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Annual Energy Outlook 1995

With Projections to 2010

January 1995

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

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Preface

The *Annual Energy Outlook 1995 (AEO95)* presents the midterm energy forecasts of the Energy Information Administration (EIA). This year's report presents projections and analyses of energy supply, demand, and prices through 2010, based on results from the National Energy Modeling System (NEMS). Quarterly forecasts of energy supply and demand for 1995 and 1996 are published in the *Short-Term Energy Outlook* (February 1995).

Forecast tables for the five cases examined in the *AEO95* are provided in Appendixes A through C. Appendix A gives historical data and forecasts for selected years from 1992 through 2010 for the reference case. Appendix B presents two additional cases, which assume higher and lower economic growth than the reference case. Appendix C presents two cases that assume higher and lower world oil prices.

Appendix D presents a summary of the forecasts in units of oil equivalence. Appendix E presents a summary of household energy expenditures. Appendix F provides detailed comparisons of the *AEO95* forecasts with those of other organizations. Appendix G briefly describes NEMS and the major *AEO95* forecast assumptions. Appendix H presents a standalone high electricity demand case. Appendix I provides a table of energy conversion factors and a table of metric conversion factors.

The *AEO95* projections are based on Federal, State, and local laws and regulations in effect on August 15, 1994. They include the fuel taxes in the Omnibus Budget Reconciliation Act of 1993, the Clean Air Act Amendments of 1990, the Energy Policy Act of 1992, and provisions of the Climate Change Action Plan. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the forecasts.

Carbon emissions projections in *AEO95* were calculated using carbon coefficients from the report *Emissions of Greenhouse Gases in the United States 1987-1992*, published in October 1994. The coefficients are revised from those used in *AEO94*, which were based on the previous report, *Emissions of Greenhouse Gases in the United States 1985-1990*, published in September 1993.

The *AEO95* definition of petroleum product imports incorporates imports of unfinished oils, alcohols, ethers, and blending components, which were not included in the *AEO94* definition. The definition was modified so that import dependency projections would align more closely with the historical series in the *Annual Energy Review* and with the product import definition in the *Short-Term Energy Outlook*. As a result, the projection of the percentage of U.S. petroleum consumption met by imports is higher in 2010 by 2.7 percent than it would have been with the *AEO94* definition.

The *AEO95* projections are used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors. They are published in accordance with Section 205(c) of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the Administrator of EIA to prepare an annual report that contains trends and projections of energy consumption and supply.

The cover graphic (designed by Gerald Quinn Information Design, Cabin John, MD) depicts a highly efficient lighting system being used to light the exterior of the Forrestal Building, U.S. Department of Energy, in Washington, DC (photos courtesy of Lightstruck Studios, Baltimore, MD, and U.S. Department of Energy).

The new lighting system, unveiled in October 1994, demonstrates a new sulfur lamp invented, designed and built by Fusion Lighting, Inc., of Rockville, MD, under contract to the U.S. Department of Energy. In a scientific and technological breakthrough, sulfur gas is excited by microwave energy to produce an extremely bright and highly efficient white light that closely matches the properties of sunlight. The light emitted by one of the golf-ball-sized sulfur bulbs is equal to the light from 250 standard 100-watt incandescent lamps. In the Forrestal Building application, the 240-foot-long light pipe, powered by a single electrodeless sulfur bulb at each end, has replaced 240 conventional mercury high-intensity discharge (HID) 200-watt lamps.

Not yet commercially available, the new lamps are not included in the *AEO95* forecasts. However, many new lighting applications, already commercially available, are included in this year's forecasts.

DISCLAIMER

ERRATA

Annual Energy Outlook 1995

DOE/EIA-0383(95)

- **On page 4, the value for Net Imports of Petroleum in the Reference Case should be 26.02, not 26.24.**

- **On page 37, Table 15, values for EIA forecasts of the natural gas wellhead price in 2010 should be revised as follows:**

	AEO91	AEO92	AEO93
Wellhead Price (1993 dollars per thousand cubic feet)	5.53	5.10	3.88

- **On page 47, Figure 74, the label "High Oxygen" should be "High Oxygen/Reformulated."**

- **On page 157, corrections to EIA forecasts should appear as follows:**

	EIA *AEO95*		
	Reference	Low Economic Growth	High Economic Growth
2000			
Wellhead Price (1993 dollars per thousand cubic feet)	2.14	1.98	2.36
2010			
Wellhead Price (1993 dollars per thousand cubic feet)	3.39	3.01	3.74
Consumption (trillion cubic feet)	24.55	23.15	25.84
Residential	4.89		

Please direct any questions to the National Energy Information Center.

National Energy Information Center
Energy Information Administration
Room 1F-048, Forrestal Building
(202) 586-8800

We regret any inconvenience this may have caused.

Released for Printing: February 2, 1995

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The *Annual Energy Outlook 1995 (AEO95)* is based on the National Energy Modeling System (NEMS)—a tool for energy policy analysis that builds upon earlier EIA modeling systems used to forecast energy prices, supply, demand, and imports over the midterm period (15 to 20 years).

This year's *Outlook* covers the gamut of energy issues, but several themes stand out. First, primary fuel price projections for 2010 from recent *Annual Energy Outlooks* have consistently declined in real terms. In some cases, the decreases from levels projected as recently as in *AEO94* are substantial. Second, this year's effort looks more closely at the impacts of technology by portraying different cases for technology penetration rates that are either faster or slower than in the reference case forecast.

Energy prices

The forecast price of a barrel of oil in 2010 is $24 in this year's *AEO*, compared with $29 in last year's publication (1993 dollars). Although the magnitude varies, prices of all fuels are projected to be lower than EIA forecast last year.

The prices of all primary fuels in real terms have followed a jagged trajectory over the past 10 years. The price trend has generally moved downward. Motor gasoline is now cheaper on a per gallon basis than almost any liquid that can be purchased at the grocery store. However, a progression of recent environmental regulations and initiatives—including the Clean Air Act Amendments of 1990, the Energy Policy Act of 1992, and the Climate Change Action Plan—are projected to increase demand for low-sulfur coal and natural gas and reverse the otherwise flat or downward price trends in recent years.

EIA projects that the nominal prices of primary fuels will rise faster than the general rate of inflation over the forecast period. In real terms, however, primary fuel prices in 2010 continue to decline from levels forecast in recent *Annual Energy Outlooks*. Projected increases in crude oil production (and capacity) by the Organization of Petroleum Exporting Countries, expanded estimates of economically recoverable reserves for oil and gas, and improved labor productivity for coal have all dampened expectations for future price increases. Larger reserves and improved productivity result, in part, from advances in technology.

Technological and productivity changes

In order to reflect the uncertainties attached to forecasting, EIA has traditionally incorporated high and low growth cases for oil prices and the economy. Such an approach expands the range of possibilities and demonstrates the impact of these variables on energy supply and demand. Because of their importance, we have continued to provide these cases.

It has become increasingly clear, however, that changes in technology have a large impact on energy, similar to that of oil price increases and economic growth. Because of the difficulties of forecasting the development and market penetration of new technologies, EIA has moved in recent forecasts to focus more attention on the impacts of technology and to look at what happens in the individual NEMS modules if technology penetration is slower or faster than anticipated.

On the supply side, increased penetration of new technology and higher labor productivity lead to expanded reserves, increased output, and, as discussed above, lower prices relative to *AEO94*. On the demand side, a faster pace for technology penetration increases efficiency, consequently reducing demand. The "what if" technology cases contained in this *AEO* demonstrate the sensitivities to technology change across the energy system. Our assumptions about technology lead this year's forecast to have lower fuel prices. The cases with higher penetration of demand-side technologies suggest considerable potential to reduce consumption growth even more than the levels forecast in the reference case.

Customer outreach

This year for the first time, PC versions of the majority of the NEMS modules, based on *AEO94*, have been made available to users. We expect the modules for *AEO95* to be completed and ready for shipment early in 1995. This step was taken with input from the NEMS/*AEO* user community. This year's *AEO* presents projections that incorporate customer feedback from the NEMS/*AEO* Conference held in April 1994 and two scenario development workshops held later that year.

Administrator's Message

For *AEO95*, NEMS has been significantly streamlined on our mainframe computer, but the mainframe is still relatively inaccessible to outside users. To make the *entire* NEMS system more accessible to our customers (as opposed to the individual modules currently available on PC), we have purchased three RISC-based UNIX systems and have begun moving the NEMS model for *AEO95* onto these workstations. Our goal is to run *AEO96* entirely on the RISC machines, and if we are successful we will make that version of the model available to our users.

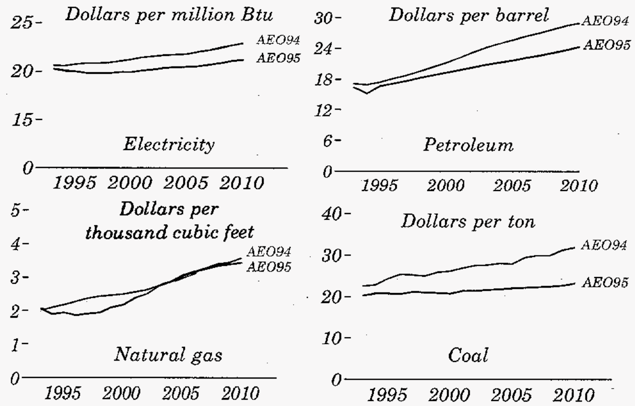
The third annual NEMS/*AEO* Conference is planned for February 28, 1995, in Arlington, Virginia. A registration form is included in the back of this publication. We invite and encourage your participation in this important event. Whether or not you are able to attend, we welcome your comments concerning the results presented in this year's *AEO*.

Because it deals with energy in such a comprehensive way, the *AEO* is one of EIA's most valuable publications, and one of the most difficult to produce. Changes in one part of the model have impacts throughout the model, requiring great discipline and interaction. I especially appreciate the diligent work of the staff of the Office of Integrated Analysis and Forecasting in dealing with these tough issues and making this effort such a success.

Jay E. Hakes
Administrator
Energy Information Administration

Fuel Price Projections in *AEO95* Lower Than Last Year's

Figure 1. Fuel price projections, 1993-2010: AEO94 and AEO95 compared (1993 dollars)



In the *Annual Energy Outlook 1995 (AEO95)*, projected world oil prices are significantly lower than those in the *Annual Energy Outlook 1994 (AEO94)* (Figure 1). In 2010, the average price is slightly more than $24 dollars per barrel (in 1993 dollars), $4.67 lower than in *AEO94*. The difference is the result of a reassessment of international oil markets and the potential for production from the Organization of Petroleum Exporting Countries (OPEC).

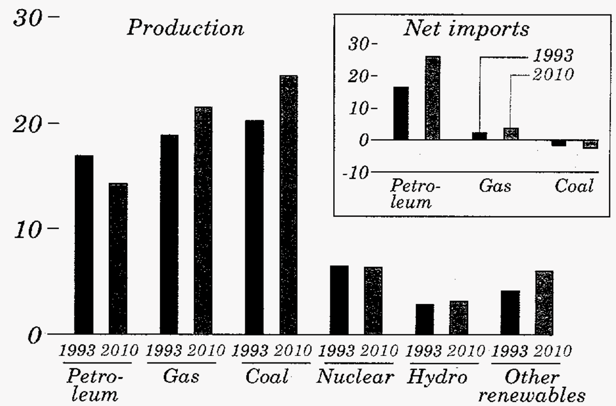
Wellhead prices of natural gas increase over most of the forecast but at a slower rate than was projected last year. The average price in 2010 reaches $3.39 per thousand cubic feet, compared with $3.55 in *AEO94*. The lower prices result from a revised appraisal of the impacts of technology improvements on oil and gas production. Delivered prices rise even more slowly than the wellhead price, because the average costs of transmission and distribution decline over most of the projection period.

Projected minemouth coal prices rise more slowly than in the *AEO94* forecast, at an average annual rate of 0.8 percent, reflecting trends of increasing productivity and lower demand for coal in the electric utility sector and for export.

The *AEO95* electricity price projections are also lower than those in *AEO94*, with an average annual growth rate of only 0.3 percent a year, due to lower input fuel prices and reduced requirements for new capacity. Recent trends to deregulate and unbundle the electricity market have the potential to contribute to even lower prices in the future.

Decline in Crude Oil Production Offset by Gas, Coal, and Renewables

Figure 2. Energy production and imports by source, 1993 and 2010 (quadrillion Btu)



Domestic crude oil production continues to decline through most of the forecast period, at an average annual rate of 1.4 percent (Figure 2). Despite significantly lower projections of world oil prices, the projected production in 2010 is slightly higher than that in *AEO94*, because of a more optimistic assessment of technologies affecting both crude oil and natural gas supply. With production declining and demand increasing over most of the forecast, the share of petroleum consumption met by net imports reaches 59 percent in 2010 (in terms of barrels per day), compared with 44 percent in 1993.

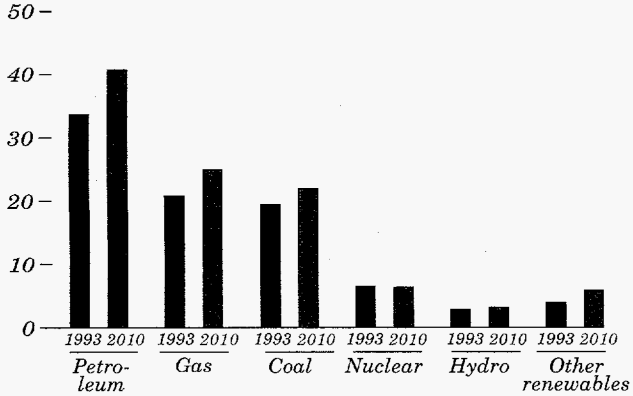
Growth in natural gas consumption is met by increases in both production and imports, primarily from Canada. Production increases at an average annual rate of 0.8 percent between 1993 and 2010, satisfying more than half the growth in consumption by 2010. Coal production increases by an average of 1.1 percent a year through 2010, to meet the demand for coal in both domestic and export markets.

Renewable energy production grows significantly throughout the projection period—at 1.6 percent a year—primarily for electricity generation. Conventional hydropower increases only slightly, but other renewable sources, including ethanol for transportation uses, increase more rapidly.

Nuclear power increases through the middle part of the next decade, then declines as existing plants are retired. By 2010, nuclear power production is only slightly below the 1993 level, because of improved performance of existing units.

Oil and Natural Gas Show Largest Increases in Consumption

Figure 3. Energy consumption by source, 1993 and 2010 (quadrillion Btu)



Consumption of petroleum grows at an average annual rate of 1.1 percent through 2010 (Figure 3). The largest share of petroleum consumption, approximately two-thirds, is in the transportation sector, with a 1.4-percent annual growth rate. Increased vehicle efficiency over the projection period is offset by an increase in vehicle-miles traveled.

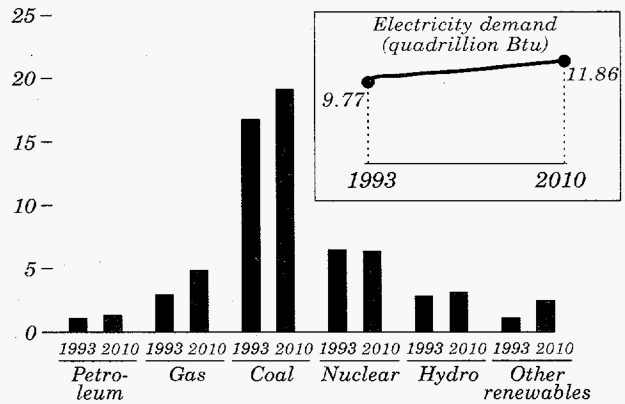
Natural gas consumption increases at an average rate of 1.2 percent a year, led by a rapid increase in gas-fired electricity generation [*1*]. Consumption of gas for generation in 2010 is 1.8 quadrillion British thermal units (Btu) higher than in 1993. Because of its competitive price, gas consumption also grows significantly in the industrial sector, with much of the increment used for cogeneration.

Coal consumption for electricity generation—nearly 90 percent of total coal use in 2010—grows at an average annual rate of 0.8 percent (Table A2). Total coal use grows by 0.7 percent a year. Consumption of renewables, including hydropower, increases from 6.6 to 8.9 quadrillion Btu between 1993 and 2010 (Table A17). In 2010, 5.9 quadrillion Btu of renewables are used for electricity generation, including cogeneration. The balance is used for dispersed heating and cooling and for blending into vehicle fuels.

Increasing capacity utilization and the addition of two new units lead to the increased use of nuclear power for generation through the next 12 years [*2*]. But by 2010, retirements of existing plants cause a slight reduction in nuclear generation relative to 1993 levels.

Gas and Renewables Have Increasing Shares in Electricity Generation

Figure 4. Electricity fuel consumption by fuel type, 1993 and 2010 (quadrillion Btu)



Demand for electricity grows at an average annual rate of 1.1 percent (Figure 4), lower than the economic growth rate of 2.2 percent, primarily because of increased performance standards for new energy-using equipment. Electricity use is the largest source of energy growth in the buildings sectors. Industrial demand for electricity also grows faster than total energy use in that sector, as new electricity-using technologies continue their penetration.

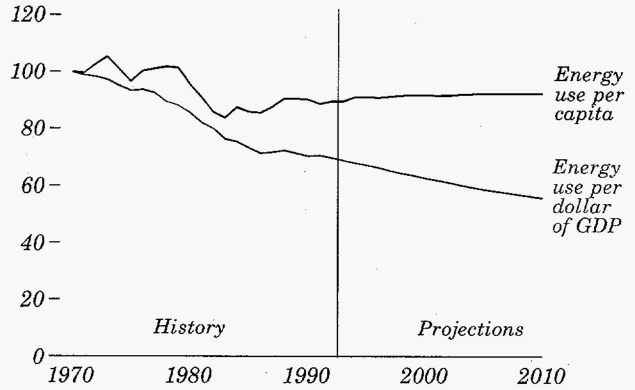
Although it is only about 15 percent of the end-use energy consumed, electricity use has a larger role in the Nation's energy balance because of the roughly 3-to-1 conversion factor from primary fuel to electricity. About 36 percent of primary energy consumed in the United States is used for electricity generation. Thus, a Btu saved at the plug by the use of more efficient appliances saves nearly 3 Btu of fuel.

Coal remains the primary fuel for generation, but natural gas use has a higher growth rate, an average annual rate of 2.8 percent. Gas-fired units are cleaner than coal-fired units, less costly to construct, and have shorter construction leadtimes. The share of coal in generation declines slightly between 1993 and 2010, while the natural gas share increases.

Consumption of renewable energy sources for generation also increases. Hydropower and geothermal remain the primary and secondary renewable sources, about 62 and 16 percent, respectively, in 2010. Wind is the fastest-growing renewable generation source, at an average 13-percent annual rate, as a result of technology improvements.

Continued Decline in Energy Intensity Expected, But at a Slower Rate

Figure 5. Energy use per capita and per dollar of gross domestic product, 1970-2010 (index, 1970 = 100)



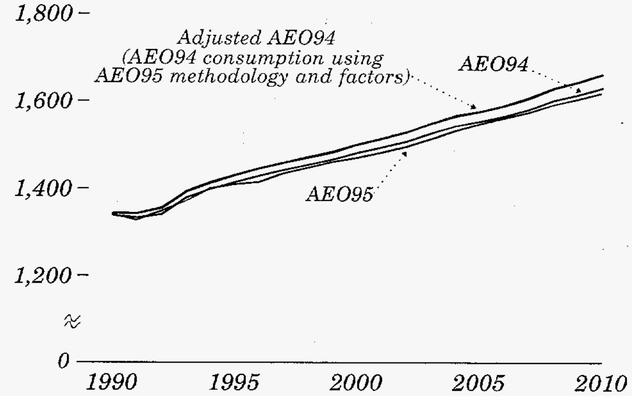
From 1970 to the mid-1980s, U.S. energy intensity declined—both energy use per capita and per dollar of gross domestic product (GDP) (Figure 5). Energy use per capita began to increase in the mid-1980s, as energy prices dropped. With projections of low prices and increasing demand for energy services, that trend is expected to continue. Energy use per person is likely to increase very slightly, at an average rate of 0.2 percent a year through 2010.

Energy use per dollar of GDP is projected to continue declining from 1993 through 2010, at an average annual rate of 1.2 percent. The expected rate of decline is slower than that seen in the 1970s and early 1980s (nearly 2 percent), when the economy shifted to less energy-intensive industries and increasingly efficient technologies. Low energy prices and the growth of more energy-intensive industries contribute to the slower rate of decline in the projection period.

The Energy Policy Act of 1992 (EPACT) and the National Appliance Energy Conservation Act of 1987 (NAECA) mandate additional efficiency standards for new energy-using equipment in the buildings sectors (residential and commercial) and for motors in the industrial sector. As demands for energy services and prices increase, additional investment in new technologies is anticipated, leading to further declines in energy intensity. Additional analyses in this report highlight the improvements that have already been achieved and those that could result from more energy-efficient technologies.

Carbon Emissions Continue to Rise, But Projections for 2010 Are Lower

Figure 6. U.S. carbon emissions, 1990-2010 (million metric tons)



Emissions of carbon from energy combustion are projected to increase from 1,376 million metric tons in 1993 to 1,621 million tons in 2010 (Figure 6). The projection of emissions is lower than the published *AEO94* projection of 1,632 million metric tons. The reduction is less than would be expected with the lower energy consumption levels in *AEO95*, because of revised carbon factors and methodology.

The *AEO95* carbon emissions forecasts are derived from coefficients in the EIA report *Emissions of Greenhouse Gases in the United States 1987-1992*, published in October 1994. Revised carbon factors and sequestration rates for industrial nonfuel use of energy produce an increase of about 8 million metric tons in the projected emissions in 2010. Computing *AEO94* emissions using the *AEO95* factors and a revised methodology in the transportation sector yields a revised *AEO94* emissions total of 1,663 million metric tons in 2010 and a net reduction of 42 million metric tons for *AEO95*.

AEO95 includes analysis of the provisions of the Climate Change Action Plan (CCAP) to stabilize U.S. carbon emissions by 2000, relative to 1990. But CCAP used a lower baseline projection of emissions; and more rapid growth in emissions in the early 1990s than assumed for CCAP, projected moderate prices, and CCAP funding curtailments make achieving stabilization more difficult. Increased investment in carbon mitigation programs or more rapid adoption of voluntary programs could lead to reductions from the projected emissions levels.

Table 1. Summary of results for five cases

Sensitivity Factors	1992	1993	2010 Reference	2010 Low Economic Growth	2010 High Economic Growth	2010 Low World Oil Price	2010 High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	17.55	16.91	14.23	13.75	14.74	10.21	15.97
Natural Gas	18.37	18.90	21.51	20.49	22.57	20.02	21.82
Coal	21.59	20.23	24.51	23.93	25.30	24.28	24.63
Nuclear Power	6.61	6.52	6.36	6.36	6.36	6.36	6.36
Renewable Energy/Other	7.14	7.06	9.25	8.79	9.68	8.94	9.57
Total Primary Production	**71.25**	**69.62**	**75.86**	**73.32**	**78.66**	**69.82**	**78.37**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	14.99	16.47	26.24	24.73	27.41	33.85	23.24
Natural Gas	1.97	2.17	3.66	3.24	3.91	3.24	3.71
Coal/Other (- indicates export)	-2.27	-1.46	-1.89	-2.16	-1.70	-2.03	-2.06
Total Net Imports	**14.68**	**17.18**	**27.78**	**25.80**	**29.62**	**35.06**	**24.88**
Discrepancy	-0.32	0.46	0.22	0.24	0.21	-0.17	0.28
Consumption (quadrillion Btu)							
Petroleum Products	33.56	33.71	40.82	39.03	42.74	44.20	39.92
Natural Gas	20.15	20.81	25.30	23.86	26.60	23.38	25.66
Coal	18.87	19.43	21.97	21.36	22.83	21.59	22.08
Nuclear Power	6.61	6.52	6.36	6.36	6.36	6.36	6.36
Renewable Energy/Other	6.43	6.80	9.41	8.75	9.95	9.18	9.51
Total Consumption	**85.61**	**87.27**	**103.88**	**99.36**	**108.48**	**104.71**	**103.53**
Prices (1993 dollars)							
World Oil Price (dollars per barrel)	18.70	16.12	24.12	23.29	24.99	14.65	28.99
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.80	2.02	3.39	3.01	3.74	2.88	3.51
Domestic Coal at Minemouth (dollars per short ton)	21.57	19.85	22.77	22.25	24.13	21.39	23.68
Average Electricity Price (cents per kilowatthour)	7.1	6.8	7.2	6.8	7.5	7.0	7.3
Economic Indicators							
Real Gross Domestic Product (billion 1987 dollars)	4,986	5,136	7,485	6,949	8,028	7,537	7,456
(annual change, 1993-2010)	--	--	2.2%	1.8%	2.7%	2.3%	2.2%
GDP Implicit Price Deflator (index, 1987=1.00)	1.211	1.242	2.074	2.724	1.823	2.062	2.082
(annual change, 1993-2010)	--	--	3.1%	4.7%	2.3%	3.0%	3.1%
Real Disposable Personal Income (billion 1987 dollars)	3,633	3,701	5,140	4,889	5,396	5,180	5,118
(annual change, 1993-2010)	--	--	2.0%	1.7%	2.2%	2.0%	1.9%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.077	1.097	1.598	1.491	1.716	1.609	1.591
(annual change, 1993-2010)	--	--	2.2%	1.8%	2.7%	2.3%	2.2%
Energy Intensity							
(thousand Btu per 1987 dollar of GDP)	17.17	16.99	13.88	14.30	13.51	13.89	13.88
(annual change, 1993-2010)	--	--	-1.2%	-1.0%	-1.3%	-1.2%	-1.2%

Notes: Specific assumptions underlying the alternative cases are defined in Chapter 1. Quantities are derived from historical volumes and assumed thermal conversion factors. Production of renewable/other includes renewable sources of energy, liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of other includes coal coke and electricity. Some of the refinery inputs appear as petroleum product consumption. Consumption of renewable/other includes renewable sources of energy, net coal coke and electricity imports, liquid hydrogen, and methanol.

Source: Tables A1, A8, A19, B1, B8, B19, C1, C8, and C19.

Key Assumptions in the Forecasts

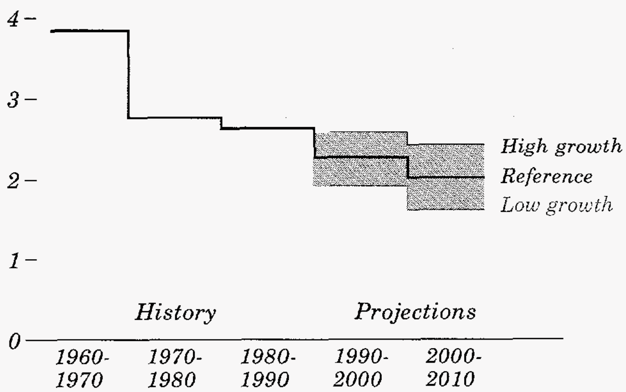
The National Energy Modeling System

The National Energy Modeling System (NEMS) generated the projections in this report. NEMS uses a unified modeling system to forecast alternative energy futures in the middle term—a time horizon of 20 years, in which the economy and the nature of energy markets are understood sufficiently well to allow for considerable structural and regional detail. Like its predecessors at the Energy Information Administration (EIA), NEMS incorporates a market-based approach to energy analysis, balancing energy supply and demand for each fuel and consuming sector and taking into account the economic competition among energy sources.

Economic growth

Economic growth rates, historically and in the NEMS cases, affect all market activities, including energy supply and demand. In the *AEO95* projections, the economy's output, as measured by real GDP, is expected to grow by 2.2 percent a year between 1993 and 2010 (Figure 7). GDP grows at a slightly declining rate over the forecast period, continuing a long-term trend. The long-run potential for economic growth depends on growth in the labor force, capital stock, and labor productivity. The slowing of the economic growth rate in large part reflects demographic changes.

Figure 7. Average annual real GDP growth rate by decade, 1960-2010 (percent)



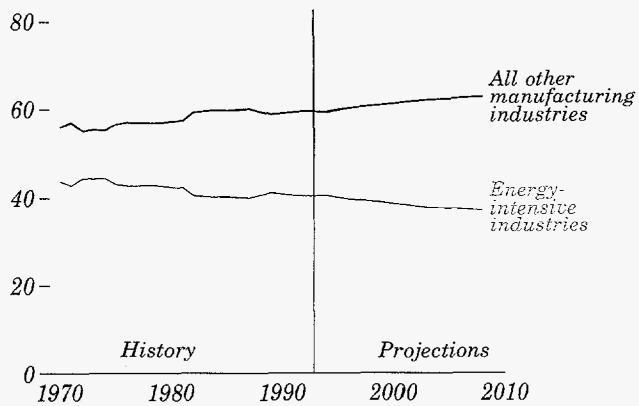
The labor force grows by 1.2 percent a year on average over the forecast horizon, with population growth of 0.9 percent a year. The labor force participation rate increases to a peak in 2005, then declines as "baby boom" cohorts reach retirement age.

In the last 15 years of the forecast, the labor force grows more slowly. At the same time, there is a slight decline in the rate of productivity growth. Consequently, the GDP growth rate slowly declines, averaging 2.5 percent a year from 1995 to 2000 and 1.8 percent from 2005 to 2010.

Productivity growth is key to achieving the long-run GDP growth rate of 2.2 percent. Productivity is expected to increase on average by 1.1 percent a year, with fixed business investment and research and development expenditures in the private sector contributing to real output gains. Savings as a share of GDP increases over time as the government deficit is reduced. Increasing the pool of funds available for investment is an important ingredient for boosting long-term economic growth.

Overall manufacturing growth in the forecast averages 2.2 percent annually from 1993 to 2010. Energy-intensive industries grow at a slower average rate of 1.7 percent a year. Thus, their share of manufacturing output declines (Figure 8). Other, non-energy-intensive manufacturing industries grow at a faster rate, 2.6 percent a year, because two major non-energy-intensive manufacturing industries—electronic equipment and industrial machinery—grow by more than 3.0 percent annually.

Figure 8. Shares of total manufacturing output, 1970-2010 (percent)



The six major energy-intensive industries are chemicals, food processing, paper, petroleum refining, primary metals, and stone, clay, and glass. Among those six industries, chemicals show the fastest growth—2.5 percent annually. The refining industry has the slowest growth rate, averaging only 0.9 percent a year from 1993 through 2010.

To analyze the uncertainty in energy market activity associated with varying economic conditions, two cases with alternative economic growth rates are presented. The *low economic growth case* (low growth) assumes an average economic growth rate of 1.8 percent a year. The *high economic growth case* (high growth) assumes a 2.7-percent growth rate. Labor force and productivity growth rates are correspondingly lower and higher, so that both contribute roughly equally to economic growth, as described above for the reference case.

Other published forecasts of long-term economic growth by economic forecasting firms range from 1.7 percent to 2.9 percent a year (Table 2). The 2.2-percent economic growth rate for the *AEO95* reference case is close to the growth rate in the Data Resources, Inc. (DRI) base case. The WEFA Group, Inc. (WEFA) assumes a somewhat higher growth rate. The basis for the higher rate relates to more optimistic expectations for productivity improvement and labor force growth. By 2010, WEFA assumes that 70 percent of the population aged 16 and over will be in the labor force and DRI only 67 percent.

Table 2. Comparative forecasts of economic growth, 1993-2010

	Average annual percentage growth		
Forecast	*Real GDP*	*Labor force*	*Productivity*
AEO95			
Low	1.8	0.9	0.9
Reference	2.2	1.2	1.1
High	2.7	1.4	1.3
DRI			
Low	1.7	0.9	0.8
Base	2.3	1.2	1.1
High	2.8	1.4	1.3
WEFA			
Low	2.0	1.2	0.8
Base	2.5	1.4	1.1
High	2.9	1.5	1.4

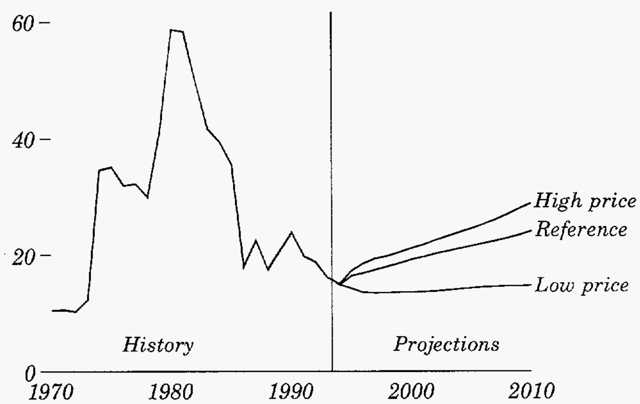
A forecast of expected economic growth through 1999 is also available from the Council of Economic Advisors [*3*]. Their February 1994 forecast, the latest available, projects real GDP growth of 2.4 percent a year from 1990 to 1999, with both labor force and productivity growing by 1.2 percent a year. Over the same period, *AEO95* forecasts a comparable overall annual GDP growth rate of 2.3 percent.

The *AEO95* overall economic growth rate is not substantially different from the *AEO94* rate. Between 1990 and 2010, real GDP grows by 2.1 percent a year in both forecasts. In *AEO94*, manufacturing output was expected to grow by 2.4 percent a year, compared with 2.0 percent in *AEO95*.

World oil prices

In the *AEO95* reference case, the world oil price path (Figure 9) is lower throughout the forecast than it was in *AEO94*. In 1993 dollars, the projected price in 2000 is about $19.10 per barrel (compared with $21.20 in *AEO94*), and in 2010 the price is about $24.10 ($28.80 in *AEO94*). The lower prices reflect the assumption that member nations of the Organization of Petroleum Exporting Countries (OPEC), particularly in the Persian Gulf, will produce more oil than was assumed previously.

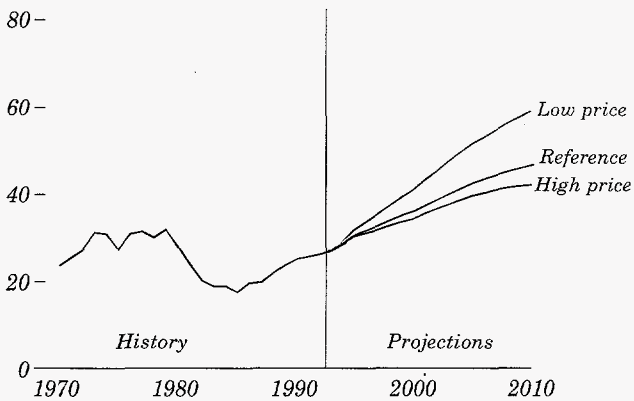
Figure 9. World oil prices, 1970-2010 (1993 dollars per barrel)



To reflect the uncertainty in world oil markets, two additional *AEO95* cases are presented—the *low world oil price case* (low price) and *high world oil price case* (high price). The two cases are based on different assumptions about oil production from OPEC countries and the posture of Eurasian nations (the former Soviet Union [FSU], Eastern Europe, and China) in international oil markets. The low price case uses optimistic production rates from OPEC and Eurasia (mainly the FSU) coupled with a pessimistic economic growth outlook for Eurasia (mainly China). It is consistent with market events over the past several years (excluding the Persian Gulf war). The high price case uses pessimistic production rates for OPEC and Eurasia and an optimistic economic growth outlook for Eurasia.

Variation in OPEC production levels is one of the key assumptions used to generate the low and high price paths for *AEO95* (Figure 10). In all cases, OPEC oil production grows significantly through the mid-1990s. The reference case assumes that Persian Gulf producers will substantially expand production, and even in the high price case (which is associated with lower production), OPEC production in 2010 is nearly twice its 1990 level.

Figure 10. OPEC oil production, 1970-2010 (million barrels per day)



The low price path assumes that OPEC production will be near the maximum feasible, because of competition among producers and aggressive development to bring additional reserves into production. Consequently, production levels in 2010 are more than twice the recorded 1990 output.

The low price case does reflect recent market trends, but the current low prices may be difficult to maintain. The Persian Gulf crisis provided impetus for most OPEC countries to expand production. In the aftermath of the war, most observers expected capacity to expand by at least 10 million barrels a day by 2000, but the persistence of lower prices in the early 1990s has somewhat tempered that optimistic outlook [*4*]. OPEC argues that low prices result in insufficient capital for investment in capacity expansion. In addition, the international oil companies whose capital OPEC hoped to attract are deferring investment decisions until their own revenues improve [*5*].

Most oil market analyses agree that OPEC will continue capacity expansion after the year 2000 to meet growing demand [*6*]. *AEO95* projects OPEC production of 47 million barrels a day by 2010 in the reference case, 42 in the high price case, and 59 in the low price case. However, many estimates have OPEC capacity peaking and stabilizing at a level of 45 to 50 million barrels a day [*7*]. Two reasons are given. First, capacity additions after 2000 must offset production declines from old fields in the Middle East (some of them "super-giant" complexes). Second, OPEC producers are not inclined to develop fields that contain heavy crude oils, and those fields make up a substantial part of total reserves. Whereas there is considerable potential to expand capacity in such fields, particularly in Saudi Arabia and Venezuela, OPEC argues that worldwide downstream refining capacity is not sophisticated enough to upgrade heavier crude oils into lighter products.

Non-OPEC oil production in the *AEO95* projections follows a path similar to that in *AEO94*, after accounting for the lower oil prices. Production rises slightly through 2000, then declines in the 2000-2010 decade. Production in mature producing areas, such as the United States, declines over time, as is normal for older oil fields. Offsetting the declines are increases in production from areas with expanded capacity or new discoveries, including Latin America and the North Sea.

Economic growth is a major determinant of the *demand* for oil throughout the world, and the fastest growth is projected for the developing countries. Particularly high growth rates are expected for the Pacific Rim. Demand growth of 2.5 percent a year is expected for developing countries and 1.5 percent for countries in the Organization for Economic Cooperation and Development (OECD).

Comparisons with other oil price forecasts are shown in Table 3. The range between the *AEO95* low and high price cases spans the range of other published forecasts.

Table 3. Comparative forecasts of world oil prices

	1993 dollars per barrel		
Forecast	2000	2005	2010
AEO95 reference case	19.13	21.50	24.12
AEO95 low price case	13.52	14.25	14.65
AEO95 high price case	21.15	24.55	28.99
DRI	19.98	24.67	28.07
WEFA	18.75	20.36	21.36
IEA	22.93	27.91	27.91
GRI	18.58	—	20.54
PEL	15.95	14.96	14.96
NRC	24.19	25.24	25.24
CEC	21.06	23.21	25.56

Legislation

The *AEO95* forecasts assume that all Federal, State, and local laws and regulations in effect as of August 15, 1994, will remain unchanged through 2010. The impacts of pending or proposed legislation and sections of existing legislation for which funds have not been appropriated are not reflected.

The projections include the provisions of the Climate Change Action Plan (CCAP), a set of 44 actions designed to achieve carbon stabilization in the United States by 2000, relative to 1990. Of the 44 actions, 13 are not related to energy fuels and are not incorporated in the analysis. Emissions in the early 1990s have grown more rapidly than projected at the time the plan was formulated, and the forecasts of continued moderate prices make it more difficult to achieve stabilization. Funding for many of the CCAP programs has been curtailed in budget negotiations at the time of this analysis, and their full impact is not reflected. Restoration of government investment in carbon mitigation programs or more rapid adoption of voluntary programs could lead to lower emissions levels.

