electricity	20.92	20.24	20.33	20.36	19.23	26.07	25.32	18.72	24.83	25.08

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease and plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]Sales-weighted average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[8]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[9]M85 is 85 percent methanol and 15 percent motor gasoline.
[10]Includes all electric power generators except cogenerators, which produce electricity as a by product of other processes.
[11]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.
1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.
1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.
Note: 1995 figures may differ from published data due to internal rounding.
Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/1-12) (Washington, DC, 1995). 1995 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). 1995 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/8) (Washington, DC, June 1996). Other 1995 natural gas delivered prices: EIA, AEO97 National Energy Modeling System runs pobase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3). Values for 1995 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995) by using consumption quantities aggregated from EIA, *State Energy Data Report 1993: Consumption Estimates*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1995 electricity prices for commercial, industrial, and transportation: EIA, AEO97 National Energy Modeling System runs pobase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3). Projections: EIA, AEO97 National Energy Modeling System runs pobase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Household Characteristics										
Households (millions)										
Single-Family	68.66	72.62	72.61	72.61	80.92	80.73	80.77	89.24	89.13	89.12
Multifamily	24.56	25.53	25.53	25.53	28.67	28.44	28.48	32.11	31.92	31.88
Mobile Homes	5.83	6.30	6.30	6.30	6.89	6.88	6.88	7.36	7.37	7.37
Total	99.06	104.45	104.44	104.44	116.48	116.04	116.12	128.71	128.41	128.37
Housing Starts (millions)										
Single-Family	1.08	1.05	1.05	1.05	1.03	1.03	1.03	1.13	1.11	1.12
Multifamily	0.28	0.36	0.36	0.36	0.48	0.45	0.45	0.48	0.47	0.48
Mobile Homes	0.34	0.29	0.29	0.29	0.28	0.28	0.28	0.30	0.30	0.30
Total	1.70	1.70	1.69	1.69	1.79	1.76	1.76	1.90	1.88	1.90
Average House Square Footage	1643	1666	1666	1666	1696	1697	1697	1718	1719	1719
Energy Intensity										
Million Btu Consumed per Household										
Delivered Energy Consumption	106.08	106.80	106.37	106.27	101.98	95.65	96.27	99.65	92.24	91.84
Electricity Related Losses	79.93	79.57	78.65	78.56	77.12	64.10	63.86	77.61	69.50	68.76
Total Energy Consumption	186.01	186.38	185.02	184.82	179.11	159.75	160.13	177.26	161.74	160.60
Thousand Btu Consumed per Square Foot										
Delivered Energy Consumption	64.57	64.13	63.86	63.80	60.12	56.37	56.73	57.99	53.66	53.42
Electricity Related Losses	48.65	47.77	47.22	47.17	45.46	37.77	37.63	45.16	40.43	40.00
Total Energy Consumption	113.21	111.90	111.09	110.97	105.58	94.14	94.37	103.16	94.09	93.42
Delivered Energy Consumption by Fuel										
Distillate										
Space Heating	0.76	0.73	0.72	0.72	0.65	0.58	0.59	0.59	0.50	0.50
Water Heating	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.09
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	0.85	0.83	0.82	0.82	0.75	0.67	0.68	0.69	0.60	0.60
Liquefied Petroleum Gas										
Space Heating	0.30	0.31	0.31	0.31	0.32	0.30	0.30	0.31	0.29	0.29
Water Heating	0.06	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10
Cooking[2]	0.03	0.03	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	0.01	0.01
Delivered Energy	0.40	0.43	0.43	0.43	0.45	0.43	0.43	0.45	0.43	0.43
Natural Gas										
Space Heating	3.48	3.73	3.72	3.71	3.88	3.38	3.42	3.94	3.41	3.36
Space Cooling	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Water Heating	1.25	1.30	1.30	1.30	1.38	1.38	1.38	1.49	1.49	1.49
Cooking[2]	0.15	0.15	0.15	0.15	0.14	0.15	0.15	0.15	0.17	0.17
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[3]	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Delivered Energy	5.01	5.33	5.31	5.30	5.57	5.07	5.12	5.78	5.26	5.21
Electricity										
Space Heating	0.43	0.46	0.45	0.45	0.48	0.43	0.43	0.50	0.44	0.44
Space Cooling	0.48	0.46	0.46	0.46	0.49	0.43	0.44	0.51	0.40	0.40
Water Heating	0.35	0.36	0.36	0.36	0.38	0.38	0.38	0.40	0.40	0.40
Refrigeration	0.40	0.36	0.35	0.35	0.32	0.30	0.31	0.32	0.29	0.29
Cooking	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.15
Clothes Dryers	0.18	0.19	0.19	0.19	0.21	0.21	0.21	0.23	0.23	0.23
Freezers	0.13	0.11	0.11	0.11	0.08	0.07	0.07	0.08	0.07	0.07
Lighting	0.32	0.33	0.33	0.33	0.35	0.35	0.35	0.38	0.36	0.36
Other Uses[4]	1.15	1.49	1.49	1.49	2.02	2.01	2.01	2.73	2.65	2.64
Delivered Energy	3.56	3.88	3.87	3.87	4.45	4.31	4.33	5.30	4.99	4.98

Table C4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Marketed Renewables										
Wood[4]	0.57	0.57	0.57	0.56	0.55	0.51	0.52	0.52	0.48	0.48
Delivered Energy	0.57	0.57	0.57	0.56	0.55	0.51	0.52	0.52	0.48	0.48
Other Fuels[5]	0.13	0.12	0.12	0.12	0.11	0.10	0.10	0.10	0.09	0.09
Delivered Energy Consumption by										
Space Heating	5.65	5.92	5.89	5.88	5.96	5.29	5.36	5.96	5.20	5.15
Space Cooling	0.48	0.47	0.47	0.47	0.50	0.46	0.45	0.54	0.43	0.43
Water Heating	1.75	1.83	1.83	1.82	1.95	1.94	1.94	2.08	2.09	2.09
Refrigeration	0.40	0.36	0.35	0.36	0.32	0.30	0.31	0.32	0.29	0.29
Cooking	0.30	0.30	0.30	0.30	0.30	0.31	0.31	0.33	0.35	0.35
Clothes Dryers	0.23	0.24	0.24	0.24	0.26	0.25	0.26	0.26	0.28	0.28
Freezers	0.13	0.11	0.11	0.11	0.08	0.07	0.07	0.08	0.07	0.07
Lighting	0.32	0.33	0.33	0.33	0.36	0.36	0.36	0.38	0.36	0.36
Other Uses[7]	1.24	1.59	1.59	1.59	2.14	2.13	2.13	2.86	2.77	2.77
Delivered Energy	10.51	11.16	11.11	11.10	11.88	11.16	11.18	12.83	11.84	11.79
Electricity Related Losses by End-Use										
Space Heating	0.95	0.98	0.96	0.96	0.98	0.74	0.74	0.94	0.78	0.77
Space Cooling	1.07	1.00	0.98	0.98	0.98	0.74	0.75	0.96	0.72	0.71
Water Heating	0.78	0.77	0.76	0.76	0.76	0.65	0.65	0.76	0.72	0.71
Refrigeration	0.90	0.77	0.75	0.75	0.65	0.53	0.52	0.61	0.51	0.51
Cooking	0.27	0.27	0.27	0.27	0.27	0.23	0.23	0.28	0.27	0.26
Clothes Dryers	0.40	0.40	0.40	0.40	0.42	0.36	0.35	0.44	0.41	0.41
Freezers	0.29	0.23	0.22	0.22	0.16	0.13	0.13	0.15	0.12	0.12
Lighting	0.70	0.71	0.70	0.70	0.71	0.60	0.59	0.72	0.65	0.64
Other Uses[7]	2.55	3.19	3.16	3.16	4.07	3.47	3.45	5.15	4.73	4.68
Total Electricity Related Losses	7.92	8.31	8.21	8.20	8.99	7.44	7.42	9.99	8.92	8.83
Total Energy Consumption by End-Use										
Space Heating	6.60	6.90	6.85	6.84	6.94	6.04	6.11	6.89	5.98	5.92
Space Cooling	1.55	1.47	1.45	1.45	1.48	1.19	1.20	1.49	1.15	1.14
Water Heating	2.54	2.60	2.59	2.59	2.71	2.59	2.59	2.84	2.81	2.81
Refrigeration	1.30	1.13	1.10	1.10	0.97	0.83	0.83	0.93	0.80	0.80
Cooking	0.58	0.58	0.57	0.57	0.58	0.55	0.55	0.61	0.62	0.61
Clothes Dryers	0.63	0.64	0.64	0.64	0.67	0.61	0.61	0.72	0.69	0.69
Freezers	0.42	0.34	0.33	0.33	0.24	0.20	0.20	0.22	0.19	0.19
Lighting	1.02	1.04	1.03	1.03	1.07	0.94	0.94	1.10	1.01	1.01
Other Uses[7]	3.79	4.78	4.76	4.75	6.21	5.60	5.58	8.01	7.51	7.46
Total	18.45	19.47	19.32	19.30	20.86	18.54	18.59	22.81	20.77	20.62
Non-Marketed Renewables										
Geothermal[8]	0.01	0.02	0.02	0.02	0.05	0.05	0.05	0.09	0.10	0.10
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	0.02	0.03	0.03	0.03	0.06	0.06	0.06	0.10	0.11	0.11