Other major pieces of recent Federal legislation included in the forecasts are the Omnibus Budget Reconciliation Act of 1993 (which adds 4.3 cents per gallon to the Federal tax on highway fuels), the Clean Air Act Amendments of 1990 (CAAA90), and the Energy Policy Act of 1992 (EPACT). The provisions of EPACT focus primarily on reducing energy demand. Minimum building efficiency standards are required for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and owners of automobile and truck fleets must phase in vehicles that do not rely on petroleum products. CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, primarily through the use of reformulated gasoline. Electric utilities are required by CAAA90 to reduce annual emissions of sulfur dioxide to less than 9 million short tons a year in 2000 and after.

Cases

Five sets of comprehensive, integrated forecasts are presented in this report: the reference, high and low macroeconomic growth, and high and low oil price cases. Results are also given for additional analyses in the supply, demand, and conversion sectors, based on different assumptions important to each sector. The alternative analyses do not entail complete, integrated analyses of all energy sectors, but focus on each specific sector in isolation.

Data

The forecasts were prepared using the most current data available as of August 15, 1994. At that time, most 1992 data but only partial 1993 data were available. The projections also incorporate the 1994 forecasts from EIA's *Short-Term Energy Outlook* published in August 1994.

Some adjustments were made to EIA data series for definitional consistency and to avoid double counting. For example, the *State Energy Data Report* includes, in industrial consumption, energy consumed by independent power producers, exempt wholesale generators, and cogenerators. Cogeneration is accounted for in the industrial sector, but other nonutility generators are included in the electricity sector. Thus, there are some differences between this report and EIA data reports. In addition, the level of detail in the model prohibits a precise reproduction of EIA's historical data as presented in the source documents.

Carbon emissions

Carbon emissions forecasts in *AEO95* are based on carbon coefficients from the report *Emissions of Greenhouse Gases in the United States 1987-1992* (published in October 1994), which differ somewhat from those used in *AEO94*. The revised coefficients increase projected carbon emissions by approximately 5 million metric tons in 2010. However, sequestration rates for nonfuel use of fossil fuels in the industrial sector are lower, and as a result, net estimated emissions are 8 million metric tons higher.

Mid-term and short-term modeling at EIA

The National Energy Modeling System (NEMS) used to produce the *AEO95* projections is a detailed, regional, mid-term model of the U.S. energy industry. As an example of its complexity, each supply and conversion activity incorporates those regions that are most appropriate for the fuel or energy source—electricity, oil, gas, coal, and renewable fuels—while the entire system produces a balance at the Census Division level. NEMS also represents the feedback of the domestic energy sector with the rest of the domestic economy, and with the international oil market. NEMS provides a rich palette of options for analysis of various legislative and policy initiatives, including the Clean Air Act Amendments of 1990 (CAAA90), EPACT, and the Climate Change Action Plan.

EIA also maintains a short-term energy model, the Short-Term Integrated Forecasting System (STIFS), projections from which are published in the quarterly *Short-Term Energy Outlook (STEO)*. STIFS is a quarterly, econometric, national model of the U.S. energy system, designed to forecast up to eight quarters into the future. Because it is econometric, it has the ability to capture the impacts on near-term energy markets of such short-term phenomena as the business cycle, short-term fluctuations in world oil prices, and fluctuations in energy stocks. Because STIFS is a national model, it is less suited for analysis of the distributional impacts of perturbations of energy markets than are regional models. And because it is primarily econometric, it has limited capability for examining the impacts of policy initiatives.

There are certain assumptions and design differences that cause NEMS and STIFS to yield different projections for common years. The electricity demand forecasts in NEMS assume efficiency improvements as a result of legislative incentives (EPACT and NAECA) and demand-side management initiatives. To the extent that these adjustments have not yet appeared in the data, STIFS does not capture them. STIFS incorporates a "discrepancy" adjustment to balance supply and demand for natural gas, which is similar to the "discrepancy" published in EIA's historical data series. NEMS assumes that supply will exactly balance demand, and no such data adjustment is necessary.

In both models the level of industrial energy consumption is driven by the level of industrial output in the economy, which is determined by a macroeconomic model. While both STIFS and NEMS use the same macroeconomic model, they use different measures for industrial output. STIFS uses the Federal Reserve Board (FRB) indices of production as drivers for industrial energy demand. To satisfy its requirements for greater detail in output for specific industries, NEMS uses projections of gross output by industry as the industrial energy demand drivers. Typically, the growth rates of the FRB indices used for STIFS have been higher than those for the gross output numbers used in NEMS, yielding a higher growth for industrial demand—and consequently for industrial energy consumption—in the *STEO* than in the *AEO* projections for the short term.

Since STIFS is designed to capture near-term trends, readers requiring only short-term forecasts for 1995 are referred to EIA's November 1994 *STEO* and later editions. In using the *AEO95* forecasts, readers should note that the 1993 data which appear in the report represent the latest available historical data. These data have replaced the model results for 1993 and may show growth trends that differ from those produced by the model. For more information on the detailed annual model forecasts produced by NEMS, readers are referred to the Office of Integrated Analysis and Forecasting. EIA's forecasting reports should be used with reference to the specific issues that each addresses—in the case of the *STEO*, the short-term response of energy markets to changes in world oil prices, stocks, weather, and the business cycle; and in the case of the *AEO*, the longer term response to changes in technology, productivity, and efficiency.

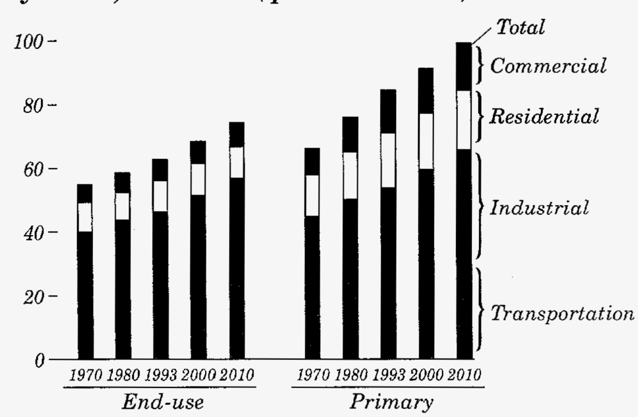
Energy Demand by End Use

Energy consumption

In the reference case, the United States is projected to consume 104 quadrillion Btu of primary energy resources in 2010, 19 percent more than in 1993. (Primary energy consumption includes fuels used directly by consumers, in addition to energy used for electricity generation and distribution.) GDP is 46 percent higher in 2010 than in 1993, and the population is 16 percent larger. Thus, on a per-capita basis, energy use is projected to increase slightly, while the overall energy intensity of the economy continues to decline.

Between 1970 and 1980, the transportation sector accounted for most of the increase in end-use energy consumption (Figure 11). Other sectors showed relatively little growth in end-use energy consumption, but because they relied increasingly on electricity, there was a 15-percent increase in primary energy use. Between 1980 and 1993, energy prices (adjusted for inflation) were either stable or declined, and end-use energy consumption increased in all sectors.

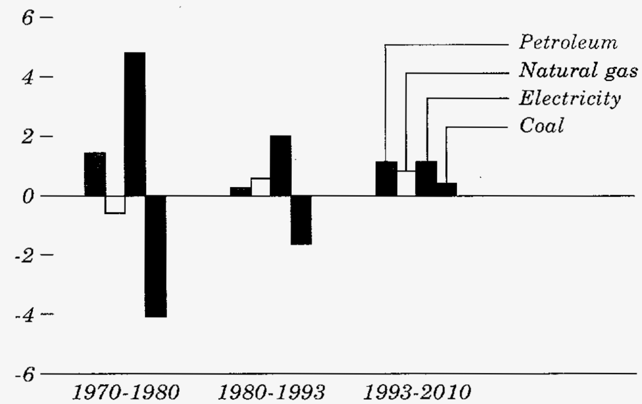
Figure 11. End-use and primary energy consumption by sector, 1970-2010 (quadrillion Btu)



Between 1993 and 2010, the residential and commercial sectors show little growth in end-use energy consumption. Energy efficiency improvements, in part mandated by legislation, largely offset energy consumption increases due to increases in the number of residential and commercial buildings. The industrial and transportation sectors, where growth in energy use is more sensitive to growth in the economy, account for about 90 percent of the projected increase in end-use energy consumption between 1993 and 2010 in the reference case.

During the 1970s, electricity consumption grew rapidly as electricity-based technologies such as air conditioning became commonplace in homes, workplaces, and commercial establishments. Between 1980 and 1993, electricity consumption grew more slowly (Figure 12). Lower growth rates are expected for electricity consumption throughout the forecast, as a result of improved efficiency and, for some applications, market saturation.

Figure 12. Growth in end-use energy consumption by fuel, 1970-2010 (percent per year)

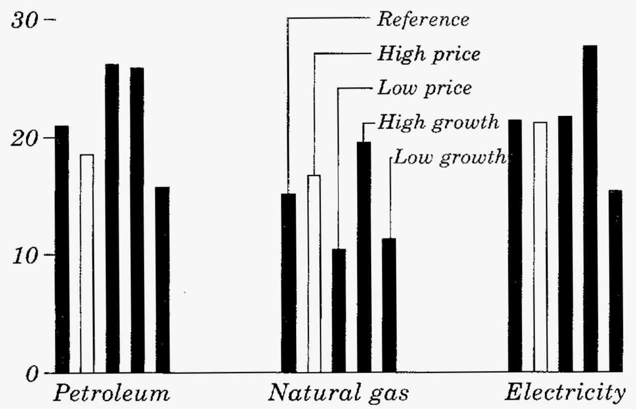


In the transportation sector, petroleum demand grew modestly during the 1970s. Rising fuel prices and new Federal vehicle efficiency standards dampened the growth in petroleum consumption between 1980 and 1993. Demand for transportation fuels rises slowly in the forecast, as a larger vehicle population and increased travel in the context of stable oil prices more than offset improvements in average fleet efficiency.

Regulation of natural gas markets during most of the 1970s had the effect of limiting the availability of natural gas. As a result, natural gas use declined. Between 1980 and 1993, as gas supplies became more certain and regulations on end uses were removed, natural gas markets expanded—a trend that is expected to continue over the forecast. The largest increase is in the industrial sector, due to increasing use of natural gas for heat and power, chemical feedstocks, and cogeneration. Natural gas meets 26 percent of end-use energy requirements by 2010, at an annual consumption level of 20.5 quadrillion Btu.

Oil price and economic growth assumptions are key inputs in developing energy use forecasts. Since the future path of oil prices or economic growth is uncertain, alternative price and growth assumptions were employed to highlight the sensitivity of the forecast to different oil price and economic growth paths (Figure 13). A variation of 0.4 percent a year in economic growth rate can cause a variation of 3 quadrillion Btu (or 4 percent) in end-use energy demand in 2010. Electricity and transportation demands for petroleum are most sensitive to variations in economic growth rates. Low oil prices tend to reduce natural gas demand and increase oil consumption compared with the reference case, whereas higher oil prices have an opposite but lesser effect.

Figure 13. Increase in energy consumption from 1993 to 2010 by fuel (percent)



Household energy expenditures

A new feature in *AEO95* is the projection of average expenditures for energy use in households, as summarized in Table 4. More detailed estimates by income, race, and geographic location are presented in Appendix E of this report. In the forecast, average household expenditures for energy increase by 12 percent through 2010. Most of the increase is for motor gasoline through 2000. Higher equipment efficiencies associated with recent standards are expected to dampen growth in energy expenditures for home use.

Table 4. Average household energy expenditures, 1993, 2000, and 2010 (1993 dollars)

Year	Total	Home	Motor gasoline
1993	2,203	1,201	1,002
2000	2,359	1,175	1,184
2010	2,463	1,266	1,197

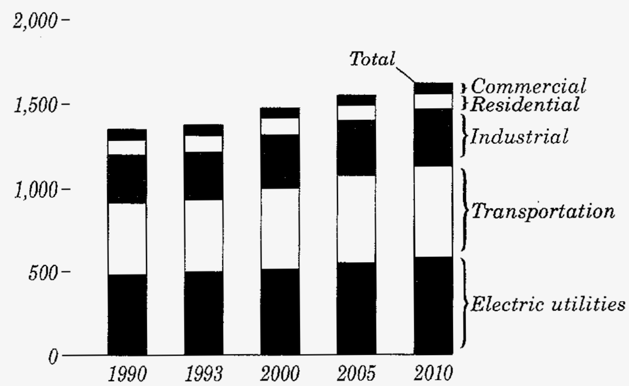
Carbon emissions

All fossil fuels are hydrocarbons, made up of molecules containing hydrogen and carbon atoms. Combustion of fossil fuels releases virtually all their carbon into the atmosphere. Hydrocarbon fuels do vary in their carbon content: of the major fossil fuels, natural gas emits the least carbon per million Btu burned while coal emits the most.

During combustion, carbon generally combines with oxygen to form both carbon monoxide (CO) and carbon dioxide (CO_2). CO is a major contributor to localized air pollution, and new gasoline blends with added oxygenates are being used in many areas to reduce CO emissions. Such gasolines, however, do not substantially reduce the total level of carbon emitted into the atmosphere.

Energy end uses account for about two-thirds of all energy-related carbon emissions, and electric utilities account for the remaining one-third. The *AEO95* reference case (which includes estimates of the impact of the CCAP) shows total carbon emissions increasing by 18 percent (245 million metric tons) between 1993 and 2010 (Figure 14). Low energy prices, coupled with substantial economic growth, have already led to an estimated 2-percent increase in carbon emissions between 1990 and 1993.

Figure 14. Carbon emissions by sector, 1990-2010 (million metric tons per year)



Four-fifths of the projected increase in carbon emissions between 1993 and 2010 results from increased fuel consumption in the transportation and electric utility sectors, where growth in fossil fuel demand outpaces modest improvements in fuel efficiency.

Primary and end-use energy consumption

This chapter focuses on choices made by end-use consumers. Their choices are influenced by energy prices, technology performance and cost characteristics, and mandated equipment efficiency standards (which are specified by energy source). Unless otherwise noted, consumption estimates in this chapter are expressed in terms of Btu of energy delivered to end-use consumers. Similarly, end-use energy prices are expressed in the common unit of 1993 dollars per million Btu (Table A3). End-use prices include all the direct costs associated with providing energy to the point of use. For electricity the costs are considerable, and the delivered price to end-use consumers is generally over 3 times that of any other energy source. Although end-use electricity applications are efficient, on average more than 3 Btu of energy are used to generate and deliver 1 Btu of electricity at the plug.

The use of electricity provides a practical means of substituting coal, nuclear, and renewable energy for direct use of fossil fuels; however, it is not likely to lower Btu energy requirements overall. Primary energy consumption (Table A1), which includes electricity generation and transmission losses, is projected to reach 104 quadrillion Btu by 2010, compared with total delivered energy of only 78 quadrillion Btu.

Energy consumption in 2010 by sector

Sector	End-use		Primary	
	quadrillion Btu	percent of total	quadrillion Btu	percent of total
Residential	10.9	14	19.3	19
Commercial	7.3	9	14.9	14
Industrial	31.3	40	40.4	39
Transportation	28.9	37	29.3	28
Total	**78.4**	**100**	**103.9**	**100**

In terms of total sectoral energy consumption (Figure 11), the difference between end-use and primary energy consumption for each sector reflects the degree to which the sector uses electricity. Within a sector the distinction between end-use and primary energy consumption is important for evaluating the potential net savings to the economy that would result from conservation measures. In the residential sector, space heating—fueled primarily by natural gas—dominates end-use energy requirements (Figure 16). In contrast, end uses such as space cooling and refrigeration depend almost exclusively on electricity. Improving energy efficiency for such end uses could substantially reduce the Nation's primary energy requirements.

For the transportation sector, which relies mainly on petroleum-based products, the difference between end-use and primary energy consumption measures is small. In the commercial sector, however, electricity accounts for more than two-fifths of end-use energy requirements, and end-use Btu measures for the sector reflect only about half the total Btu requirements of commercial buildings.

In 2010 the residential and commercial sectors, which together account for 63 percent of electricity demand, make up only 23 percent of total *end-use* energy consumption. In contrast, they account for 33 percent of total *primary* energy requirements. The distinction is particularly important for conservation and technology improvement efforts. For example, programs to improve building shell efficiencies—such as stricter building codes—can significantly reduce both space heating and cooling requirements, resulting in reduced electricity demand and even greater savings in primary energy consumption.

Carbon emissions also can be measured at the source (end use) (Table A17, Figure 14) or attributed to the end-use sectors where electricity is consumed (primary). The distinction is important because end-use sectors differ in their relative reliance on electricity. The primary carbon emissions shares of the residential and commercial sectors, for example, are more than twice their shares of direct, or end-use, emissions.

Carbon emissions in 2010 by sector

Sector	End-use		Primary	
	million metric tons	percent of total	million metric tons	percent of total
Residential	94	9	288	18
Commercial	60	6	232	14
Industrial	335	32	544	34
Transportation	548	53	557	34
Total	**1,037**	**100**	**1,621**	**100**

Alternative energy efficiency cases

In the *AEO95* forecasts, energy efficiency improvements play an important role in moderating the growth of energy consumption. The rate at which new, more efficient technologies will be adopted in the marketplace, however, remains one of the key uncertainties in mid-term and long-term energy forecasting. This chapter includes end-use cases that contrast the reference case consumption forecasts with forecasts based on alternative assumptions about efficiency improvements. The alternative estimates are based solely on the end-use energy demand models. As such, they do not account for any feedback effects on either energy prices or economic growth. Brief descriptions follow; complete descriptions for each end-use sector are provided in Appendix G.

For the residential and commercial sectors, two similar but slightly different alternative cases are compared with the reference case: a *1993 technology case*, in which equipment efficiencies are based on the technologies available in 1993; and a *best technology case*, in which the most energy-efficient technologies available in each forecast year are chosen. Entirely new technology applications, such as the use of fuel cells to generate electricity in homes, are not considered.

In the industrial and transportation sectors, two alternatives to the reference case are also presented. One, the *1993 technology case*, parallels the methodology used in the residential and commercial sectors. The 1993 technology case assumes that average efficiencies for equipment sold in 1993 will be sustained throughout the forecast period. The other alternative case, the *high efficiency case*, assumes that efficiency gains in the future will match those achieved between 1970 and 1990, when the average rate of energy efficiency improvement in the industrial sector was 1.9 percent a year and average on-road car efficiency increased by 1.3 percent a year. In contrast, in the reference case, industrial efficiency improves at an average rate of 0.9 percent a year and on-road car efficiency at 0.7 percent a year.

Climate Change Action Plan

The CCAP was developed by the Clinton Administration in response to a worldwide commitment to stabilize greenhouse gas concentrations in the atmosphere at levels that would prevent "dangerous anthropogenic interference with the climate system" [*8*]. The goal of the plan was to stabilize greenhouse gas emissions in 2000 at their 1990 levels. Emissions include carbon dioxide, methane, nitrous oxide, and other gases. Energy use is the primary source of carbon emissions and constitutes 87 percent of the total.

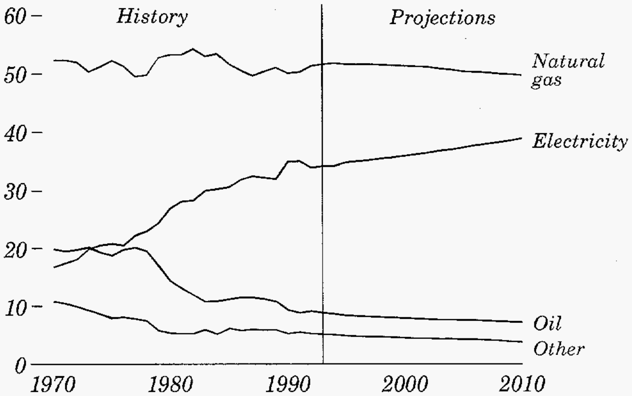
This report accounts for carbon releases from fuel combustion and related activities. However, emissions of other gases from other sources, such as methane from landfills and agriculture, are not considered. Moreover, NEMS does not provide a net emissions balance that takes into account carbon "sinks," such as forests, which remove carbon from the atmosphere.

Estimates of energy consumption in the *AEO95* reference case include a significant decline in the growth rate of carbon emissions as a result of anticipated improvements in end-use equipment and building shell efficiencies. Additional assumptions made to account for the incremental carbon savings from CCAP provisions are enumerated in the *AEO95 Supplement* [*9*].

As shown in Figure 14, residential and commercial buildings are expected to have stable on-site carbon emissions as they rely increasingly on electricity to meet their energy requirements. Industrial sector carbon emissions are expected to increase, but at a lower rate than energy use, as natural gas use increases relative to other fossil fuels. In the transportation sector, carbon emissions are expected to grow at about the same rate as energy consumption, because petroleum products remain the dominant transportation fuel.

Electricity Share of Residential Energy Use Rises, Other Fuels Decline

Figure 15. Fuel shares of residential nonrenewable energy consumption, 1970-2010 (percent of total)



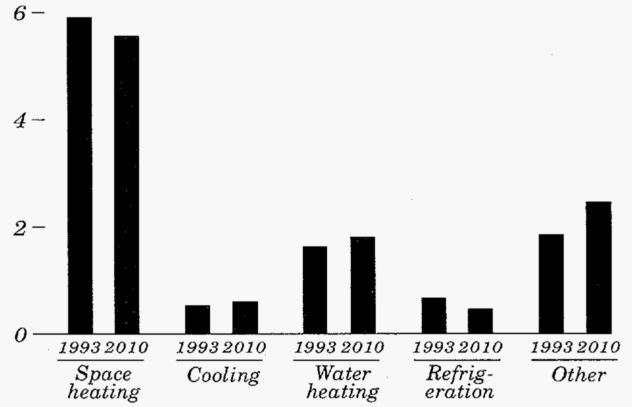
Over the past two decades, electricity's share of residential energy demand has doubled (Figure 15), as electrically powered services such as air conditioning have become commonplace in American households. In 1970, fewer than 40 percent of new single-family homes were equipped with central air conditioning, compared with 78 percent in 1993 [*10*]. In 1985, as many as 30 percent of new single-family homes had electric air-source heat pumps as the primary space heating devices [*11*]. With competition from natural gas increasing, only 24 percent of new homes used heat pumps in 1993 [*12*]. Tighter Federal appliance efficiency standards are also expected to slow future growth in residential electricity demand to 0.9 percent a year from 1993 to 2010.

Natural gas is expected to continue to account for about 50 percent of residential energy use throughout the forecast, virtually the same share as in 1993. While the number of households using gas rises, overall gas demand is stable as a result of substantial gains in end-use efficiency.

Distillate use has fallen considerably over the past 20 years because of a shrinking customer base and improved efficiency of oil heating equipment. Further declines are projected, with declines in new distillate-fueled installations and conversions of existing units to natural gas.

Space and Water Heating Continues To Dominate Residential Energy Use

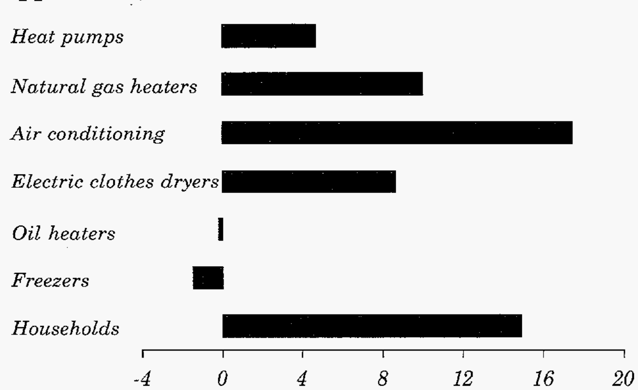
Figure 16. Residential energy consumption by end use, 1993 and 2010 (quadrillion Btu)



Space and water heating are the two most energy-intensive services in the residential sector (Figure 16), accounting for over two-thirds of residential energy use in the forecast. Space heating continues to dominate energy use in the sector, but a 19-percent decline in average heating energy intensity between 1993 and 2010 is expected to reduce overall energy requirements for space heating. In addition, refrigerators and freezers are projected to use nearly 31 percent less total electricity in 2010 than in 1993.

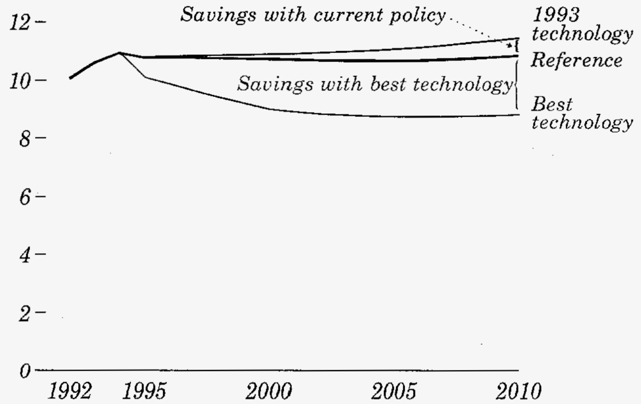
Growth in households and appliances (Figure 17) is a major determinant of residential energy consumption. Air conditioning and natural gas heaters grow substantially during the forecast period, as most new homes are built with them and additional units are added through retrofits of existing stock. Freezers and distillate-fueled heaters decline in use.

Figure 17. Cumulative net additions of residential appliances, 1993-2010 (million units)



Improved Appliances Could Provide Significant Energy Savings

Figure 18. Residential energy consumption in three cases, 1992-2010 (quadrillion Btu)



The *AEO95* reference case incorporates the effects of current policies aimed at increasing residential end-use efficiency, such as minimum efficiency standards for appliances, new building codes, and "Golden Carrot" programs to promote manufacturing innovations [*13*]. In contrast, the 1993 technology case, which assumes that all new equipment will only be as efficient as the mix of equipment sold in 1993, requires 6 percent more energy than the reference case in 2010 (Figure 18). In the best technology case, which assumes that the most energy-efficient equipment will always be chosen (regardless of cost), energy use is almost 19 percent below the reference case in 2010 [*14*]. Table 5 provides a summary of changes in stock average appliance efficiencies across the three cases. Also included in the table are the average efficiencies for 1993 new purchases and the best available efficiencies in 1993.

Natural Gas Appliances Have the Greatest Potential for Improvement

Figure 19. Cumulative residential energy savings from improved technology, 1995-2010 (quadrillion Btu)

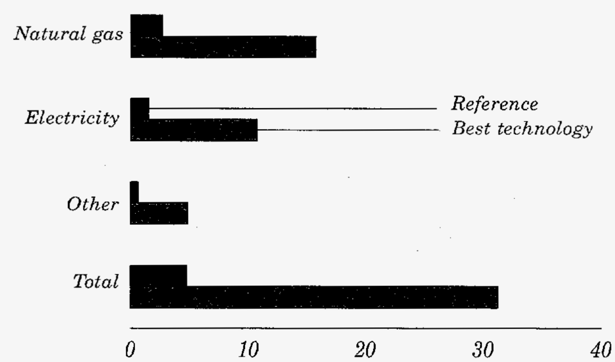


Figure 19 shows cumulative energy savings from 1995 through 2010 that are expected in the reference case and the best technology case, as compared with the 1993 technology case [*15*]. The reference case saves almost 5 quadrillion Btu of residential energy use between 1995 and 2010—nearly equal to the energy requirements of all residential appliances other than space heaters in 1993. More than half the savings come from better natural gas space heaters, the largest single application of any residential fuel.

The best technology case shows even more dramatic savings in cumulative energy use through 2010. More than 31 quadrillion Btu of end-use energy could be saved if the most energy-efficient technologies available were purchased between 1995 and 2010.

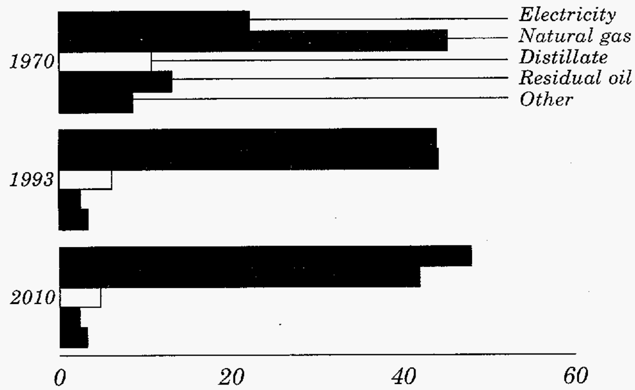
Table 5. Residential appliance stock average efficiencies, 1993 and 2010

	1993			2010		
Equipment type	*Stock average*	*New purchases*	*Best available*	*Reference case*	*1993 technology*	*Best technology*
Furnace (annual fuel utilization efficiency)						
Natural gas	0.70	0.83	0.96	0.82	0.81	0.90
Distillate oil	0.74	0.83	0.89	0.83	0.82	0.86
Cooling systems						
Electric heat pumps (seasonal energy efficiency ratio)	9.20	10.86	16.00	10.91	10.83	14.70
Central air conditioners (seasonal energy efficiency ratio)	9.01	10.56	16.90	10.52	10.50	15.70
Room air conditioners (energy efficiency ratio)	7.77	8.88	12.10	10.28	8.85	11.97
Water heaters (energy factor)						
Electric	0.84	0.86	2.50	0.91	0.86	1.90
Natural gas	0.52	0.54	0.72	0.56	0.54	0.68
Refrigerators (kilowatthours per year)	1,356	902	599	768	930	723
Building shell integrity (index, 1993 = 1.00)	1.00	NA	NA	0.94	0.97	0.80

NA = not available.

Electricity Claims Increasing Share of Commercial Energy Use

Figure 20. Fuel shares of commercial nonrenewable energy consumption, 1970, 1993, and 2010 (percent)



Projected energy use trends in the commercial sector feature an increasing market share for electricity, a stable share for natural gas, and declining shares for petroleum and other fuels (Figure 20). Growth in electricity consumption is expected to slow considerably from the pace over the past two decades, with significant efficiency gains attributed to recent equipment standards, government programs aimed at increasing efficiency, and lower growth in commercial floorspace. Much of the growth in electricity is due to continued penetration of office equipment.

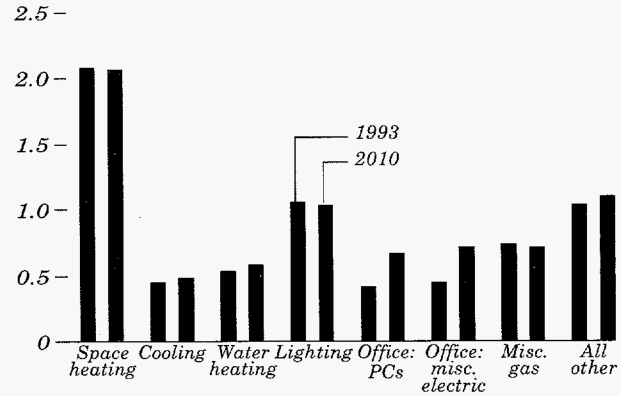
During the past 10 years, the share of energy supplied by natural gas in the commercial sector has ranged between 40 and 44 percent, as increases in gas-heated floorspace were offset by the improved efficiency of gas-using equipment. Natural gas continues to be the fuel of choice for space heating and water heating, but no new end uses are expected to increase its share.

Distillate's share has dropped by half since 1970, but no further major declines in its current market share (about 7 percent) are anticipated. The stability of the distillate share is attributable to the historically low levels of its projected price.

Renewable energy currently accounts for only a small part of commercial energy use (0.2 percent). Its share is expected to more than double by 2010, with anticipated gains in solar technologies.

Most Commercial Energy Uses Show Little or No Growth

Figure 21. Commercial energy consumption by end use, 1993 and 2010 (quadrillion Btu)

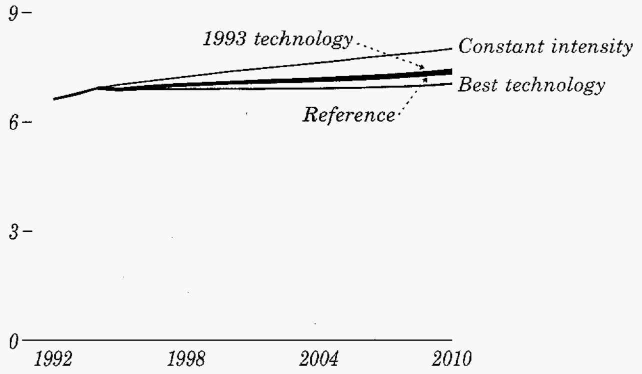


Between 1993 and 2010, new commercial floorspace is added at an average rate of 1 percent a year in the reference case. Commercial energy use is expected to grow at half that rate. Only two of the major commercial end uses of energy—office personal computers and miscellaneous electric office equipment—have projected growth rates in excess of floorspace growth (Figure 21). For the other end uses, which are assumed to be at full market penetration, increases in energy consumption are the net of consumption by new equipment resulting from floorspace additions, offset by savings resulting from retrofits with more energy-efficient equipment in existing floorspace.

Consumption of electricity for lighting remains practically unchanged over the forecast period, implying an average efficiency increase of over 1 percent annually. Most of the efficiency gain comes from the replacement of existing equipment with more efficient lighting. The forecast for lighting includes the estimated effects of the Environmental Protection Agency's Green Lights program. Participants in Green Lights will replace existing equipment as long as the payback of the project is greater than the prime rate plus 6 percentage points. If energy consumption for lighting grew at the same rate as floorspace, total electricity consumption in 2010 would be about 240 trillion Btu, or roughly 7 percent higher than in the reference case.

Current Technologies Can Provide Significant Future Energy Savings

Figure 22. Commercial energy consumption in four cases, 1992-2010 (quadrillion Btu)



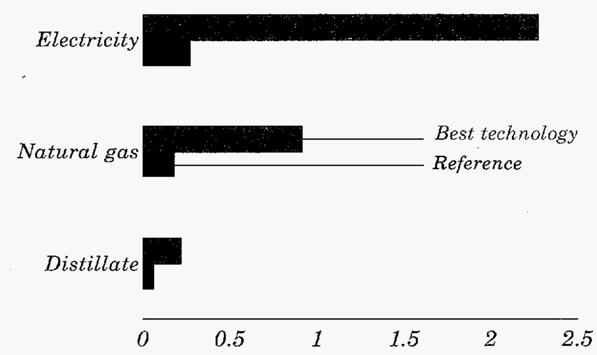
In the reference case, efficiency gains in the commercial sector can be attributed largely to equipment available for purchase today. The 1993 technology case and the best technology case vary from the reference case in their treatment of market penetration of new technologies. The 1993 technology case limits equipment choices in all years to the technologies available in 1993. The best technology case restricts choices to the most energy-efficient equipment available in each forecast year, regardless of cost (for example, the most efficient electric space heater competes with the most efficient gas space heater) [*16*].

The reference case forecast is only slightly below that of the 1993 technology case (Figure 22), mainly because most of the reference case choices are made within the efficiency range of equipment available in 1993. If commercial energy intensity were frozen at 1994 levels over the forecast, energy consumption would be nearly 0.6 quadrillion Btu higher in 2010 than projected in the reference case.

Opportunities for additional savings of 0.3 quadrillion Btu a year by 2010 could be gained by the use of the best available technologies. In the best technology case, only the most efficient available technologies are selected, such as heat pumps for water heating. Potential energy savings from completely new technologies, such as fuel cells for on-site electricity generation, are not included in the best technology case.

Electricity-Using Equipment Has the Greatest Potential for Improvement

Figure 23. Cumulative commercial energy savings from improved technology, 1995-2010 (quadrillion Btu)



The most significant opportunities for energy savings in the commercial sector are provided by technologies that use electricity and natural gas (Figure 23). From 1995 through 2010, cumulative energy savings of 0.5 quadrillion Btu are projected in the reference case relative to the 1993 technology case. Savings of more than 3 quadrillion Btu are projected in the best technology case, primarily from improvements in electric equipment.

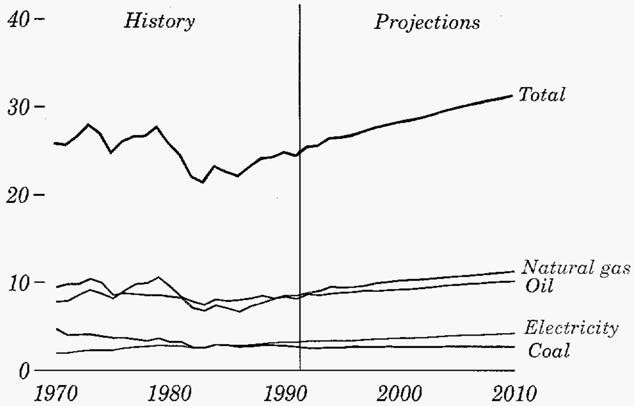
In the best technology case, the most important contributions to savings in electricity use are from lighting, ventilation, and space heating end uses. Technologies contributing to these savings are improved fluorescent lighting, efficient variable-speed ventilation systems, and more efficient heat pumps for both space and water heating (Table 6). The biggest contributions to energy savings for natural gas and distillate are from space heating equipment.

Table 6. Increase in efficiency of most efficient equipment available, relative to 1989 stock (percent)

	1990	1995	2010
Electric heat pumps	5.1	62.2	73.1
Electric air conditioners	34.8	43.5	69.6
Electric water heaters	22.4	132.9	132.9
Ventilation systems	0.0	25.0	25.0
Fluorescent lighting	14.4	34.8	38.5
Gas furnaces	11.4	14.3	22.9
Gas chillers	17.4	21.7	28.5
Gas water heaters	13.0	20.3	20.3
Distillate furnaces	5.9	12.4	12.4
Distillate water heaters	13.0	13.0	13.0

Industrial Fuel Shares Stable As Total Consumption Rises

Figure 24. Industrial energy consumption by fuel, 1970-2010 (quadrillion Btu per year)

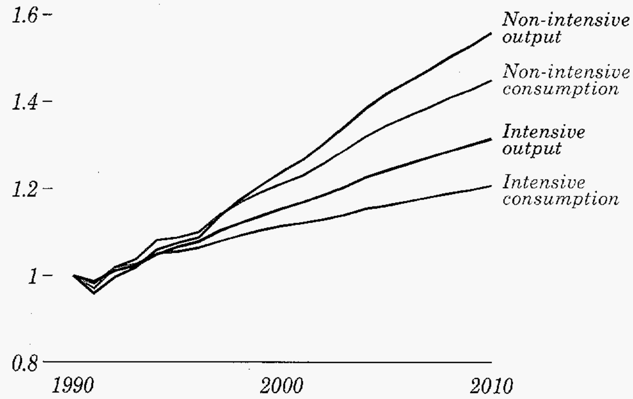


Overall energy use in the industrial sector—which includes the agriculture, mining, and construction (nonmanufacturing) industries in addition to traditional manufacturing industries—has not grown over the past two decades (Figure 24). However, there has been a shift in consumption toward electricity (early in the period) and natural gas (more recently). In the forecast, industrial use of purchased electricity grows at a significantly slower rate than was seen in the early 1980s, reflecting significant efficiency gains in electricity-based processes as well as increased reliance on self-generated electricity.

Natural gas is used both as a raw material (feedstock) in the chemical industry and as a fuel in other industrial applications. Between 1993 and 2010, gas consumption grows at an average annual rate of 1.3 percent, reaching 11.3 quadrillion Btu (including lease and plant fuel) by 2010. High prices and concerns over possible supply shortages have curtailed the use of oil as an industrial boiler fuel, but there have been recent increases in the use of petroleum as a feedstock for petrochemicals, as a byproduct fuel in refineries, and as a motor fuel in the nonmanufacturing industries. This trend is expected to continue. The use of coal for steelmaking, which dropped radically during the 1970s, is not expected to recover. As a boiler fuel, coal faces competition from natural gas, but its use in industrial boilers increases by 1.4 percent a year in the forecast because projected coal prices are more stable than either natural gas or oil prices.

Less Energy-Intensive Manufacturing Industries Grow Faster

Figure 25. Industrial energy consumption and production, 1990-2010 (index, 1990 = 1)



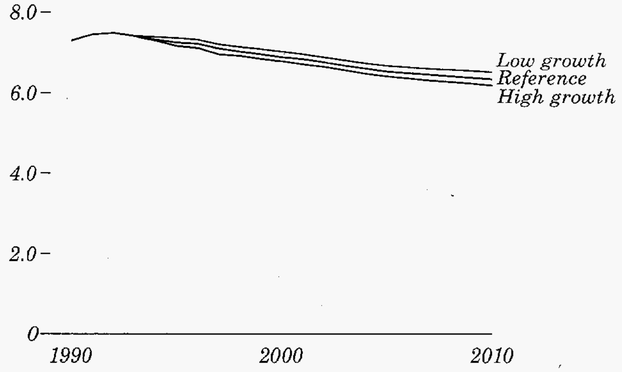
The six energy-intensive industries—chemicals, food processing, paper, petroleum refining, primary metals, and stone, clay and glass—accounted for 67 percent of all manufacturing energy consumption in 1993. By 2010, however, their share of manufacturing energy use is expected to fall to 64 percent, as their output (the value of manufactured products) grows more slowly than that of the other, non-energy-intensive manufacturing industries (Figure 25).

Energy conservation is expected to continue its important role in industries that rely heavily on energy, either as a fuel or as a feedstock. In the reference case, manufacturing output from the energy-intensive industries increases by 33 percent between 1993 and 2010, while their energy consumption increases by only 18 percent. The output from other manufacturing industries, such as transportation equipment, increases by 54 percent between 1993 and 2010. Energy expenditures in these industries, however, typically represent a small portion of total production costs. Nonetheless, over the same period, energy use in the non-energy-intensive manufacturing industries is projected to increase by only 40 percent.

The major use of energy in the nonmanufacturing industries is to fuel off-road equipment, such as farm tractors, bulldozers and coal-handling equipment. Between 1993 and 2010, output from these industries increases by 35 percent, and energy consumption increases by 24 percent.

Aggregate Industrial Output Grows Faster Than Energy Consumption

Figure 26. Aggregate industrial energy intensity in three cases, 1990-2010 (thousand Btu per 1987 dollar)



Aggregate industrial energy intensity (thousand Btu per dollar of output) decreased by 2.5 percent a year between 1970 and 1987, reflecting the use of more energy-efficient technologies and a shift toward less energy-intensive products. Intensity rose briefly in the late 1980s, when energy prices fell and output from energy-intensive industries rose slightly. Between 1993 and 2010, industrial energy consumption and output are projected to grow at average annual rates of 1.2 and 2.1 percent, respectively, in the reference case, with a 0.9-percent average annual decline in energy intensity (Figure 26).

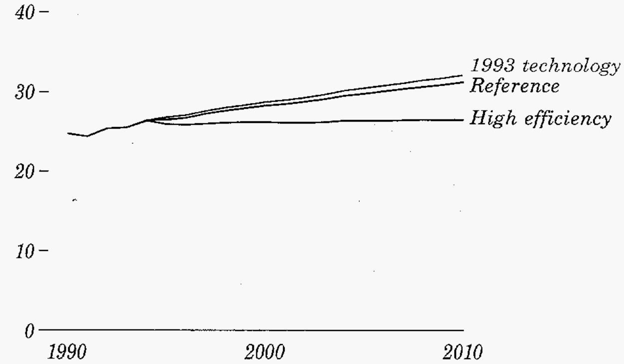
Higher rates of economic growth result in a greater reliance on new, more energy-efficient manufacturing plants. As a result, industrial energy intensity is 5 percent lower in the high growth case than in the low growth case. Industrial output is 16 percent higher in the high growth case than in the low growth case in 2010, but energy consumption is only 10 percent higher. Substantially higher output growth rates are expected for key non-energy-intensive manufacturing industries, compared with the growth rates expected for energy-intensive industries such as iron and steel production (Table 7).

Table 7. Energy intensity and industry growth

Industry	*1993 energy intensity (thousand Btu per dollar)*	*1993-2010 industry growth (percent)*
Cement	*129.0*	*1.4*
Iron and steel	*30.5*	*0.2*
Transportation equipment	*0.9*	*2.4*
Industrial machinery	*1.2*	*3.5*

Further Efficiency Gains Could Produce More Energy Savings

Figure 27. Industrial energy consumption in two alternative energy efficiency cases, 1990-2010 (quadrillion Btu per year)



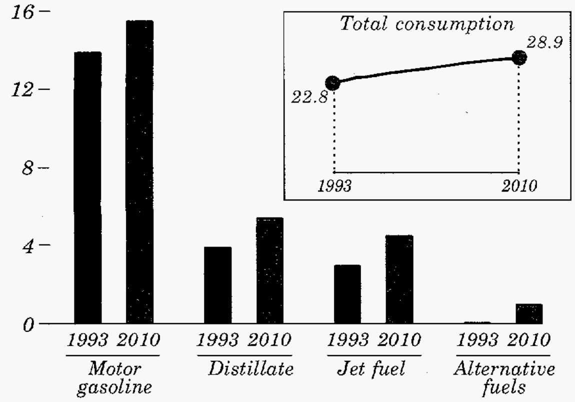
The use of more energy-efficient technologies and relatively low growth in energy-intensive industries moderate industrial energy consumption. Since 1970 these factors have offset higher aggregate industrial output levels, and overall energy consumption in 1993 was practically the same as two decades earlier.

In the 1993 technology case, almost 1 quadrillion Btu more energy is used in 2010 than in the reference case (Figure 27). The *AEO95* reference case includes engineering estimates of energy efficiency, cost, and market penetration for new technologies, and anticipates continuing improvement in the energy efficiency of equipment and processes. In the 1993 technology case, industrial energy efficiency remains at the level achieved in new plants in 1993. Average efficiency still improves in this case as old technology is replaced with 1993 technology.

In the high efficiency case, almost 5 quadrillion Btu less energy is used in 2010 than in the reference case for the same level of output. Energy intensity declines in the high efficiency case at an average rate of 1.9 percent a year beginning in 1995. This equals the rate of efficiency improvement seen between 1970 and 1990. In this case, industrial energy consumption remains practically unchanged over the forecast, just as it did between 1970 and 1990. These alternative efficiency cases are based solely on the industrial model and do not incorporate any feedback effects on energy markets.

Transportation Energy Use Increases, Petroleum Fuels Dominate

Figure 28. Transportation energy consumption by fuel, 1993 and 2010 (quadrillion Btu)



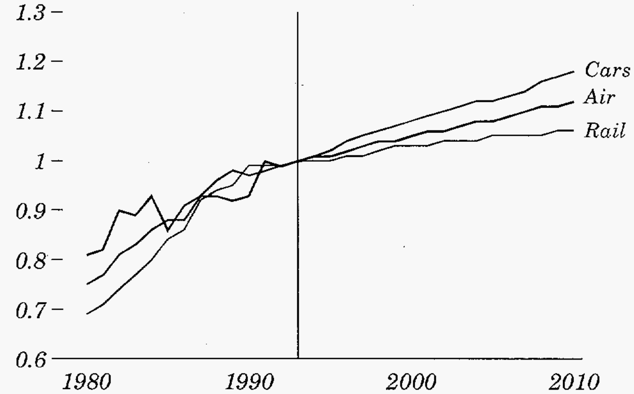
Motor gasoline consumption increases by 0.7 percent annually between 1993 and 2010 in the reference case, a total increase of 1.6 quadrillion Btu (Figure 28). Gasoline's share of transportation energy use declines, as the overall fuel efficiency of conventional light-duty vehicles continues to improve and sales of alternative-fuel vehicles increase. In 2010, alternative fuels displace some 465 thousand barrels of oil per day.

Distillate fuel oil is used mostly to transport freight. As such, its use follows trends in industrial output. In the reference case, distillate use is expected to increase by an average of 2 percent a year between 1993 and 2010. Compared with the reference case estimate for 2010, distillate oil consumption is 5.0 percent higher in the high growth case and 5.5 percent lower in the low growth case.

Total jet fuel consumption increases at an average annual rate of 2.3 percent between 1993 and 2010, due to a 3.9-percent annual increase in commercial air travel. Fuel efficiency gains in new aircraft, increasing reliance on more fuel-efficient (per passenger mile) jumbo jets, and declining military use of jet fuel account for the difference in growth rates. Air travel is sensitive to changes in the economic growth rate: commercial air travel is 7.4 percent higher in the high growth case and 7.4 percent lower in the low growth case than in the reference case in 2010.

Light-Duty Vehicles Lead Gains in Transportation Fuel Efficiency

Figure 29. Transportation stock fuel efficiency by mode, 1980-2010 (index, 1993 = 1)



Average fuel efficiency continues to improve in the forecast, but at a slower pace than during the 1980s (Figure 29). Automobiles show the greatest average efficiency improvement between 1993 and 2010—1 percent a year, or about one-third the rate of improvement between 1980 and 1990. Contributing to the slower efficiency gains for light-duty vehicles are relatively low and stable projected gasoline prices and increases in disposable per-capita income, both of which tend to reduce consumer demand for fuel economy and increase demand for larger, better-performing cars. New car fuel economy in the reference case is only 18 percent higher in 2010 than it was in 1993 (Table 8).

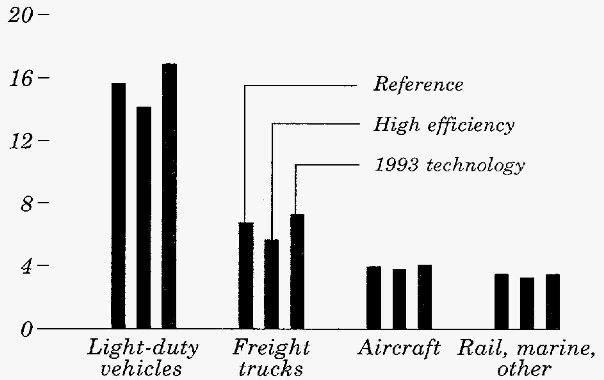
Even smaller efficiency gains are projected for large trucks and locomotives, because their stock turnover is slower and there is limited potential for new technologies to improve fuel efficiencies. Aircraft stock efficiency improves at an average annual rate of 0.7 percent, as more wide-body aircraft are purchased.

Table 8. New car EPA-rated fuel efficiencies by world oil price case, 1980-2010

	Miles per gallon					
Forecast	1980	1990	1993	2000	2005	2010
Reference	24.3	28.2	27.8	28.9	30.0	32.8
High price	--	--	--	29.1	30.3	33.5
Low price	--	--	--	28.4	29.3	31.5

Energy Use for Transportation Rises in All Cases

Figure 30. Transportation energy consumption by mode in alternative efficiency cases, 2010 (quadrillion Btu)



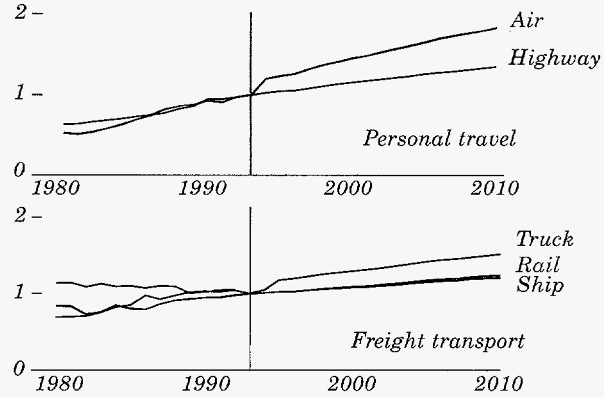
Light-duty vehicles (cars, vans, and light trucks) currently account for more than one-half of all transportation energy consumption, and their dominant role continues in the forecast (Figure 30). Fuel use by light-duty vehicles increases on average by 1.0 percent annually between 1993 and 2010, slightly higher than the rate of population growth (0.9 percent). Fuel use by light trucks grows rapidly because of a 2.4-percent annual growth rate in vehicle-miles traveled by small commercial trucks. In the high efficiency case, in which fuel efficiency increases throughout the forecast at the 1970-1990 annual rate of 1.9 percent (compared with 1.0 percent in the reference case), fuel use in 2010 is 9.4 percent less than in the reference case. In the 1993 technology case, which assumes that new vehicle efficiencies remain at their 1993 levels throughout the forecast period, light-duty vehicles use 7.8 percent more fuel than in the reference case in 2010.

Fuel consumption by freight trucks grows by 1.9 percent a year. In 2010, demand for freight fuel is 14.9 percent lower in the high efficiency case and 7.1 percent higher in the 1993 technology case than in the reference case.

Air transport fuel consumption grows by 2.2 percent a year, mainly because of an increase in travel demand, by 3.9 percent a year. Jet fuel consumption is 6.0 percent lower in the high efficiency case and 2.4 percent higher in the 1993 technology case than in the reference case in 2010.

Personal Travel Grows More Slowly Than in the Past

Figure 31. Growth in personal travel and freight transport by mode, 1980-2010 (indices, 1993 = 1)



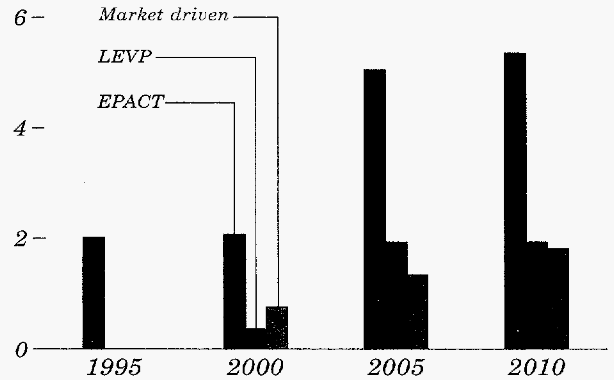
Personal travel, consisting primarily of air travel and highway travel in light-duty vehicles, continues to grow with increasing population, personal income, and GDP. Other modes of personal travel, such as commuter rail and intercity bus, have historically accounted for an estimated 4 percent of passenger miles, and their share is assumed to remain stable over the forecast. Implementation of CCAP provisions that promote telecommuting, adoption of a transportation system efficiency strategy, and reform of tax subsidies for employer-provided parking lead to a 1.3-percent reduction in vehicle miles traveled by 2000.

Highway travel by light-duty vehicles, which grew at an annual rate of 3.4 percent from 1980 to 1990, increases at a more moderate 1.8-percent annual rate from 1993 to 2010. Contributing factors include slower growth of the driving-age population and demographic aging trends. Air travel grows at an annual rate of 3.9 percent from 1993 to 2010, substantially below the 5.8-percent annual growth between 1980 and 1990, reflecting the gradual maturation of the industry.

Freight transport by truck grows steadily from 1993 to 2010, driven by the growth of industrial output. Truck transport has the highest annual growth rate, 2.0 percent, but is well below the 4.1-percent annual growth rate recorded between 1980 and 1990. Rail and waterborne freight services maintain modest annual growth rates in the forecast, 1.3 percent and 1.1 percent, respectively.

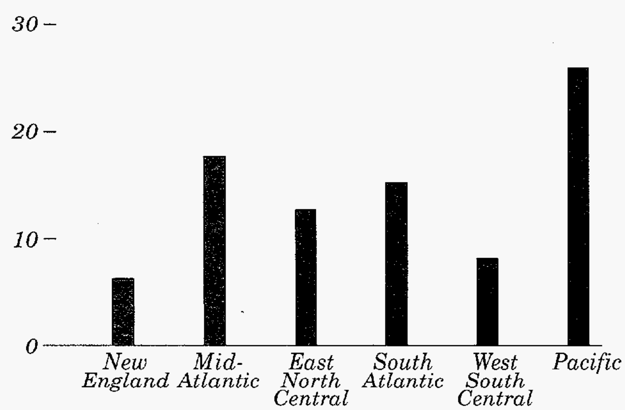
Legislative Mandates Drive Sales of Alternative-Fuel Vehicles

Figure 32. Effects of legislation and market forces on alternative-fuel vehicle sales, 1995-2010 (percent of total)



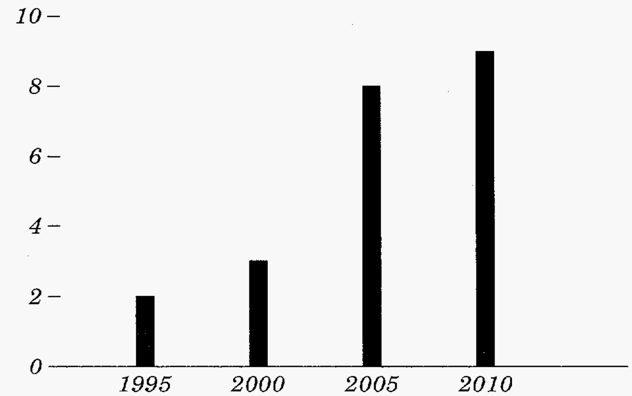
Practically all sales of alternative-fuel vehicles (AFVs) before 1997 result from legislation (Figure 32), but by 2010, about one-fifth of AFV sales are based on market competition. Federal legislation mandates increasing use of AFVs by government and by energy utilities, and more sales are expected as a result of California's Low Emissions Vehicle Program (LEVP). CAAA90 includes a provision for States to join the pilot LEVP, which requires 2 percent of vehicles sold within the State in 1997 to be capable of using alternative fuels. By 2003, 10 percent of sales must be zero emission (electric) vehicles. All *AEO95* cases assume that California, New York, and Massachusetts—which currently account for 21 percent of all vehicle sales in the country—will participate. The expected regional distribution of AFV sales (Figure 33) reflects regional fuel prices and availability, as well as regional legislation.

Figure 33. Alternative-fuel vehicle sales by Census Division, 2010 (percent of total)



Natural Gas and Propane Vehicles Lead Market Penetration

Figure 34. Alternative-fuel vehicle share of total light-duty vehicle sales, 1995-2010 (percent)



Approximately 3 percent of all new light-duty vehicles are expected to be capable of running on alternative fuels by 2000. The share of AFV sales rises to 9 percent by 2010, when the total stock of AFVs is expected to equal about 6 percent of the U.S. light-duty vehicle fleet (Figure 34). AFVs are expected to displace 465 thousand barrels of oil per day in 2010, reducing transportation sector carbon emissions by approximately 7.3 million metric tons.

Among the AFV technologies, compressed natural gas, liquefied petroleum gas (propane), and electric vehicles claim the largest market shares in 2010 (Table 9). Almost 60 percent of all AFVs are purchased for use in commercial fleets, where natural gas and propane technologies are preferred. Electric, methanol, and ethanol vehicles are used primarily in nonfleet applications for personal use.

Table 9. Shares of alternative-fuel light-duty vehicle sales by technology type, 2010

Technology	Percent share	Technology	Percent share
Ethanol	10.1	Compressed natural gas	29.9
Methanol	9.9	Liquefied petroleum gas	23.6
Gas turbine	0.0	Electric hybrid	19.6
Electric	7.0	Fuel cell	0.0

Non-electric renewable energy uses

In addition to projections for renewable energy use in electricity generation, *AEO95* contains projections for non-electric renewable energy uses for industrial and residential wood consumption, residential and commercial solar water heating, and residential and commercial geothermal (ground-source) heat pumps. Additional renewable energy applications—such as direct solar thermal industrial applications or direct lighting, off-grid photovoltaics, wind turbines for pumping or for off-grid electricity generation, and geothermal water use (e.g., for district heating or greenhouses)—are not included in the projections, either because their current and expected market penetration is small or because there is little current data on the applications.

Projections for wood use include steam production in the industrial sector and heating in the residential sector. The primary industries that use wood for energy are the pulp and paper and lumber industries. Growth in wood use in the industrial sector is a direct function of the growth in demand for wood-based products. Wood use in the residential sector is affected by changes in the housing stock and, to some degree, by fossil fuel and electricity prices.

Wood consumption is by far the largest contributor among the non-electric renewable energy categories in the forecast. In 1993, wood use accounted for almost 97 percent of total non-electric renewable energy consumption (excluding ethanol), and it accounts for nearly 90 percent of the projected growth in the use of these renewables over the forecast period. Nevertheless, wood consumption for heat and steam production is expected to increase relatively slowly, from 2.09 quadrillion Btu in 1993 to 2.61 quadrillion Btu in 2010, at an average annual rate of 1.3 percent a year. Furthermore, in contrast to most renewable energy applications, the use of energy for wood stoves in the residential sector is expected to decline slightly.

Projections of geothermal energy use other than for electricity generation are limited to ground-source heat pumps. Ground-source heat pumps include a buried heat exchanger to permit the extraction of ground heat. Because ground temperatures remain relatively stable throughout the year from about 42 to 77 degrees Fahrenheit (depending on the region of the country), earth energy can be more effective than air in providing cooling in the summer and heating in winter. Growth in the use of ground-source heat pumps is likely to be the greatest for new construction in the residential and commercial markets.

Geothermal energy use for ground-source heat pumps increases rapidly over the forecast period, from about 10 trillion Btu in 1993 to about 40 trillion Btu in 2010, increasing at an average annual rate of over 7 percent a year. However, ground-source heat pumps are expected to remain a small share of the overall heating and cooling market.

Similarly, solar thermal energy use for water heating in the residential and commercial sectors is expected to expand through 2010. Energy consumption for water heating is expected to grow from around 60 trillion Btu in 1993 to about 90 trillion Btu in 2010.

Overall, these non-electric renewable energy uses are expected to increase more slowly than electricity applications, growing at an average rate of 1.4 percent a year through 2010 and continuing to account for less than one-third of total renewable energy consumption throughout the forecast.

Non-electric renewable energy consumption

	Annual consumption (quadrillion Btu)			*Growth rate, 1993-2010*
Energy source	*1993*	*2000*	*2010*	*(percent)*
Geothermal[1]	*0.01*	*0.02*	*0.04*	*7.3*
Biofuels[2]	*2.09*	*2.32*	*2.61*	*1.3*
Solar thermal[3]	*0.06*	*0.08*	*0.09*	*2.3*
Total	***2.16***	***2.42***	***2.74***	***1.4***

[1]Ground-source geothermal heat pumps.
[2]Wood and wood waste.
[3]Solar thermal water heaters only.
Source: Table A17, excluding ethanol.

Challenges for the future

Forecasts of energy consumption through 2010 are framed by our current perceptions of future energy services, the rate of economic growth, changes in energy prices, and technological developments. The major uncertainties in forecasts over this long a period stem from possible new energy services not now anticipated and from new technologies for energy consumption or production that are not yet commercially viable.

The *AEO95* forecasts are based largely on technologies that are currently available or very close to commercialization. The penetration of new technologies that have not reached this stage of development could potentially alter energy consumption by 2010 in significant ways. Examples of potentially significant emerging technologies include photovoltaic solar collectors and fuel cells, both of which could provide on-site supplies of electricity and alter the demand for utility-generated electricity.

The product mix in the industrial sector also directly affects requirements for purchased energy. Changes in product mix based on major structural shifts in the pattern of international trade or consumer acceptance of recycled products could have a substantial effect on energy consumption. On the basis of recent experience, a shift toward a less energy-intensive industrial sector is more likely than a shift toward one with greater energy intensity.

The pressure to reduce vehicle emissions and dependence on foreign oil has led to several laws requiring the use of alternative-fuel vehicles. As the mandated use of these vehicles becomes more prevalent, barriers to their use may be reduced to the extent that market-based adoption rates increase. Fueling locations will become more common, and technological improvements beyond those in the current forecast could arise.

Comparative forecasts

The *AEO95* forecast projects slower rates of energy growth over the forecast period than those in the past decade. The projected growth rate is less than two-thirds the rate experienced between 1983 and 1993. A combination of expected lower population and economic growth, the penetration of energy-efficient technologies associated with market forces, and mandated efficiency improvements in many types of energy-using equipment significantly dampens growth in end-use energy demand.

Other forecasts (Table 10) also project slower future growth in energy demand relative to recent experience. In all the forecasts, total end-use energy demand increases at between one-third and one-half the 1983-1993 rate. Different economic and energy price assumptions show a relatively narrow range of impact on overall energy demand across the forecasts considered. The largest sources of variation in demand relate typically to the impacts of new technologies, which can change the relative competitiveness of alternative fuels and the energy needs associated with various end-use services. Another source of variation is the impact of government policy, which can alter prices and technologies available to energy consumers. The forecast comparisons in this section exclude renewable energy because of differences in the way renewable energy is treated in the different forecasts.

Table 10. Forecasts of total end-use energy demand

Forecast	*1983*	*1993*	*2010 AEO95*	*2010 DRI*	*2010 GRI*	*2010 WEFA*
	Annual energy consumption (quadrillion Btu)					
Petroleum	28.5	32.6	39.5	39.9	37.0	35.5
Natural gas	14.4	17.8	20.5	18.8	21.7	19.7
Coal	2.7	2.7	2.8	2.8	2.4	2.5
Electricity	7.3	9.8	11.9	13.1	12.6	13.2
All energy	52.9	63.0	74.7	74.5	73.7	71.1
	1987 dollars					
Real GDP	3,907	5,133	7,485	7,457	7,400	7,797
	Annual growth rates (percent)					
	1983-1993		*1993-2010*			
Petroleum	1.4		1.1	1.2	0.7	0.5
Natural gas	2.2		0.8	0.2	1.1	0.5
Coal	-0.1		0.4	0.4	-0.6	-0.2
Electricity	2.9		1.1	1.7	1.5	1.8
All energy	1.8		1.0	1.0	0.9	0.7
Real GDP	2.8		2.2	2.2	2.2	2.5

Residential and commercial sectors

In contrast to the 2.2-percent average annual growth in residential energy consumption between 1983 and 1993, residential demand forecasts (Table 11) show more modest growth. Lower expected growth rates for population and households explain most of the difference, along with efficiency improvements in the stock of energy-using equipment. In the *AEO95* forecast, growth in commercial floorspace trails overall economic growth (1.0 percent and 2.2 percent, respectively), and energy demand rises by only 0.5 percent a year. Expected growth in electricity use is lower in *AEO95* than in the other estimates, primarily because efficiency gains expected from equipment efficiency standards, EPA's "Green Lights" program, and other programs designed to reduce energy requirements for lighting are included in the *AEO95* forecast.

Table 11. Forecasts of average annual growth in residential and commercial energy demand (percent)

Forecast	1983-1993	1993-2010 AEO95	1993-2010 DRI	1993-2010 GRI	1993-2010 WEFA
Residential					
Natural gas	1.2	-0.1	0.1	0.6	0.3
Electricity	2.8	0.9	1.9	1.7	1.8
Petroleum	-0.1	-1.3	-0.4	-0.6	1.5
All energy	2.2	0.1	0.2	0.4	0.6
Households	1.2	0.9	1.1	1.2	1.3
Commercial					
Natural gas	1.8	0.2	0.6	1.4	1.0
Electricity	3.5	1.0	1.8	1.9	1.9
Petroleum	-3.2	-0.5	-0.9	-0.9	-0.1
All energy	1.4	0.5	1.0	1.4	1.3

Industrial sector

All the forecasts for total industrial energy consumption show significantly less growth in total energy use than occurred between 1983 and 1993. Lower expected growth in aggregate manufacturing output and the continuing shift toward a less energy-intensive output mix account for the expected decline in growth. The growth rates for different fuels between 1983 and 1993 reflect a significant shift from reliance on petroleum products and the direct use of coal to greater reliance on natural gas and electricity in the industrial sector. Because much of the potential for fuel switching was realized during the 1980s as natural gas became increasingly available and new electricity-based processes were introduced, industrial use of natural gas and electricity grows more slowly in each of the forecasts than in recent history (Table 12). Much of the decrease reflects expected lower growth rates for GDP and manufacturing output. Coal forecasts vary considerably, as declines in coal use for steelmaking partially offset increased use of coal as a boiler fuel.

Table 12. Forecasts of average annual growth in industrial energy demand (percent)

Forecast	1983-1993	1993-2010 AEO95	1993-2010 DRI	1993-2010 GRI	1993-2010 WEFA
Petroleum	2.0	1.1	0.6	1.3	0.6
Natural gas	3.1	1.3	0.5	1.7	0.2
Coal	0.1	0.4	1.2	-1.0	0.8
Electricity	2.4	1.4	1.6	1.8	1.8
All energy	2.0	1.1	0.6	1.3	0.6

Transportation sector

Transportation energy use grows faster than population in most of the forecasts (Table 13), as growth in both personal and business travel offsets increases in vehicle fuel efficiency. This trend follows historical patterns; it does not anticipate major changes in the ways people and products are transported. New car fuel economy was practically unchanged between the mid-1980s and 1993, hovering around the EPA-mandated standard of 27.5 miles per gallon. Gasoline prices, adjusted for inflation, actually declined. In the forecasts, higher gasoline prices and the introduction of more fuel-efficient alternative-fuel vehicles lead to more significant increases in fuel economy. Variations among forecasts relate primarily to different expectations regarding growth in commercial as compared with personal travel. Despite differences, all the forecasts indicate lower growth than that recorded over the past decade.

Table 13. Forecasts of average annual growth in transportation energy demand (percent)

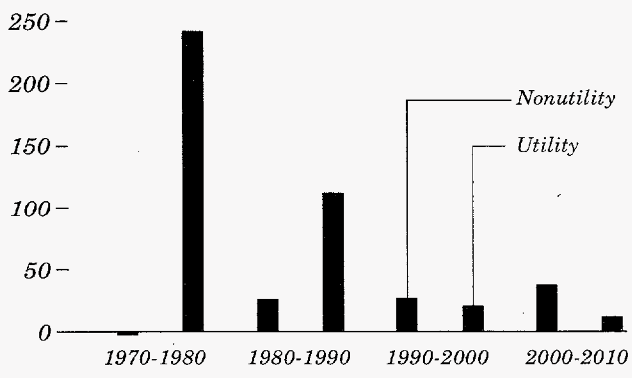
Forecast	1983-1993	1993-2010 AEO95	1993-2010 DRI	1993-2010 GRI
Consumption				
Gasoline	1.1	0.7	0.7	0.2
Diesel fuel	2.9	2.0	2.8	2.1
Jet fuel	3.6	2.3	1.6	1.6
Residual fuel	3.0	2.5	1.8	1.1
All energy	1.8	1.4	1.4	0.7
Key indicators				
Car and light truck travel	2.9	1.8	1.9	2.1
Air travel	5.6	3.9	3.3	3.0
Average new car fuel efficiency	0.6	1.0	0.9	1.8
Gasoline prices	-4.4	1.3	2.0	1.3

Electricity

Electricity markets in the United States are in the midst of a period of rapid change. The age of the domination of the vertically integrated system, where one utility controlled the generation, transmission, and distribution of electricity to each customer—while not over—is waning. The final outcome of the changes occurring is still unclear, but various States are taking steps to look to a more competitive future (see box on page 27).

One indication of the changes occurring is the rise of nonutility generators in wholesale power markets. From the beginning of this century through the 1970s, the economies of scale associated with large generating facilities led the industry to be dominated by large, vertically integrated utilities. During the 1970s, the capacity of nonutility generators actually declined, while utility generating capacity grew by more than 240 gigawatts (Figure 35). Electric utilities continued to dominate through the 1980s, but nonutilities, spurred by the passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA), increased their capacity substantially. Their growth continued into the early 1990s, when nonutilities accounted for approximately half of all new capacity additions.

Figure 35. Utility and nonutility net capacity additions by decade, 1970-2010 (gigawatts)

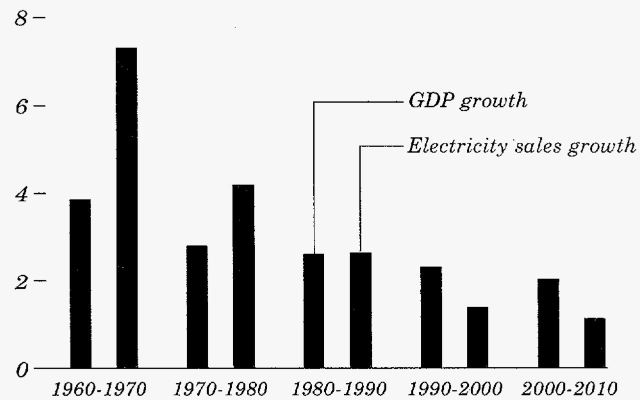


Further stimulated by the passage of EPACT, nonutilities are expected to continue to play an important role in meeting growth in the demand for electricity through 2010. However, utilities are also taking steps to increase their competitiveness. Through consolidations, staffing reductions, and other cost-cutting measures, utilities are preparing for a more competitive future.

While utilities and nonutilities try to keep up with the evolving structure of the electricity market, they are also faced with slower growth in demand than in the past. Historically, the demand for electricity has been linked with economic growth. This positive relationship will continue, but the magnitude of the ratio is uncertain.

During the 1960s, electricity demand grew by over 7 percent a year, nearly twice the rate of economic growth (Figure 36). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Throughout the forecast this slowing trend is expected to continue. Several factors have contributed to this trend, including increasing market penetration of electric appliances; improvements in equipment efficiency brought about by consumer expectations of higher energy prices; utility investments in demand-side management programs; and legislation establishing more stringent equipment efficiency standards. For example, by 1991, nearly 70 percent of homes in the United States, the majority of those in warmer climates, had air conditioning systems.

Figure 36. Growth in electricity sales and gross domestic product by decade, 1960-2010 (percent)



There are factors that could mitigate the slowing of electricity demand growth seen in these projections. New electricity appliances seem to appear almost daily. Only a few years ago, no one could have foreseen the growth in home computers, facsimile machines, copiers, and security systems, all powered by electricity. If the new uses of electricity are more substantial than currently expected, they could partially offset the efficiency gains shown in these projections (see discussion in Appendix H).

Electricity: moving toward competition

The U.S. electricity market is marching toward a more competitive future. Spurred by changes in prices, technologies, and regulations in the 1970s and 1980s, the industry began to evolve away from one dominated by large, vertically integrated utilities. Today, in most States, regulators, utilities, nonutility power producers, and their customers are struggling to define the future of the industry. The degree to which the market will, or should, move toward open competition is unclear.

There are, however, a few clear trends. The wholesale power market is becoming increasingly competitive. In many States, when a need for new resources is identified, the competition among utility and nonutility plants, utility demand-side management (DSM) programs, and DSM programs provided by energy service companies is fierce. Many utilities have instituted integrated resource planning (IRP) programs, which attempt to weigh the costs and benefits of all available resource options, and many are using competitive bidding processes to acquire new resources.

Large electricity consumers, mainly industrial customers, are pressuring utilities to reduce their prices. Industrial customers have many options for meeting their energy needs, including self-generation, cogeneration, fuel switching, and relocation. Disparities among the industrial rates of neighboring utilities, and among utilities and nearby nonutility generators, have led industrial customers to demand lower rates from franchised utilities or access to cheaper power supplies. In some cases, utilities have offered lower rates in the form of economic development or interruptible rates. Utilities are also taking steps to reduce costs and increase competitiveness, such as consolidating with other utilities, reducing staff, and buying out uneconomical contracts with nonutilities.

The use of traditional cost-based ratemaking is also under review in some States. Concerned that cost-of-service based pricing does not provide sufficient incentive to utilities to reduce their costs and provide electricity at the lowest possible rates, State commissions are looking at alternative methodologies, such as performance-based rate mechanisms and price caps.

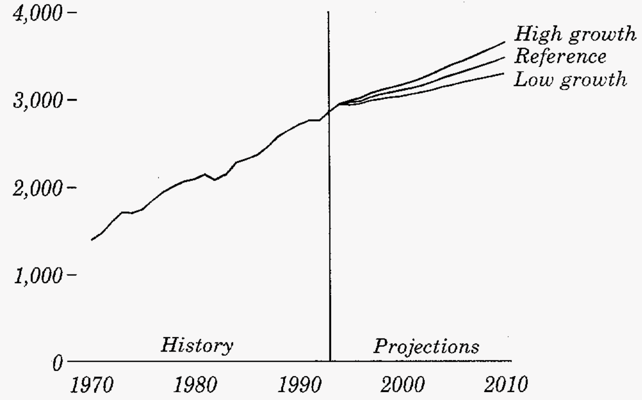
States are taking a variety of approaches to test the competitive waters. Many, often through the use of IRP programs, are continuing efforts to open wholesale markets to all resource options. The Federal Energy Regulatory Commission (FERC) is contributing to the effort through its implementation of Section 211 of EPACT, which gives FERC the authority to order owners of transmission capacity to provide services to all requesters.

Michigan and California have taken even more aggressive steps to open both wholesale and retail electricity markets. In Michigan, regulators have decided to test open retail competition in a small experiment, allowing the customers of the State's two largest utilities to purchase power from other utilities or nonutilities for up to 60 megawatts of capacity. Regulators in California have stepped away from other States by proposing to give all customers access to any electricity supplier. Their proposal contains a timetable for moving from traditional franchised cost-of-service regulation to performance-based regulation, with all consumers being able to choose their suppliers by 2002.

The debate on the merits of increased competition is continuing, and numerous areas of contention remain. Among the most important are how best to ensure transmission access for wholesale suppliers, the potential impacts of consumer choice on utility systems, and how nonproduction expenditures—such as those associated with DSM, IRP, fuel diversity, and environmental compliance programs—can be recovered in a more competitive marketplace. Through individual cases, FERC is establishing criteria for acceptable transmission tariffs, but some argue that it may be necessary to force utilities to divest their transmission assets in order to ensure truly open access. If customers are permitted to leave their utilities and shop for other power providers, utilities could be left with underutilized, uneconomical assets. There is disagreement about whether the costs of such "stranded assets" should be recovered from the departing customers, the utility's remaining ratepayers, or stockholders.

Slower Growth in Electricity Demand Is Seen in All Cases

Figure 37. Electricity demand in three cases, 1970-2010 (billion kilowatthours)



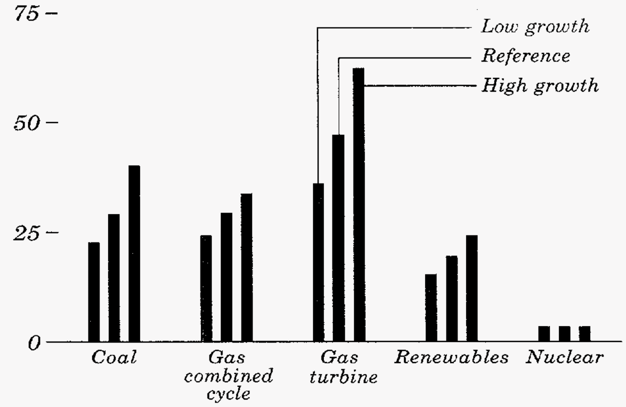
From 1993 to 2010, the annual growth rate for electricity demand is projected to be between 0.8 percent and 1.4 percent (Figure 37), well below the projected annual GDP growth rates of 1.8 percent and 2.7 percent in the *AEO95* low and high growth cases, respectively. The electricity demand growth rate from 1993 to 2010 is also significantly lower than the historical 3.2-percent annual growth in electricity demand from 1970 to 1993.