[1]Includes such appliances as swimming pool and hot tub heaters.
[2]Does not include outdoor grills.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as microwave ovens, television sets, and dishwashers.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported by the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes such appliances as swimming pool heaters, hot tub heaters, outdoor grills, outdoor lighting (natural gas), microwave ovens, television sets, and dishwashers.
[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.
N/A = Not applicable.
1344 Fixed = this 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a [illegible] year ramp-in period.
1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to the [illegible] level of carbon emissions [illegible]
Note: Totals may not equal sum of components due to independent roundings.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); Projections: EIA, AEO97 [illegible] Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avg\1344.d041297a (3).

Table C5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	68.9	72.8	72.8	72.8	79.1	79.0	79.0	86.2	86.0	86.0
New Additions	1.7	1.5	1.5	1.5	1.6	1.6	1.6	1.9	1.8	1.9
Total	70.7	74.3	74.3	74.3	80.7	80.5	80.8	88.0	87.8	87.8
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	101.2	101.6	101.0	100.9	100.9	93.4	94.1	100.8	93.0	92.6
Electricity Related Losses	101.6	100.9	99.0	98.9	97.8	75.9	76.1	94.3	80.7	79.7
Total Energy Consumption	202.8	202.5	200.1	199.8	198.6	169.3	170.3	195.1	173.6	172.3
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.11	0.12	0.12	0.12	0.13	0.11	0.11	0.14	0.11	0.11
Space Cooling	0.58	0.53	0.53	0.53	0.53	0.49	0.49	0.56	0.51	0.51
Water Heating	0.17	0.16	0.16	0.16	0.14	0.11	0.11	0.12	0.09	0.09
Ventilation	0.17	0.18	0.17	0.17	0.19	0.17	0.17	0.21	0.19	0.19
Cooking	0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.03	0.02	0.02
Lighting	1.20	1.30	1.27	1.27	1.32	1.08	1.10	1.37	1.13	1.12
Refrigeration	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.19	0.18	0.18
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Office Equipment (non-PC)	0.18	0.20	0.20	0.20	0.25	0.24	0.24	0.28	0.28	0.28
Other Uses[1]	0.56	0.75	0.75	0.75	1.08	1.06	1.07	1.40	1.34	1.34
Delivered Energy	3.23	3.50	3.46	3.46	3.92	3.54	3.58	4.40	3.96	3.95
Natural Gas[2]										
Space Heating	1.30	1.33	1.33	1.33	1.36	1.23	1.24	1.40	1.25	1.24
Space Cooling	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Water Heating	0.48	0.48	0.48	0.48	0.52	0.46	0.47	0.59	0.53	0.52
Cooking	0.18	0.20	0.20	0.20	0.23	0.20	0.20	0.26	0.22	0.22
Other Uses[3]	1.17	1.32	1.32	1.32	1.40	1.40	1.40	1.51	1.50	1.50
Delivered Energy	3.16	3.36	3.36	3.36	3.54	3.32	3.34	3.80	3.54	3.52
Distillate										
Space Heating	0.20	0.18	0.18	0.18	0.16	0.15	0.15	0.14	0.13	0.13
Water Heating	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04
Other Uses[4]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	0.41	0.37	0.37	0.37	0.35	0.33	0.33	0.33	0.31	0.31
Other Fuels[5]	0.35	0.32	0.32	0.32	0.33	0.33	0.33	0.35	0.35	0.35
Marketed Renewable Fuels										
Biomass	0.00	0.00	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	0.00	0.00
Delivered Energy Consumption by End-Use										
Space Heating	1.61	1.63	1.63	1.63	1.64	1.48	1.50	1.68	1.49	1.48
Space Cooling	0.61	0.55	0.55	0.55	0.56	0.52	0.53	0.60	0.55	0.54
Water Heating	0.70	0.70	0.69	0.69	0.70	0.61	0.62	0.75	0.66	0.65
Ventilation	0.17	0.18	0.17	0.17	0.19	0.17	0.17	0.21	0.19	0.19
Cooking	0.22	0.23	0.23	0.23	0.26	0.22	0.23	0.29	0.25	0.24
Lighting	1.20	1.30	1.27	1.27	1.32	1.08	1.10	1.37	1.13	1.12
Refrigeration	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.19	0.18	0.18
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Office Equipment (non-PC)	0.18	0.20	0.20	0.20	0.25	0.24	0.24	0.28	0.28	0.28
Other Uses[6]	2.24	2.52	2.52	2.52	2.98	2.93	2.94	3.41	3.34	3.34
Delivered Energy	7.15	7.56	7.50	7.50	8.14	7.52	7.59	8.89	8.17	8.13

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Electricity Related Losses by End-Use										
Space Heating	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.26	0.20	0.19
Space Cooling	1.29	1.13	1.12	1.12	1.07	0.85	0.85	1.06	0.91	0.90
Water Heating	0.36	0.36	0.34	0.34	0.26	0.19	0.19	0.23	0.17	0.16
Ventilation	0.36	0.36	0.37	0.37	0.36	0.30	0.30	0.39	0.34	0.33
Cooking	0.07	0.08	0.08	0.08	0.06	0.04	0.04	0.05	0.04	0.04
Lighting	2.67	2.79	2.70	2.69	2.69	1.87	1.89	2.58	2.02	1.98
Refrigeration	0.31	0.32	0.31	0.31	0.32	0.27	0.27	0.35	0.32	0.32
Office Equipment (PC)	0.16	0.19	0.18	0.18	0.26	0.17	0.17	0.21	0.19	0.19
Office Equipment (non-PC)	0.40	0.45	0.43	0.43	0.50	0.41	0.42	0.53	0.50	0.49
Other Uses[1]	1.25	1.61	1.60	1.60	2.16	1.65	1.63	2.65	2.40	2.37
Total Electricity Related Losses	7.16	7.59	7.39	7.36	7.99	6.11	6.13	8.36	7.09	7.00
Total Energy Consumption by End-Use										
Space Heating	1.87	1.89	1.89	1.87	1.90	1.67	1.69	1.94	1.69	1.67
Space Cooling	1.90	1.68	1.67	1.67	1.64	1.37	1.37	1.65	1.46	1.44
Water Heating	1.09	1.05	1.03	1.03	0.98	0.80	0.81	0.98	0.82	0.82
Ventilation	0.55	0.56	0.55	0.55	0.57	0.47	0.47	0.59	0.53	0.52
Cooking	0.29	0.30	0.29	0.29	0.31	0.27	0.27	0.34	0.29	0.29
Lighting	3.87	4.09	3.97	3.96	3.97	2.95	2.98	3.95	3.15	3.12
Refrigeration	0.46	0.48	0.48	0.48	0.49	0.43	0.43	0.54	0.50	0.50
Office Equipment (PC)	0.23	0.27	0.27	0.27	0.30	0.27	0.27	0.32	0.30	0.30
Office Equipment (non-PC)	0.59	0.69	0.63	0.63	0.74	0.66	0.66	0.81	0.77	0.77
Other Uses[2]	3.50	4.13	4.12	4.12	5.14	4.76	4.77	6.06	5.74	5.71
Total	14.33	15.04	14.86	14.84	16.04	13.63	13.72	17.18	15.25	15.13
Non-Marketed Renewable Fuels										
Solar[3]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Total	0.01	0.02	0.02	0.02	0.03	0.03	0.03	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.
1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.
1344 Average = This case targets the average of combustion-related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). Projections: EIA, AEO97 National Energy Modeling System runs: [illegible].d032497a (1), f1344nXL.d040997a (2), and avgV1344.d041297a (3).