Several factors contribute to the decrease in electricity demand growth in the forecast. By complying with EPACT, businesses and municipalities are expected to improve energy efficiency through the installation of energy-efficient lighting and appliances, increased building efficiency, and support of energy efficiency in process-related industries. In addition, NAECA requires appliance manufacturers to meet efficiency standards for certain appliances before they can be marketed.

Demand-side management programs are also expected to increase throughout the 1990s. By granting customers rebates for installing energy-efficient appliances, utilities provide incentives to lower energy consumption. In charging reduced rates for off-peak service, utilities can delay the need for new capacity by promoting the efficient use of currently available capacity. Demand-side management programs are expected to reduce the demand for electricity by 73 billion kilowatthours in 1997, relative to the level that would have been reached in their absence.

Natural Gas, Renewables Compete With Coal for New Capacity Additions

Figure 38. New generating capacity by type in three cases, 1993-2010 (gigawatts)

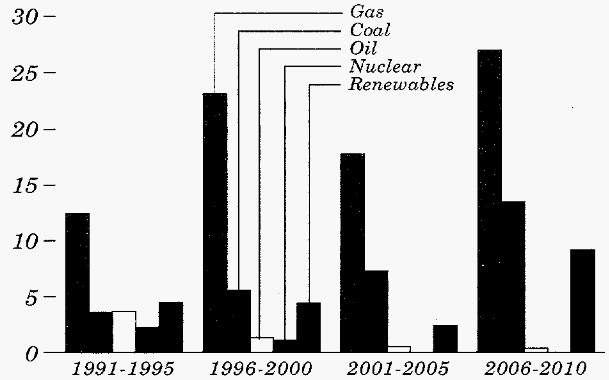


A difference of 0.9 percentage points in the economic growth rate yields a 63-gigawatt range in total capacity additions required—from 107 gigawatts in the low growth case to nearly 170 gigawatts in the high growth case. This capacity range is equivalent to 207 power plants, assuming a capacity of 300 megawatts per plant. In the reference case, utilities are expected to add 78 gigawatts of new capacity and retire 53 gigawatts between 1993 and 2010, for a net gain of 25 gigawatts. Nonutilities add 41 gigawatts of new net capacity, accounting for 62 percent of the total net capacity added. Renewable capacity additions range from 15 gigawatts in the low growth case to more than 24 gigawatts in the high growth case. Nearly 16 gigawatts of new net capacity is supplied by cogenerators during this period.

Gas-fired combined-cycle and combustion turbine technologies provide a significant share of the expected new capacity (Figure 38). These technologies have the advantages of relatively low initial capital cost, high efficiency, and low emissions. New coal and renewable capacity will also be used for baseload and peak requirements, respectively. Across the low and high growth cases, coal-fired capacity additions vary by 18 gigawatts, and renewable capacity additions vary by 9 gigawatts. Gas turbines, while adding the most capacity, essentially meet peak requirements. Most electricity requirements will be met by coal-fired and gas combined-cycle capacity.

Flexibility Makes Gas-Fired Capacity More Attractive

Figure 39. Utility, nonutility, and cogeneration capacity additions by fuel type, 1991-2010 (gigawatts)



Before building new capacity, utilities are expected to use other options to meet demand growth—life extension and repowering of existing plants, imported power from Canada and Mexico, demand-side management, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 450 new plants with a total of 135 gigawatts of capacity will be needed by 2010 to meet growing demand and to offset retirements.

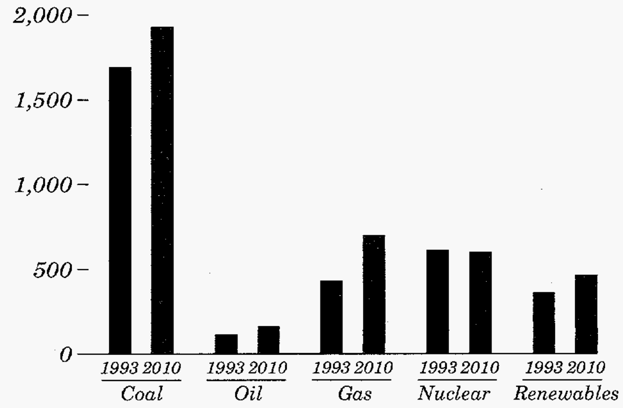
Of the new capacity needed, 61 percent is projected to be gas-fired or oil- and gas-fired combined-cycle or combustion turbine technology. Both technologies are designed primarily to supply peak and intermediate capacity, whereas combined-cycle technology can also be used to meet baseload requirements.

Through 2010, the equivalent of 97 plants with a total of 29 gigawatts of new planned and additional unplanned coal-steam capacity are projected to come online, and the equivalent of 52 plants totaling 16 gigawatts are expected to retire. After 2005, coal-steam plants will compete effectively with gas-fired plants for baseload capacity. More than 46 percent of the new coal-fired capacity will be added after 2005 (Figure 39).

Except for units in the construction pipeline, no additional nuclear or hydroelectric capacity is expected. Nuclear plants are assumed to retire, with no life extension, as their current operating licenses expire. Increases in hydroelectric capacity that result from repowering are expected to be offset by retirements.

Coal Remains the Dominant Fuel for Electricity Generation

Figure 40. Electricity generation by fuel, 1993 and 2010 (billion kilowatthours)



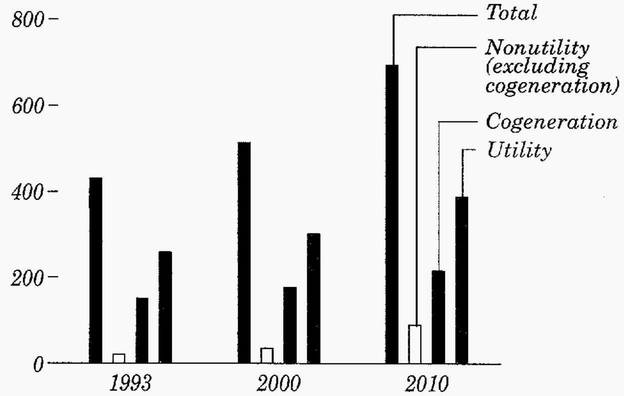
As they have since early in this century, coal-fired power plants are expected to remain the dominant source of electricity through 2010 (Figure 40). In 1993, coal plants accounted for 41 percent of the generating capacity in the United States and for 53 percent of the electricity generated. Rising environmental concerns about coal plants, combined with their relatively long construction leadtimes and the availability of economical natural gas, make it unlikely that many new coal plants will be built before 2000. However, slow demand growth and the huge investment in existing plants will keep coal in its dominant position.

The large investment in existing plants will also make nuclear power an important source of electricity through 2010. In recent years, the performance of nuclear power plants has improved substantially, and two units now under construction are expected to become operable in the near term [*17*]. As a result, nuclear generation increases through 2006. After 2006, however, nuclear generation is expected to decline as older units are retired (see discussion on page 31).

In percentage terms, generation from gas-fired power plants shows the largest increase in the forecast. As a result, by 2010, gas-fired generation by utilities, nonutilities, and cogenerators overtakes nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants remains fairly small throughout the forecast.

Gas-Fired Generation Increases for All Types of Generators

Figure 41. Electricity generation from natural gas, 1993, 2000, and 2010 (billion kilowatthours)



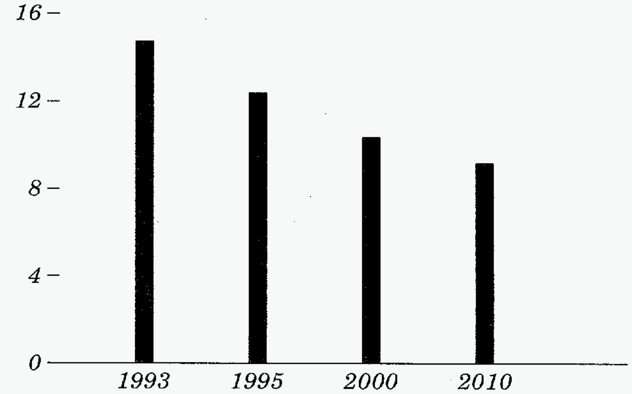
The future for natural gas in electricity generation is bright (Figure 41). Between 1993 and 2010, gas-fired generation is expected to increase by over 60 percent. Increased use of gas by utilities, nonutilities, and cogenerators is projected to raise its share of total generation to 18 percent by 2010. New combustion turbine and combined-cycle plants, with efficiencies approaching 50 percent, make gas-fired plants competitive with other resource options. Their high efficiencies relative to other resource options, such as conventional coal-fired power plants (around 35 percent), partially offset their higher fuel costs. Only after 2005 do rising gas prices begin to make gas-fired plants less economical.

Financially, combustion turbines and combined-cycle plants are attractive because of their modularity and relatively low capital costs. Unlike with traditional steam plants, the per-kilowatt costs and thermal efficiencies of small turbine and combined-cycle plants are similar to those for larger plants. Thus, it is economical to add them in small increments, reducing the financial burden on the utility or nonutility and allowing capacity to be added slowly as demand grows.

Gas-fired plants are also attractive for environmental reasons, since gas produces much lower carbon and sulfur emissions during combustion than do coal and oil. Because sulfur dioxide emissions from gas-fired plants are near zero, there is no need for operators to purchase the emission allowances required for coal- and oil-fired plants under CAAA90.

Sulfur Dioxide Emissions Cap Goes Into Effect

Figure 42. Sulfur dioxide emissions from electricity generation, 1993-2010 (million short tons)



In response to CAAA90, utilities and nonutilities have begun taking steps to reduce sulfur dioxide emissions below the established ceilings. Relatively "dirty" plants must take action by 1995, while other affected plants have until 2000. The goal is to reduce annual emissions (Figure 42) below 9 million short tons, compared with 14.8 million in 1993 [*18*].

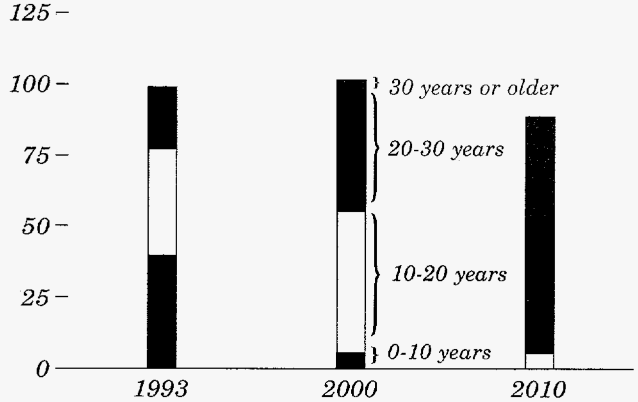
In each phase of CAAA90, affected facilities are issued annual permits, or allowances, to emit a fixed amount of sulfur dioxide in the permit year or any year thereafter. Each operator must ensure that there are sufficient allowances on hand to cover the year's emissions. Compliance options include fuel switching (to lower sulfur fuels) or blending, purchasing allowances, and installing flue gas desulfurization equipment (scrubbers). Utilities have reported plans to switch or blend fuels at most of their units affected by Phase I [*19*]. They have already begun actions to modify older plants that burn bituminous coal to enable them to burn lower sulfur subbituminous coal. For other affected units, utilities have reported plans to purchase allowances and add scrubbers. After 2000, as the restrictions tighten, more operators are expected to use scrubber retrofits to stay within compliance limits (Table 14).

Table 14. Scrubber retrofits and allowance costs, 2000-2010

Forecast	2000	2005	2010
Cumulative retrofits from 1993 (gigawatts of capacity)	18.4	18.4	22.2
Allowance costs (1993 dollars per ton SO_2)	238	221	235

Performance Uncertainties Cloud the Future of Aging Nuclear Reactors

Figure 43. Nuclear generating capacity by age of reactor units, 1993, 2000, and 2010 (gigawatts)



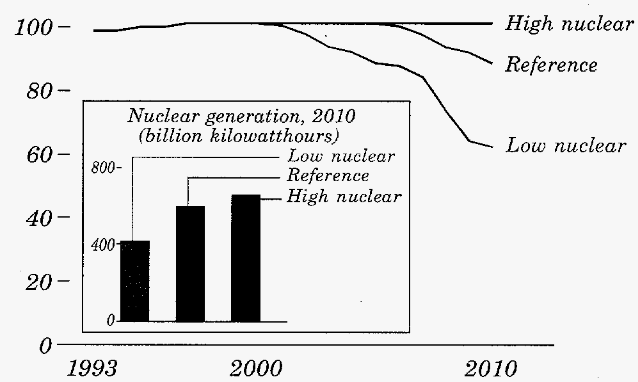
The *AEO95* reference case forecast assumes that all nuclear units will operate to the end of their current license terms, with 19 units (13.7 gigawatts) retiring by 2010. Two units under construction, Watts Bar 1 and 2, are assumed to be completed by 1997 [*20*], and no newly ordered plants become operational during the forecast period. Given these assumptions, 93 nuclear units are projected to produce 16 percent of total electricity generation in 2010.

Because the average age of nuclear units is currently less than 20 years, the performance of older reactors is not well established. By 2010 most operable units will have been in service for more than 20 years (Figure 43); however, their expected lifetimes are uncertain. The early retirements of Yankee Rowe and San Onofre 1 in 1992 and Trojan in 1993 occurred because the utilities faced costly repairs when future competitiveness was uncertain. Also, the lack of a permanent waste repository may require increased on-site spent fuel storage capability for continued operation at some units.

The Nuclear Regulatory Commission has recognized that nuclear reactors can operate safely beyond the initial license period. There is a process in place for utilities to extend their operating licenses for up to 20 years past the current 40-year license term. Also, two advanced designs have recently received Final Design Approval, which, under the new streamlined Design Certification Process, will allow future orders of the same type to be placed without a complete design safety review each time [*21*].

Nuclear Capacity Projections Depend on Reactor Lifetime Assumptions

Figure 44. Operable nuclear capacity in three cases, 1993-2010 (gigawatts)

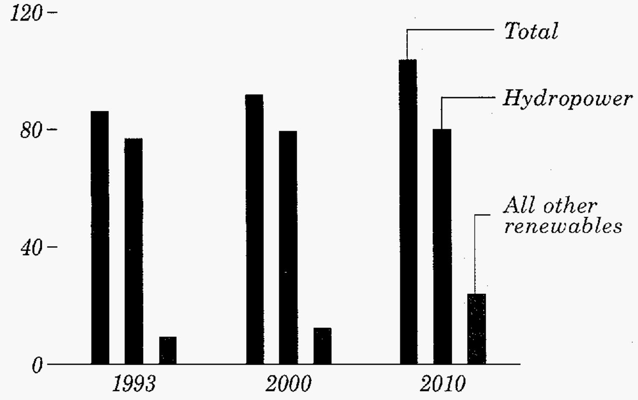


Two alternative cases were developed to show the effects of different operating lifetime assumptions on total nuclear capacity (Figure 44). In the *low nuclear case*, all units were assumed to be retired 5 years before their license expiration dates (52 units between 1993 and 2010). In the *high nuclear case*, 5 additional years of operation were assumed (only 2 units retiring by 2010). In the low case, new coal-fired, combined-cycle, and combustion turbine units would replace the retiring nuclear units. Assuming an average unit size of 300 megawatts, approximately 88 additional unplanned fossil-fueled units would be built. In the high case, new builds of all plant types would be reduced slightly, as the additional power supplied by nuclear units reduces the need for new capacity by 12 gigawatts.

As a result of new build decisions, the consumption of various fuels is affected in the alternate cases. In the low nuclear case, consumption of oil and natural gas increases by 0.8 quadrillion Btu and coal by 0.9 quadrillion Btu relative to the reference case, resulting in an additional 35 million metric tons of carbon emissions, or 6 percent higher than in the reference case. Additionally, the utility price of coal increases by $1.26 per short ton and the price of natural gas by $0.15 per thousand cubic feet. In the high nuclear case, consumption of fossil fuels by electric generators decreases by 0.5 quadrillion Btu, and carbon emissions are reduced by 11 million metric tons, from 584 million metric tons in the reference case to 573 million metric tons [*22*].

Hydropower Remains the Primary Source of Renewable Generation

Figure 45. Generating capacity from renewable fuels, 1993, 2000, and 2010 (gigawatts)



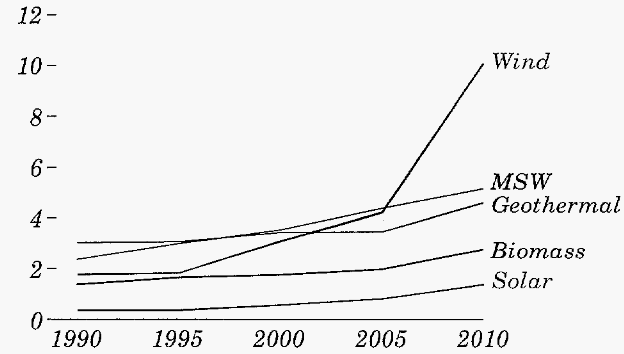
Hydropower, used primarily for baseload generation, now generates as much electricity as about 100 medium-sized (500-megawatt) coal plants. According to the reported plans of electric utilities, hydroelectric generation will grow slightly (about 0.6 percent annually) through 2010, mainly as a result of turbine repowering. New hydropower developments will face increased environmental constraints, and FERC relicensing requirements will offset capacity increases in many cases.

FERC now considers relicensing of hydroelectric plants on a "cumulative impacts" basis, weighing the environmental and water use impacts of existing and proposed projects on an entire river basin and modifying existing licenses when it finds the cumulative negative impacts of all dams in a given river basin unacceptable. In May 1994, the U.S. Supreme Court held that States may impose conditions on hydroelectric operations, such as minimum stream flow requirements, as part of their authority under the Clean Water Act of 1977. That interpretation could limit hydroelectric generation at both existing and proposed projects as States require FERC to impose license conditions that operators release water over spillways instead of through turbines.

Because of hydropower's zero fuel cost, it is used by electricity producers whenever available. However, variations in precipitation can limit its availability, and generation from the same installed capacity can vary by 5 percent or more from one year to another as a result of variations in annual water flows.

Wind Power Could Grow the Most Among Nonhydroelectric Renewables

Figure 46. Nonhydroelectric generating capacity from renewable fuels by fuel type, 1990-2010 (gigawatts)



Much of the wind energy market before 2000 will result from legislated set-asides, which add about a gigawatt of capacity, bringing the total to 3 gigawatts in 2000. Strong growth is expected, especially after 2005, as improved technology, higher fuel prices, increased capacity needs, and externality costs combine to make wind energy more attractive.

Currently exploitable geothermal resources (hot water and steam) are limited to the western United States, where capacity from geothermal plants is projected to grow by about 1.5 gigawatts by 2010. Most of the expected growth occurs after 2005 as demand for new capacity begins to grow.

Municipal solid waste (MSW) generation capacity is projected to grow at a rate just over 4 percent a year. MSW plants serve a dual purpose: they are a source of baseload generation, and they provide a means for the disposal of MSW. Legal issues could affect the use of MSW as an energy source, with plants seeking to obtain guaranteed fuel supplies through local ordinances that direct the flow of waste. Environmental issues could also have adverse effects on MSW plants.

Generation from biomass (wood) is projected to grow only slightly before 2005, because new competitive biomass technologies are as yet unproven and conventional fuel prices remain relatively low. After 2005, however, the market for biomass energy begins to grow, driven by expected technology enhancements, slightly higher prices for conventional fuels, and increased need for new capacity.

Solar-electric power

Photovoltaic (PV) and solar thermal electricity will become increasingly important through 2010, primarily for high-value uses, both disconnected from the transmission grid and on the grid. Before 2000, most large PV units will be for commercial tests.

Because electricity generation from large fossil-fueled plants is almost always less expensive than from photovoltaics, off-grid PV applications will increase primarily where delivery costs for utility power are high. Typically, off-grid PV will be used for small, highly valued energy services—consumer devices, yard, security, and accent lighting, sensing devices, cathodic protection (rust inhibition), warning and other lights, water pumps, transmitters, and defense and space applications. Off-grid PV units may also substitute for utility power in some large-scale uses, such as remote or vacation homes.

AEO95 does not project off-grid PV capacity or generation. Manufacturers' shipment data indicate that less than 60 megawatts of off-grid PV are operating today, with likely growth of 5 to 10 megawatts a year through the rest of the century [*23*]. However, the interest of electric utilities in marketing, installing, and supporting off-grid PV for remote homes, its growing acceptability to housing lenders, and the increased availability of packaged PV systems all raise possibilities for more rapid growth in off-grid PV.

Grid-connected PV applications could grow along three paths: (1) multimegawatt central station PV plants, (2) end-of-transmission-line peaking stations, and (3) groups of rooftop PV units. Although good solar conditions exist in most of the United States, the greatest expansion in grid-connected PV is expected in the Southwest, where solar conditions are best. Peaking units could forestall the need for new transmission lines or new generating capacity. Small grid-connected PV units could be placed among residential, commercial, and industrial buildings for their own supply and for peaking power to the grid.

Growth in central station grid-connected PV through 2000 will be primarily for commercialization and demonstration projects, often conducted by utility consortia and the U.S. Department of Energy (DOE). Major collaboratives, such as the Utility Photovoltaic Group (UPVG), Photovoltaics for Utility Scale Applications (PVUSA), and PV-Bonus, work to bring grid-connected PV to market.

From no more than 12 megawatts today (most at sites too small to be enumerated by EIA), *AEO95* estimates 20 megawatts of new central station grid-connected PV through 2000. Growth will accelerate if costs drop significantly or if large-scale investment occurs, as recently proposed by Enron for a 100-megawatt PV plant, or as proposed for the Solar Enterprise Zone at the Nevada Test Site. Further, to the extent that current expectations for dramatically increased U.S. production capacity are realized, the U.S. PV industry could grow more rapidly.

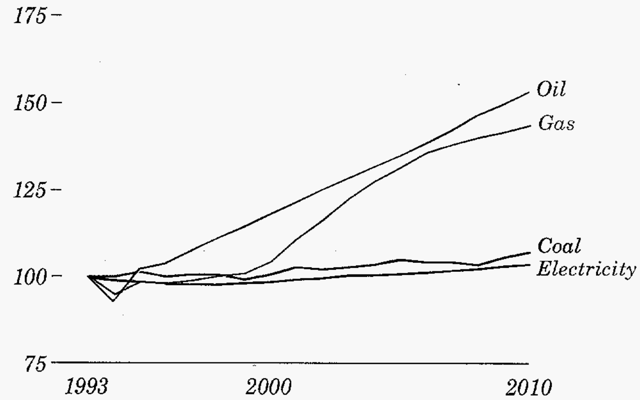
AEO95 also includes aggregate projections for central receiver, parabolic dish (energy focused on a Stirling heat engine), and parabolic trough solar thermal generators, most of which are in various test stages today. Solar thermal capacity is projected to grow from about 330 megawatts in 1993 to more than 510 megawatts in 2000. After 2000, combined projections add about 830 megawatts of central station grid-connected PV and solar thermal generating capacity by 2010, capable of providing electricity equal to the consumption of more than 250,000 homes [*24*].

The international market should also expand over the forecast period. Of U.S. shipments of PV cells in 1993 totaling 21 megawatts, 14.8 megawatts were exported [*25*]. In parts of some third-world countries, central station power and transmission grids are absent or far less reliable than in the United States. In those areas, PV systems are effective for highly valued uses such as refrigeration, pumping, communications, and lighting.

Overall, solar-electric power will require substantial cost reductions to become a major source of electricity supply. Because solar thermal and off-grid PV usually need energy storage devices to improve reliability and extend service hours, their success will also depend on improved batteries and other energy storage technologies.

Electricity Prices Remain Steady Despite Rising Fuel Prices

Figure 47. Utility fossil fuel prices and electricity prices, 1993-2010 (index, 1993=100)



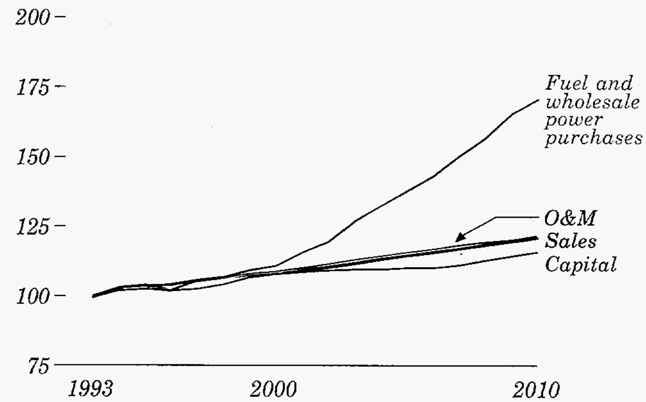
Between 1993 and 2010, average electricity prices are expected to remain nearly unchanged, rising by a scant 0.4 cents per kilowatthour (Figure 47). Although residential prices rise slightly more, the average household electric bill increases by only $3 to $4 (1993 dollars) per month by 2010. Rising natural gas prices place upward pressure on electricity prices, but stable coal prices, slowing expenditures on new and existing plants, and steady operations and maintenance costs nearly offset their impact.

From 1993 to 2010, natural gas prices to electric generators rise by 45 percent, from $2.63 to $3.82 per thousand cubic feet. Over the same period, utilities and nonutilities (including cogenerators) will increase their generation from natural gas by 49 and 78 percent, respectively. By 2010, purchases of natural gas are expected to account for 35 percent of total utility fossil fuel expenditures, up from 23 percent in 1993 (excluding purchases by cogenerators). As discussed on page 30, dependence on natural gas plants increases because of their relatively low construction costs, high efficiencies, and low sulfur and carbon emissions. These factors partially offset their higher fuel costs relative to those of coal plants.

Coal prices to electric utilities are projected to increase very little, rising by only 8 percent between 1993 and 2010. Large domestic coal reserves and improvements in mining productivity combine to keep coal prices stable. Because coal plants provide over half the electricity generated, stable coal prices contribute to stable electricity prices.

Electricity Sales Grow Faster Than Utility Capital Expenditures

Figure 48. Utility revenue requirements and sales, 1993-2010 (index, 1993 = 100)



Utility capital costs—associated with recovery of investments in power plants and transmission and distribution facilities (including annual depreciation expenses, return on investment, and taxes)—are expected to grow more slowly than electricity sales, reducing their impact on electricity prices. In contrast, purchases of power from wholesale suppliers are expected to grow in importance (Figure 48). Factors contributing to these trends include the abundant generating capacity that exists today, increasing reliance on economical wholesale suppliers for new resources as needed, and construction of relatively inexpensive natural gas combustion turbine and combined-cycle plants.

Most regions of the country have sufficient capacity in place to meet expected demand growth for many years. As a result, growth in generating capacity will lag sales growth for the next decade or so, before picking up when existing capacity is fully utilized. From 1993 through 2010, generating capacity grows at an annual rate of only 0.6 percent, while electricity sales grow by 1.1 percent a year.

The need for utilities to make capital investments should also be reduced in two other ways. First, when new generating resources are needed, utilities are expected, in large part, to look to wholesale suppliers. Thus, the suppliers will make the needed capital investments. Second, building natural gas combustion turbine and combined-cycle plants, which are less expensive to build than other generating options, reduces capital requirements.

As discussed elsewhere in *AEO95* (see box on page 27), the U.S. electric utility industry is in a period of transition. Among the issues facing the industry—which could significantly affect the outlook for the future—are the continued development of integrated resource planning (IRP) and demand-side management (DSM) programs by utilities, recent legislation affecting nonutility generators, new environmental regulations, the emergence of new generating technologies, changes in nuclear plant refurbishment and retirement options, and State policies affecting the electric power market.

Many utilities have developed IRP programs to evaluate the resource options available to meet the demand for electricity. These programs attempt to make all options equally accessible and allow for the participation of all interested stakeholders in the evaluation of costs and benefits. In some cases, utilities and their public utility commissions (PUCs) have attempted to adjust for factors not normally captured in traditional cost-benefit comparisons, such as including emission adders to account for environmental externalities associated with particular technologies or evaluating the impacts on the local economy of choosing one technology over another.

Utility investments in DSM programs have also increased dramatically during the 1990s. Utilities reported to EIA that DSM programs reduced their peak demand by 17.7 gigawatts in 1992, and they reported plans to continue investing heavily in DSM programs through 2000. With the passage of EPACT, however, utility DSM programs may be co-opted by the Act's stringent appliance efficiency standards as consumers purchase new appliances. The future of utility programs targeted at the same appliances is therefore ambiguous. The new standards may lead utilities to refocus their programs on other areas, and continued technological development may create new opportunities for DSM programs.

EPACT also contains provisions with potentially significant impacts on the development of nonutility generators and the flow of electricity trade. EPACT creates a class of generators, referred to as exempt wholesale generators (EWGs), which can develop non-rate-based generating systems and market the power from them to utilities. EPACT also guarantees EWGs greater access to utility transmission systems. These provisions will lead to an increase in nonutility generation and, to some degree, a restructuring of the electricity industry.

The possibility of new environmental legislation and the continued development of advanced generating technologies also present challenges for the future. While the CCAP primarily involves voluntary compliance, more stringent carbon reduction regulations are possible if the current approach does not achieve the desired reductions. Efforts to develop generating technologies with reduced environmental impacts are underway. New technologies, particularly for generation from renewable fuels, might play an important role in reducing the emissions associated with electricity generation.

In the area of nuclear power, the Advanced Light-Water Reactor Program—a joint initiative by DOE and the nuclear supply industry—is a current priority. The goal of the program is to develop a standardized nuclear plant design for commercial orders. Four plant types are involved, two "evolutionary" and two "midsized." The current schedule calls for design certification in 1996 and 1997, respectively. It is still unlikely, however, that any new orders for nuclear plants will be placed until a number of difficult issues are satisfactorily resolved: concerns about disposal of radioactive waste; public concerns with safety; concerns about economic and financial risks; uncertainty about future power plant performance; and uncertainty in the licensing and regulatory processes.

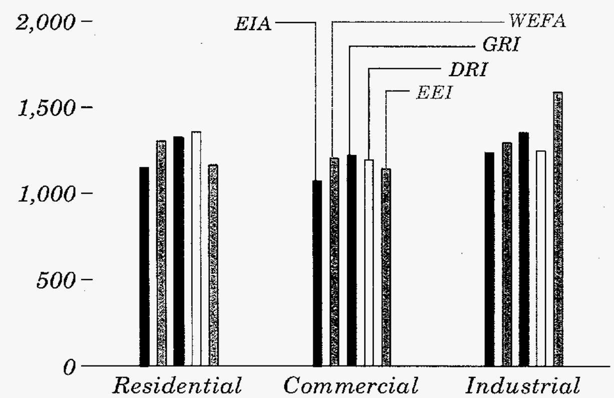
At the Federal and State levels, initiatives that will change the way electric power is marketed are being proposed and implemented. Their goal is to lower the cost of electricity to all classes of consumers through increased competition in the electric power industry. The initiatives will grant utilities the flexibility to compete for market share, ensure nonutilities a fair opportunity to compete, and give consumers direct access to electricity markets. There is still much uncertainty about how effective such measures will be in achieving lower costs for consumers. In many cases, the initiatives introduce potential problems, such as increased risk, higher cost of capital, conflict between State and Federal authority, multiple ownership of transmission systems, and cost allocation.

Electricity: Comparative Forecasts

Sales

Among forecasters, projections of 2010 electricity sales in the commercial and residential sectors show considerable variation, ranging from 1,156 to 1,363 billion kilowatthours for residential sales and from 1,078 to 1,223 billion kilowatthours for commercial sales (Figure 49). Different assumptions concerning economic growth and the penetration of more efficient electric and gas appliances in these sectors are the major reasons for the differences. EIA's lower sales projections for 2010 reflect new data showing that consumers are choosing relatively efficient appliances and, for some applications, such as heating, choosing gas over electric appliances. EIA's projections also reflect the impact of new appliance efficiency standards resulting from EPACT.

Figure 49. Electricity sales projections, 2010 (billion kilowatthours)



With respect to industrial sales in 2010, all the projections are similar except for those from the Edison Electric Institute (EEI). EEI's higher projections are driven by stronger economic growth assumptions and a more favorable outlook for electricity-using technologies in the industrial sector.

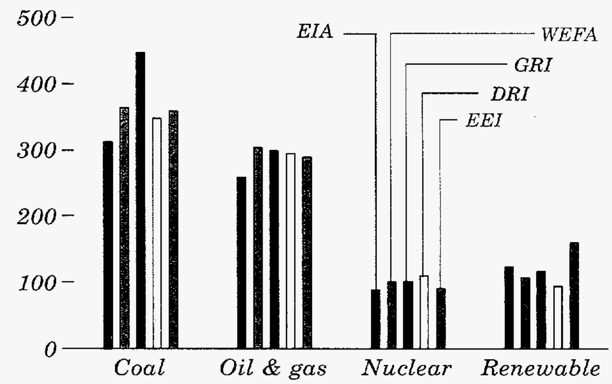
Prices

In all the forecasts, real electricity prices remain stable or decline through 2010. The relative stability of electricity prices is driven by almost flat real coal prices and the relatively slow demand growth underlying all the forecasts.

Capability

EIA's projection of electricity generating capability needed in 2010 (Figure 50) is lower than those of the other forecasters by between 74 and 191 gigawatts (247 to 640 typical 300-megawatt plants). The difference is attributable primarily to the higher projections for electricity sales growth included in the other forecasts; stronger growth leads to higher capacity needs. For example, in 2010, GRI's electricity sales projections exceed EIA's by 433 billion kilowatthours. The difference translates into a need for some 85 to 95 additional gigawatts of capacity—or more than 300 new plants—to meet demand.

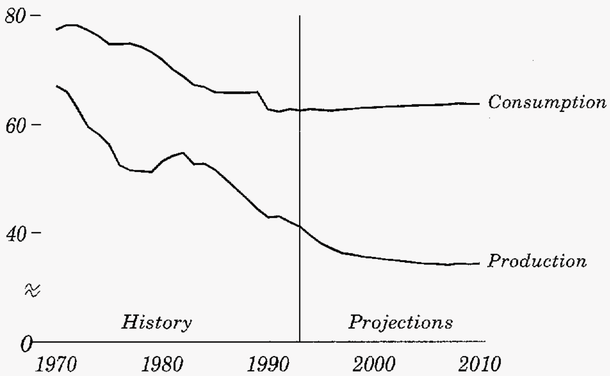
Figure 50. Electricity generating capacity projections, 2010 (gigawatts)



The distribution of EIA's capability projections among the various fuels is similar to that in other forecasts, although the total amount added is lower. Again, the differences are mainly the result of EIA's lower projection of growth in electricity sales. The exceptions are nuclear and renewable capability: EIA assumes that two nuclear units currently under construction by the Tennessee Valley Authority (Bellefonte units 1 and 2) will not be completed due to rising costs, and that older nuclear units will be retired when their operating licenses expire, rather than being life-extended. EIA is more optimistic about the penetration of renewable capability, particularly wind, because of expected improvements in cost and performance.

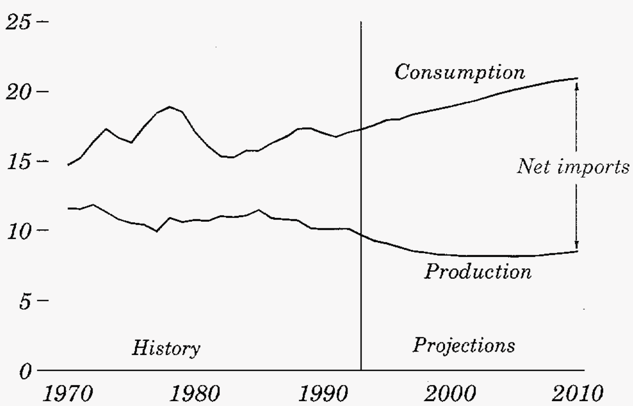
Although the share of total U.S. energy *production* captured by oil and gas declines in the *AEO95* reference case, the combined oil and gas share of total energy *consumption* increases (Figure 51). Domestic production of dry natural gas increases from 18.9 quadrillion Btu in 1993 to 21.5 in 2010, but that increase is more than offset by a drop in crude oil production (including natural gas plant liquids) from 16.9 to 14.2 quadrillion Btu. Oil production falls to 13.6 quadrillion Btu in 2005, as the depletion of lower cost existing resources continues, then rebounds to the 2010 level as prices rise and technological advances, especially for enhanced oil recovery (EOR), reduce production costs.

Figure 51. Oil and natural gas production and consumption as shares of total energy consumption, 1970-2010 (percent)



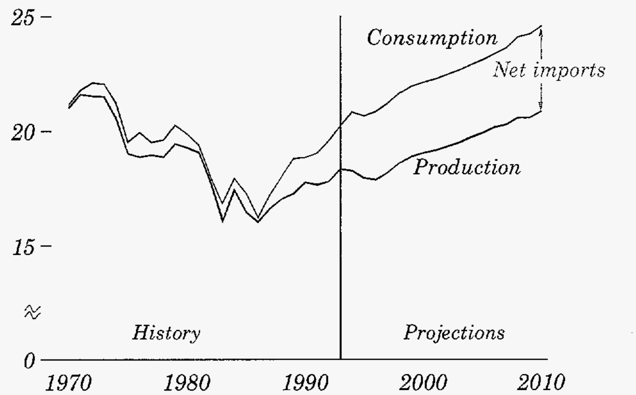
Net petroleum imports are needed to fill the widening gap between domestic production [*26*] and consumption. In 2010, 59 percent of U.S. domestic petroleum consumption is met by imports, compared with 44 percent in 1993 (Figure 52).

Figure 52. Oil production, consumption, and imports, 1970-2010 (million barrels per day)



A significant increase in natural gas consumption is driven by its expanding role as a boiler fuel for electric generators [*27*]. Natural gas also continues to be the leading source of end-use energy for space heating. Natural gas is further expected to capture the largest share of the alternative-fuel vehicle market in 2010. In total, natural gas consumption grows in the forecast from 20.8 quadrillion Btu in 1993 to 25.3 quadrillion Btu in 2010 (Figure 53). Net imports of natural gas total only 3.7 quadrillion Btu in 2010, and thus they satisfy a much smaller percentage of consumption (15 percent) than is the case for oil imports.

Figure 53. Natural gas production, consumption, and imports, 1970-2010 (trillion cubic feet per year)



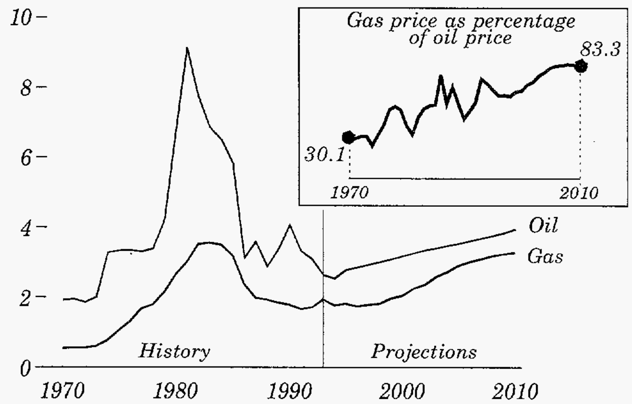
There has been a steady downward trend in EIA forecasts of oil and natural gas wellhead prices over the past 5 years. Projected wellhead oil prices in 2010 are 37 percent lower in *AEO95* than they were in *AEO91*, and gas price projections are 41 percent lower (Table 15). The revisions have been based primarily on reassessments of the resource base, reevaluations of improvements in exploration and production technology, changing expectations with regard to the global oil supply/demand balance, and revised estimations of the effects of increased competition following ongoing restructuring of the natural gas industry.