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fbsd	1344 Average	Policy Base	1344 Fbsd	1344 Average	Policy Base	1344 Fbsd	1344 Average
Key Indicators										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	2907	3280	3275	3274	4116	3928	3946	4723	4403	4399
Nonmanufacturing	765	847	846	846	977	948	953	1081	1043	1046
Total	3672	4128	4121	4121	5094	4876	4899	5804	5446	5444
Energy Prices (1995 dollars per million Btu)										
Electricity	14.7	14.19	14.30	14.33	13.31	18.34	17.79	12.72	17.08	17.26
Natural Gas	2.28	2.40	2.45	2.44	2.58	5.11	4.78	3.08	5.52	5.73
Steam Coal	1.49	1.50	1.49	1.49	1.38	4.48	3.97	1.28	4.98	5.24
Residual Oil	2.55	2.74	2.78	2.77	3.04	5.79	5.37	3.14	6.20	6.42
Distillate Oil	4.61	4.94	5.04	5.04	5.36	7.90	7.51	5.52	8.54	8.73
Liquefied Petroleum Gas	6.53	5.82	6.04	6.06	6.13	8.23	7.86	6.04	8.18	8.41
Motor Gasoline	9.18	8.39	8.47	8.47	8.93	11.44	11.03	8.95	11.41	11.61
Metallurgical Coal	1.76	1.76	1.74	1.73	1.59	4.82	4.32	1.42	5.25	5.52
Energy Consumption										
Consumption[1] (quadrillion Btu per year)										
Purchased Electricity	3.46	3.81	3.84	3.85	4.32	4.16	4.19	4.82	4.29	4.31
Natural Gas[2]	9.74	10.62	10.48	10.55	11.47	10.49	10.64	11.75	10.36	10.32
Steam Coal	1.59	1.64	1.76	1.72	1.86	1.18	1.23	2.35	0.98	0.97
Metallurgical Coal and Coke[3]	0.91	0.87	0.87	0.87	0.74	0.54	0.57	0.66	0.37	0.36
Residual Fuel	0.34	0.29	0.30	0.28	0.31	0.30	0.30	0.33	0.28	0.28
Distillate	1.15	1.27	1.26	1.26	1.48	1.49	1.49	1.63	1.62	1.62
Liquefied Petroleum Gas	2.01	2.09	2.09	2.09	2.30	2.13	2.12	2.45	2.06	2.09
Petrochemical Feedstocks	1.16	1.25	1.25	1.25	1.35	1.23	1.23	1.45	1.15	1.15
Other Petroleum[4]	4.03	4.42	4.50	4.49	4.77	4.58	4.61	4.83	4.46	4.45
Renewables[5]	1.74	1.91	1.91	1.91	2.29	2.04	2.06	2.54	2.00	1.99
Delivered Energy	26.12	28.16	28.25	28.27	30.88	28.13	28.42	32.79	27.57	27.54
Electricity Related Losses	7.69	8.15	8.16	8.18	8.71	7.17	7.17	9.08	7.69	7.63
Total	33.81	36.31	36.41	36.45	39.59	35.30	35.59	41.88	35.26	35.17
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.94	0.92	0.93	0.94	0.85	0.85	0.85	0.83	0.79	0.79
Natural Gas[2]	2.65	2.57	2.54	2.56	2.25	2.15	2.17	2.02	1.90	1.90
Steam Coal	0.43	0.40	0.43	0.42	0.37	0.24	0.25	0.40	0.18	0.18
Metallurgical Coal and Coke[3]	0.25	0.21	0.21	0.21	0.15	0.11	0.12	0.11	0.07	0.07
Residual Fuel	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05
Distillate	0.31	0.31	0.31	0.31	0.29	0.31	0.30	0.28	0.30	0.30
Liquefied Petroleum Gas	0.55	0.51	0.51	0.51	0.45	0.44	0.43	0.42	0.38	0.38
Petrochemical Feedstocks	0.32	0.30	0.30	0.30	0.27	0.25	0.25	0.25	0.21	0.21
Other Petroleum[4]	1.10	1.07	1.09	1.09	0.94	0.94	0.94	0.83	0.82	0.82
Renewables[5]	0.47	0.46	0.46	0.46	0.45	0.42	0.42	0.44	0.37	0.37
Delivered Energy	7.11	6.82	6.86	6.86	6.06	5.77	5.80	5.65	5.06	5.06
Electricity Related Losses	2.09	1.98	1.98	1.99	1.71	1.47	1.46	1.57	1.41	1.40
Total	9.21	8.80	8.84	8.85	7.77	7.24	7.26	7.21	6.47	6.46

[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.
1344 Fbsd = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.
1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995-1996). 1995 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/05) (Washington, DC, August 1996). 1995 electricity prices: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3). 1995 prices derived from EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles (vehicle miles traveled)	2205	2373	2361	2361	2764	2680	2689	3079	2972	2989
Freight Trucks (vehicle miles traveled)	166	194	193	193	237	228	229	282	248	248
Air (seat miles available)	931	1218	1216	1216	1686	1585	1601	2032	1945	1936
Rail (ton miles traveled)	1182	1276	1271	1273	1463	1377	1384	1607	1440	1437
Marine (ton miles traveled)	871	933	939	931	1048	988	997	1151	1044	1048
Energy Efficiency Indicators										
New Car (miles per gallon)[1]	27.5	28.6	28.6	28.6	31.4	36.9	34.8	33.6	43.5	43.6
New Light Truck (miles per gallon)[1]	20.5	20.5	21.2	21.2	22.7	27.4	27.1	25.5	38.8	38.6
Light-Duty Fleet (miles per gallon)[2]	19.6	19.6	19.7	19.7	20.3	21.7	21.7	22.2	25.5	25.5
Aircraft Efficiency (seat miles per gallon)	53.7	53.3	53.3	53.3	58.2	58.0	58.1	63.1	63.0	62.9
Freight Truck Efficiency (miles per gallon)	5.5	5.7	5.7	5.7	6.0	6.0	6.0	6.1	6.2	6.2
Rail Efficiency (ton miles per thousand Btu)	2.6	2.7	2.7	2.7	3.0	3.0	3.0	3.3	3.3	3.3
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.1	3.1	3.1
Energy Use by Mode (quadrillion Btu per										
Light-Duty Vehicles[3]	14.20	15.37	15.25	15.25	17.29	15.55	15.66	17.83	14.97	14.94
Freight Trucks[3]	3.86	4.28	4.27	4.27	4.96	4.79	4.81	5.38	5.02	5.03
Air	3.18	3.73	3.73	3.73	4.55	4.38	4.39	5.05	4.86	4.85
Rail	0.48	0.50	0.49	0.49	0.52	0.49	0.49	0.52	0.47	0.47
Marine	1.83	1.88	1.88	1.88	2.30	2.24	2.25	2.63	2.55	2.55
Pipeline Fuel	0.72	0.77	0.76	0.76	0.88	0.96	1.00	0.95	0.98	0.99
Other[4]	0.21	0.25	0.29	0.25	0.29	0.27	0.27	0.30	0.28	0.29
Total[5]	24.32	26.69	26.77	26.77	30.96	28.83	29.01	32.63	29.30	29.27

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.
1344 Average = This case targets the average of combustion-related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.
Note: Totals may not equal sum of components due to independent roundings.
Sources: 1995: Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1995-2004*, (Washington, DC, February 1994); Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); EIA, *Fuel Oil and Kerosene Sales 1995*, DOE/EIA-0535(95) (Washington, DC, September 1996); and United States Department of Defense, Defense Fuel Supply Center. Projections: EIA, AEO97 National Energy Modeling System runs pobase.d032497a (1), f1344nXL.d040997a (2), and avgV1344.d041297a (3).

Table C8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Generation by Fuel Type										
Electric Generators[1]										
Coal	1671	1834	1751	1760	1936	699	723	2273	749	662
Petroleum	64	55	48	49	57	19	19	73	17	16
Natural Gas	322	430	519	516	848	1684	1690	1191	1698	1729
Nuclear Power	673	687	695	695	614	676	676	359	782	842
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	354	355	357	355	374	530	524	491	768	763
Total	3083	3357	3368	3372	3825	3605	3630	4384	4008	4009
Cogenerators[3]										
Coal	43	46	46	46	52	50	50	55	51	51
Petroleum	5	5	5	5	6	5	5	6	5	5
Natural Gas	180	195	195	195	217	213	213	226	215	215
Other Gaseous Fuels[4]	7	8	8	8	8	8	8	8	8	8
Renewable Sources[2]	42	45	45	44	53	50	50	59	50	50
Other[5]	3	3	3	3	4	3	3	4	3	3
Total	279	302	302	302	340	329	329	358	333	333
Sales to Utilities	148	155	155	155	164	161	161	169	163	163
Generation for Own Use	132	146	146	146	175	168	168	189	170	170
Net Imports	38	39	39	39	33	71	70	29	83	83
Electricity Sales by Sector										
Residential	1043	1137	1133	1133	1306	1264	1268	1552	1462	1461
Commercial	946	1025	1015	1014	1148	1039	1049	1289	1160	1158
Industrial	1013	1115	1126	1129	1266	1219	1227	1411	1259	1263
Transportation	6	7	8	8	24	36	36	33	85	85
Total	3009	3285	3281	3284	3744	3558	3580	4286	3966	3967
End-Use Prices (1995 cents per kwh)[6]										
Residential	8.4	8.3	8.3	8.3	7.9	10.6	10.3	7.7	10.1	10.2
Commercial	8.0	7.6	7.7	7.7	7.3	10.0	9.7	7.1	9.5	9.6
Industrial	5.0	4.8	4.9	4.9	4.5	6.3	6.1	4.3	5.8	5.9
Transportation	5.2	5.2	5.2	5.2	4.9	5.4	5.4	4.7	5.2	5.3
All Sectors Average	7.1	6.9	6.9	6.9	6.6	8.9	8.6	6.4	8.5	8.6
Price Components (1995 cents per kwh)										
Capital Component	2.6	2.6	2.6	2.6	2.4	2.8	2.8	2.2	2.5	2.6
Fuel Component	1.1	1.1	1.1	1.1	1.0	1.8	1.8	0.9	1.8	1.8
Operation and Maintenance Component	3.0	2.7	2.7	2.7	2.5	2.7	2.6	2.3	2.5	2.5
Wholesale Power Cost	0.4	0.5	0.5	0.5	0.7	1.6	1.6	1.0	1.6	1.7
Total	7.1	6.9	6.9	6.9	6.6	8.9	8.6	6.4	8.5	8.6

[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, other biomass, solar and wind power.

[3]Includes cogeneration at facilities whose primary function is not electricity production. 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]Prices represent average revenue per kilowatthour.

Kwh=Kilowatthour

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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

Sources: 1995 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995), 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 15* (May 1995) which indicates the transportation value should be higher. 1995 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1995 electricity prices for commercial, industrial, and transportation; price components; and projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Electric Generators[2]										
Capability										
Coal Steam	304.9	302.8	287.2	288.0	303.8	282.8	282.8	346.9	254.8	254.1
Other Fossil Steam[3]	140.0	120.2	111.8	111.8	96.8	95.8	95.8	95.0	90.7	90.7
Combined Cycle	14.7	34.1	51.4	49.8	98.1	227.8	226.7	158.6	229.9	233.8
Combustion Turbine/Diesel	58.8	112.3	108.5	108.5	154.8	120.8	119.5	190.6	125.7	120.7
Nuclear Power	99.2	99.1	109.4	109.4	99.1	109.4	109.4	48.9	112.6	121.0
Pumped Storage	19.9	19.9	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	2.1	2.9	5.0	2.4	3.1	5.3
Renewable Sources[4]	89.2	90.8	91.2	91.1	94.6	133.5	132.4	117.7	190.1	189.7
Total	723.8	779.9	780.4	779.9	869.5	993.2	994.3	980.0	1026.6	1035.9
Cumulative Planned Additions[5]										
Coal Steam	1.4	3.7	3.7	3.7	5.3	3.7	3.7	5.3	3.7	3.7
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	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	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9
Total	8.0	15.3	15.3	15.3	17.1	15.8	15.8	17.1	15.5	15.5
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	8.2	1.7	3.6	17.1	8.4	8.2	67.1	8.8	8.5
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	18.0	35.9	34.4	83.8	211.5	213.2	143.1	214.4	218.0
Combustion Turbine/Diesel	1.0	55.4	51.5	50.5	98.5	66.3	65.0	135.9	73.0	68.0
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6	21.9
Pumped Storage	0.0	0.0	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	2.1	2.9	5.0	2.4	3.1	5.3
Renewable Sources[4]	0.3	0.7	1.2	1.0	4.3	43.3	42.1	28.3	100.7	100.3
Total	1.2	82.3	90.3	89.5	205.4	332.4	334.3	376.7	413.6	422.0
Cumulative Total Additions	9.3	98.0	105.6	104.8	222.5	347.5	349.7	393.8	429.0	437.5
Cumulative Retirements[7]	11.8	43.2	59.6	59.6	63.9	89.6	89.6	137.7	97.4	97.4

Table C9. Electric Generating Capacity (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Cogenerators[7]										
Capacity										
Coal	8.2	8.7	8.7	8.7	9.6	9.3	9.3	10.2	9.5	9.5
Petroleum	0.9	0.9	0.9	0.9	1.0	0.9	0.9	1.0	0.9	0.9
Natural Gas	28.9	30.9	30.9	30.9	34.0	33.4	33.4	35.3	33.8	33.7
Other Gaseous Fuels	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources[3]	6.2	6.6	6.6	6.6	8.0	7.4	7.4	8.8	7.5	7.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	45.1	48.0	48.0	48.0	53.5	52.0	52.0	56.2	52.6	52.5
Cumulative Additions[5]	10.2	13.1	13.1	13.1	18.5	17.0	17.0	21.3	17.6	17.6

[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, other biomass, solar and wind power.

[5]Cumulative additions after December 31, 1994.

[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 on the basis of historic relationships.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity data are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 net summer capability of electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1995 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	155.0	149.3	149.3	149.3	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	76.7	67.2	70.1	69.0	86.3	52.3	57.0	74.8	62.6	58.6
Gross Domestic Trade	231.7	216.6	219.5	218.3	225.5	191.5	196.3	214.0	201.7	197.8
Gross Domestic Firm Power Sales (million 1995 dollars)	7023.6	6767.2	6767.2	6767.2	6308.7	6308.7	6308.7	6308.7	6308.7	6308.7
Gross Domestic Economy Sales (million 1995 dollars)	1809.4	1466.8	1466.8	1466.8	2037.4	2189.4	2197.2	2003.8	2636.8	2722.6
Gross Domestic Sales (million 1995 dollars)	8833.0	8258.2	8228.0	8192.0	8381.3	8478.0	8488.2	8312.6	8139.6	8031.3
International Electricity Trade										
Firm Power Imports From Canada and Mexico	30.3	32.0	32.0	32.0	20.1	58.1	58.1	20.1	74.0	74.0
Economy Imports From Canada and Mexico	18.0	22.2	22.2	22.2	33.6	33.7	33.7	30.1	30.1	30.1
Gross Imports From Canada and Mexico	48.3	54.2	54.2	54.2	53.7	91.7	91.8	50.2	104.0	104.0
Firm Power Exports To Canada and Mexico	3.4	8.3	8.3	8.3	13.4	13.4	13.4	13.4	13.4	13.4
Economy Exports To Canada and Mexico	7.2	6.4	6.4	6.4	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	10.7	14.7	14.7	14.7	21.0	21.0	21.0	21.0	21.0	21.0