Table 15. EIA forecasts of world oil price and domestic oil and gas wellhead prices, 2010

Forecast	AEO91	AEO92	AEO93	AEO94	AEO95
World oil price (1993 dollars per barrel)	37.62	36.74	31.06	28.88	24.12
Oil wellhead price (1993 dollars per barrel)	36.39	35.51	29.75	27.67	22.92
Gas wellhead price (1993 dollars per thousand cubic feet)	5.75	5.27	4.05	3.56	3.39

Wellhead Prices for Oil and Gas Rise in the Forecast

Figure 54. Lower 48 oil and gas wellhead prices, 1970-2010 (1993 dollars per million Btu)



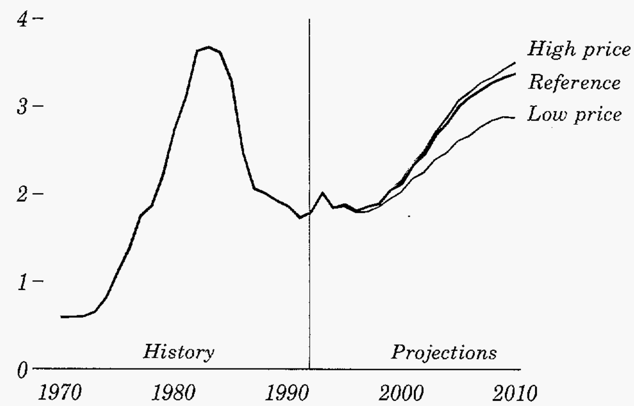
Domestic oil and natural gas prices are projected to reverse recent declines (Figure 54). Domestic oil prices are determined largely by the international market, whereas domestic natural gas prices are determined largely by competition in North American energy markets. Natural gas, unlike oil, is not easily transported between the United States and countries outside North America.

The prices of both fuels increase over most of the forecast in response to rising domestic demand and resource depletion. Natural gas prices rise despite increased competition and technological advances that reduce the cost of finding and developing reserves.

The world oil price interacts with domestic natural gas markets in complex ways. A positive, direct effect occurs on gas *supply* when oil prices, and hence levels of oil drilling, increase. Nearly one-sixth of domestic gas production (associated and dissolved natural gas) is currently a coproduct of oil production. On the other hand, a negative, indirect effect on gas *supply* also occurs, because increases in oil prices increase the profitability of oil drilling relative to gas drilling. The change in relative profitability induces drillers to shift exploration and development investments in the direction of oil, the increasingly profitable opportunity. Crude oil prices can also affect *demand* for natural gas, as oil and gas compete as substitute fuels in some end-use sectors. The competition affects natural gas demand—and thus natural gas prices—in the forecast period.

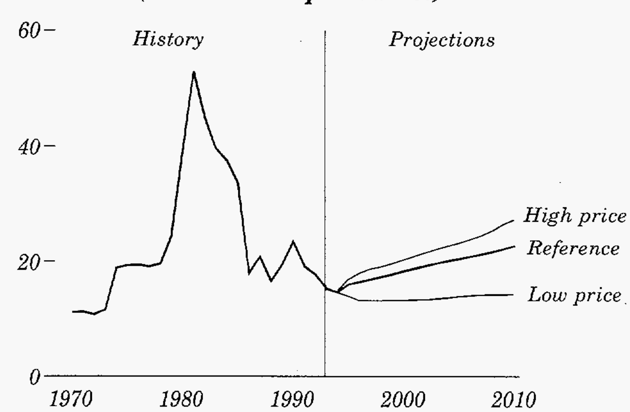
Gas Prices Increase More Dramatically Than Oil Prices

Figure 55. Lower 48 natural gas wellhead prices, 1970-2010 (1993 dollars per thousand cubic feet)



Lower 48 natural gas wellhead prices in the reference case grow at an average annual rate of 3.1 percent between 1993 and 2010 (Figure 55). Significant variation in the projected price of oil between the low and high price cases (Figure 56) has only limited effect on the projected price of natural gas, in part because oil and natural gas do not compete directly in all domestic markets [*28*].

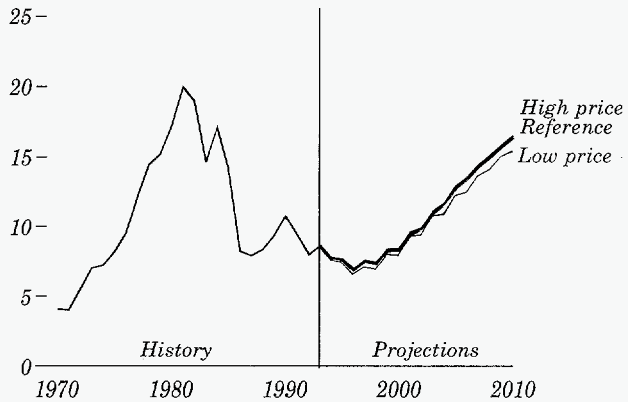
Figure 56. Lower 48 crude oil wellhead prices, 1970-2010 (1993 dollars per barrel)



Lower 48 wellhead prices for crude oil in the reference case grow more slowly than gas prices, at an average rate of 2.4 percent a year over the 1993-2010 period (Figure 56). However, the variation in oil prices among different cases (as a percentage of reference case prices) is much greater than the variation in natural gas prices. In all cases examined, the average natural gas price comes much closer to attaining its historic peak than does the crude oil price [*29*].

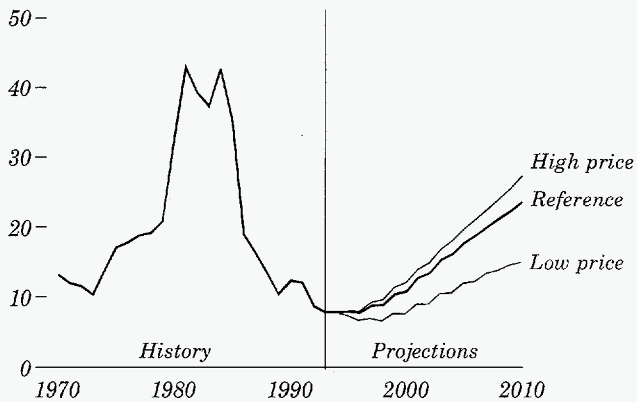
Drilling for Oil and Gas Increases in All Cases

Figure 57. Successful new lower 48 natural gas wells, 1970-2010 (thousand successful wells)



Rising prices (combined with lower finding and operating costs) generally lead to more drilling for both natural gas (Figure 57) and crude oil (Figure 58) [*30*]. The number of successful natural gas wells grows at an average annual rate of 3.9 percent over the 1993-2010 period.

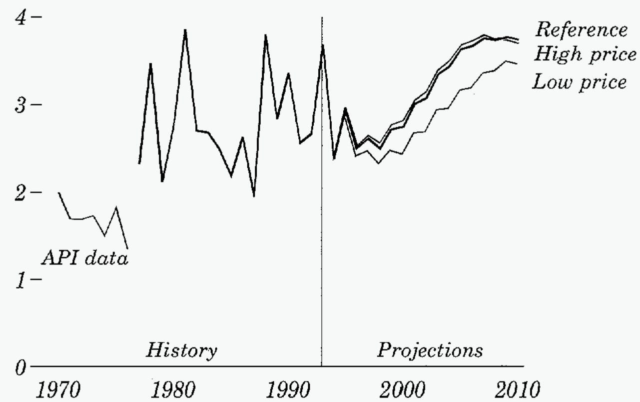
Figure 58. Successful new lower 48 oil wells, 1970-2010 (thousand successful wells)



The number of successful oil wells grows at a faster average annual rate—6.7 percent—over the same period, reaching significantly higher drilling levels by 2010. In 1993, gas drilling exceeded oil drilling by 10 percent; by 2010, oil drilling exceeds gas drilling by 43 percent. For both natural gas and oil, the exploratory share of total wells rises between 1993 and 2010 [*31*]. The stronger relative growth in oil well completions occurs because the prospective profitability of new oil projects increases more than the prospective profitability of new natural gas projects over the forecast period.

Gas Reserve Additions Exceed Oil Reserve Additions

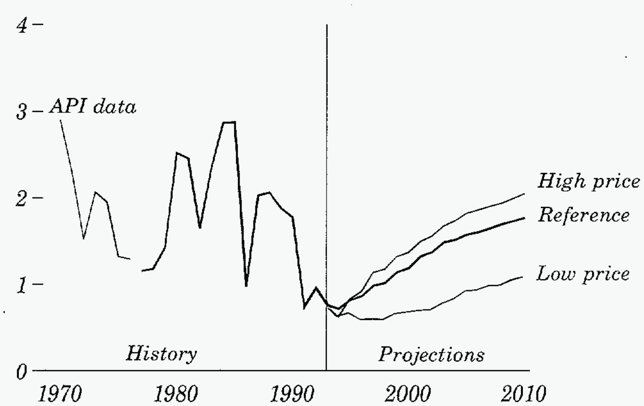
Figure 59. Lower 48 natural gas reserve additions, 1970-2010 (billion barrels oil equivalent)



Higher levels of natural gas drilling produce significant increases in annual reserve additions (Figure 59), continuing the trend of the past 2 decades [*32*]. Lower 48 reserve additions generally increase to about the level of their recent peaks, but lower 48 reserves fall at a 0.7-percent annual rate as production exceeds reserve additions.

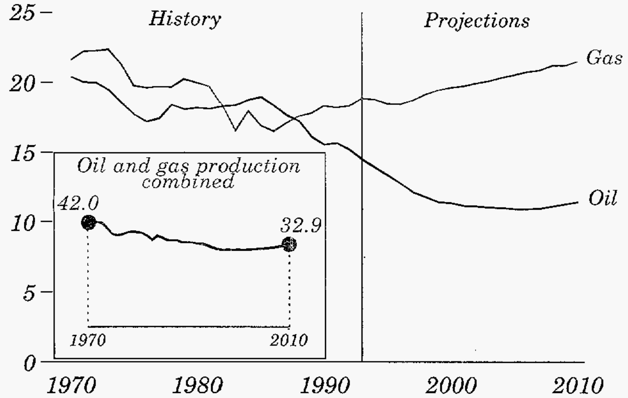
Higher levels of crude oil drilling also lead to significant increases in annual reserve additions, reversing the generally declining trend of the past two decades (Figure 60). However, reserve additions per new well are lower for oil than for gas. Lower 48 oil reserve additions increase on average by 5.2 percent a year. Still, lower 48 oil reserves fall at an average annual rate of 1.6 percent, because oil production generally exceeds reserve additions.

Figure 60. Lower 48 oil reserve additions, 1970-2010 (billion barrels)



Oil Production Declines, Gas Production Rises

Figure 61. Oil and gas production, 1970-2010 (quadrillion Btu)



Despite increasing reserve additions, domestic natural gas production generally declined over the 1970-1986 period [33]. Gas production has increased since 1986, largely because of increasing industry deregulation and rising demand. In the forecast, relatively abundant natural gas is expected to be available from lower cost sources, allowing production to increase steadily (Figure 61) to meet rising demand. In contrast, oil production [34] is projected to continue its historic decline through 2005 [35], increasing slightly thereafter in response to rising prices and improvements in drilling technology.

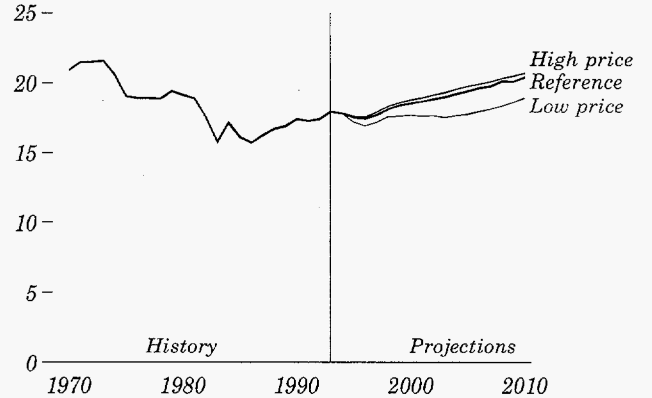
The resource estimates underlying the production projections assume that, given technological innovation, economically recoverable domestic oil and natural gas resources (measured as of 1990) will increase (Table 16) [36,37].

Table 16. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions

	Crude oil (billion barrels)		*Natural gas (trillion cubic feet)*	
Resources	***1990 technology***	***2010 technology***	***1990 technology***	***2010 technology***
Proved	*26.3*	*26.3*	*169.4*	*169.4*
Unproved	*85.7*	*128.9*	*851.9*	*1,449.2*
U.S. total	***112.0***	***155.2***	***1,021.2***	***1,618.6***

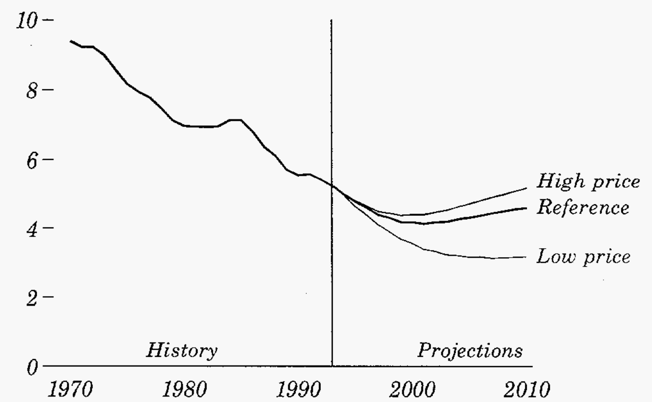
Oil Production Varies More Than Gas When World Oil Prices Change

Figure 62. Lower 48 natural gas production, 1970-2010 (trillion cubic feet)



Lower 48 natural gas production in the reference case is projected to grow at an average annual rate of 0.8 percent over the 1993-2010 period (Figure 62). Historically, for both natural gas and oil, major price and drilling peaks have had only limited impact on contemporaneous levels of new reserve additions and production [38]. The projections reflect a continuation of those basic relationships.

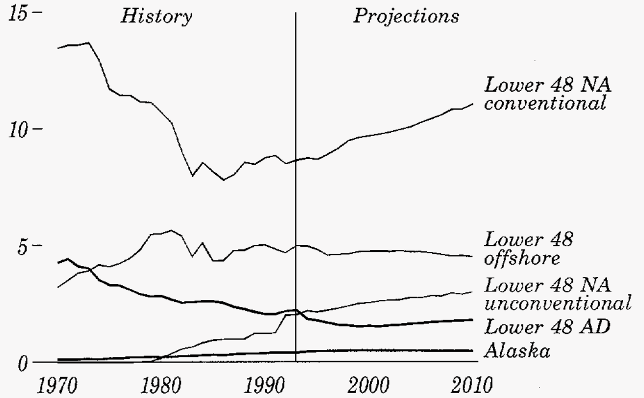
Figure 63. Lower 48 oil production, 1970-2010 (million barrels per day)



Lower 48 crude oil production is projected to decline at an average annual rate of 0.8 percent over the 1993-2010 period (Figure 63). The higher variation in crude oil prices—as compared with gas prices—across oil price cases leads to higher variation in crude oil production than in natural gas production.

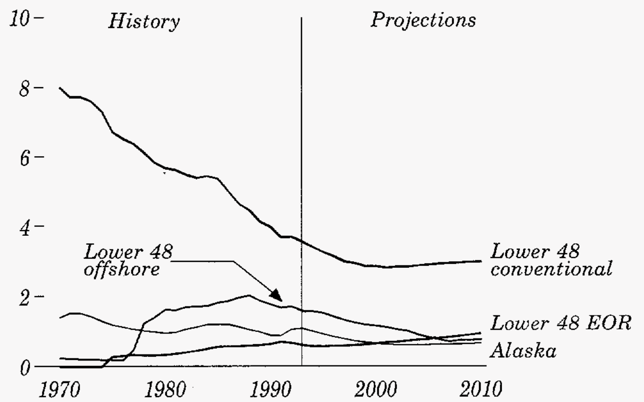
Lower 48 Conventional Gas Production Shows Largest Increase

Figure 64. Natural gas production by source, 1970-2010 (trillion cubic feet)



The continuing increase in domestic natural gas production for most of the forecast is partly attributable to increases in onshore conventional production and increasing use of unconventional gas recovery (UGR) technologies (Figure 64) [*39*].

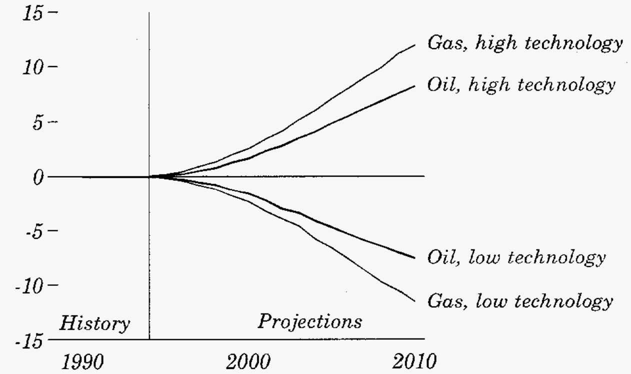
Figure 65. Oil production by source, 1970-2010 (million barrels per day)



The increasing levels of domestic oil production from 2005 to 2010 (Figure 65) are attributable primarily to increasing production by enhanced oil recovery (EOR) methods [*40*]. Despite technological advances that improve recovery, conventional oil production in the lower 48 onshore regions is expected to decline from 1993 levels as a result of the maturity of the oil resource base.

Technology Gains More Important for Gas Than for Oil Production

Figure 66. Variations from reference case projections of lower 48 natural gas and oil production in two cases, 1990-2010 (percent)



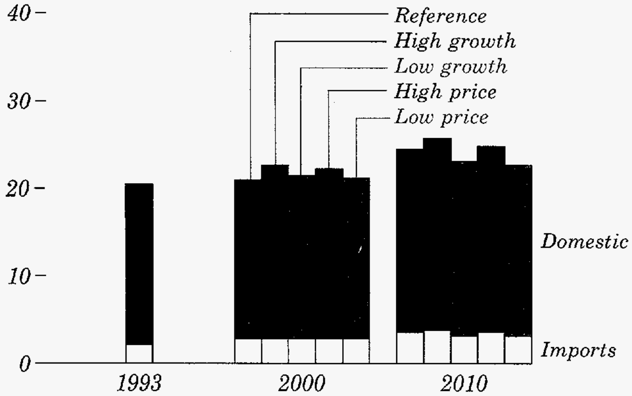
Historically, technological progress has expanded the economically recoverable oil and natural gas resource base and reduced effective exploration and development costs. However, the extent to which such expansion and reduction are likely to continue is uncertain, depending on future rates of technological development and deployment (that is, the adoption of technological improvements by firms). In *AEO95*, for all five integrated cases presented, technological progress is assumed to continue at rates characteristic of the past two decades [*41*].

To assess the sensitivity of the projections to the above assumptions, an additional analysis was performed. Two special technology cases were created by adjusting all oil and gas technological progress rates upward and downward by a given proportion—overall, approximately 50 percent. This change affects both the size of reserve additions per new well and the number of new well completions [*42*].

The analysis indicated that gas production is more sensitive than oil production to the rate of technology improvement (Figure 66) [*43*]. While not definitive, this finding is consistent with the projection that, compared with oil, a significantly greater share of future natural gas production is from frontier supply sources (for example, deep gas, unconventional gas recovery, and offshore), where the rate of technology progress is expected to be higher [*44*].

Both Domestic and Foreign Suppliers Gain From an Expanding Gas Market

Figure 67. Natural gas production and imports, 1993, 2000, and 2010 (trillion cubic feet per year)



Between 1993 and 2000, foreign and domestic producers capture equal shares in the growth of 1.5 trillion cubic feet in the U.S. natural gas market (Figure 67). Domestic producers fare better after 2000, capturing 73 percent of the market growth of 2.5 trillion cubic feet between 2000 and 2010.

Total gas consumption in the industrial, electric generator, and vehicle market sectors increases by more than 4 trillion cubic feet by 2010 in the reference case (Table 17). The market expansion is driven primarily by the demand for electricity (including industrial cogeneration) and the requirements for alternative-fuel vehicles. Residential and commercial consumption remains flat, as conservation and efficiency improvements offset the growth in the number of customers.

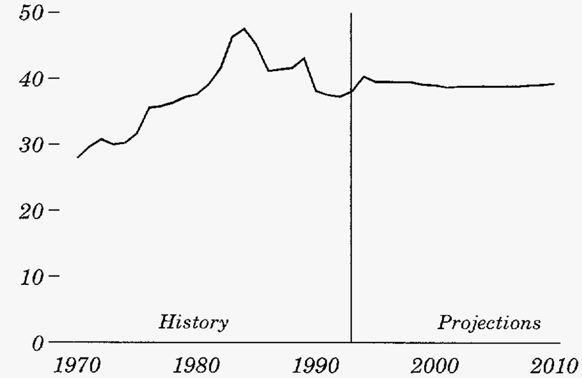
Natural gas market expansion varies across the economic growth and oil price cases (Figure 67) [*45*]. Dual-fired boiler markets are vulnerable to lower residual oil prices in the low price case [*46*], and lower power generation requirements reduce the size of the market expansion in the low growth case relative to the reference case.

Table 17. Reference case natural gas consumption, 1993, 2000, and 2010 (trillion cubic feet per year)

	1993	2000	2010
Residential	4.96	5.01	4.89
Commercial	2.89	2.95	2.97
Industrial	7.61	8.68	9.50
Electric generators	2.94	3.34	4.72
Transportation	0.01	0.15	0.42
Total	**18.40**	**20.14**	**22.49**

Gas Transmission and Distribution Revenues Stabilize, Margins Decline

Figure 68. Natural gas transmission and distribution revenues, 1970-2010 (billion 1993 dollars)



Transmission and distribution revenues [*47*] stabilize over the forecast period (Figure 68), in contrast to their nearly continuous growth through the early 1980s and the 17.8-percent decline between 1983 and 1993. The leveling of revenues reflects a balance between cost decreases resulting from improved alignment of services with customer needs and technology improvements, and cost increases resulting from the investment needed to support market expansion.

Unlike revenues, the average transmission and distribution margin (revenue divided by consumption) [*48*] continues the decline that began after 1983, when margins were at their peak (Table 18). In the forecast, the average margin declines from $2.07 per thousand cubic feet in 1993 to $1.75 in 2010. Greater throughput, a large base of depreciated plant, industry automation [*49*], and the growing number of end users that typically use nonfirm services all contribute—along with increased competition—to the decline in the average transmission and distribution margin.

Table 18. Transmission and distribution revenues and margins, 1970, 1983, 1993, and 2010

	1970	1983	1993	2010
T&D revenues (billion 1993 dollars)	27.99	46.34	38.07	39.32
End-use consumption (trillion cubic feet)	19.02	15.37	18.40	22.49
Average margin* (1993 dollars per thousand cubic feet)	1.47	3.02	2.07	1.75

*Revenue divided by end-use consumption.

Natural gas market competitive issues

Over the past decade, the focus of Federal policy initiatives has been to promote competition in the procurement of natural gas supplies by deregulating wellhead prices and restructuring the natural gas interstate pipeline industry. The concept of relying on market forces for the pricing of natural gas services by deregulating services in workably competitive markets is expected to expand into other industry segments. Although refinement of recent Federal initiatives continues, attention is now shifting to promoting competition in the gathering and distribution segments of the industry. The goal of the policy changes is to modify the market to allow pricing signals to flow freely between the wellhead and the burnertip.

Industry restructuring [*50*] is leading to an environment in which the prices of services are based on their commercial value. This is a major change for the industry and contrasts with the old environment, where service prices were often based on the cost of placing and maintaining physical assets in service. As the market continues to change direction, the industry may find that it has surplus plant, leading to a significant amount of stranded investment [*51*]. This could bring about a number of writedowns [*52*], internal restructuring, sales of assets, or a new round of "transition costs" [*53*].

The effects of the increasingly competitive market are evident in the observed changes in the components of end-use prices over the past decade. All end-use sectors have seen some reduction in the cost of supplies and the cost of getting those supplies to the burnertip. Changes in the components of the residential and commercial end-use prices are shown in the following table. Benefits of industry restructuring could spread further downstream, resulting in lower end-use prices, if similar changes occur in the industry's distribution segment.

Components of natural gas end-use prices (1993 dollars per thousand cubic feet)

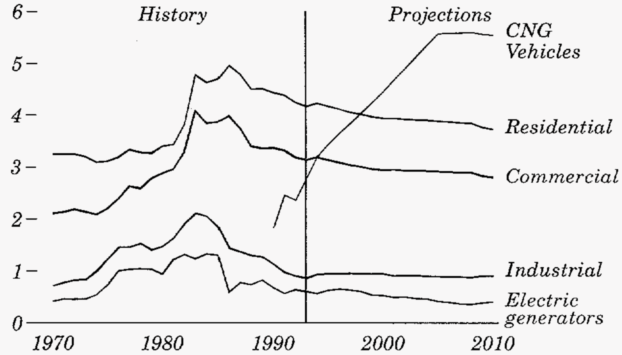
Price component	*1984*	*1993*
Wellhead price	*2.73*	*2.02*
Markup to citygate	*1.67*	*1.19*
LDC distribution markup		
Residential	*2.96*	*2.98*
Commercial	*2.18*	*1.97*
End-use price		
Residential	*8.35*	*6.19*
Commercial	*7.57*	*5.18*

The lowering of wellhead prices and wellhead-to-citygate markups since 1984, coupled with little change in distribution markups, has caused a significant increase in the distribution share of the core market end-use price [*54*]. Many States and local distribution companies (LDCs) are currently investigating restructuring of the distribution segment of the industry to move toward competitive pricing—either through deregulation or through performance-based ratemaking—and a number of possible scenarios have been suggested. Examples are New Jersey's proposal to unbundle gas utility services to all customers [*55*] and Boston Gas Company's proposal to consolidate all Massachusetts LDCs into a single utility [*56*]. Such changes in the distribution segment of the industry could improve the competitive position of natural gas at the burnertip and increase its use in the residential and commercial sectors, which traditionally have been supplied by the LDCs [*57*].

Changes are also anticipated in the gathering end of the industry. A May 1994 FERC ruling that gathering falls under FERC jurisdiction only if performed by a regulated interstate pipeline has encouraged pipelines to either transfer their gathering facilities to existing affiliates, create new affiliates to handle their gathering facilities, or sell their facilities to nonaffiliates. The rate of those activities will most likely accelerate, bringing competition to yet another segment of the natural gas market [*58*]. Although FERC will no longer have direct jurisdiction over the transfers it approves, it maintains a built-in safeguard in the right to step in if there appears to be an abuse of the pipeline/gathering relationship.

Lower Margins Dampen Wellhead Price Increases at the Burnertip

Figure 69. Natural gas transmission and distribution margins by end use, 1970-2010 (1993 dollars per thousand cubic feet)



The industry restructuring begun in 1984 has allowed competition to place downward pressure on transmission and distribution margins in most end-use sectors (Figure 69). The exception is the vehicle natural gas market, where margins are projected to rise as they reflect motor fuels taxes and changes in service as the market moves from demonstration programs to commercial multi-user refueling stations [*59*]. Nevertheless, natural gas still retains a significant price edge over motor gasoline (Table 19).

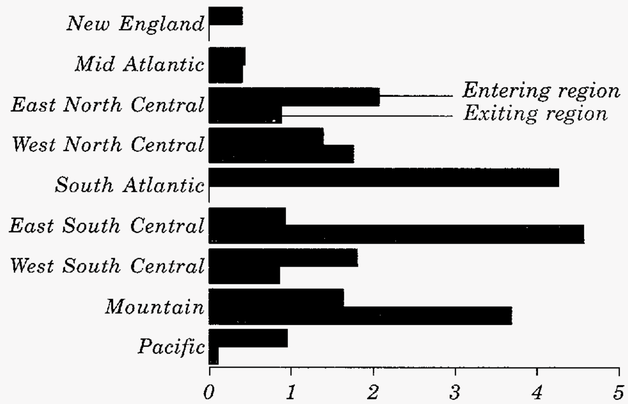
In contrast with petroleum products, the relative fuel prices favor coal over natural gas in the electric generator sector. Although they have higher fuel costs, gas plants currently operate more efficiently than coal plants, generally cost less to build and operate, and have additional advantages in siting, permitting, construction time, and load-following flexibility. Toward the end of the forecast period, coal's price advantage begins to outweigh other factors, and coal is generally chosen over natural gas for new electric generator builds.

Table 19. Ratio of natural gas to competing fuel prices, 1993, 2000, and 2010

	1993	2000	2010
Residential			
Distillate	0.92	0.76	0.79
Electricity	0.25	0.25	0.27
Electric generators			
Coal	1.85	1.86	2.49
Residual fuel	1.04	0.89	1.01
Distillate fuel	0.54	0.49	0.63
Vehicle fuel			
Motor gasoline	0.52	0.60	0.77

Pipeline Capacity Expands To Reach New Markets and Supplies

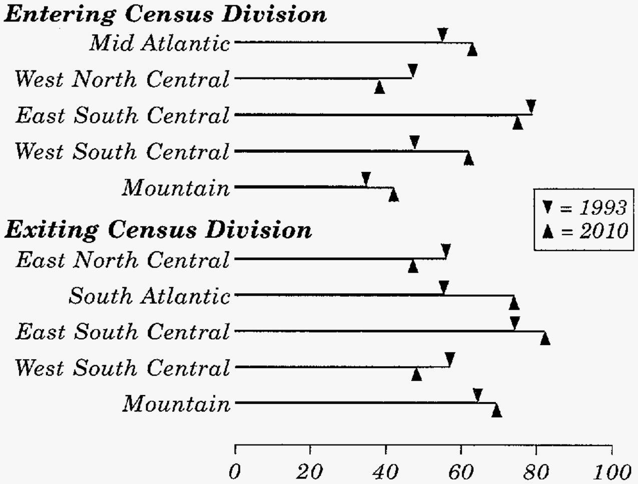
Figure 70. Increases in natural gas pipeline capacity by region, 1993-2010 (billion cubic feet per day)



New interregional capacity [*60*] for interstate facilities will be required to support the expansion of natural gas markets and regional shifts in supply. Much of the expected capacity expansion occurs in the early years of the forecast [*61*].

Pipeline capacity (Figure 70) and utilization (Figure 71) continue to increase in many regions to support emerging supply sources, such as Canadian imports and the East South Central and Mountain regions. Continuing production declines in traditional producing regions (for example, the West South Central region) result in no new capacity beyond planned additions, as well as decreases in the capacity utilization of pipelines exiting these regions [*62*].

Figure 71. Pipeline capacity utilization by region, 1993 and 2010 (percent)



Pipeline safety and refurbishment

In March 1994, a natural gas transmission line exploded in Edison, New Jersey, resulting in a blast and fire that destroyed an apartment complex and displaced several hundred people [*63*]. Despite preliminary findings that the explosion was caused by external construction activity, probably during the 1980s, the explosion focused national attention on a major issue—the safety of the gas transmission infrastructure.

The Nation's gas pipeline network is aging. Most of the system was constructed before the 1972 peak in natural gas consumption, although newer segments have been added to meet shifting regional supply and demand patterns. With proper maintenance and new technology, it is possible to extend the useful life of the existing transmission network. Costs for routine maintenance are accounted for in the pipeline operation and maintenance expenses included in the reference case forecast; however, significant additional investment may be needed to extend the life of aging plants or to refurbish and replace pipe as it approaches the end of its useful life. On the basis of a survey of major pipeline companies, conducted as part of the study published in *The Potential for Natural Gas in the United States* (December 1992), the National Petroleum Council (NPC) has estimated that the industry could be faced with an average annual capital investment of $1.7 billion (1991 dollars) in replacement/refurbishment expenses through 2010.

Industry research and development expenditures, operation and maintenance activities, and passage of the Pipeline Safety Act of 1992 (PSA) provide ample evidence that pipeline safety has long been of concern to legislators and the pipeline industry. A key provision of the PSA requires that all new and replacement pipelines accommodate internal inspection devices known as "smart pigs" [*64*]. After the New Jersey explosion, the Department of Transportation's Research and Special Programs Administration (RSPA) expanded the definition of "replacement" as referenced in the PSA to include any line section of pipe requiring replacement of any portion of the pipe or other component of the line.

The new definition could require replacement of many miles of pipe whenever a small section is repaired. As a result of industry contention that the ruling would have an adverse financial impact on the industry [*65*], the RSPA has indefinitely suspended enforcement of the "line section" replacement ruling pending further investigation.

In order to quantify the cost increases to customers that may result from potential safety and refurbishment expenditures, an alternative case—the *refurbishment case*—was developed for *AEO95* and modeled in the Pipeline Tariff module of NEMS [*66*]. The table below compares the level of investment and corresponding revenue requirements in the refurbishment case with those used for the *AEO95* reference case.

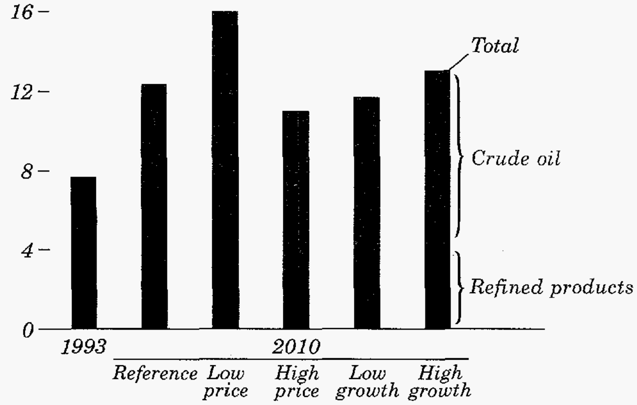
Rate base and revenue requirements for interstate pipeline transmission, 2010 (billion current year dollars)

Item	*Reference case*	*Refurbishment case*
Plant in service		
Gross plant in service	58.74	94.75
Accumulated depreciation	44.01	53.98
Net plant in service	14.73	40.77
Adjusted rate base	11.85	33.33
Revenue requirements		
Return on capital	1.15	3.33
Normal operating expenses	10.58	14.67
Total	***11.73***	***18.00***
Total (billion 1993 dollars)	***7.02***	***10.78***

If the additional refurbishment and safety expenses modeled in the refurbishment case were fully recovered from customers, the average transmission and distribution markup in 2010 is estimated to increase by 17 cents per thousand cubic feet. Most of the cost increase would likely be in fixed costs, which, under current ratemaking practice, would be collected largely through the reservation fees paid by core customers subscribing to firm transportation services. If the costs were passed through exclusively to core customers, their average transmission and distribution markup in 2010 is estimated to increase by 24 cents per thousand cubic feet, or by 10 percent, compared with the level projected in the reference case.

Refined Products Make Up a Growing Share of Petroleum Imports

Figure 72. Imports of crude oil and refined products, 1993 and 2010 (million barrels per day)



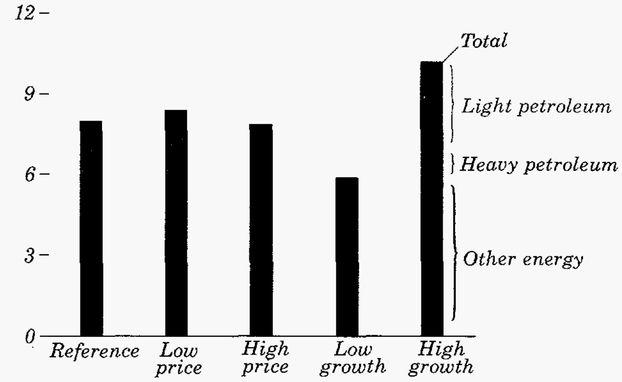
Imports of both crude oil and refined petroleum products are projected to increase in the forecast (Figure 72). Refined products represent a growing share of petroleum imports, between 22 and 33 percent in 2010 in the low growth and low price cases, respectively, compared with 12 percent in 1993.

Reliance on foreign refining is expected to increase, because expansions in domestic refining will not keep pace with growing domestic consumption. Large, new refineries are not expected to be built in the United States, because of the time and costs associated with obtaining permits and meeting environmental regulations [*67*]. Investment funds will also be limited, as refiners make large investments to comply with CAAA90. Expansion of existing refineries will result in capacity additions of 0.5 and 0.7 million barrels a day in the high and low price cases over the 1993 level of 15.3 million barrels a day.

In the reference case, crude oil inputs to U.S. refineries in 2010 are only 0.6 million barrels a day higher than 1993 levels, because refinery utilization rates remain stable at around 90 percent. A growing share of the crude oil processed in U.S. refineries is imported, as domestic crude oil production declines over time. The expected share of foreign crude oil processed is higher in the low price case, where lower price incentives result in a faster decline in domestic oil production.

Petroleum Continues To Be a Major Source of U.S. Energy Consumption

Figure 73. Composition of changes in energy consumption, 1993-2010 (million barrels crude oil equivalent per day)



Despite programs to encourage the use of alternative fuels, between 38 and 60 percent of the growth in domestic energy consumption over the forecast is supplied by petroleum products (Figure 73). Light products (including diesel fuel, heating oil, jet fuel, gasoline, kerosene, and liquefied petroleum gases), distilled from crude oil at lower temperatures, represent 67 to 80 percent of the growth in petroleum consumption. Transportation fuels continue to account for around two-thirds of U.S. petroleum use.

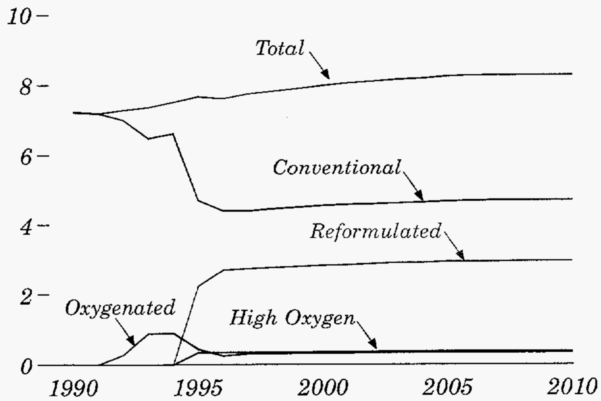
Of all the petroleum products, residual fuel oil shows the greatest variation in consumption across the *AEO95* cases (Table 20). Competition from natural gas and coal makes residual fuel consumption highly sensitive to price. In the low price case, residual fuel oil consumption in 2010 is 2.39 million barrels a day, more than double the 1993 level of 1.08 million barrels a day, with approximately two-thirds of the increase resulting from fuel switching by electric utilities.