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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: 1995 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1995 international electricity trade data: DOE Form FE-781R, "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, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Crude Oil										
Domestic Crude Production[1]	6.56	5.85	5.84	5.84	5.40	5.33	5.34	5.27	5.11	5.09
Alaska	1.48	1.11	1.11	1.11	0.77	0.77	0.77	0.55	0.53	0.53
Lower 48 States	5.08	4.74	4.73	4.73	4.62	4.56	4.57	4.73	4.58	4.56
Net Imports	7.14	8.82	8.54	8.55	9.90	8.94	8.99	9.97	8.34	8.38
Other Crude Supply[2]	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	13.97	14.67	14.38	14.39	15.29	14.26	14.32	15.24	13.45	13.47
Natural Gas Plant Liquids	1.76	1.93	1.96	1.97	2.25	2.50	2.51	2.44	2.51	2.51
Other Inputs[3]	0.48	0.25	0.24	0.24	0.21	0.27	0.27	0.19	0.73	0.71
Refinery Processing Gain[4]	0.77	0.77	0.74	0.74	0.81	0.65	0.64	0.76	0.63	0.62
Net Product Imports[5]	0.75	1.70	1.91	1.89	3.04	2.23	2.26	3.97	2.53	2.52
Total Primary Supply[6]	17.73	19.31	19.24	19.23	21.59	19.91	20.01	22.60	19.85	19.84
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.81	8.44	8.37	8.37	9.23	8.30	8.35	9.33	7.81	7.80
Jet Fuel[8]	1.51	1.79	1.78	1.78	2.18	2.08	2.10	2.41	2.32	2.32
Distillate Fuel[9]	3.25	3.53	3.52	3.52	3.99	3.79	3.81	4.23	3.92	3.92
Residual Fuel	0.85	0.94	0.93	0.92	1.10	0.95	0.96	1.29	1.05	1.05
Other[10]	4.32	4.64	4.66	4.66	5.11	4.81	4.81	5.34	4.70	4.72
Total	17.73	19.34	19.27	19.26	21.61	19.92	20.03	22.61	19.81	19.80
Refined Petroleum Products Supplied										
Residential and Commercial	1.07	1.05	1.04	1.04	1.02	0.95	0.96	0.98	0.92	0.91
Industrial[11]	4.58	4.89	4.93	4.92	5.37	5.09	5.10	5.63	5.00	5.02
Transportation	11.79	13.16	13.09	13.09	14.97	13.80	13.89	15.67	13.82	13.80
Electric Generators[12]	0.30	0.24	0.21	0.21	0.25	0.08	0.08	0.32	0.07	0.07
Total	17.73	19.34	19.27	19.26	21.61	19.92	20.03	22.61	19.81	19.80
Discrepancy[13]	-0.01	-0.03	-0.03	-0.03	-0.01	-0.02	-0.02	-0.01	0.04	0.04
World Oil Price (1995 dollars per barrel)[14]	17.26	18.13	18.13	18.13	20.53	20.53	20.53	22.17	22.17	22.17
Import Share of Product Supplied	0.44	0.54	0.54	0.54	0.69	0.58	0.58	0.62	0.55	0.55
Expenditured for Imported Crude Oil and Petroleum Products (billion 1995 dollars)	49.39	68.30	68.37	68.26	96.33	83.20	83.67	109.48	85.71	86.00
Domestic Refinery Distillation Capacity	15.4	15.7	15.4	15.4	16.3	15.4	15.4	16.5	15.4	15.4
Capacity Utilization Rate (percent)	92.0	93.6	93.6	93.7	94.0	92.9	93.3	92.6	87.6	87.7

[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 type.
[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 as a by product of other processes.
[13]Balancing item. Includes unaccounted for supply losses and gains.
[14]Average refiner acquisition cost for imported crude oil.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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

Sources: 1995 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1995 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C12. Petroleum Product Prices
(1995 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
World Oil Price (dollars per barrel)	17.26	18.13	18.13	18.13	28.53	28.53	28.53	22.17	22.17	22.17
Delivered Sector Product Prices										
Residential										
Distillate Fuel	86.5	97.1	96.2	96.4	108.0	132.6	132.4	104.9	145.8	146.0
Liquefied Petroleum Gas	69.8	99.2	98.5	98.4	101.8	118.4	118.4	101.8	119.2	121.3
Commercial										
Distillate Fuel	80.5	89.8	70.6	71.8	74.0	100.2	104.8	76.2	117.8	120.5
Residual Fuel	44.7	41.2	40.7	40.8	44.8	80.8	79.2	46.0	93.4	99.8
Residual Fuel (dollars per barrel)	18.78	17.29	17.08	17.13	18.80	33.94	33.26	19.30	39.23	40.58
Industrial[1]										
Distillate Fuel	63.9	69.6	69.8	69.9	74.2	100.8	104.1	76.8	118.4	121.1
Liquefied Petroleum Gas	56.4	50.2	52.2	52.5	52.9	71.0	67.8	52.5	70.8	72.8
Residual Fuel	38.2	41.0	41.3	41.5	46.5	80.3	80.3	47.0	92.8	98.1
Residual Fuel (dollars per barrel)	16.08	17.21	17.51	17.42	18.19	33.48	33.74	18.74	38.98	40.35
Transportation										
Distillate Fuel[2]	111.4	120.2	120.9	120.9	128.5	155.0	149.5	118.1	157.1	155.9
Jet Fuel[3]	52.0	69.7	69.8	69.7	74.7	108.7	101.9	76.4	114.1	116.9
Motor Gasoline[4]	114.8	120.1	121.0	121.0	122.7	153.5	149.5	119.9	150.3	152.9
Residual Fuel	36.5	40.0	39.5	39.5	47.4	80.8	81.7	47.3	94.8	97.8
Residual Fuel (dollars per barrel)	15.32	16.81	16.60	16.58	19.91	33.97	34.32	19.86	39.68	40.96
Electric Generators[5]										
Distillate Fuel	54.5	62.5	64.2	63.8	67.5	104.2	98.6	70.2	113.0	115.7
Residual Fuel	39.2	41.9	42.2	42.3	47.7	96.6	88.2	48.2	105.7	110.0
Residual Fuel (dollars per barrel)	16.46	17.58	17.73	17.77	20.03	39.91	37.06	20.25	44.49	46.18
Refined Petroleum Product Prices[6]										
Distillate Fuel	96.8	105.8	106.7	106.7	107.5	143.5	137.3	105.9	147.1	146.9
Jet Fuel	52.0	69.7	69.8	69.7	74.7	108.7	101.9	76.4	114.1	116.9
Liquefied Petroleum Gas	62.2	58.4	61.2	61.7	64.2	82.2	79.3	63.8	83.2	84.8
Motor Gasoline	114.8	119.8	120.7	120.6	122.5	153.3	149.3	119.7	150.2	152.7
Residual Fuel	36.5	40.0	40.4	40.4	47.5	80.8	81.8	47.4	94.8	97.8
Residual Fuel (dollars per barrel)	16.01	17.05	16.97	16.95	19.78	37.05	34.35	19.89	39.91	41.10
Average	92.4	97.5	98.3	98.5	100.6	130.6	125.6	97.9	130.4	130.6

[1] Includes cogenerators.
[2] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3] Kerosene-type jet fuel.
[4] Sales-weighted average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[5] Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumptions.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion-related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-95/4) (Washington, DC, 1995-1995). 1995 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report, 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). Projections: EIA, AEO97 National Energy Modeling System runs pobase.d[illegible] and [1344n].d[illegible]; and avgV1344.d041297a (3).

Table C13. Natural Gas Supply and Disposition, and Prices
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Production										
Dry Gas Production[1]	18.49	20.22	20.57	20.60	23.97	26.66	26.78	26.09	26.88	26.93
Supplemental Natural Gas[2]	0.13	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.68	3.46	3.54	3.55	3.97	4.46	4.47	4.42	4.59	4.55
Canada	2.79	3.44	3.52	3.53	3.79	4.28	4.29	4.24	4.36	4.37
Mexico	-0.05	-0.10	-0.10	-0.10	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Liquefied Natural Gas	-0.05	0.12	0.12	0.12	0.29	0.29	0.29	0.29	0.34	0.29
Total Supply	21.30	23.77	24.20	24.24	27.99	31.19	31.30	30.56	31.53	31.53
Consumption by Sector										
Residential	4.87	5.18	5.16	5.15	5.41	4.93	4.98	5.62	5.11	5.06
Commercial	3.07	3.27	3.26	3.26	3.44	3.22	3.25	3.69	3.44	3.42
Industrial[3]	8.33	9.01	8.87	8.93	9.62	8.54	8.67	9.75	8.36	8.32
Electric Generators[4]	3.46	3.99	4.51	4.50	6.67	11.39	11.30	8.36	11.41	11.53
Lease and Plant Fuel[5]	1.14	1.31	1.32	1.33	1.53	1.66	1.67	1.67	1.71	1.71
Pipeline Fuel	0.70	0.75	0.76	0.76	0.86	0.97	0.97	0.92	0.96	0.97
Transportation[6]	0.01	0.05	0.05	0.05	0.25	0.22	0.22	0.32	0.29	0.29
Total	21.58	23.55	23.94	23.98	27.79	30.92	31.05	30.32	31.28	31.29
Discrepancy[7]	-0.28	0.22	0.25	0.26	0.21	0.26	0.25	0.24	0.25	0.24

[1]Market 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 as a by product of other processes.
[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, 1995 values include net storage injections.