Table 20. Petroleum consumption by product, 1993 and 2010 (million barrels per day)

Products	1993	Reference	Low price	High price	Low growth	High growth
Light	**15.03**	**17.99**	**18.78**	**17.66**	**17.22**	**18.71**
Gasoline	7.48	8.41	8.72	8.20	8.14	8.64
Jet fuel	1.47	2.15	2.21	2.12	2.01	2.29
Distillate	3.04	3.78	3.92	3.72	3.57	3.98
Other	3.04	3.65	3.93	3.62	3.50	3.80
Heavy	**2.21**	**2.86**	**3.74**	**2.77**	**2.75**	**3.12**
Residual	1.08	1.61	2.39	1.53	1.53	1.79
Other	1.13	1.27	1.36	1.24	1.22	1.33
Total	**17.24**	**20.88**	**22.52**	**20.44**	**19.97**	**21.83**

Environmental Regulations Change the U.S. Gasoline Market

Figure 74. Gasoline consumption by type, 1990-2010 (million barrels per day)

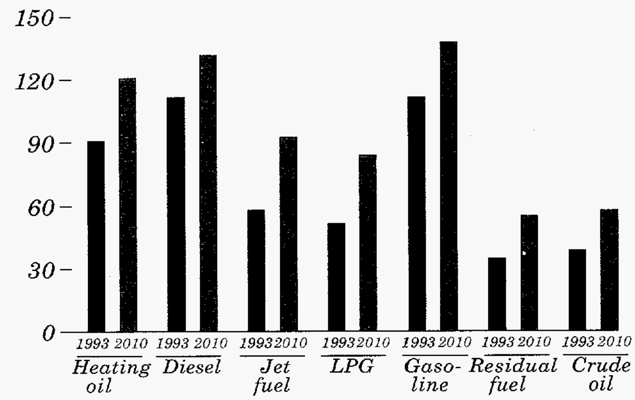


The makeup of U.S. gasoline consumption will change significantly as CAAA90 requirements continue to be phased in. Starting in 1995, cleaner burning "reformulated gasoline" will be sold in the nine metropolitan areas with the most severe ozone pollution and in other areas—predominantly in the Northeast—that choose to impose the requirement [*68*]. In California, beginning in 1996, all gasoline sold must be "reformulated" according to standards set by the California Air Resources Board. After 1996, reformulated gasoline will make up some 40 percent of the gasoline consumed in the United States (Figure 74). About one-eighth of the reformulated gasoline must also meet preexisting higher oxygen standards in areas with high carbon monoxide levels [*69*].

Higher oxygen content is one characteristic that sets reformulated gasoline apart from conventional gasoline. Oxygen is added to gasoline by blending with "oxygenates," including methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), and ethanol, which offset a small portion of the petroleum content of gasoline. Moreover, a recent EPA ruling—the Renewable Oxygenate Standard (currently pending legal review) [*70*]—requires that 15 percent of reformulated gasoline use renewable oxygenates for blending. The requirement will be stepped up to 30 percent in 1996. In the *AEO95* reference case, approximately 0.57 million barrels of petroleum a day (about 6 percent of gasoline) is offset by blending with renewable and nonrenewable oxygenates in 2010.

Prices for Lighter Products Rise More Sharply Than Heavy Product Prices

Figure 75. Petroleum product prices, 1993 and 2010 (1993 cents per gallon)



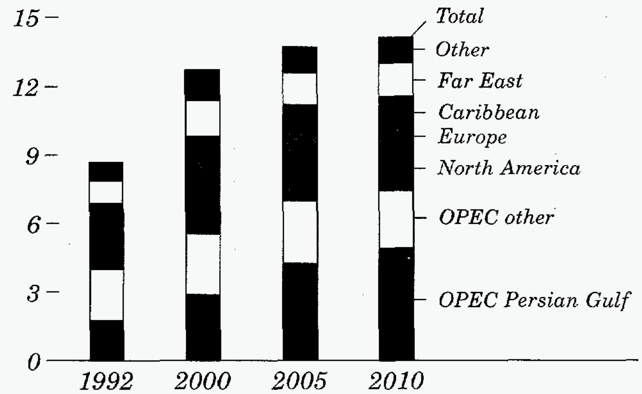
Prices of lighter petroleum products, including heating oil, diesel, gasoline, jet fuel, and liquefied petroleum gases (LPG), increase in the forecast relative to the prices of heavier products, including residual fuel (Figure 75). Growth in the consumption of lighter products, which are distilled from crude oil at lower boiling ranges, will require investment in conversion processes that turn the heavier streams into lighter ones.

Compared with prices in the early 1990s, the prices of lighter products will bear an additional 3 to 5 cents per gallon as a result of refinery compliance with emissions, health, and safety regulations. The prices of heavier petroleum products will not be affected, because they compete closely with other products, such as natural gas, and are therefore more price-sensitive.

Requirements for reformulated gasoline will increase the cost of producing and distributing gasoline. In the forecast, reformulated gasoline has a national price premium of 4 to 7 cents a gallon over conventional gasoline. In the Northeast, where reformulated gasoline use will be heavily concentrated, the premium ranges between 4 and 6 cents a gallon. Higher price premiums, between 10 and 14 cents a gallon, will be seen on the West Coast as a result of the mandate for reformulated gasoline in California beginning in 1996. Relative to Federal requirements, the California law places tighter limits on the sulfur and olefin contents of reformulated gasoline, which make it more costly to produce.

Persian Gulf Oil, Lighter Products Have Larger Shares of U.S. Imports

Figure 76. U.S. petroleum imports by source, 1992, 2000, 2005, and 2010 (million barrels per day)



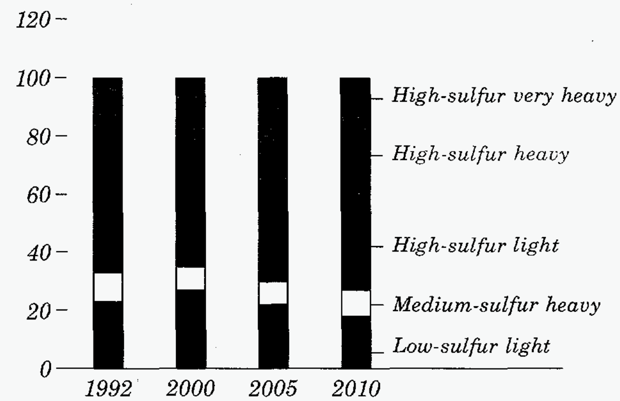
The 1.1-percent annual growth rate of oil consumption in the *AEO95* reference case translates into increased U.S. imports of both crude oil and refined products. Crude oil imports grow by 1.6 percent a year, and refined products by a vigorous 4.8 percent (see page 37).

OPEC is expected to account for approximately one-half of total U.S. petroleum imports for the remainder of this decade. After 2000, however, the OPEC share increases to just under 60 percent. The Persian Gulf share of U.S. imports from OPEC increases more dramatically, from today's 44 percent to more than 65 percent in 2010. Crude oil imports from the North Sea increase throughout the 1990s but then begin to decline as North Sea production ebbs. Significant quantities of crude oil continue to be imported from both Canada and Mexico.

Most additions to worldwide refining capacity over the next 15 years will be outside the United States, with significant capacity increases expected in the Caribbean Basin, Middle East, and Far East. U.S. imports of refined products from each of these regions are expected to increase, with the most dramatic gain for the Caribbean Basin. Traditionally, significant volumes of residual fuel oil have been imported from Caribbean Basin exporters; however, lighter products are expected to make up a larger share of imports from the region as demand for them increases.

Declining Quality of Crude Oil Supply Will Challenge Refiners Worldwide

Figure 77. Shares of world petroleum production by quality, 1992, 2000, 2005, and 2010 (percent)



The declining quality of world crude oil production over the forecast period presents challenges to the refining industry. The production of light, low-sulfur oils—so valued by industrialized nations for their robust yield of light products—peaks around the turn of the century, then drops off with the decline of North Sea fields. OPEC members with significant light, low-sulfur crude oil production (Algeria, Libya, Nigeria, Gabon, and Indonesia) are not expected to maintain current output levels through 2010.

A large volume of the reserves in the Persian Gulf region consists of light, high-sulfur crude oils, which make up the largest share of world production throughout the forecast. A substantial drop in their share is expected, however, as giant Middle East oil fields mature and decline. The production losses are likely to be replaced by Middle East heavier crude oils, but some analysts are uncertain about the willingness of Persian Gulf producers to expand production capacity when world oil prices are low.

Crude oil reserves—especially in the Middle East—can satisfy world petroleum demand well into the next century. The real challenge faces the refining industry. With demand for lighter products increasing and more stringent product specifications resulting from environmental regulations, refining becomes more complex and more expensive. Additions to distillation capacity will be needed worldwide merely to keep pace with demand, and significant downstream capacity will have to be added so that heavier crude oils can be upgraded.

Natural gas markets

Far-reaching changes have occurred in the U.S. natural gas industry over the past decade as a result of deregulation of many aspects of the industry, and significant future changes are anticipated. The *AEO95* reference case assumes modest changes from current market trends, but the gas market of the future may deviate substantially from that pattern.

Currently, interstate pipeline companies are reassessing their markets and positioning themselves for the new environment. The strategic position a pipeline company could take depends on the market position of its parent company and its physical relationships to suppliers and consumers in existing and potential markets. Companies only offering transportation service need to be profitable transporting gas, while integrated firms may use gas transportation as an entree to their other businesses. Slightly higher margins may be seen in the case of companies with captive LDCs as customers, provided that natural gas remains competitive at the burnertip. Companies only offering transportation service may face competition from alternative transportation routes. They will strive to provide the lowest rates possible by cutting operating costs. A key issue that must be taken into account in efforts to cut costs is that of pipeline safety and refurbishment (see box on page 45).

Ongoing market developments may change the capacity expansion and utilization picture reflected in the *AEO95* forecasts. Requirements for new capacity could be reduced and utilization increased if traditional users of transportation services adopt a portfolio strategy that includes more storage and some noncore services. DSM programs, as well as pricing changes (including straight fixed variable rate design [*71*] and incremental pricing of new capacity), may levelize transmission loads and increase pipeline capacity utilization.

Other challenges lie in future LDC developments (see box on page 43), the outcome of electric utility deregulation (see box on page 27), and the market for alternative-fuel vehicles. Prices for compressed natural gas could be considerably lower than those presented in the forecasts if advances in technology lower dispensing costs, if incentives such as a reduction in the motor fuels tax are provided, or if the industry provides favorable transportation rates.

Petroleum markets

Producers and distributors of petroleum products will also be facing a number of long-term challenges over the forecast period. First, under the Air Toxics title of CAAA90, many petroleum refineries will be required to install "maximum achievable control technology" (MACT) to prevent releases of hazardous air pollutants at the facilities. After EPA promulgates the MACT standards in 1995, refineries will have 3 to 5 years to comply.

The gradual decline in the quality of crude oil inputs, coupled with relatively flat demand for residual fuel oil, will present another challenge. U.S. refineries will need to alter refinery configurations and invest in conversion units to handle crude oils with higher sulfur contents and lower gravities.

Another challenge will result from continued pressure to produce environmentally friendly products. CAAA90 requirements for cleaner burning fuels have been phased in over the past 5 years. Reformulated gasoline, which will begin to be used in 1995, will evolve over the forecast period. Certification of reformulated gasoline is currently based on a uniform set of EPA standards described as the "simple model" [*72*]. Beginning in 1998, reformulated gasoline must be certified by a results-oriented "complex formula," based on achieving EPA emissions parameters. Initial requirements for a 15-percent reduction of volatile organic compounds (VOCs) and air toxics relative to baseline 1990 gasoline will be stepped up after 2000.

Combined with Federal clean fuel requirements, State gasoline requirements [*73*] will multiply the logistical problems already complicating the distribution of motor fuels. Refiners and distributors will have to produce and handle multiple octane grades of conventional, oxygenated, reformulated, and reformulated-high oxygen gasoline; and during the summer, all gasoline blends must meet regional requirements for Reid vapor pressure. Reformulated blendstock for oxygenate blending (RBOB) will be delivered to terminals for possible blending with ethanol and other oxygenates before delivery at the pump. The greatly increased number of gasoline products and blendstocks can be expected to restrict the flexibility of the marketing system and increase the potential for distribution problems. Testing and recordkeeping will play increasingly vital roles.

Natural gas forecasts

The wide range of natural gas forecasts highlights the uncertainty about future market directions. Total natural gas consumption in 2010 varies from a low of 20.7 trillion cubic feet in the WEFA forecast to a high of 26.9 trillion cubic feet in the GRI forecast, with the EIA forecast falling near the middle at 24.6 trillion cubic feet. The greater consumption in the GRI forecast can be attributed, at least in part, to a wellhead price forecast that falls considerably below the others (Table 21). The GRI wellhead price is driven by a number of supply-related assumptions, including GRI's characterization of the resource base.

Table 21. Comparative forecasts for natural gas, 2010

Forecast	*AEO95*	*DRI*	*GRI*	*AGA*	*WEFA*
World oil price (1993 dollars per barrel)	24.12	28.07	20.54	24.45	21.36
Average wellhead price, lower 48 states (1993 dollars per thousand cubic feet)	3.39	3.56	2.71	3.09	3.47
U.S. natural gas production (trillion cubic feet)	20.88	22.60	23.20	21.90	19.00
U.S. natural gas consumption (trillion cubic feet)	24.59	25.90	26.90	25.30	20.70

Price, however, is not the only determining factor in the forecasts. For example, the lower consumption in the WEFA forecast is a result of more intense competition with oil, as well as analyst assumptions that there will be a decline in the pace of additional cogeneration capacity in the industrial sector and that the trend toward a more service-oriented rather than manufacturing-oriented economy dampens growth in industrial sector gas consumption. WEFA projects industrial sector consumption of 8.0 trillion cubic feet, while industrial sector consumption in the other forecasts ranges up to 11.8 trillion cubic feet in the GRI forecast, with *AEO95* at 9.5.

Oil forecasts

DRI has the highest 2010 projections for oil prices, petroleum net imports, and domestic petroleum consumption (Table 22), comparing DRI, GRI, and WEFA petroleum projections with *AEO95*. The *AEO95* reference case is most similar to the DRI forecast but falls below DRI projections in these categories and slightly above DRI in domestic crude oil and natural gas liquids production. Despite significantly lower oil price forecasts, both GRI and WEFA project relatively higher production and lower consumption, resulting in lower net imports. The GRI projections feature the highest domestic production by far, and the lowest net imports of the four forecasts. Compared to GRI, DRI's production forecast is more than 1.4 million barrels a day lower. The WEFA projection for net imports is set apart from the others in that 10.6 of the 10.9 million barrels per day of petroleum imports—over 95 percent—are imports of crude oil, implying much stronger growth in refining capacity in the United States.

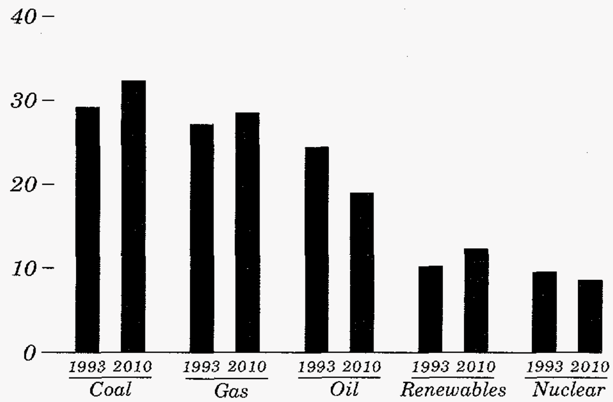
Table 22. Comparative forecasts of petroleum prices, production, imports, and consumption, 2010

Forecast	*AEO95*	*DRI*	*GRI*	*WEFA*
World oil price (1993 dollars per barrel)	24.12	28.07	20.54	21.36
Crude oil and natural gas liquids production (million barrels per day)	7.42	6.94	8.37	7.57
Net imports (million barrels per day)				
Crude oil	8.88	9.15	NA	10.56
Products	3.34	3.76	NA	0.34
Total	12.22	12.91	10.88	10.90
Petroleum consumption (million barrels per day)	20.88	21.13	19.25	19.50

NA = not available.

Currently accounting for a greater share of U.S. primary energy production than any other fuel, coal maintains its lead position in energy production in the forecast (Figure 78). The continued growth of coal consumption for electricity generation and the response of the coal industry and electric utilities to CAAA90 are the two major determinants of the *AEO95* coal forecasts. In the industrial sector, steam coal demand will increase in certain energy-intensive process industries, reflecting higher levels of output and greater use of cogeneration in those industries. However, domestic coking coal consumption will decline, primarily as a result of changes in domestic steelmaking technology. Coal exports rise in the forecast as a result of increases in steam coal imports in Europe.

Figure 78. Primary energy production by fuel, 1993 and 2010 (percent of total)

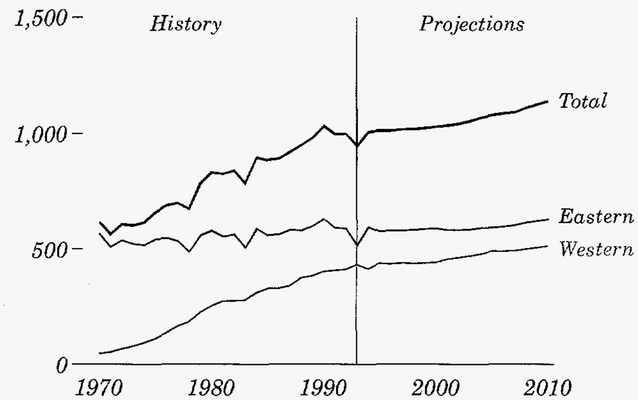


The average minemouth price of U.S. coal is expected be only slightly higher by 2010 than in 1993, reflecting the interplay of changes in coal mine capacity utilization rates [*74*], continued gains in labor productivity, and the cost impacts of opening new mines. This is in contrast to the *AEO94* forecast, which showed a significant increase in the average minemouth price of coal [*75*]. This year's lower price forecast is due primarily to assumptions of higher labor productivity growth [*76*] and a less optimistic outlook for electricity coal consumption and exports. Relative to the *AEO94* reference case, this year's forecasts for electricity coal consumption and exports in 2010 are both lower by 37 million short tons [*77*].

Annual coal production rises to 1,137 million tons by 2010, an increase of 192 million tons from 1993. The slower growth in coal production over the forecast relative to the preceding 20 years (1.1 percent a year compared with 2.3 percent a year) is primarily the result of a smaller projected increase in electricity coal demand.

Between 1993 and 2010, western coal production increases by 18 percent, from 429 million tons in 1993 to 508 million tons in 2010 (Figure 79). Production from mines east of the Mississippi River rises by 22 percent, from 516 million tons in 1993 to 629 million tons in 2010.

Figure 79. Coal production by region, 1970-2010 (million short tons)

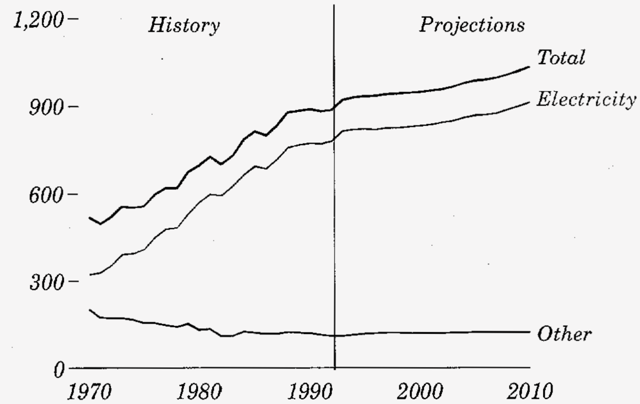


In the forecast, the increase in western production is based primarily on the ability of western producers to satisfy increased demand for low-sulfur coal in the electricity sector. Growth in eastern production results from increases in electricity coal demand, a recovery in U.S. coal exports, and a return to more normal coal supply conditions after 1993.

Eastern production declined by 72 million tons in 1993, mainly due to a strike against the Bituminous Coal Operators Association. As a result of strike-related disruptions in coal supply, electric utilities drew heavily from their coal stockpiles to meet electricity demand [*78*], and U.S. exports declined sharply. In the forecast, eastern production recovers rapidly after 1993, primarily due to replenishment of utility coal stocks and increases in domestic coal demand. U.S. coal exports recover gradually after 1994.

Electricity Generation Accounts for Nearly All the Increase in Coal Use

Figure 80. Electricity and other coal consumption, 1970-2010 (million short tons)

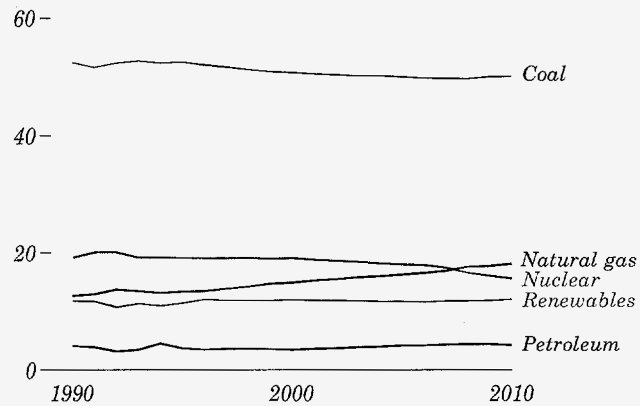


Domestic coal demand rises by 113 million tons in the forecast, from 926 million tons in 1993 to 1,039 million tons in 2010 (Figure 80). Most of the increase is caused by growth in coal use for electricity generation. Coal demand in the other end-use sectors, taken as a whole, increases by 13 million tons.

Coal consumption for electricity generation (excluding cogenerators) rises from 814 million tons in 1993 to 913 million tons in 2010. By region, electricity coal consumption increases by 54 million tons west of the Mississippi River and by 45 million tons east of the Mississippi River, benefitting coal suppliers in both the East and the West. Increases in coal-fired generation come from a combination of increased utilization of existing generating capacity and additions of new capacity. The average utilization rate for existing coal-fired plants increases from 63 percent in 1993 to 68 percent in 2010. Together, utilities, nonutilities, and cogenerators increase net coal-fired generating capacity by 14 gigawatts over the forecast period. One gigawatt of coal-fired generating capacity corresponds to roughly 2.5 million tons of electric utility coal consumption, varying with changes in the average utilization rate of coal-fired plants and the heat content of coal consumed. Coal consumption (in tons) per kilowatthour of generation is higher for lower rank coals, such as lignite and subbituminous, than for higher rank bituminous coal.

Coal Maintains the Largest Share of Electricity Generation

Figure 81. Shares of electricity generation by fuel, 1990-2010 (percent)



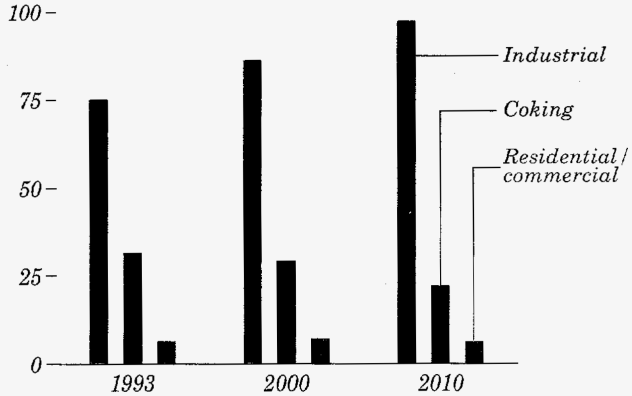
Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired combined cycle is the most economical choice for new power generation through 2005 in terms of total generating costs (capital, operating, and fuel). Between 2000 and 2010, rising natural gas prices and a growing need for baseload generation result in an increase in coal-fired capacity [*79*].

Through 2000, increases in coal consumption for electricity generation result mainly from increased utilization of existing plants. During this period, more coal-fired capacity is retired than built, resulting in a net capacity reduction of 1 gigawatt. Although coal-fired generation increases substantially, its share of total generation declines from 53 percent in 1993 to 51 percent in 2000 (Figure 81), as gas, nuclear, and renewable fuels are used for additional generation. Increased nuclear generation between 1993 and 2000 is attributable mostly to improved operating performance of existing plants.

Between 2000 and 2010, 15 gigawatts (net of retirements) of new coal capacity is added, and coal fuels 44 percent of the new generation required to satisfy demand. As a result, coal's share of total generation is further eroded, falling to 50 percent by 2010. Generation from natural gas and renewable fuels continues to increase during the period, but expected retirements of nuclear plants result in a decline in nuclear generation.

Rising Industrial Coal Use Is Offset by Falling Demand for Coking Coal

Figure 82. Non-electricity coal consumption by sector, 1993, 2000, and 2010 (million short tons)



In the non-electricity sectors, an increase in industrial steam coal consumption of 22 million tons between 1993 and 2010 is partly offset by a decline of 9 million tons in coking coal consumption (Figure 82).

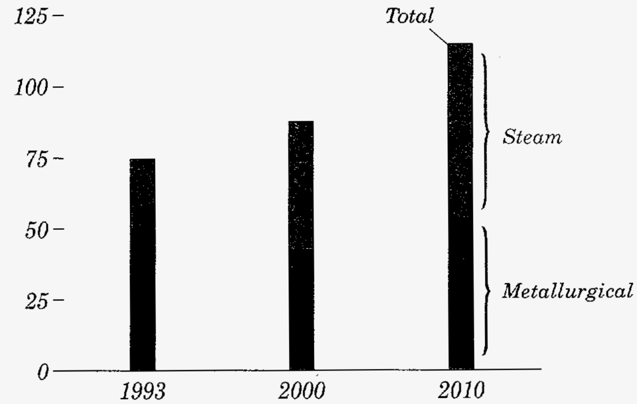
The higher consumption forecast for industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries. In addition to higher levels of output projected for these industries, the increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes) also contributes to the overall increase.

A projected decline in domestic consumption of coking coal results from the displacement of raw steel production from integrated steel mills (which use coal coke both for energy and as a raw material input) by increased steel production from minimills (which use electric arc furnaces, and thus bypass the use of coal coke) and increased imports of semifinished steels. Also contributing to the decrease is a reduction in the amount of coke required per ton of pig iron produced, based on energy efficiency improvements and increased supplemental fuel injections (mostly pulverized coal) to blast furnaces.

Coal consumption in the residential and commercial sectors remains constant, accounting for less than 1 percent of total U.S. coal demand over the forecast.

Steam Coal Leads Rise in Total U.S. Coal Exports

Figure 83. U.S. coal exports, 1993, 2000, and 2010 (million short tons)



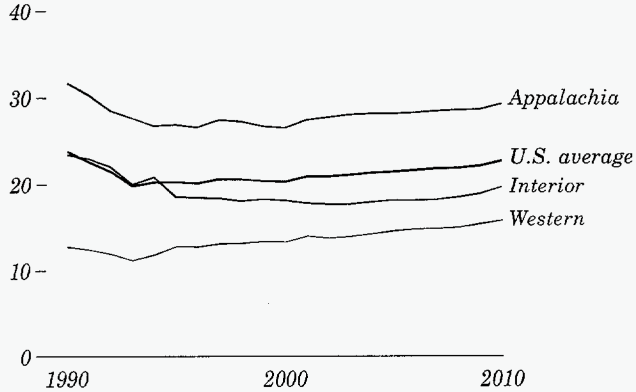
U.S. coal exports rise in the forecast from 75 million tons in 1993 to 115 million tons in 2010 (Figure 83), because of higher demand for steam coal imports for electricity generation in Europe. U.S. exports of metallurgical coal change little, falling from 50 million tons in 1993 to 42 million tons in 2000, then rising to 53 million tons by 2010. World metallurgical coal trade declines slightly over the forecast.

U.S. coal exports to Europe increase from 38 million tons in 1993 to 70 million tons in 2010. Coal imports to Europe from all sources are projected to rise by 69 million tons, from 168 million tons in 1993 to 237 million tons in 2010. Coal demand for electricity generation is expected to rise in Europe, while reduced producer subsidies curtail European coal production. However, increased use of natural gas, as well as environmental considerations, restrain the growth in coal consumption for electricity generation and, consequently, the need for additional imports of steam coal.

U.S. coal exports to Asia increase by only 5 million tons, from 19 million tons in 1993 to 24 million tons in 2010. Coal imports to Asia from all sources rise in the forecast by 174 million tons, from 211 million tons in 1993 to 385 million tons in 2010. The large increase is based on current plans to add substantial amounts of coal-fired generating capacity, together with the expectation that much of the new capacity will be fueled by imported coal. Most of the increased exports to Asia should originate from Australia, South Africa, and Indonesia.

Productivity Gains, Abundant Reserves Keep Coal Prices Stable

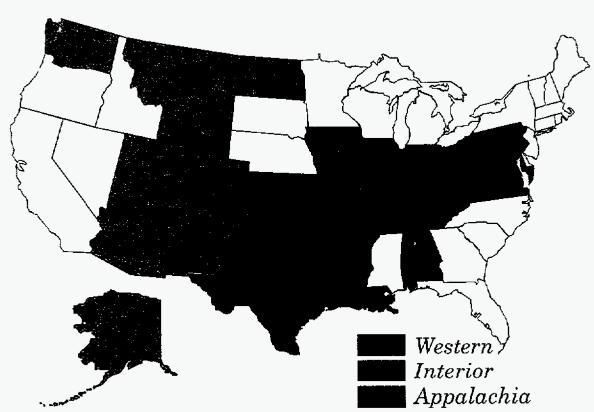
Figure 84. Average minemouth price of coal by region, 1990-2010 (1993 dollars per ton)



On average, the minemouth price of domestic coal rises by 0.8 percent a year between 1993 and 2010 (Figure 84). Gains in coal-mining productivity, an abundant coal reserve base, and lingering excess production capacity in the predominantly high-sulfur coal regions help stabilize U.S. average coal prices.

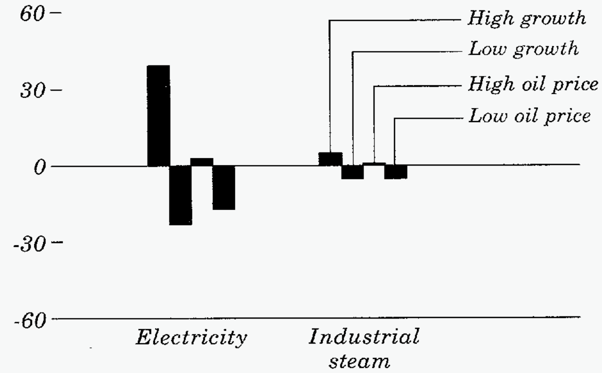
Between 1993 and 2000, the minemouth price of coal declines in both Appalachia and the Interior, with continuing improvements in labor productivity and lingering excess mine capacity for high-sulfur coal. During the same period, the average price in the West rises in response to increased demand for the region's low-sulfur coal. Prices rise in all three supply regions (Figure 85) after 2000 as a result of reserve depletion and higher capacity utilization levels, which are only partially offset by slower growth in labor productivity.

Figure 85. U.S. coal-producing regions



Electricity Coal Demand Is Sensitive to Economic Growth Assumptions

Figure 86. Variation from reference case projections of coal demand in four cases, 2010 (million short tons)

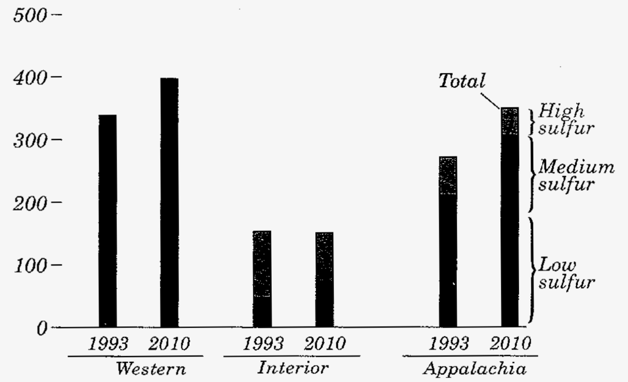


The *AEO95* coal forecasts vary with different assumptions about economic growth and world oil prices. A strong positive correlation between economic growth and electricity demand accounts for the variation in electricity coal demand across the economic growth cases (Figure 86). There is a similar positive correlation between economic growth and industrial output, but the resulting effect on industrial coal demand is not as significant. Electricity coal demand is 35 million tons higher in 2010 in the high growth case than in the reference case, and industrial steam coal is 5 million tons higher. In the low economic growth case, electricity coal demand is 23 million tons lower in 2010 than in the reference case, and industrial steam coal demand is 5 million tons lower. Most of the variation in total electricity generation in the alternative economic growth cases is accounted for by changes in coal- and gas-fired generation.

Changes in world oil prices affect petroleum fuel costs associated with the extraction and transportation of coal, and thus affect coal mining costs and prices. In the high oil price case, the average minemouth price of coal is 4 percent higher in 2010 than in the reference case, and in the low price case it is 6 percent lower. In the low oil price case, interfuel price competition leads to a slightly lower coal demand forecast, as oil-fired generation displaces some coal-fired generation.

Clean Air Legislation Shifts Coal Distribution Patterns

Figure 87. Coal distribution to the electricity sector by region and sulfur content, 1993 and 2010 (million short tons)

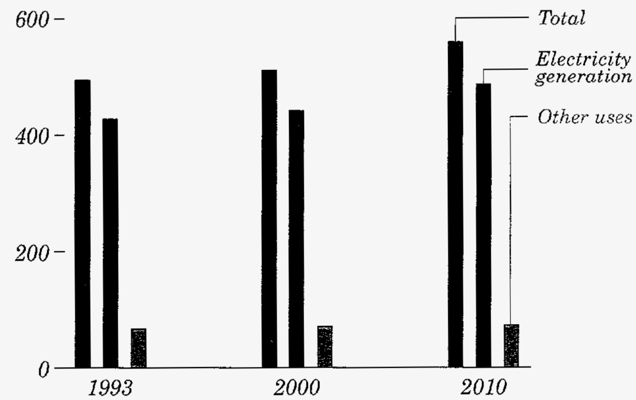


CAAA90 imposes a two-phase tightening of restrictions on sulfur dioxide emissions. Phase I, which began on January 1, 1995, requires that 110 large, high-emitting power plants (mostly coal-fired boilers) reduce their emissions rates to approximately 2.5 pounds of sulfur dioxide per million Btu of heat input. Beginning on January 1, 2000, Phase II imposes a permanent cap on sulfur dioxide emissions, which averages out to approximately 1.2 pounds of sulfur dioxide per million Btu of heat input for all generating units that existed before 1990.

For both Phase I and Phase II, CAAA90 provides utilities with several options for bringing existing coal-fired units into compliance: (1) retrofits with flue gas desulfurization equipment; (2) boiler repowering with new technologies that emit less sulfur dioxide; (3) transfer or purchase of emission allowances [*80*]; (4) reduction of plant utilization; and (5) switching (fully or partially) to a lower sulfur fuel. New coal-fired plants will not be issued emission allowances. Instead, they will have to obtain allowances that were initially allocated to other units. Between 1993 and 2010, the above factors, along with growth in the distribution of coal to the electricity sector [*81*], increased utilization of existing plants, and some capacity retirements, lead to a 203-million-ton increase in the distribution of low-sulfur coal from Appalachia and the West. The distribution of medium- and high-sulfur coal from Appalachia is projected to fall by 52 million tons (Figure 87).

Carbon Emissions From Coal Are One-Third of the U.S. Total

Figure 88. Carbon emissions from coal use, 1993, 2000, and 2010 (million metric tons)



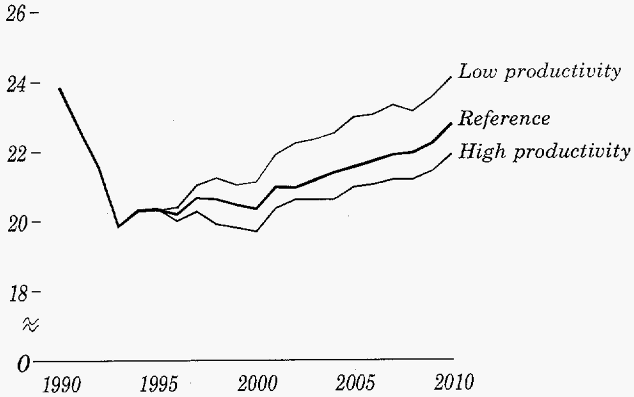
In the reference case, total carbon emissions from coal combustion rises by 4 percent, from 493 million metric tons in 1993 to 511 million metric tons in 2000 (Figure 88). Most of the increase is from electricity coal consumption. In the other sectors, a slight increase in carbon emissions from industrial steam coal consumption is partially offset by a decline in emissions from coking coal consumption. Reflecting higher growth in electricity coal consumption, carbon emissions from coal increase by 9 percent between 2000 and 2010, rising to 557 million metric tons in 2010.

The share of total U.S. carbon emissions originating from coal combustion changes little, from 36 percent in 1993 to 34 percent in 2010. Over the forecast, coal consumption increases at a slower rate than consumption of petroleum products and natural gas, which account for virtually all the remaining U.S. carbon emissions from sectoral energy consumption. Mostly because of their importance as transportation fuels, petroleum products are the largest source of U.S. carbon emissions, accounting for 42 percent of the total in 1993 and 43 percent in 2010.

When it is burned, coal produces almost twice the amount of carbon emissions per unit of energy input that natural gas does, and average carbon emissions from combustion of petroleum products are between those for coal and gas [*82*]. In the electricity sector, carbon emissions per unit of generation vary even more, because of differences in the conversion efficiencies of combustion technologies [*83*].

Labor Productivity Assumptions Affect Minemouth Coal Prices

Figure 89. Average minemouth price of coal in three cases, 1990-2010 (1993 dollars per ton)



Coal mining productivity has varied considerably in the past and is particularly difficult to forecast. Recent history shows that U.S. coal mining productivity declined by an average of 3.2 percent a year between 1970 and 1978 and then increased by 6.7 percent a year between 1978 and 1993 [*84*]. In the reference case, labor productivity is assumed to increase by an average rate of 3.9 percent a year through 2010 [*85*]. To provide perspective on the reference case forecasts, two standalone alternative cases were modeled in the NEMS Coal Market Module, assuming labor productivity growth of 5.4 percent a year (*high productivity case*) and 2.4 percent a year (*low productivity case*).

Higher labor productivity reduces coal production costs, which, in turn, results in lower prices. In the high productivity case, the average minemouth price of coal is $21.91 per ton in 2010, or 3.8 percent lower than in the reference case. In the low productivity case, the minemouth price is $24.14 per ton in 2010, or 6 percent higher than in the reference case. The average delivered price of coal varies by similar amounts (in dollars per ton), reflecting little change in the average transportation cost or in coal distribution patterns.

Because these are standalone Coal Market Module cases, the domestic coal demands are held constant (in terms of Btu requirements), but coal exports vary in response to the change in U.S. prices. As a result, total coal production levels (in tons) change only slightly (0.5 percent) relative to the reference case.

Challenges for the Future

Two key areas of uncertainty that affect the U.S. coal outlook are environmental concerns and the ability of the coal industry to keep prices competitive with those for other fuels.

Environmental issues

Regulations to control utility emissions of air toxics [*86*], permitting requirements, and legislation or policy initiatives to restrain greenhouse gas emissions could significantly affect coal's future in electricity generation. Title III of CAAA90 requires the EPA to submit its findings and recommendations on utility emissions to Congress in 1995. A decision to regulate emissions could require utilities to install equipment for removing air toxics from combustion gases. On the supply side, regulations could result in some interregional switching to coals with lower levels of toxic trace elements or affect the amount and degree of preparation required.