Btu = British thermal unit.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 imports and dry gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 transportation sector consumption: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3). Other 1995 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996), with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C14. Natural Gas Prices, Margins, and Revenue
(1995 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Source Price										
Average Lower 48 Wellhead Price[1]	1.61	1.61	1.85	1.84	1.98	2.84	2.58	2.48	2.82	2.69
Average Import Price	1.46	1.70	1.88	1.71	1.92	2.31	2.22	2.45	2.72	2.56
Average[2]	1.59	1.70	1.82	1.82	1.95	2.80	2.55	2.48	2.80	2.65
Delivered Prices[3]										
Residential	6.19	5.76	5.78	5.80	5.96	8.04	7.77	5.89	8.22	8.01
Commercial	5.16	4.80	4.78	4.83	4.85	7.20	6.88	4.87	7.48	7.70
Industrial[4]	2.36	2.48	2.58	2.51	2.69	5.36	4.80	3.17	5.68	5.58
Electric Generators[5]	2.08	2.27	2.28	2.28	2.47	5.40	5.10	3.09	5.65	5.90
Transportation[6]	5.94	6.04	6.08	6.10	6.85	9.55	9.28	7.85	10.21	10.49
Average[7]	3.67	3.58	3.58	3.58	3.85	6.80	5.73	3.88	6.36	6.63
Transmission and Distribution Margins[8]										
Residential	4.58	3.98	3.91	4.00	3.46	5.46	5.20	3.18	5.42	5.65
Commercial	3.51	3.01	2.94	3.03	2.68	4.84	4.58	2.49	4.62	4.83
Industrial[4]	0.78	0.68	0.70	0.68	0.68	2.56	2.27	0.68	2.85	3.03
Electric Generators[5]	0.47	0.48	0.47	0.47	0.59	2.61	2.58	0.61	2.85	3.03
Transportation[6]	4.36	4.25	4.19	4.28	4.99	8.06	8.79	5.22	7.41	7.63
Average[7]	2.08	1.88	1.78	1.78	1.96	3.46	3.22	1.48	3.58	3.77
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	22.36	20.52	20.17	20.61	18.58	27.03	26.69	17.58	27.69	28.58
Commercial	10.79	9.82	9.62	9.87	9.12	14.57	14.23	8.62	15.90	16.56
Industrial[4]	6.31	6.17	6.21	6.13	6.65	22.73	20.54	6.75	24.05	25.20
Electric Generators[5]	1.61	1.90	2.14	2.11	3.90	31.99	28.98	5.16	32.54	34.90
Transportation[6]	0.04	0.23	0.23	0.23	1.23	1.54	1.58	1.69	2.13	2.18
Total	41.11	38.64	38.39	38.96	39.48	98.26	91.16	39.88	102.31	107.41

[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 United States border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[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 United States 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, other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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

Sources: 1995 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1997*. 1995 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 values and projections: EIA, AEO97 National Energy Modeling System runs pollbase.d082497a (1), 1344nrLd040897a (2), and avg1344.d041297a (3).

Table C15. Oil and Gas Supply

Production and Supply	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1995 dollars per barrel)	15.58	17.90	17.72	17.71	20.13	20.10	20.11	22.30	21.73	21.74
Production (million barrels per day)[2]										
U.S. Total	6.56	5.85	5.84	5.84	5.40	5.33	5.34	5.27	5.11	5.09
Lower 48 Onshore	3.82	3.41	3.40	3.40	3.05	3.04	3.04	3.16	3.12	3.12
Conventional	3.24	2.88	2.87	2.87	2.38	2.35	2.35	2.42	2.39	2.39
Enhanced Oil Recovery	0.58	0.54	0.53	0.53	0.69	0.70	0.70	0.73	0.73	0.73
Lower 48 Offshore	1.26	1.33	1.32	1.32	1.57	1.51	1.52	1.57	1.46	1.45
Alaska	1.48	1.11	1.11	1.11	0.77	0.77	0.77	0.55	0.53	0.53
Lower 48 End of Year Reserves (billion barrels)	17.18	15.05	14.99	14.99	15.55	15.32	15.30	16.18	15.76	15.71
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1995 dollars per thousand cubic feet)	1.61	1.81	1.85	1.84	1.95	2.64	2.59	2.48	2.82	2.87
Production (trillion cubic feet)[2]										
U.S. Total	18.48	20.22	20.57	20.60	23.97	26.66	26.78	26.09	26.88	26.93
Lower 48 Onshore	13.00	13.58	13.80	13.81	16.94	19.15	19.19	19.28	20.23	20.23
Associated-Dissolved[4]	1.85	1.53	1.53	1.53	1.21	1.22	1.22	1.20	1.19	1.19
Non-Associated	11.15	12.05	12.27	12.28	15.72	17.93	17.98	18.08	19.04	19.03
Conventional	7.92	9.11	9.32	9.32	12.09	14.20	14.21	13.09	13.62	13.61
Unconventional	3.24	2.95	2.95	2.97	3.64	3.73	3.77	4.99	5.41	5.43
Lower 48 Offshore	5.05	6.15	6.29	6.31	6.48	6.97	7.03	6.21	6.06	6.11
Associated-Dissolved[4]	0.71	0.73	0.73	0.73	0.81	0.80	0.80	0.80	0.78	0.78
Non-Associated	4.34	5.42	5.55	5.57	5.67	6.17	6.24	5.40	5.28	5.33
Alaska	0.42	0.49	0.49	0.49	0.55	0.55	0.55	0.60	0.59	0.59
U.S. End of Year Reserves (trillion cubic feet)	155.03	162.89	163.20	163.73	183.06	201.52	198.70	182.86	184.49	185.51
Supplemental Gas Supplies (trillion cubic feet)[5]	0.13	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Total Lower 48 Wells (thousands)	18.52	28.89	29.03	28.96	37.16	45.81	45.27	52.53	54.52	55.19

[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.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1995 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). 1995 natural gas lower 48 average wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/06) (Washington, DC, June 1996). 1995 total natural gas production: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 values: EIA, Office of Integrated Analysis and Forecasting. Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nXd040997a (2), and avgV1344.d041297a (3).

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Production[1]										
Appalachia	435	454	441	439	474	259	265	541	275	286
Interior	169	167	164	167	163	60	61	182	75	59
West	429	495	476	476	562	203	213	686	190	168
East of the Mississippi	544	580	544	546	572	300	307	636	324	309
West of the Mississippi	489	556	537	537	628	223	232	751	216	184
Total	1033	1116	1081	1082	1199	523	539	1388	540	493
Net Imports										
Imports	7	8	8	8	8	9	9	9	9	9
Exports	88	96	96	96	111	112	112	125	125	125
Total	-81	-88	-88	-88	-103	-103	-103	-117	-117	-117
Total Supply[2]	951	1028	994	995	1096	420	436	1272	424	377
Consumption by Sector										
Residential and Commercial[3]	6	6	6	6	6	6	6	6	6	6
Industrial[3]	73	76	81	79	86	54	56	106	45	44
Coke Plants	33	29	29	29	23	17	18	18	10	10
Electric Generators[4]	847	919	880	883	982	342	356	1141	361	314
Total	959	1030	995	998	1096	419	436	1273	422	374
Discrepancy and Stock Change[5]	-8	-2	-2	-3	0	1	0	-2	2	2
Average Minemouth Price										
(1995 dollars per short ton)	18.93	18.70	18.41	18.48	16.93	14.38	14.20	15.23	15.33	15.89
(1995 dollars per million Btu)	0.88	0.89	0.87	0.88	0.81	0.68	0.65	0.73	0.70	0.72
Delivered Prices (1995 dollars per short ton)[6]										
Industrial	32.54	32.69	32.44	32.45	29.97	97.65	86.38	27.38	108.30	113.91
Coke Plants	47.25	47.24	46.60	46.47	42.55	129.11	115.74	38.03	140.69	147.87
Electric Generators										
(1995 dollars/short ton)	27.01	26.75	26.31	26.36	24.34	86.26	75.74	21.94	98.31	105.27
(1995 dollars/million Btu)	1.32	1.31	1.29	1.30	1.20	4.25	3.72	1.09	4.80	5.06
Average[6]	28.14	27.77	27.41	27.48	25.17	89.58	78.89	22.83	100.44	107.46
Exports[7]	39.79	39.63	39.02	39.02	35.66	32.42	32.26	31.49	31.15	31.46