In addition to obtaining sulfur dioxide emission allowances as specified by CAAA90, electricity producers face permitting requirements under the Prevention of Significant Deterioration (PSD) program and for nonattainment areas [*87*]. Proposed new plants in PSD areas face minimum acceptable technological requirements for pollution control and a maximum allowable increment test for particulate matter, sulfur dioxide, and nitrogen oxides. They also are subject to an adverse impact test for key air-quality-related values for nearby areas, such as national parks or wilderness areas. Similar but generally stricter requirements apply to plants in nonattainment areas. How greatly the requirements limit additions of new coal-fired capacity depends on such factors as growth in electricity demand, costs and dependability of pollution control technologies, the ability to model environmental impacts accurately, remaining emissions increments in PSD areas, and the cost of environmental assessment activities.

In regard to greenhouse gas emissions, the CCAP provides environmental agencies, regulatory bodies, and electric utilities with guidelines and incentives for increasing the use of low-carbon fuels, such as natural gas and renewables, and for reducing growth in electricity demand. Success in meeting these objectives would reduce demand for both coal and oil in the electricity sector. For stabilizing greenhouse gas emissions in the long term, the CCAP states that measures must be taken to "ensure that a constant stream of improved technologies is available and that market conditions are favorable to their adoption." As a result, the prospects for increased reliance on coal in the Nation's energy mix may hinge on the success of elements in DOE's Clean Coal Technology Demonstration Program [*88*], as well as on other Federal and State initiatives [*89*].

Coal prices

In addition to labor productivity, other key areas of uncertainty in the *AEO95* coal price forecasts relate to estimates of reserve depletion and State actions aimed at bringing about full-cost pricing of energy. As new reserves are opened to mining, incremental costs related to differences in geologic conditions of new mines versus existing mines can raise mining costs, even when factor input costs, labor productivity, and technology remain constant. In the forecast, the effects of reserve depletion come into play as new mines are opened to meet increased demand and to replace capacity lost when existing mines are retired. The effects on future coal prices depend on the rate at which existing capacity is retired, growth in both domestic and foreign demand, and the availability and geological characteristics of coal reserves for new mines.

In recent years, several States have issued proposed rules and regulations specifying that estimated costs and benefits of factors such as pollution externalities, economic development, and social distributional effects be included in the prices consumers pay for energy [*90*]. While consideration of environmental costs favors cleaner burning fuels such as natural gas and renewable fuels over coal, it is unclear how consideration of other externalities will affect relative fuel prices. Additional uncertainties relate to the ability of States to implement full-cost pricing policies and how widespread such policies may become. The *AEO95* forecasts account for the costs of environmental externalities for electric capacity planning decisions for regions with established externality costs.

Comparative Forecasts

Table 23. Comparative forecasts for coal, 2010

Forecast	***AEO95***	***DRI***	***GRI***	***WEFA***
Consumption by sector	***Million short tons***			
Electricity	*913*	*927*	*1,160*	*1,053*
Coking plants	*22*	*29*	*19*	*28*
Industrial/Other	*103*	*151*	*106*	*84*
Total	***1,039***	***1,107***	***1,285***	***1,165***
Net coal exports	*100*	*116*	*136*	*112*
Prices	***1993 dollars per short ton***			
Minemouth price	*22.77*	*NA*	*15.85*	*27.86*
Delivered price, electricity	*31.43*	*31.88*	*25.64*	*42.32*

NA = not available.

The EIA forecast for U.S. coal consumption is lower than the consumption levels in the comparative forecasts. This is primarily because of EIA's lower electricity coal consumption forecast for 2010 and, in the case of DRI, lower EIA forecasts for both electricity and industrial coal consumption.

The higher electricity coal consumption forecasts by DRI, GRI, and WEFA are attributable to higher projected growth in electricity demand. The higher forecast for industrial steam coal consumption by DRI is due primarily to a greater projected increase in conventional (i.e., non-electricity) steam coal demand. DRI forecasts that non-electricity coal demand in the industrial sector will rise to 87 million tons in 2010, and that coal consumption by cogenerators and nonutilities taken together will rise to 58 million tons [*91*].

The GRI forecast for U.S. coal exports differs the most from the EIA forecast. The higher forecast for net U.S. coal exports in 2010 by GRI is attributable to a higher forecast of steam coal exports.

Both the WEFA and GRI projections for the delivered price of coal to electricity producers in 2010 differ substantially from the EIA forecast. GRI has the lowest delivered price forecast by far, reflecting high labor productivity growth over the forecast and the expectation that reserve depletion will have little effect on mining costs. WEFA's larger projected increase in the delivered price of coal to electricity producers is attributable to both higher minemouth prices and transportation margins.

List of Acronyms

AEO	*Annual Energy Outlook*
AEO95	*Annual Energy Outlook 1995*
AGA	American Gas Association
AFV	Alternative-fuel vehicle
BACT	Best available control technology
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CCAP	Climate Change Action Plan
CEC	California Energy Commission
CO	Carbon monoxide
CO_2	Carbon dioxide
DRI	Data Resources, Inc./McGraw Hill
DSM	Demand-side management
EEI	Edison Electric Institute
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
EWG	Exempt wholesale generator
FERC	Federal Energy Regulatory Commission
FRB	Federal Reserve Board
GDP	Gross domestic product
GRI	Gas Research Institute
IEA	International Energy Agency
IRP	Integrated resource planning
LDC	Local distribution company
LEVP	Low Emissions Vehicle Program
LPG	Liquefied petroleum gases
MACT	Maximum achievable control technology
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NAECA	National Appliance Energy Conservation Act of 1987
NEMS	National Energy Modeling System
NPC	National Petroleum Council
NRC	Natural Resources Canada
PEL	Petroleum Economics Limited
PSA	Pipeline Safety Act of 1992
PSD	Prevention of Significant Deterioration
PUC	Public utility commission
PURPA	Public Utilities Regulatory Policy Act of 1978
PV	Photovoltaic
PVUSA	Photovoltaics for Utility Scale Applications
RBOB	Reformulated blendstock for oxygenate blending
RSPA	Research and Special Programs Administration, U.S. Department of Transportation
SPR	Strategic Petroleum Reserve
STEO	*Short-Term Energy Outlook*
STIFS	Short-Term Integrated Forecasting System
UGR	Unconventional gas recovery
UPVG	Utility Photovoltaic Group
VOC	Volatile organic compound
WEFA	The WEFA Group (formerly the Wharton Econometric Forecasting Associates)

Text notes

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1. Electricity generation includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
2. One of the two new units anticipated was Watts Bar 2. After this analysis was completed, the Tennessee Valley Authority (TVA) announced that it was halting construction work on the unit. TVA stated that it is considering conversion of the plant to alternative fuel or seeking a financial partner to complete the construction.

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3. Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1994), Table 2-3.

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4. I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures." Presentation to the Sixth Meeting of the International Energy Workshop (Vienna, Austria, June 1993).
5. I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures" (June 1993).
6. I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures" (June 1993).
7. I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures" (June 1993).

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8. United Nations Conference on Environment and Development (Rio de Janeiro, Brazil, June 1992).
9. Energy Information Administration, *Supplement to the Annual Energy Outlook 1995* (Washington, DC, in preparation).

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10. U.S. Bureau of the Census, *Current Construction Reports*, Series C25 (Washington, DC: U.S. Department of Commerce, 1971 and 1994).
11. U.S. Bureau of the Census, *Current Construction Reports*, Series C25 (Washington, DC: U.S. Department of Commerce, 1988).
12. U.S. Bureau of the Census, *Current Construction Reports*, Series C25 (Washington, DC: U.S. Department of Commerce, 1994).

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13. "Golden Carrot" programs offer financial incentives to appliance manufacturers for the design and production of super-efficient appliances through nonregulatory means.
14. The best technology case is modeled as if a standard specifying minimum efficiencies equal to the best available equipment in 1993 had been in place from 1995 forward. This method disregards the economic costs of such a decision, and is merely designed to show how much currently available, high-efficiency equipment could affect energy consumption, if chosen. Fuel shares of each technology remain fixed at the reference case level; only efficiencies change.
15. The 1993 technology case assumes that equipment efficiencies chosen in 1993 are only augmented by 1994 standards for clothes dryers.

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16. The best technology case is modeled as if a standard specifying minimum efficiencies equal to the best equipment available in all forecast years had been in place from 1995 forward. This method disregards the economic costs of such a decision, and is merely designed to show how much currently available, high-efficiency equipment could affect energy consumption, if chosen. Fuel shares are allowed to change for an end use as the best technologies from each technology type compete to serve certain segments of the commercial floorspace market. This case is slightly different from the one developed for the residential sector, primarily because of structural differences between the two models. The commercial model includes forecast technologies (the residential model includes current technologies, plus any future standards), and thus upgrades available efficiencies as new equipment becomes available. Also, commercial fuel shares are determined simultaneously with equipment choice, and therefore fuel shares are a function of the equipment available in any particular year. In contrast, the residential model uses a nested equipment choice algorithm, in which fuel choices are determined in the first stage and equipment choices within each fuel are chosen in the second stage. The first-stage fuel choices were held fixed across the residential efficiency side cases.

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17. One of the two new units anticipated was Watts Bar 2. After this analysis was completed, the Tennessee Valley Authority (TVA) announced that it was halting construction work on the unit. TVA stated that it is considering conversion of the plant to alternative fuel or seeking a financial partner to complete the construction.

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18. Because utilities can hold allowances for use in future years, and because temporary allowances are issued

between 2000 and 2010, the 9-million-ton cap is not reached until 2010 or later.

19. For more information on the electricity industry's CAAA90 compliance plans, see *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March 1994).

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20. One of the two new units anticipated was Watts Bar 2. After this analysis was completed, the Tennessee Valley Authority (TVA) announced that it was halting construction work on the unit. TVA stated that it is considering conversion of the plant to alternative fuel or seeking a financial partner to complete the construction.

21. Given the challenges facing the nuclear industry, there is considerable uncertainty in the assumptions for the nuclear forecast. Other possible assumptions could allow for early retirements, different completion schedules for units under construction, and possible new orders of advanced reactors.

22. The nuclear side cases were developed to analyze the effects of early retirements or life extension on new capacity additions and the change in fuel mix. Effects on electricity prices were not examined because there are no accurate data on decommissioning and defueling costs, and because of the uncertainty regarding the ability of utilities to recover costs from ratepayers in the event of an early shutdown. Necessary research, data collection, and model enhancements are being carried out so that pricing effects can be addressed in the future.

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23. Energy Information Administration, *Solar Collector Manufacturing Activity 1993* (Washington, DC, August 1994), pp. 71-72.

24. Assuming electricity consumption averaging 10,000 kilowatthours a year per residence, produced by photovoltaic and solar-thermal facilities with weighted average capacity factors of 35 percent. In practice, the projected solar units could meet the peak demand for many more homes, but, unless accompanied by energy storage devices, solar generators cannot be used to meet all baseload electricity needs.

25. Energy Information Administration, *Solar Collector Manufacturing Activity 1993* (Washington, DC, August 1994), p. 1.

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26. Production includes other domestic supplies and processing gains.

27. Electric generators, as defined in this chapter, include all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.

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28. Projected natural gas prices are nearly the same for both the reference and high oil price cases. This occurs largely because natural gas consumption requirements vary little between the two cases: demand-side constraints on fuel substitution and other factors limit the extent of potential increases in natural gas consumption in the high oil price case. The various advantages of natural gas in the reference case have already induced most end users of equipment capable of using oil or natural gas to use natural gas. These similar market conditions result not only in similar natural gas price projections, but also in similar natural gas drilling, reserve addition, and production projections. In contrast, projected natural gas prices for the reference and low oil price cases differ significantly. In the low oil price case, natural gas consumption requirements decrease considerably from the reference case, in the absence of comparable demand-side constraints. These differing market conditions also lead to differing natural gas drilling, reserve addition, and production projections.

29. The historic peak for average annual lower 48 wellhead prices was reached in 1983 for natural gas ($3.58 per million Btu in constant 1993 dollars) and in 1981 for oil ($9.15 per million Btu). Reasons for the closer approach of the gas price to its historic peak include faster growth in demand for gas and the fact that, over most of the historical period, the price of gas was regulated at artificially low levels. It should be noted, however, that relative trends in wellhead prices are not necessarily equivalent to relative trends in end-use prices. End-use prices are the primary determinant of fuel selection in end-use applications where technologies provide a choice among competing fuels. Natural gas end-use prices increase less than the wellhead price because transmission and distribution margins decline over most of the forecast. In contrast, petroleum product prices (in particular, prices for light products) increase more than the oil wellhead price because markups from the wellhead to the end user increase during the forecast (see Table 19).

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30. Projected drilling statistics include the expected smoothed values of both exploratory and developmental well completions.

31. The exploratory share of total natural gas wells rises from 4.5 to 10.5 percent over the period. The exploratory share of total oil wells rises less sharply—from 4.7 to 7.7 percent. The diminishing size of new discoveries requires less developmental drilling relative to exploratory drilling.

32. Projected reserve additions for both gas and oil include expected smoothed volumes from new field discoveries, extensions, and revisions.

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33. This unusual relationship reflected supply and demand imbalances that arose from distorted price signals, generally associated with the past regulatory environment affecting natural gas.

34. Oil production includes lease condensate (a mixture of hydrocarbons recovered as a liquid from natural gas through the normal process of condensation in lease or field separation facilities). It does not include natural gas plant liquids (those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants). Natural gas production comprises nonassociated (NA) and associated-dissolved (AD) production. NA natural gas is not in contact with significant quantities of crude oil in a reservoir. AD natural gas consists of the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

35. This result is accounted for by the high degree of maturity of the oil resource base in the United States, as well as the projections of relatively low prices.

36. Economically recoverable resources are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional or nonconventional technologies, under specified economic conditions. Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Unproved resources comprise inferred reserves and undiscovered resources. Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves. Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields, when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

37. Future domestic oil and natural gas production depend on many uncertain factors—the size and geologic distribution of remaining resources; technological advances in exploration, development, and production; and prices, costs, and other factors affecting industry profitability and expectations. The *AEO95* 1990 estimate for crude oil resources of 85.7 billion barrels exceeds the comparable *AEO94* estimate of 82.5 billion barrels. The difference is due to different EOR estimates. The improved analytic method for EOR used in *AEO95* does not readily yield 1990 resource estimates based on 1990 technology. Hence, the *AEO95* 1990 resource estimates for EOR that are based on 1990 technology include additional resources due to more advanced technology assumptions.

    More generally, a comparison of *AEO95* with the outlook presented in *AEO94* shows oil and gas production volumes that are comparable despite lower prices. *AEO95* reflects an outlook of greater optimism regarding the supply potential of the oil and gas industry, which allows for comparable production levels, despite the lower prices. The *AEO95* data and assumptions reflect the demonstrated successes of the industry during the recent period of low prices.

    Two major reasons account for the improved outlook: technology and productivity. An upward revision to the impact of technological advances affecting recoverable resource potential from higher cost recovery (e.g., tight gas and coalbed methane) and the frontier areas of the lower 48 offshore and Alaska was incorporated into the analysis. This change is warranted due to a continued review of the relevant literature and discussions with DOE and other experts. Technological advances expected by 2010 are assumed to raise estimated economically recoverable oil and gas resources by 38.6 and 58.5 percent compared to the volumes based on 1990 technology. The 2010 oil and gas estimates in *AEO95* are 6.6 and 12.8 percent higher than the levels assumed for *AEO94*. In addition, the production potential of new reserves was increased for *AEO95* after a review of more recent production and reserves data. However, the nonuniform adjustments to the production potential across categories do not allow for a ready comparison between the input data for the two outlooks.

38. This is in large part because higher levels of drilling tend to lead to the drilling of less promising prospects, and because production levels tend to be proportional to the overall stock of reserves rather than annual reserve additions.

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39. Unconventional gas recovery (UGR) consists principally of production from reservoirs with low permeability (tight sands) but also includes methane from coal seams and gas from Devonian shales. Natural gas production comprises nonassociated (NA) and associated-dissolved (AD) production. NA natural gas is not in contact with significant quantities of crude oil in a reservoir. AD natural gas consists of the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The trends in natural gas production shown in Figure 64 reflect the advantage of relatively lower costs associated with conventional production and the reduction in unit costs of UGR production due to technological advances. The gradual decline in offshore production reflects the impact of relatively higher costs and resource depletion.
40. Enhanced oil recovery (EOR) is the extraction of the oil that can be economically produced from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. EOR methods usually involve injecting heated fluids, pressurized gases, or special chemicals into an oil reservoir in order to produce additional oil.
41. The onshore conventional resource base is assumed to expand at an across-the-board average rate of about 2 percent a year for the period through 2010. Higher cost oil and gas resources, such as those from offshore and Alaskan operations and UGR, are assumed to expand at an average rate of 3 percent a year.
42. The analysis used the oil and gas prices of the reference case to examine the impact on oil and gas production of varying just the oil and gas technological assumptions, without demand-related feedback effects.
43. Specifically, in the high technology case, natural gas production in 2010 is projected to be 12 percent higher than in the reference case, whereas oil production is projected to be only 8 percent higher. In the low technology case in 2010, gas production is 12 percent lower than in the reference case, whereas oil production is a more modest 8 percent lower.
44. One limitation of the analysis is that EOR was not subject to the technology adjustment. Appropriately varying EOR in the analysis would be unlikely to affect the basic conclusion that gas production is more sensitive than oil production to the rate of technological change.

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45. The spread in 2010 consumption between the high and low economic growth cases is 2.7 trillion cubic feet. The spread in 2010 consumption between the high and low world oil price cases is 2.2 trillion cubic feet.
46. Relative to the reference case, 2010 consumption in the industrial and electric generator sectors in the low price case is reduced by 0.7 and 1.1 trillion cubic feet, respectively. In the industrial sector, natural gas consumption is reduced as a variety of petroleum products penetrate boiler markets in the West South Central and Pacific regions. The reduction in gas use in the electric generator sector is largely attributable to greater use of residual fuel oil in dual-fired boilers in the West South Central region and a reduction in natural gas use in combined-cycle plants.
47. Revenues are net of commodity costs.
48. 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.
49. Included in industry automation is the general impact of the industry's adopting advances in electronic information systems technology in end-use meter reading, billing systems, and real-time metering, and the employment of Supervisory Control and Data Acquisition (SCADA) systems on the transmission and distribution network.

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50. For further information on industry restructuring, see Energy Information Administration *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994).
51. The level of physical assets that were used to provide bundled sales service, including assets related to storage, production, product extraction, transmission, gathering, and upstream capacity needed for operational integrity, may no longer be required to meet the demand for various services in an unbundled environment. The costs associated with these assets

are all categorized as stranded costs. For further discussion of stranded costs, refer to page 52 of Energy Information Administration *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994).

52. A writedown is the lowering of the book value of an asset.

53. In the implementation of Order 636, the term "transition costs" referred to the costs associated with the transition from a bundled to an unbundled environment and included costs incurred in reforming contracts with gas producers (gas supply realignment costs), unrecovered gas costs (account 191) remaining when the purchased gas adjustment mechanism was terminated, stranded costs for assets no longer needed in an unbundled environment, and new facilities costs for new assets required because of unbundling, such as electronic bulletin boards. In the context of this discussion, "transition costs" refer to the costs associated with surplus pipeline capacity that becomes available as long-term transportation agreements expire.

54. The core market consists of customers who historically have required on-demand fuel service because gas is their only fuel option. NEMS includes in this category most residential and commercial customers, as well as industrial customers using natural gas as a feedstock and electric generation plants without fuel-switching capability.

55. In November 1993, the New Jersey Board of Regulatory Commissioners approved a set of guidelines involving the unbundling of gas utility services to all commercial, industrial, and electricity generation customers (*Foster Natural Gas Report*, December 16, 1993, p. 24). This would effectively remove the regulated LDCs from the gas supply business for all nonresidential customers. The LDCs were given an April 1, 1994 deadline to file tariffs for new competitive natural gas services. All have filed, and the approval process is ongoing. The Board intends to conduct a review of "the successes of this deregulation effort in the future and consider how the benefits can be extended to residential customers." No date for the review has been set, and it is expected that it will not occur for at least two, and more likely three, years.

56. Boston Gas Company, the largest gas distribution company in New England, has submitted an analysis paper (known as a "white paper") to the Massachusetts Department of Public Utilities (DPU) detailing substantial cost savings and service improvements that could be achieved through the consolidation of the 10 gas distribution companies in Massachusetts into 1 large utility. This has been evaluated by the DPU, and a mergers and acquisitions order has been released with comments invited. The Massachusetts DPU is also looking into incentive ratemaking for gas and electric utilities and in September 1994 issued a Notice of Inquiry (NOI) inviting comment.

57. The New Jersey and Massachusetts proposals illustrate how industry restructuring could move the roles of LDCs in two different directions. Since FERC Order 636 is bringing system supply costs in line with off-system purchases, LDCs may play a larger role as supply aggregators in the future. Individual customers could go off-system (purchase supplies from an entity other than the pipeline) prior to Order 636, but LDCs were bound by contracts with the pipelines limiting their ability to go off-system for supply. Order 636 provided the opportunity to renegotiate the contracts and unbundle the supply from the transportation service, putting all pipeline customers on a level playing field with comparable service and access to receipt and delivery points. Thus, the costs of supply offered by the LDCs are coming in line with off-system purchases. Consolidation in the industry could occur either through mergers, as proposed by Boston Gas, or by LDCs pooling together in a fashion similar to the electric utility power pools. (A pool is a grouping of companies for the common benefit of all member companies.) Some municipal gas distributors have grouped together to form cooperatives for the purpose of procuring natural gas supplies. In contrast, the New Jersey proposal extends the unbundling concept to the distribution segment of the industry, increasing the opportunity for natural gas marketing firms to expand their base of customers and intensifying competition among suppliers of natural gas.

58. Included in current plans are the transfer of Panhandle Eastern Pipeline's gathering facilities in Oklahoma and Kansas to existing affiliate Panhandle Gathering, the spindown (formation of a new affiliate) of Northern Natural Gas's gathering system to affiliate Enron Gathering, the spindown of NorAm Gas Transmission's gathering operations to Arkla Gathering, and the spinoff (sale to a nonaffiliate entity) of Northern Natural's Montana gathering facilities to NGC Energy and its New Mexico facilities to Hobbs Processing Company.

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59. Historical data do not fully capture all costs, including dispensing costs and all levied Federal and State taxes.

60. Some of the projected interregional capacity may be in the form of additional storage facilities.

61. Between 40 and 50 percent of the projected pipeline capacity additions by 2010 occur between 1993 and

1996. These additions largely reflect industry plans to expand pipeline capacity as documented in current regulatory filings. It is assumed that over the forecast period there is no change in load profiles in the end-use sectors.

62. In some cases utilization declines when capacity is added because the capacity is generally built to meet peak period demand. It may take many years for off-peak demand to grow to achieve the overall utilization rate observed prior to expansion. In some cases, utilization may never fully recover because energy efficiency improvements and other market changes reduce demand.

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63. *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994).

64. Smart pigs are electronic devices that are sent through the pipeline to inspect for structural weaknesses.

65. The American Gas Association (AGA) and others have argued that the additional costs to the industry could be as high as $100 million annually.

66. The refurbishment case was run as a standalone case and assumed constant demand. It also assumed that the industry will face costs in addition to those operation and maintenance costs included in the reference case. Specifically, the incremental costs included in the refurbishment case reflect the assumption that the $1.7 billion annual investment estimated by the NPC would be undertaken, that $16.2 million a year in budget expenses requested by the Department of Transportation to fund safety programs would be approved and passed through to consumers, and that the proposed RSPA ruling would be implemented at an estimated cost of $100 million a year. These costs are over and above the costs of capacity expansion to support the growing market. The costs were developed from various sources. The refurbishment case does not assume that these specific actions will be undertaken; it merely shows the impact that this level of incremental investment and operation and maintenance costs may have on the industry's revenue requirements and the corresponding increase in the average markup to the end user.

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67. Compliance with the Clean Water Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act, and the Oil Pollution Act, as well as anticipated regulations related to limiting pollution at refinery sites.

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68. Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, and San Diego. 1995 opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Texas, Virginia, and the District of Columbia. Additional 1996 opt-ins include Atlanta and areas of Wisconsin.

69. Since October 1992, the CAAA90 has required "oxygenated" gasoline, containing 2.7 percent oxygen by weight, in 39 carbon monoxide nonattainment areas.

70. The Renewable Oxygenate Standard is included in the *AEO95* projections; however, a stay was issued in September 1994, to allow for legal review of the standard.

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71. Over the past several decades, the Federal Energy Regulatory Commission has altered the design methodology used in deriving the rates that interstate natural gas pipelines charge their customers for various services. The straight fixed variable rate design allocates all fixed costs to the reservation component of the rate and all variable costs to the usage component of the rate. Upon full implementation of FERC Order 636, most interstate natural gas pipelines adopted straight fixed variable rate design. For a complete discussion of the history of rate design, differences among various rate designs, and the policy motivations behind the changes in rate design, see *Natural Gas Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993).

72. The simple model includes specifications for the content of aromatics, benzene, oxygen, and sulfur and on Reid vapor pressure (Rvp).

73. As mentioned previously, California will require its own version of reformulated gasoline statewide beginning in 1996. As an alternative to Federal reformulated gasoline, a number of States have proposed further restrictions on Reid vapor pressure as a means of reducing pollution in ozone nonattainment areas.

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74. Capacity utilization is defined as the ratio of production to capacity.

75. In the *AEO94* reference case, the average minemouth price of coal was projected to rise to $31.55 per ton in 2010. Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), Table A15.

76. For the *AEO95* reference case forecast, coal mining labor productivity is assumed to grow at an average rate of 3.9 percent per year. In comparison, productivity in the *AEO94* reference case was assumed to grow by 2.9 percent per year. Energy Information Administration, AEO95 Forecasting System, run AEO95B. D1103942, and AEO94 Forecasting System, run AEO94B.D1221934.

77. Throughout this chapter, tons refers to short tons (2,000 pounds).

78. At the end of 1993, stocks at electric utilities were 41 million tons lower than at the end of 1992. Energy Information Administration, *Quarterly Coal Report, October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994), Table 54.

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79. Baseload capacity represents the generating equipment normally operated to serve loads on an around-the-clock basis.

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80. One sulfur dioxide allowance permits 1 ton of sulfur dioxide emissions.

81. Because electric utilities drew down coal stockpiles in 1993 by 41 million tons to offset the impact of the strike against the Bituminous Coal Operator's Association, distribution of coal to utilities in 1993 was substantially less than consumption. Thus, the increase in the domestic distribution of coal to the electricity sector between 1993 and 2010 exceeds the increase in consumption by 34 million tons. The increase in coal imports by electricity producers also accounts for some of the difference between distribution and consumption.

82. Carbon coefficients used to estimate emissions for fossil fuel combustion, in units of million metric tons carbon per quadrillion Btu heat input, ranged as follows: coal (excluding anthracite)—25.37 to 26.62; petroleum products (excluding petroleum coke)—17.16 to 21.49; and natural gas—14.47. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1987-1992,* DOE/EIA-0573(94) (Washington, DC, October 1994).

83. Of the commercially available generation technologies, gas-fired combined cycle offers the highest conversion efficiency, approximately 44 percent, which compares with approximate conversion efficiencies of 35 percent for pulverized coal-fired units and 30 percent for gas-fired combustion turbine units. Energy Information Administration, Office of Integrated Analysis and Forecasting, EIA Cost and Performance Database for New Generating Technologies.

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84. Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994) and *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

85. In the reference case, labor productivity is assumed to grow by approximately 3.9 percent per year, declining from an annual rate of 7.7 percent in 1993 to 2.2 percent in 2010.

86. Air toxics (or hazardous air pollutants) are those pollutants which are hazardous to human health or the environment. Recent field studies conducted by the U.S. Department of Energy and the Electric Power Research Institute have been undertaken to determine and evaluate emissions of air toxics from coal-fired power plants. Air toxic emissions being evaluated include: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, mercury, chlorine/hydrochloric acid (HCl), selenium, benzene, toluene, formaldehyde, polycyclic aromatic hydrocarbons, and dioxins. With the exception of three of the pollutants, preliminary findings indicate that hazardous pollutants emitted by coal-fired power plants are: (1) effectively removed from the combustion gases with electrostatic precipitators (ESP) or fabric filters; or (2) low from the perspective of both presence in the flue gas and health risk impact. Mercury, selenium, and chlorine/HCl are not effectively controlled with conventional particulate control devices, because they are relatively volatile at stack gas conditions. P. Chu and C. Schmidt, "Hazardous Air Pollutant Emissions from Coal Fired Power Plants," in *Eleventh Annual International Pittsburgh Coal Conference*, Pittsburgh, PA, September 12-16, 1994, ed. Shiao-Hung Chiang (Pittsburgh, PA: University of Pittsburgh, 1994), pp. 551-556.

87. The Clean Air Act Amendments of 1977 established three types of regions with respect to National Ambient Air Quality Standards (NAAQS): attainment, nonattainment, and unclassifiable. Attainment and unclassifiable areas were made subject to a new program for prevention of significant deterioration (PSD) of air quality and were further divided into three classes: Class I, Class II, and Class III. Of the three, Class I areas are the most pristine areas and are afforded the greatest degree of protection. They include international parks, national wilderness areas, national memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres that were established as of August 7, 1977. Because of the general nature of Class I areas, the siting of a new coal-fired power plant within their boundaries is not

likely to occur. In Class II areas, all new major power plants or major modifications of plants are required to use Best Available Control Technology (BACT). The BACT requirement is at least as stringent as a new source performance standard, but only as strict as the Lowest Achievable Emission Rate (LAER) requirement. In addition to technology-related requirements, proposed new plants in Class II areas face a maximum allowable increment test for particulate matter, sulfur dioxide, and nitrogen oxides, and are subject to an adverse impact test regarding key air-quality-related values for nearby Class I areas. At present, no PSD areas are classified as Class III. For nonattainment areas, new power plants are required to use control technologies that meet specifications for LAER. In addition, new sources in nonattainment areas must obtain offsets, and meet various other requirements as well. A.F. Loeb and T.J. Elliott, "PSD Constraints in Utility Planning: A Review of Recent Visibility Litigation," *Natural Resources Journal*, Vol. 34 (Spring 1994), pp. 1-40.

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88. Current Clean Coal Technology projects include the development of such advanced coal technologies as gasification combined cycle and pressurized fluidized bed combustion, which have the potential to reduce carbon emissions through improvements in conversion efficiencies. These advanced coal plants offer conversion efficiencies in the range of 40 to 45 percent, which corresponds to a reduction in carbon emissions per unit of generation of between 17 and 27 percent relative to current units fired with pulverized coal. U.S. Department of Energy, Office of Fossil Energy, *Clean Coal Technology: The New Coal Era*, DOE/FE-0193P (Washington, DC, June 1990).
89. State funding for the development of clean coal technologies is provided by governmental agencies such as the Pennsylvania Energy Development Authority and the Ohio Coal Development Office.
90. Currently, the following States have issued proposed rules and regulations aimed at bringing about full-cost pricing of energy: California, New York, Massachusetts, Nevada, New Jersey, and Wisconsin. T.F. Torries and V.J. Norton, "Implications of Full Cost Pricing of Fossil Energy," in *Eleventh Annual International Pittsburgh Coal Conference*, Pittsburgh, PA, September 12-16, 1994, ed. Shiao-Hung Chiang (Pittsburgh, PA: University of Pittsburgh, 1994), pp. 1598-1603.
91. Unlike the *AEO95* coal forecasts, DRI accounts for coal consumption by independent power producers and exempt wholesale generators in the industrial rather than the electricity sector. As a result, the *AEO95* and DRI forecasts of electricity and industrial coal consumption are not directly comparable. DRI/McGraw Hill, *Energy Review* (Second Quarter 1994).

Table notes

Table 1. Summary of results for five cases (page 4): Tables A1, A8, A19, B1, B8, B19, C1, C8, and C19.

Table 2. Comparative forecasts of economic growth, 1993-2010 (page 6): **DRI:** DRI/McGraw-Hill, OPTIM-25YR0894, PESSIM25YR0894, TREND25YR0894. **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook*, Volumes I and II (Third Quarter 1994).

Table 3. Comparative forecasts of world oil prices (page 7): **AEO95:** Tables A1, B1, and C1. **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Summer 1994). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook* (Third Quarter 1994). **IEA:** International Energy Agency, *World Energy Outlook, 1994*. **GRI:** Gas Research Institute, *Baseline Projection Data Book* (1994 Edition). **PEL:** Petroleum Economics Limited, *World Long-Term Oil and Energy Outlook* (December 1993). (Note: PEL assumes that world oil prices in real terms will remain constant.) **NRC:** Natural Resources Canada, *Canada's Energy Outlook 1992-2020* (September 1993). **CEC:** California Energy Commission, "Delphi VII" (1993).

Table 4. Average household energy expenditures, 1993, 2000, and 2010 (page 11): Tables E1, E2, E3, and E4.

Table 5. Residential appliance stock average efficiencies, 1993 and 2010 (page 15): AEO95 Forecasting System, runs AEO95B.D1103942, FROZEN.D1107941, and TECH95.D1107941; and American Council for an Energy-Efficient Economy (ACEEE), *Consumer Guide to Home Energy Savings* (Washington, DC, 1993).

Table 6. Increase in efficiency of most efficient equipment available, relative to 1989 stock (page 17): Commercial module technology database used for the reference case.

Table 7. Energy intensity and industry growth (page 19): AEO95 Forecasting System, run AEO95B.D1103942.

Table 8. New car EPA-rated fuel efficiencies by world oil price case, 1980-2010 (page 20): **History:** Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 14 (Oak Ridge, TN, May 1994). **Projections:**

AEO95 Forecasting System, runs AEO95B.D1103942, HWOP95.D1103942, and LWOP95.D1103941.

Table 9. Shares of alternative-fuel light-duty vehicle sales by technology type, 2010 (page 22): U.S. Department of Energy, Office of Domestic and International Energy Policy, *Technical Report Ten: Analysis of Alternative-Fuel Fleet Requirements* (May 1992). California Air Resources Board, "Proposed Regulations for Low-Emission Vehicles and Clean Fuels, Staff Report" (Sacramento, CA, August 13, 1990). AEO95 Forecasting System, run AEO95B.D1103942.

Table 10. Forecasts of total end-use energy demand (page 24): ***AEO95:*** Table A2. **DRI:** DRI/McGraw Hill, *Energy Review* (Third Quarter, 1994). **GRI:** Gas Research Institute, *GRI Projection of U.S. Energy Supply and Demand* (1995 Edition). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook* (Third Quarter, 1994).

Table 11. Forecasts of average annual growth in residential and commercial energy demand (page 25): ***AEO95:*** Tables A2, A4, and A5. **DRI:** DRI/McGraw Hill, *Energy Review* (Third Quarter, 1994). **GRI:** Gas Research Institute, *GRI Projection of U.S. Energy Supply and Demand* (1995 Edition). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook* (Third Quarter, 1994).

Table 12. Forecasts of average annual growth in industrial energy demand (page 25): ***AEO95:*** Table A2. **DRI:** DRI/McGraw Hill, *Energy Review* (Third Quarter, 1994). **GRI:** Gas Research Institute, *GRI Projection of U.S. Energy Supply and Demand* (1995 Edition). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook* (Third Quarter, 1994).

Table 13. Forecasts of average annual growth in transportation energy demand (page 25): ***AEO95:*** Table A2. **DRI:** DRI/McGraw Hill, *Energy Review* (Third Quarter, 1994). **GRI:** Gas Research Institute, *GRI Projection of U.S. Energy Supply and Demand* (1995 Edition).

Table 14. Scrubber retrofits and allowance costs, 2000-2010 (page 30): AEO95 Forecasting System, run AEO95B.D1103942.

Table 15. EIA forecasts of world oil price and domestic oil and gas wellhead prices, 2010 (page 37): Energy Information Administration, Office of Integrated Analysis and Forecasting, from Reference Case 1991 to 1995 *Annual Energy Outlook* runs. **Note:** In the 1991, 1992, and 1993 *Annual Energy Outlook*, world oil price was an input assumption rather than a forecast as it is in the 1994 and 1995 *Annual Energy Outlook*. **Note:** The world oil price is the average refiner's acquisition cost of imported crude oil.

Table 16. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions (page 40): Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 17. Reference case natural gas consumption, 1993, 2000, and 2010 (page 42): Table A13.

Table 18. Transmission and distribution revenues and margins, 1970, 1983, 1993, and 2010 (page 42): **History:** Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** AEO95 Forecasting System, run AEO95B.D1103942. End-use consumption is net of pipeline and lease and plant fuels.

Table 19. Ratio of natural gas to competing fuel prices, 1993, 2000, and 2010 (page 44): AEO95 Forecasting System, run AEO95B.D1103942.

Table 20. Petroleum consumption by product, 1993 and 2010 (page 46): Tables B11 and C11 and AEO95 Forecasting System, runs AEO95B.D1103942, LWOP95.D1103941, HWOP95.D1103942, LMAC95.D1103941, and HMAC95.D1103941. **Notes:** Light Other includes: liquefied petroleum gases, still gas, aviation gasoline, kerosene, and petrochemical feedstocks. Heavy Other includes: lubricants and waxes, asphalt and road oil, and petroleum coke. Totals may not equal sum of components due to independent rounding.

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Table 23. Comparative forecasts for coal, 2010 (page 57): Table F4.

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Review 1993, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** Tables A1 and A19.

Figure 6. U.S. carbon emissions, 1990-2010 (page 3): Table A18.

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Figure 9. World oil prices, 1970-2010 (page 6): **History:** Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** Tables A19, B19, and C19.

Figure 10. OPEC oil production, 1970-2010 (page 7): **History:** Energy Information Administration, *International Petroleum Statistics Report*, DOE/EIA-0520(94/07) (Washington, DC, August 1994). **Projections:** Tables A19, B19, and C19.

Figure 11. End-use and primary energy consumption by sector, 1970-2010 (page 10): Table A2.

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Annual 1989, DOE/EIA-0131(89) (Washington, DC, September 1990). 1990-1991: Energy Information Administration, *Natural Gas Annual 1991*, DOE/EIA-0131(91) (Washington, DC, October 1992). 1992: Energy Information Administration, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, DC, November 1993). 1993: Energy Information Administration, Office of Integrated Analysis and Forecasting. • Offshore, 1970-1976: Minerals Management Service, *Federal Offshore Statistics: 1991*. 1977-1992: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-216 (annual reports, 1977-1992). 1993: Energy Information Administration, Office of Integrated Analysis and Forecasting. • Unconventional Gas, 1978-1986: Energy Information Administration, *Drilling and Production Under Title I of the Natural Gas Policy Act, 1978-1986*, DOE/EIA-0448 (Washington, DC, January 1989). Preliminary 1987-1993: Energy Information Administration, Office of Integrated Analysis and Forecasting. • Associated-Dissolved and Nonassociated Gas, 1970-1976: American Petroleum Institute, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada* (annual reports, 1970-1976). 1977-1992: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216 (annual reports, 1977-1992). 1993: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** Table A15.