[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 as a by-product of other processes.
[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 United States port-of-exit.
Btu = British thermal unit.
1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.
1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 derived from: Energy Information Administration (EIA), *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). Projections: EIA, AEO National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C17. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Electric Generators[1]										
(excluding cogenerators)										
Capability										
Conventional Hydropower	78.48	80.05	80.05	80.05	80.38	80.38	80.38	80.38	80.38	80.38
Geothermal[2]	2.97	3.21	3.42	3.16	3.30	5.27	4.98	4.19	8.02	7.34
Municipal Solid Waste	2.70	3.00	3.00	3.00	4.12	4.07	4.08	4.45	4.42	4.41
Wood and Other Biomass[3]	1.86	1.86	1.87	1.86	2.21	12.67	12.22	12.13	26.71	26.91
Solar Thermal	0.36	0.39	0.39	0.39	0.64	0.64	0.64	1.14	1.30	1.22
Solar Photovoltaic	0.01	0.02	0.02	0.02	0.35	0.35	0.35	1.02	1.02	1.02
Wind	1.83	2.26	2.56	2.58	3.57	30.11	29.72	14.43	68.20	68.46
Total	88.22	90.80	91.32	91.07	94.57	133.49	132.36	117.74	190.05	189.73
Generation (billion kilowatthours)										
Conventional Hydropower	309.8	301.50	301.39	301.40	304.09	303.93	303.94	304.33	304.14	304.14
Geothermal[2]	14.66	18.48	19.95	18.10	20.25	34.01	31.96	29.36	56.10	51.34
Municipal Solid Waste	18.69	20.01	20.00	20.00	27.71	27.34	27.41	30.04	29.79	29.74
Wood and Other Biomass[3]	7.12	8.61	8.69	8.61	10.75	83.92	80.76	80.12	182.23	183.57
Solar Thermal	0.82	1.01	1.01	1.01	1.80	1.80	1.80	3.41	4.01	3.72
Solar Photovoltaic	0.00	0.08	0.08	0.08	0.88	0.88	0.88	2.57	2.57	2.57
Wind	3.17	4.93	5.71	5.77	8.66	77.95	77.00	41.26	187.16	188.21
Total	354.2	354.62	356.84	354.97	374.14	529.84	523.75	491.09	766.00	763.29
Cogenerators[4]										
Capability										
Municipal Solid Waste	0.41	0.42	0.42	0.42	0.45	0.45	0.45	0.47	0.47	0.46
Biomass	5.79	6.21	6.21	6.20	7.51	6.95	6.94	8.30	7.00	6.99
Total	6.19	6.62	6.62	6.62	7.96	7.39	7.39	8.77	7.46	7.45
Generation (billion kilowatthours)										
Municipal Solid Waste	1.97	2.02	2.02	2.02	2.17	2.14	2.15	2.26	2.21	2.20
Biomass	39.58	42.49	42.49	42.48	51.23	47.44	47.43	56.52	47.79	47.74
Total	41.58	44.51	44.51	44.50	53.41	49.59	49.58	58.78	50.00	49.94

[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 projections for energy crops after 2010.

[4]Cogenerators are facilities whose primary function is not electricity production.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capability is used to be consistent with electric utility capacity estimates. Electric utility capacity data are the most recent data available as of August 15, 1996. 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 capacity sources.

Sources: 1995 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report," 1995 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1995 generation: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

ble C18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1995	Projections								
		2005			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Marketed Renewable Energy[2]										
Residential	0.57	0.57	0.57	0.57	0.58	0.58	0.58	0.59	0.48	0.48
Wood	0.57	0.57	0.57	0.57	0.58	0.58	0.58	0.59	0.48	0.48
Commercial[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Biomass	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Industrial[4]	1.79	1.80	1.80	1.80	2.01	2.01	2.01	2.03	2.03	1.80
Conventional Hydroelectric	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Municipal Solid Waste	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Biomass	1.70	1.68	1.68	1.68	1.89	1.89	1.89	1.90	1.90	1.68
Transportation	0.06	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.08	0.88
Ethanol used in E85[5]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.11	0.11
Ethanol used in Gasoline Blending[6]	0.06	0.10	0.10	0.10	0.06	0.10	0.10	0.06	0.98	0.88
Electric Generators[7]	3.88	4.08	4.08	4.08	4.49	5.13	5.13	5.66	9.34	9.34
Conventional Hydroelectric	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19
Geothermal	0.39	0.58	0.58	0.58	0.60	1.31	1.31	0.91	1.93	1.93
Municipal Solid Waste	0.31	0.33	0.33	0.33	0.40	0.40	0.40	0.40	0.40	0.40
Biomass	0.07	0.08	0.08	0.08	0.11	0.60	0.60	0.60	1.83	1.83
Solar Thermal	0.01	0.01	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	0.00	0.00
Wind	0.03	0.03	0.03	0.03	0.03	0.03	0.70	0.45	1.90	1.90
Total Marketed Renewable Energy	6.36	6.60	6.79	6.60	7.25	8.10	8.10	8.83	12.83	12.83
Non-Marketed Renewable Energy[8]										
Selected Consumption										
Residential	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.10	0.10	0.10
Solar Hot Water Heating	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.10	0.10
Commercial	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Solar Thermal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06

[1]Actual heat rates used to determine fuel consumption for all renewable fuels consumed (except solar, and wind. Consumption of hydroelectric, solar, and wind energy [illegible] by using the fossil fuel equivalent of 10,260 Btu per kilowatthour[illegible].

[2]Includes nonelectric renewable energy groups for which the energy source is [illegible] and that are consumed either [illegible] marketed renewable energy inputs for electricity entering the marketplace [illegible].

[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.

[4]Includes all electricity production [illegible] industrial and other cogenerators [illegible].

[5]Excludes motor gasoline component of E85.

[6]Includes renewable energy [illegible] by the grid from electric [illegible] sectoral electricity energy [illegible].

[7]Includes selected renewable [illegible] consumption for which the energy [illegible] Administration does not estimate or project total consumption of [illegible].

N/A = Not available.

Btu = British thermal unit.

1344 Fixed = This 1990 Level Carbon Stabilization case targets [illegible] year ramp-in period.

1344 Average = This case targets the average of [illegible].

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

Sources: 1995 electric generators: Energy Information Administration (EIA), Form EIA-[illegible]; Form EIA-[illegible]; and "Renewable Energy Producer Report." 1995 ethanol: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95)/1 (Washington, DC, [illegible]); DOE [illegible]; EIA, Office of [illegible] Forecasting. Projections: EIA, AEO97 National Energy Modeling System [illegible].

Table C19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Residential										
Petroleum	25.0	25.1	24.8	24.9	23.7	21.7	22.0	22.3	20.2	20.2
Natural Gas	72.1	76.7	76.5	76.3	80.2	73.0	73.7	83.2	75.8	75.1
Coal	1.4	1.3	1.2	1.2	1.1	1.1	1.1	1.0	0.9	0.9
Electricity	175.6	191.4	185.6	186.0	216.5	124.3	126.1	264.6	133.0	125.3
Total	274.0	294.4	288.1	288.4	321.5	220.1	222.8	371.2	229.8	221.4
Commercial										
Petroleum	13.4	11.9	11.9	11.9	11.7	11.3	11.4	11.6	11.2	11.2
Natural Gas	45.8	49.4	48.3	48.2	51.0	47.8	48.1	54.8	51.0	50.7
Coal	2.0	2.1	2.1	2.1	2.3	2.2	2.2	2.4	2.4	2.4
Electricity	159.2	172.6	166.2	166.5	191.4	102.1	104.3	219.8	105.6	99.3
Total	220.2	236.0	228.5	228.8	256.9	163.5	166.0	288.5	170.2	163.7
Industrial[1]										
Petroleum	92.4	99.8	101.1	100.5	110.0	103.3	106.6	114.2	105.3	105.6
Natural Gas[2]	138.5	151.0	149.1	150.0	163.4	140.3	151.3	167.3	147.4	146.8
Coal	62.8	61.8	64.4	63.6	32.8	41.4	43.2	71.9	31.8	31.2
Electricity	170.5	187.7	184.4	185.4	210.0	119.8	122.0	240.7	114.5	106.3
Total	464.2	498.9	498.9	498.5	536.1	416.8	423.0	594.0	399.1	392.0
Transportation										
Petroleum	453.4	501.4	498.5	498.5	571.8	524.0	527.3	599.4	515.4	514.7
Natural Gas[3]	10.5	11.9	12.1	12.1	16.4	17.6	17.7	18.4	18.4	18.5
Other[4]	0.0	0.1	0.1	0.1	1.0	1.1	1.1	1.7	2.1	2.1
Electricity	3.0	1.2	1.3	1.3	4.0	3.5	3.6	5.6	7.8	7.3
Total	466.9	514.5	511.9	512.0	593.2	546.2	549.7	625.2	543.6	542.6
Total Carbon Emissions[5]										
Petroleum	584.2	638.0	636.3	635.7	717.2	663.3	667.2	747.5	652.1	651.6
Natural Gas	266.7	288.0	286.0	286.7	311.0	287.6	290.8	323.5	292.6	291.1
Coal	66.2	64.9	67.7	66.9	36.1	44.8	46.5	75.3	35.2	34.6
Other[4]	0.0	0.1	0.1	0.1	1.0	1.1	1.1	1.7	2.1	2.1
Electricity	500.3	552.9	537.5	539.2	620.6	349.8	355.9	730.8	360.8	340.3
Total	1423.5	1543.9	1527.5	1528.6	1716.2	1346.7	1361.6	1878.9	1342.8	1319.7
Electric Generators[6]										
Petroleum	14.4	11.4	10.0	10.1	11.9	3.7	3.8	15.1	3.3	3.1
Natural Gas	50.9	68.7	66.4	66.3	98.2	167.6	168.3	123.0	167.9	169.6
Coal	441.1	482.9	461.0	462.3	510.7	178.6	185.9	592.6	189.6	167.6
Total	506.3	552.9	537.5	538.2	620.8	349.8	358.9	730.8	360.8	340.3
Total Carbon Emissions[7]										
Petroleum	598.5	649.4	646.3	645.8	729.1	667.0	671.0	762.7	655.5	654.7
Natural Gas	317.6	348.7	352.4	353.0	409.2	455.2	457.1	446.5	460.5	460.7
Coal	507.3	547.8	528.8	529.8	576.9	223.2	232.4	667.9	224.8	202.2
Other[4]	0.0	0.1	0.1	0.1	1.0	1.1	1.1	1.7	2.1	2.1
Total	1423.5	1543.9	1527.5	1528.6	1716.2	1346.7	1361.6	1878.9	1342.8	1319.7
Carbon Emission (tons per person)	5.4	5.6	5.5	5.5	5.7	4.5	4.6	5.8	4.2	4.1

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]"Other" includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity as a by product of other processes.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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

Sources: Utility coal carbon emissions from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, DOE/EIA-0573 (Washington, DC, November 1994). Carbon coefficients from EIA, *Emissions of Greenhouse Gases in the United States 1995*, DOE/EIA-0573(93) (Washington, DC, October 1996). 1995 consumption estimates based on: EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). Projections: EIA, AEO97 National Energy Modeling System runs polbase.d032497a (1), f1344nX.d040997a (2), and avgV1344.d041297a (3).

Table C20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
World Oil Price (1995 dollars per barrel)[1]	17.28	18.13	18.13	18.13	20.53	20.53	20.53	22.17	22.17	22.17
Production[2]										
OECD										
U.S. (50 states)	9.29	8.76	8.76	8.77	8.71	8.89	8.89	8.77	9.17	9.15
Canada	2.44	2.55	2.55	2.55	2.35	2.34	2.34	2.24	2.23	2.23
Mexico	3.09	3.20	3.20	3.20	3.07	3.06	3.06	3.01	3.00	3.00
OECD Europe[3]	6.55	6.92	6.92	6.91	5.20	5.20	5.20	4.26	4.25	4.25
Other OECD	0.74	0.76	0.76	0.76	0.68	0.68	0.68	0.69	0.69	0.69
Total OECD	22.11	22.18	22.17	22.18	19.96	20.11	20.12	18.96	19.34	19.33
Developing Countries										
Other South & Central America	3.08	4.09	4.08	4.08	3.99	3.98	3.98	3.82	3.81	3.81
Pacific Rim	2.04	2.12	2.12	2.12	2.17	2.16	2.16	2.02	2.01	2.01
OPEC	28.07	33.09	33.03	33.00	50.65	49.28	49.33	59.91	57.55	57.55
Other Developing Countries	4.05	5.11	5.11	5.11	4.72	4.71	4.71	4.29	4.27	4.27
Total Developing Countries	37.21	44.39	44.32	44.29	61.53	60.12	60.18	70.05	67.64	67.64
Eurasia										
Former Soviet Union	6.96	7.28	7.28	7.28	9.43	9.41	9.41	10.12	10.08	10.08
Eastern Europe	0.31	0.27	0.27	0.27	0.21	0.21	0.21	0.18	0.18	0.18
China	3.02	3.14	3.14	3.14	3.00	2.99	2.99	2.95	2.94	2.94
Total Eurasia	10.29	10.69	10.69	10.69	12.64	12.61	12.61	13.26	13.21	13.21
Total Production	69.62	77.25	77.18	77.17	94.18	92.84	92.92	102.19	100.09	100.06
Consumption										
OECD										
U.S. (50 states)	17.73	19.35	19.26	19.25	21.60	19.94	20.06	22.66	19.83	19.81
U.S. Territories	0.26	0.30	0.30	0.30	0.39	0.39	0.39	0.41	0.42	0.42
Canada	1.76	1.88	1.88	1.88	2.14	2.16	2.16	2.25	2.29	2.29
Mexico	1.96	2.12	2.13	2.13	2.69	2.70	2.70	3.06	3.10	3.10
Japan	5.73	6.38	6.39	6.38	7.31	7.38	7.38	7.89	7.87	7.87
Australia and New Zealand	0.96	1.02	1.02	1.02	1.17	1.17	1.17	1.24	1.24	1.24
OECD Europe[3]	13.88	14.39	14.30	14.30	15.11	15.18	15.18	15.32	15.43	15.43
Total OECD	42.28	45.35	45.27	45.26	50.40	48.92	49.05	52.82	50.18	50.17
Developing Countries										
Other South and Central America	3.58	3.94	3.94	3.94	4.62	4.63	4.63	4.90	4.92	4.92
Pacific Rim	4.87	5.80	5.80	5.80	9.07	9.10	9.10	10.63	10.69	10.69
OPEC	4.94	5.62	5.62	5.62	7.09	7.06	7.06	7.91	7.91	7.91
Other Developing Countries	4.79	6.09	6.06	6.06	7.99	8.00	8.00	8.34	8.46	8.46
Total Developing Countries	18.19	21.45	21.42	21.42	28.78	28.78	28.78	31.78	31.98	31.98

Table C20. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	Projections								
		2000			2010			2020		
		Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average	Policy Base	1344 Fixed	1344 Average
Eurasia										
Former Soviet Union	4.75	4.89	4.89	4.89	6.74	6.76	6.76	7.62	7.66	7.66
Eastern Europe	1.39	1.49	1.49	1.49	1.72	1.73	1.73	1.95	1.96	1.96
China	3.31	4.40	4.41	4.41	6.89	6.94	6.93	8.52	8.61	8.61
Total Eurasia	9.46	10.78	10.79	10.79	15.35	15.43	15.42	18.09	18.23	18.23
Total Consumption	69.92	77.55	77.46	77.47	94.46	93.14	93.22	102.48	100.39	100.38
Non-OPEC Production	41.55	44.16	44.15	44.17	43.50	43.57	43.59	42.28	42.55	42.53
Net Eurasia Exports	0.83	-0.09	-0.10	-0.10	-2.71	-2.81	-2.81	-4.83	-5.02	-5.02
OPEC Market Share	0.40	0.43	0.43	0.43	0.54	0.53	0.53	0.59	0.57	0.58

[1]Average refiner acquisition cost of imported crude oil.

[2]Includes production of crude oil (including lease condensate), natural gas plant liquids, other hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.

[3]OECD Europe includes the united Germany.

OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).

Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.

OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.

1344 Fixed = This 1990 Level Carbon Stabilization case targets combustion-related carbon emission stabilization to the 1990 level (1344 million metric tons of carbon) using a five-year ramp-in period.

1344 Average = This case targets the average of combustion - related carbon emissions over the period 2010-2015 to be the 1990 level of carbon emissions.

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

Sources: 1995 derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). Projections: AEO97 National Energy Modeling System runs psfbase.d032497a (1), f1344nJ.d040897a (2), and avgV1344.d041297a (3).