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Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case 1992	1993	2000	2005	2010	Annual Growth 1993-2010 (percent)
Production						
Crude Oil and Lease Condensate	15.19	14.50	11.33	10.92	11.42	-1.4%
Natural Gas Plant Liquids	2.36	2.41	2.57	2.69	2.81	0.9%
Dry Natural Gas	18.37	18.90	19.65	20.53	21.51	0.8%
Coal	21.59	20.23	22.08	23.21	24.51	1.1%
Nuclear Power	6.61	6.52	6.96	6.97	6.36	-0.1%
Renewable Energy/Other[1]	7.14	7.06	7.92	8.43	9.25	1.6%
Total	**71.25**	**69.62**	**70.51**	**72.75**	**75.86**	**0.5%**
Imports						
Crude Oil[2]	13.25	14.79	19.14	19.72	19.53	1.6%
Petroleum Products[3]	3.73	3.79	5.18	7.10	8.12	4.6%
Natural Gas	2.18	2.32	3.17	3.33	3.97	3.2%
Other Imports[4]	0.41	0.50	0.71	0.73	1.00	4.2%
Total	**19.57**	**21.40**	**28.20**	**30.87**	**32.62**	**2.5%**
Exports						
Petroleum[5]	2.00	2.11	1.97	1.68	1.64	-1.5%
Natural Gas	0.21	0.15	0.21	0.27	0.31	4.5%
Coal	2.68	1.96	2.22	2.54	2.89	2.3%
Total	**4.89**	**4.21**	**4.40**	**4.49**	**4.83**	**0.8%**
Discrepancy[6]	**-0.32**	**0.46**	**0.31**	**0.24**	**0.22**	**N/A**
Consumption						
Petroleum Products[7]	33.56	33.71	36.89	39.30	40.82	1.1%
Natural Gas	20.15	20.81	22.78	23.76	25.30	1.2%
Coal	18.87	19.43	20.14	21.01	21.97	0.7%
Nuclear Power	6.61	6.52	6.96	6.97	6.36	-0.1%
Renewable Energy/Other[8]	6.43	6.80	7.83	8.32	9.41	1.9%
Total	**85.61**	**87.27**	**94.61**	**99.37**	**103.88**	**1.0%**
Net Imports - Petroleum	**14.99**	**16.47**	**22.36**	**25.13**	**26.02**	**2.7%**
Prices (1993 dollars per unit)						
World Oil Price (dollars per barrel)[9]	18.70	16.12	19.13	21.50	24.12	2.4%
Gas Wellhead Price (dollars per thousand cubic feet)[10]	1.80	2.02	2.14	3.02	3.39	3.1%
Coal Minemouth Price (dollars per ton)	21.57	19.85	20.34	21.55	22.77	0.8%

[1]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[2]Includes imports of crude oil for the Strategic Petroleum Reserve.
[3]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[4]Includes coal, coal coke (net), and electricity (net).
[5]Includes crude oil and petroleum products.
[6]Balancing item. Includes unaccounted for supply, losses, and gains.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[8]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, net coal coke imports, net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1992 and 1993 may differ from published data due to internal conversion factors.
Sources: 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992, Volume 1*, DOE/EIA-0131(92)/1 (Washington, DC, November 1993). 1992 coal minemouth prices: EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993). Other 1992 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). 1993 natural gas price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 coal minemouth price: EIA, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Other 1993 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A2. Energy Consumption by End-Use Sector and Source
(Quadrillion Btu per Year)

Sector and Source	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Residential						
Distillate Fuel	0.86	0.88	0.79	0.75	0.73	-1.1%
Kerosene	0.06	0.07	0.06	0.06	0.05	-1.1%
Liquefied Petroleum Gas	0.38	0.39	0.34	0.31	0.29	-1.8%
Natural Gas	4.82	5.11	5.17	5.04	5.04	-0.1%
Coal	0.06	0.06	0.06	0.06	0.05	-0.2%
Renewable Energy[1]	0.69	0.72	0.72	0.73	0.74	0.2%
Electricity	3.19	3.39	3.61	3.73	3.94	0.9%
Total	**10.07**	**10.61**	**10.75**	**10.69**	**10.85**	**0.1%**
Commercial						
Distillate Fuel	0.46	0.42	0.39	0.37	0.35	-1.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.1%
Motor Gasoline[2]	0.08	0.07	0.07	0.07	0.08	0.5%
Residual Fuel	0.19	0.17	0.17	0.17	0.17	-0.1%
Natural Gas	2.87	2.98	3.04	3.04	3.06	0.2%
Other[3]	0.15	0.15	0.15	0.15	0.15	-0.1%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.1%
Electricity	2.86	2.96	3.22	3.34	3.50	1.0%
Total	**6.64**	**6.77**	**7.08**	**7.17**	**7.34**	**0.5%**
Industrial[5]						
Distillate Fuel	1.14	1.12	1.24	1.33	1.39	1.3%
Liquefied Petroleum Gas	1.86	1.82	2.04	2.24	2.40	1.6%
Motor Gasoline[2]	0.19	0.19	0.21	0.23	0.24	1.4%
Petrochemical Feedstocks	1.19	1.17	1.31	1.42	1.52	1.5%
Residual Fuel	0.39	0.38	0.49	0.54	0.56	2.2%
Other Petroleum[6]	3.86	3.78	3.86	3.98	4.07	0.4%
Natural Gas[7]	8.84	9.09	10.32	10.71	11.28	1.3%
Metallurgical Coal	0.87	0.84	0.77	0.67	0.59	-2.1%
Steam Coal	1.65	1.66	1.87	2.01	2.11	1.4%
Net Coal Coke Imports	0.03	0.02	0.02	0.03	0.04	5.5%
Renewable Energy	2.09	2.12	2.45	2.67	2.84	1.7%
Electricity	3.32	3.35	3.68	4.01	4.24	1.4%
Total	**25.44**	**25.55**	**28.25**	**29.83**	**31.28**	**1.2%**
Transportation						
Distillate Fuel	3.81	3.86	4.59	5.02	5.43	2.0%
Jet Fuel[8]	3.00	3.04	3.74	4.13	4.46	2.3%
Motor Gasoline[2]	13.70	13.88	14.97	15.44	15.51	0.7%
Residual Fuel	1.08	1.10	1.32	1.51	1.67	2.5%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.16	0.24	16.3%
Other Petroleum[9]	0.20	0.20	0.23	0.24	0.25	1.2%
Pipeline Fuel Natural Gas	0.61	0.63	0.67	0.67	0.67	0.4%
Compressed Natural Gas	0.00	0.01	0.16	0.29	0.43	26.3%
Renewables (ethanol)[10]	0.00	0.00	0.01	0.03	0.06	35.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	N/A
Methanol[11]	0.00	0.00	0.01	0.03	0.05	30.8%
Electricity	0.06	0.06	0.09	0.13	0.18	6.5%
Total	**22.48**	**22.79**	**25.86**	**27.66**	**28.94**	**1.4%**
Electric Generators[12]						
Distillate Fuel	0.01	0.01	0.01	0.01	0.05	10.2%
Residual Fuel	0.97	1.07	0.93	1.26	1.31	1.2%
Natural Gas	3.01	3.00	3.42	4.01	4.82	2.8%
Steam Coal	16.21	16.78	17.36	18.19	19.13	0.8%
Nuclear Power	6.61	6.52	6.96	6.97	6.36	-0.1%
Renewable Energy/Other[13]	3.61	3.92	4.60	4.80	5.65	2.2%
Total	**30.42**	**31.30**	**33.27**	**35.23**	**37.32**	**1.0%**

Table A2. Energy Consumption by End-Use Sector and Source (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Primary Energy Consumption						
Distillate Fuel	6.29	6.29	7.02	7.49	7.95	1.4%
Kerosene	0.09	0.09	0.08	0.08	0.07	-0.9%
Jet Fuel[8]	3.00	3.04	3.74	4.13	4.46	2.3%
Liquefied Petroleum Gas	2.33	2.29	2.53	2.77	2.99	1.6%
Motor Gasoline[2]	13.97	14.14	15.25	15.75	15.83	0.7%
Petrochemical Feedstocks	1.19	1.17	1.31	1.42	1.52	1.5%
Residual Fuel	2.63	2.72	2.90	3.47	3.70	1.8%
Other Petroleum[14]	4.05	3.98	4.07	4.21	4.31	0.5%
Natural Gas	20.15	20.81	22.78	23.76	25.30	1.2%
Metallurgical Coal	0.87	0.84	0.77	0.67	0.59	-2.1%
Steam Coal	18.00	18.59	19.37	20.34	21.38	0.8%
Net Coal Coke Imports	0.03	0.02	0.02	0.03	0.04	5.5%
Nuclear Power	6.61	6.52	6.96	6.97	6.36	-0.1%
Renewable Energy/Other[15]	6.41	6.78	7.81	8.29	9.37	1.9%
Total	**85.61**	**87.26**	**94.61**	**99.37**	**103.88**	**1.0%**
Electricity Consumption (all sectors)	**9.43**	**9.77**	**10.60**	**11.21**	**11.86**	**1.1%**

[1]Includes electricity generated by the sector for self-use from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, and non-electric energy from renewable sources, such as solar thermal water heaters, groundwater heat pumps, and wood.

[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3]Includes liquefied petroleum gas and coal.

[4]Includes commercial sector electricity cogenerated using wood and wood waste, municipal solid waste, and other biomass; non-electric energy from renewable sources, such as active solar and passive solar systems, geothermal heat pumps, and solar water heating systems.

[5]Fuel consumption includes consumption for cogeneration.

[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[7]Includes lease and plant fuel.

[8]Includes naphtha and kerosene type.

[9]Includes aviation gas and lubricants.

[10]Only E85 (85 percent ethanol).

[11]Only M85 (85 percent methanol).

[12]Includes consumption of energy by all electric power generators except cogenerators and generators with standard industrial classification other than 49, both of which produce electricity as a byproduct of other processes.

[13]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus net electricity imports.

[14]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, and miscellaneous petroleum products.

[15]Includes electricity generated for sale to electric utilities and for self use from renewable sources, non-electric energy from renewable sources, net electricity imports, liquid hydrogen, and methanol.

Btu = British thermal unit.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1992 and 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.

Sources: 1992 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, DC, November 1993). Other 1992 values: EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. 1993 natural gas lease, plant, and pipeline fuel values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 transportation sector compressed natural gas consumption: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. 1992 and 1993 coal consumption is estimated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1992 and 1993 metallurgical consumption is estimated from this source using unpublished data. 1992 and 1993 residential and commercial coal consumption tonnages are from EIA, *Quarterly Coal Report, October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994) and have been converted to quadrillion Btu using *State Energy Data Report 1992* thermal conversion factors. Other 1993 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural by electric wholesale generators based on EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A3. Energy Prices by End-Use Sector and Source
(1993 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Residential	**12.52**	**12.48**	**12.72**	**13.73**	**14.53**	**0.9%**
Primary Energy	6.28	6.32	6.41	7.18	7.42	0.9%
Petroleum Products	7.99	7.72	8.97	9.54	10.06	1.6%
Distillate Fuel	6.86	6.55	7.70	8.24	8.71	1.7%
Liquefied Petroleum Gas	10.55	10.40	11.96	12.72	13.58	1.6%
Natural Gas	5.87	6.00	5.88	6.71	6.92	0.8%
Electricity	24.62	24.30	23.93	24.66	25.67	0.3%
Commercial	**12.54**	**12.25**	**12.53**	**13.49**	**14.25**	**0.9%**
Primary Energy	4.86	4.93	5.00	5.79	6.07	1.2%
Petroleum Products	5.16	4.96	5.76	6.32	6.84	1.9%
Distillate Fuel	4.89	4.61	5.52	6.05	6.49	2.0%
Residual Fuel	2.66	2.67	3.06	3.48	3.89	2.2%
Natural Gas[1]	4.86	5.02	4.93	5.79	6.03	1.1%
Electricity	22.66	21.63	21.47	22.25	23.15	0.4%
Industrial[2]	**5.22**	**5.02**	**5.28**	**5.95**	**6.42**	**1.5%**
Primary Energy	3.42	3.32	3.67	4.32	4.77	2.2%
Petroleum Products	4.66	4.34	4.99	5.57	6.19	2.1%
Distillate Fuel	4.99	4.78	5.52	6.06	6.53	1.8%
Liquefied Petroleum Gas	5.04	4.85	7.18	7.91	8.69	3.5%
Residual Fuel	2.40	2.35	2.93	3.34	3.75	2.8%
Natural Gas[3]	2.62	2.79	2.96	3.80	4.17	2.4%
Metallurgical Coal	1.84	1.77	1.71	1.74	1.76	0.0%
Steam Coal	1.51	1.45	1.45	1.48	1.53	0.3%
Electricity	15.40	14.53	14.34	14.78	15.22	0.3%
Transportation	**8.11**	**7.76**	**9.06**	**9.52**	**9.70**	**1.3%**
Primary Energy	8.09	7.74	9.04	9.49	9.66	1.3%
Petroleum Products	8.09	7.74	9.06	9.51	9.68	1.3%
Distillate Fuel[4]	8.22	8.05	8.89	9.22	9.49	1.0%
Jet Fuel[5]	4.63	4.28	5.80	6.46	6.85	2.8%
Motor Gasoline[6]	9.33	8.93	10.54	11.07	11.21	1.3%
Residual Fuel	2.24	2.07	2.76	3.17	3.59	3.3%
Natural Gas[7]	4.03	4.65	6.36	8.34	8.67	3.7%
Electricity	15.63	14.85	15.34	15.55	15.73	0.3%
Total End-Use Energy	**8.22**	**8.05**	**8.61**	**9.24**	**9.64**	**1.1%**
Primary Energy	7.90	7.68	8.32	8.90	9.25	1.1%
Electricity	20.72	20.08	19.78	20.30	21.04	0.3%
Electric Generators[8]						
Fossil Fuel Average	1.64	1.61	1.65	1.88	2.05	1.4%
Petroleum Products	2.53	2.48	2.91	3.33	3.78	2.5%
Distillate Fuel	4.80	4.72	5.27	5.53	5.91	1.3%
Residual Fuel	2.52	2.46	2.90	3.30	3.70	2.4%
Natural Gas	2.40	2.57	2.59	3.38	3.73	2.2%
Steam Coal	1.45	1.39	1.39	1.45	1.50	0.5%

Table A3. Energy Prices by End-Use Sector and Source (Continued)
(1993 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Average Price to All Users[9]						
Petroleum Products	7.04	6.73	7.91	8.35	8.65	1.5%
Distillate Fuel[4]	7.19	7.02	7.97	8.39	8.74	1.3%
Jet Fuel	4.63	4.28	5.80	6.46	6.85	2.8%
Liquefied Petroleum Gas	6.09	5.94	8.13	8.90	9.74	3.0%
Motor Gasoline[6]	9.33	8.93	10.52	11.05	11.20	1.3%
Residual Fuel	2.40	2.30	2.85	3.26	3.67	2.8%
Natural Gas	3.79	3.97	3.94	4.74	5.01	1.4%
Coal	1.47	1.41	1.40	1.45	1.50	0.4%
Electricity	20.72	20.08	19.78	20.30	21.04	0.3%

[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]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.
[8]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[9]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: 1992 and 1993 figures may differ from published data due to internal rounding in the AEO95 National Energy Modeling System.
Sources: 1992 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, DC, July 1993). 1993 prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). 1992 and 1993 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). 1992 residential and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1992*, Volume 1, DOE/EIA-0131(92)/1 (Washington, DC, November 1993). 1993 residential natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1992 and 1993 natural gas delivered prices: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. 1992 coal sectoral prices are from EIA, *State Price and Expenditure Report 1992*, DOE/EIA-0376(92) (Washington, DC, December 1994) except for the Utility sector which is from EIA, *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(93) (Washington, DC, July 1994). Values for 1993 coal prices have been estimated from EIA, *State Price and Expenditure Report 1992* using consumption quantities aggregated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1992 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). 1992 and 1993 electricity prices for commercial, industrial, and transportation: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Household Characteristics						
Households (millions)						
Single-Family	65.58	66.39	71.78	75.21	78.56	1.0%
Multifamily	24.27	24.19	24.69	25.57	26.62	0.6%
Mobile Homes	5.19	5.24	5.42	5.46	5.51	0.3%
Total	**95.04**	**95.82**	**101.89**	**106.25**	**110.69**	**0.9%**
Housing Starts (millions)						
Single-Family	1.03	1.13	1.04	1.06	1.06	N/A
Multifamily	0.17	0.16	0.39	0.43	0.50	N/A
Mobile Homes	0.21	0.26	0.22	0.22	0.23	N/A
Total	**1.41**	**1.55**	**1.64**	**1.72**	**1.78**	**N/A**
Energy Intensity (million Btu per year per household)						
Heating	58.60	61.60	56.75	52.64	50.02	-1.2%
Total	**105.97**	**110.72**	**105.55**	**100.57**	**98.06**	**-0.7%**
Fuel Consumption						
Distillate						
Space Heating	0.79	0.80	0.72	0.68	0.66	-1.1%
Water Heating	0.07	0.08	0.07	0.07	0.07	-0.4%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.9%
Total	**0.86**	**0.88**	**0.79**	**0.75**	**0.73**	**-1.1%**
Liquefied Petroleum Gas						
Space Heating	0.25	0.26	0.22	0.19	0.17	-2.4%
Water Heating	0.08	0.08	0.08	0.07	0.07	-0.7%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-0.9%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	1.0%
Total	**0.38**	**0.39**	**0.34**	**0.31**	**0.29**	**-1.8%**
Natural Gas						
Space Heating	3.43	3.68	3.67	3.53	3.50	-0.3%
Space Cooling	0.00	0.00	0.00	0.01	0.01	10.9%
Water Heating	1.08	1.11	1.17	1.19	1.22	0.6%
Cooking[2]	0.18	0.18	0.18	0.17	0.16	-0.9%
Clothes Dryers	0.08	0.08	0.08	0.08	0.08	0.1%
Other Uses[3]	0.06	0.06	0.07	0.07	0.07	1.1%
Total	**4.82**	**5.11**	**5.17**	**5.04**	**5.04**	**-0.1%**
Electricity						
Space Heating	0.34	0.37	0.40	0.41	0.43	0.8%
Space Cooling	0.44	0.53	0.54	0.55	0.58	0.5%
Water Heating	0.35	0.36	0.38	0.38	0.38	0.3%
Refrigeration	0.52	0.53	0.46	0.41	0.39	-1.8%
Cooking	0.15	0.16	0.17	0.17	0.18	0.7%
Clothes Dryers	0.18	0.19	0.20	0.20	0.21	0.6%
Freezers	0.14	0.14	0.11	0.09	0.07	-3.9%
Lighting	0.31	0.32	0.35	0.36	0.37	0.9%
Other Uses[4]	0.75	0.79	1.01	1.16	1.34	3.1%
Total	**3.19**	**3.39**	**3.61**	**3.73**	**3.94**	**0.9%**

Table A4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Renewables						
Wood[5]	0.63	0.66	0.65	0.65	0.65	-0.1%
Geothermal[6]	0.01	0.01	0.02	0.03	0.04	7.3%
Solar[7]	0.05	0.05	0.05	0.06	0.06	1.1%
Total	**0.69**	**0.72**	**0.72**	**0.73**	**0.74**	**0.2%**
Other Fuels[8]	**0.12**	**0.12**	**0.12**	**0.11**	**0.11**	**-0.7%**
Total Fuels						
Space Heating	5.57	5.90	5.78	5.59	5.54	-0.4%
Space Cooling	0.44	0.53	0.55	0.57	0.60	0.7%
Water Heating	1.64	1.67	1.74	1.77	1.80	0.4%
Cooking	0.37	0.38	0.40	0.38	0.37	-0.2%
Clothes Dryers	0.26	0.27	0.28	0.28	0.29	0.4%
Other Uses	1.79	1.85	2.00	2.10	2.25	1.2%
Total	**10.07**	**10.61**	**10.75**	**10.69**	**10.85**	**0.1%**

[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.
[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: 1990 (RECS)*.
[6]Includes primary energy displaced by ground-source (geothermal) heat pumps in space heating and cooling applications.
[7]Includes primary energy displaced by solar thermal water heaters.
[8]Includes kerosene and coal.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Key Indicators						
Total Floor Space (billion square feet)						
Surviving	64.7	65.6	71.0	73.9	76.8	0.9%
New Additions	1.4	1.5	1.4	1.5	1.6	0.6%
Total	**66.1**	**67.0**	**72.4**	**75.3**	**78.4**	**0.9%**
Energy Consumption Intensity (Thousand Btu per square feet)	**100.4**	**101.1**	**97.8**	**95.1**	**93.7**	**-0.4%**
End-Use Consumption						
Electricity						
Space Heating	0.09	0.09	0.08	0.07	0.06	-1.8%
Space Cooling	0.29	0.29	0.29	0.29	0.29	0.0%
Water Heating	0.03	0.03	0.04	0.05	0.06	5.0%
Ventilation	0.30	0.30	0.32	0.32	0.33	0.6%
Cooking	0.06	0.06	0.06	0.06	0.07	0.4%
Lighting	1.04	1.06	1.03	1.02	1.03	-0.1%
Refrigeration	0.19	0.19	0.20	0.20	0.20	0.3%
Office Equipment (PC)	0.20	0.20	0.25	0.29	0.33	2.9%
Office Equipment (non-PC)	0.21	0.21	0.26	0.29	0.33	2.6%
Other Uses[1]	0.46	0.53	0.70	0.74	0.79	2.4%
Total Electricity	**2.86**	**2.96**	**3.22**	**3.34**	**3.50**	**1.0%**
Natural Gas[2]						
Space Heating	1.32	1.33	1.38	1.37	1.38	0.2%
Space Cooling	0.01	0.01	0.01	0.02	0.02	5.2%
Water Heating	0.35	0.35	0.36	0.35	0.36	0.0%
Cooking	0.21	0.21	0.23	0.23	0.23	0.5%
Other Uses[3]	0.98	1.08	1.06	1.07	1.08	0.0%
Total Natural Gas	**2.87**	**2.98**	**3.04**	**3.04**	**3.06**	**0.2%**
Distillate						
Space Heating	0.30	0.31	0.29	0.27	0.25	-1.2%
Water Heating	0.03	0.03	0.02	0.02	0.02	-1.5%
Other Uses[4]	0.13	0.08	0.08	0.08	0.08	-0.3%
Total Distillate	**0.46**	**0.42**	**0.39**	**0.37**	**0.35**	**-1.0%**
Other Fuels[5]	**0.43**	**0.40**	**0.39**	**0.39**	**0.40**	**0.0%**
Renewable Fuels						
Solar	0.01	0.01	0.02	0.03	0.03	6.1%
Biomass	0.00	0.00	0.00	0.00	0.00	N/A
Total Renewable Fuels	**0.01**	**0.01**	**0.03**	**0.03**	**0.03**	**5.1%**
Total Consumption	**6.64**	**6.77**	**7.08**	**7.17**	**7.34**	**0.5%**

[1]Includes miscellaneous commercial uses such as service station equipment and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous commercial uses such as lighting and emergency electric generators.
[4]Includes miscellaneous commercial uses such as cooking and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
Btu = British thermal unit.
N/A = Not applicable
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case 1992	1993	2000	2005	2010	Annual Growth 1993-2010 (percent)
Key Indicators						
Value of Gross Output (billion 1987 dollars)						
Manufacturing	2512	2559	3048	3427	3728	2.2%
Nonmanufacturing	886	889	1046	1132	1198	1.8%
Total	**3397**	**3448**	**4094**	**4560**	**4926**	**2.1%**
Energy Prices (1993 dollars per million Btu)						
Electricity	15.40	14.53	14.34	14.78	15.22	0.3%
Natural Gas	2.62	2.79	2.96	3.80	4.17	2.4%
Steam Coal	1.51	1.45	1.45	1.48	1.53	0.3%
Residual Oil	2.40	2.35	2.93	3.34	3.75	2.8%
Distillate Oil	4.99	4.78	5.52	6.06	6.53	1.8%
Liquefied Petroleum Gas	5.04	4.85	7.18	7.91	8.69	3.5%
Motor Gasoline	9.30	8.90	9.33	10.06	10.36	0.9%
Metallurgical Coal	1.84	1.77	1.71	1.74	1.76	0.0%
Energy Consumption						
Consumption[1] (quadrillion Btu per year)						
Purchased Electricity	3.32	3.35	3.68	4.01	4.24	1.4%
Natural Gas[2]	8.84	9.09	10.32	10.71	11.28	1.3%
Steam Coal	1.65	1.66	1.87	2.01	2.11	1.4%
Metallurgical Coal and Coke[3]	0.89	0.86	0.79	0.71	0.63	-1.8%
Residual Fuel	0.39	0.38	0.49	0.54	0.56	2.2%
Distillate	1.14	1.12	1.24	1.33	1.39	1.3%
Liquefied Petroleum Gas	1.86	1.82	2.04	2.24	2.40	1.6%
Petrochemical Feedstocks	1.19	1.17	1.31	1.42	1.52	1.5%
Other Petroleum[4]	4.05	3.97	4.07	4.21	4.31	0.5%
Renewables[5]	2.09	2.12	2.45	2.67	2.84	1.7%
Total	**25.44**	**25.55**	**28.25**	**29.83**	**31.28**	**1.2%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)						
Purchased Electricity	0.98	0.97	0.90	0.88	0.86	-0.7%
Natural Gas[2]	2.60	2.64	2.52	2.35	2.29	-0.8%
Steam Coal	0.48	0.48	0.46	0.44	0.43	-0.7%
Metallurgical Coal and Coke[3]	0.26	0.25	0.19	0.15	0.13	-3.8%
Residual Fuel	0.12	0.11	0.12	0.12	0.11	0.1%
Distillate	0.34	0.33	0.30	0.29	0.28	-0.8%
Liquefied Petroleum Gas	0.55	0.53	0.50	0.49	0.49	-0.5%
Petrochemical Feedstocks	0.35	0.34	0.32	0.31	0.31	-0.6%
Other Petroleum[4]	1.19	1.15	0.99	0.92	0.87	-1.6%
Renewables[5]	0.62	0.62	0.60	0.58	0.58	-0.4%
Total	**7.49**	**7.41**	**6.90**	**6.54**	**6.35**	**-0.9%**

[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, still gas, motor gasoline, and miscellaneous petroleum products.
[5]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, DC, July 1993). 1993 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). 1992 and 1993 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(94/08) (Washington, DC, August 1994). 1992 and 1993 natural gas and electricity prices: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. Other 1992 values and 1993 prices derived from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). Other 1993 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994).
Projections: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A7. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Reference Case 1992	1993	2000	2005	2010	Annual Growth 1993-2010 (percent)
Key Indicators						
Level of Travel Index (1990 = 1.0)						
Light-Duty Vehicles	1.03	1.06	1.20	1.32	1.42	1.8%
Freight Trucks	1.10	1.12	1.33	1.46	1.56	2.0%
Air	1.03	1.05	1.55	1.80	2.02	3.9%
Rail	1.03	1.06	1.14	1.23	1.31	1.3%
Marine	1.03	0.98	1.04	1.11	1.18	1.1%
Energy Efficiency Indicators						
New Car MPG[1]	27.57	27.81	28.88	29.96	32.83	1.0%
New Light Truck MPG[1]	20.38	20.34	21.52	22.74	23.80	0.9%
Light-Duty Fleet MPG[2]	19.15	19.30	20.33	20.96	21.82	0.7%
Aircraft Efficiency Index	1.01	1.02	1.07	1.11	1.14	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.06	1.08	1.09	0.5%
Rail Efficiency Index	1.00	1.01	1.04	1.06	1.07	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.00	1.01	1.01	0.1%
Energy Use by Mode (quadrillion Btu per year)						
Light-Duty Vehicles[3]	12.85	13.09	14.31	15.09	15.50	1.0%
Freight Trucks[3]	5.12	4.97	6.06	6.51	6.88	1.9%
Air	3.05	3.09	3.77	4.17	4.50	2.2%
Rail	0.55	0.59	0.61	0.65	0.68	0.8%
Marine	1.60	1.63	1.90	2.13	2.32	2.1%
Pipeline Fuel	0.61	0.63	0.67	0.67	0.67	0.4%
Other[4]	0.15	0.16	0.18	0.19	0.21	1.6%
Total[5]	**22.48**	**22.79**	**25.86**	**27.66**	**28.94**	**1.4%**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes light-duty trucks used for freight.
[4]Includes lubricants and aviation gasoline.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Btu = British thermal unit.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1992 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 1992, Volume 1*, DOE/EIA-0131(92)/1 (Washington,DC, November 1993). Other 1992 values: Federal Highway Administration, *Highway Statistics 1992* (Washington, DC, 1992); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13 and 14*, (Oak Ridge, Tn., May 1994); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 1993); EIA, *Residential Transportation Energy Consumption Survey 1991*, DOE/EIA-0464(91) (Washington, DC, December 1993); Argonne National Laboratory, FRATE Model 1990; and EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 pipeline fuel consumption: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1993 values: FAA, *FAA Aviation Forecasts Fiscal Years 1993-2004*,(Washington, DC, February 1993); and EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Generation by Fuel Type						
Electric Utilities						
Coal	1576	1639	1689	1761	1825	0.6%
Petroleum	89	100	80	111	118	1.0%
Natural Gas	264	259	301	342	387	2.4%
Nuclear Power	619	610	652	653	596	-0.1%
Pumped Storage	-3	-2	-2	-2	-2	-0.8%
Renewable Sources[1]	253	277	303	306	317	0.8%
Total	**2797**	**2883**	**3022**	**3171**	**3241**	**0.7%**
Nonutilities (excluding cogenerators)[2]						
Coal	2	5	9	12	44	13.4%
Petroleum	1	1	0	0	0	-10.4%
Natural Gas	16	21	36	53	90	8.8%
Renewable Sources[1]	40	45	64	73	101	4.9%
Total	**60**	**73**	**109**	**139**	**236**	**7.1%**
Cogenerators[3]						
Coal	46	49	55	58	60	1.3%
Petroleum	8	10	38	41	44	9.2%
Natural Gas	144	151	177	196	216	2.2%
Renewable	35	35	38	38	39	0.5%
Other[4]	3	3	4	5	5	3.0%
Total	**237**	**248**	**313**	**338**	**365**	**2.3%**
Sales to Utilities	102	111	138	148	159	2.1%
Generation for Own Use	135	137	175	190	206	2.4%
Net Imports	**28**	**28**	**35**	**33**	**56**	**4.1%**
Electricity Sales by Sector						
Residential	936	994	1058	1094	1156	0.9%
Commercial	837	868	945	979	1026	1.0%
Industrial	973	983	1079	1174	1242	1.4%
Transportation	18	18	25	38	52	6.5%
Total	**2763**	**2862**	**3108**	**3285**	**3475**	**1.1%**
End-Use Prices (1993 cents per kilowatthour)[5]						
Residential	8.4	8.3	8.2	8.4	8.8	0.3%
Commercial	7.7	7.4	7.3	7.6	7.9	0.4%
Industrial	5.3	5.0	4.9	5.0	5.2	0.3%
Transportation	5.3	5.1	5.2	5.3	5.4	0.3%
All Sectors Average	**7.1**	**6.8**	**6.7**	**6.9**	**7.2**	**0.3%**
Price Components (1993 cents per kilowatthour)						
Capital Component	2.9	2.8	2.6	2.5	2.5	-0.5%
Fuel Component	1.2	1.2	1.2	1.4	1.4	1.1%
Operation and Maintenance Component	2.8	2.7	2.7	2.8	2.7	0.0%
Wholesale Power Cost	0.1	0.1	0.2	0.3	0.5	7.0%
Total	**7.1**	**6.8**	**6.7**	**6.9**	**7.2**	**0.3%**

[1]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[2]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).
[3]Includes generation and cogeneration at facilities whose primary function is not electricity production (standard industrial classification other than 49). Includes sales to utilities and generation for own use.
[4]Other includes methane, propane, and blast furnace gas.
[5]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992 commercial and transportation sales: Total transportation plus commercial sales comes from Energy Information Administration (EIA), *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994), but individual sectors do not match because sales taken from commercial and placed in transportation, because Oak Ridge National Laboratories, *Transportation Energy Data Book 14* (May 1994) indicates the transportation value should be higher. 1992 and 1993 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). 1992 residential electric prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **1992 and 1993 electricity prices for commercial, industrial, and transportation, price components, and projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	301.0	300.7	297.1	301.1	306.4	0.1%
Other Fossil Steam[2]	141.8	141.3	130.4	124.3	120.4	-0.9%
Combined Cycle	9.2	9.7	17.7	23.4	27.2	6.2%
Combustion Turbine/Diesel	49.2	49.2	65.9	71.0	77.8	2.7%
Nuclear Power	99.0	99.0	101.3	101.3	88.7	-0.6%
Pumped Storage	19.1	19.1	20.0	20.0	20.0	0.3%
Renewable Sources[3]	76.6	76.8	78.1	78.9	81.6	0.4%
Total	**695.9**	**695.7**	**710.5**	**720.0**	**722.1**	**0.2%**
Cumulative Planned Additions[4]						
Coal Steam	0.00	0.00	5.63	11.98	13.74	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A
Combined Cycle	0.00	0.61	7.22	11.79	12.38	19.3%
Combustion Turbine/Diesel	0.00	0.14	16.20	22.41	22.77	35.2%
Nuclear Power	0.00	1.15	3.49	3.49	3.49	6.7%
Pumped Storage	0.30	0.30	1.29	1.29	1.29	9.0%
Renewable Sources[3]	0.19	0.20	1.14	1.15	1.15	10.9%
Total	**0.49**	**2.40**	**34.97**	**52.11**	**54.82**	**20.2%**
Cumulative Unplanned Additions[4]						
Coal Steam	0.00	0.00	0.02	0.34	6.68	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A
Combined Cycle	0.00	0.00	1.42	2.56	5.79	N/A
Combustion Turbine/Diesel	0.00	0.00	0.74	1.23	8.05	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A
Pumped Storage	0.00	0.00	0.00	0.00	0.00	N/A
Renewable Sources[3]	0.00	0.00	0.13	0.52	3.07	N/A
Total	**0.00**	**0.00**	**2.32**	**4.66**	**23.59**	**N/A**
Cumulative Total Additions	**0.49**	**2.40**	**37.29**	**56.77**	**78.41**	**22.8%**
Cumulative Retirements[5]	**6.50**	**8.71**	**29.26**	**39.86**	**59.57**	**12.0%**
Nonutilities (excludes cogenerators)[6,7]						
Capability						
Coal Steam	0.47	0.62	1.82	2.10	7.11	15.5%
Other Fossil Steam[2]	0.21	0.21	0.25	0.25	0.25	0.9%
Combined Cycle	2.02	2.03	5.29	7.00	10.48	10.1%
Combustion Turbine/Diesel	1.28	1.33	2.80	3.97	13.72	14.7%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A
Pumped Storage	0.00	0.00	0.00	0.00	0.00	N/A
Renewable Sources[3]	8.61	9.11	13.45	15.47	22.07	5.3%
Total	**12.60**	**13.30**	**23.61**	**28.79**	**53.62**	**8.5%**

Table A9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Cogenerators[7,8]						
Capacity						
Coal	6.64	6.90	8.03	8.37	8.72	1.4%
Petroleum	2.89	3.36	5.96	6.37	6.81	4.2%
Natural Gas	20.83	21.06	24.12	26.74	29.52	2.0%
Renewables	6.66	6.92	7.41	7.46	7.51	0.5%
Other	0.00	0.00	0.03	0.03	0.03	N/A
Total	**37.01**	**38.25**	**45.54**	**48.96**	**52.59**	**1.9%**
Cumulative Additions[4,7]	**5.86**	**7.80**	**25.40**	**34.00**	**62.46**	**13.0%**

[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 oil-, gas-, and dual-fired capability.

[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.

[4]Cumulative additions after December 31, 1992. Non-zero utility planned additions in 1992 indicate units operational in 1992, but not supplying power to the grid.

[5]Cumulative total retirements from 1990.

[6]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).

[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 capacity based on historic relationships.

[8]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification other than 49).

N/A = Not applicable.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 15, 1994. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: Net summer capacity at electric utilities in 1992 and 1993, and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capacity for nonutilities and cogeneration in 1992 and 1993 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Interregional Electricity Trade						
Gross Domestic Firm Power Sales	146.4	153.4	133.4	124.8	124.8	-1.2%
Gross Domestic Economy Sales	51.2	58.5	75.0	59.7	49.5	-1.0%
Gross Domestic Trade	**197.5**	**211.9**	**208.4**	**184.5**	**174.3**	**-1.1%**
Gross Domestic Firm Power Sales (million 1993 dollars)	6586.5	7022.3	6897.0	7038.7	7676.5	0.5%
Gross Domestic Economy Sales (million 1993 dollars)	1044.5	1194.2	1710.7	1670.3	1556.7	1.6%
Gross Domestic Sales (million 1993 dollars)	**7631.0**	**8216.5**	**8607.8**	**8709.1**	**9233.2**	**0.7%**
International Electricity Trade						
Firm Power Imports From Canada and Mexico	10.9	14.9	20.9	21.8	42.5	6.3%
Economy Imports From Canada and Mexico	26.3	24.1	28.2	30.9	34.8	2.2%
Gross Imports From Canada and Mexico	**37.2**	**39.1**	**49.1**	**52.7**	**77.3**	**4.1%**
Firm Power Exports To Canada and Mexico	2.3	2.5	8.1	13.1	13.1	10.4%
Economy Exports To Canada and Mexico	6.6	8.2	6.4	7.0	7.7	-0.4%
Gross Exports To Canada and Mexico	**8.9**	**10.7**	**14.5**	**20.1**	**20.8**	**4.0%**

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: 1992 and 1993 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1992 and 1993 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1992 firm/economy share: National Energy Board, *Annual Report 1992*. 1993 firm/economy share: National Energy Board, *Annual Report 1993*. 2000 planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1994. **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Crude Oil						
Domestic Crude Production[1]	7.17	6.85	5.35	5.16	5.39	-1.4%
Alaska	1.71	1.58	1.16	0.83	0.77	-4.2%
Lower 48 States	5.46	5.26	4.19	4.33	4.62	-0.8%
Net Imports	5.99	6.69	8.70	8.97	8.88	1.7%
Other Crude Supply[2]	0.25	0.08	0.00	0.00	0.00	N/A
Total Crude Supply	**13.41**	**13.61**	**14.05**	**14.13**	**14.27**	**0.3%**
Natural Gas Plant Liquids	**1.70**	**1.74**	**1.85**	**1.93**	**2.03**	**0.9%**
Other Inputs[3]	**0.21**	**0.19**	**0.23**	**0.23**	**0.23**	**1.1%**
Refinery Processing Gain[4]	**0.77**	**0.77**	**0.80**	**0.81**	**0.83**	**0.5%**
Net Product Imports[5]	**0.94**	**0.93**	**1.76**	**2.82**	**3.34**	**7.8%**
Total Primary Supply[6]	**17.03**	**17.24**	**18.69**	**19.92**	**20.71**	**1.1%**
Refined Petroleum Products Supplied						
Motor Gasoline[7]	7.27	7.48	8.10	8.36	8.41	0.7%
Jet Fuel[8]	1.45	1.47	1.81	1.99	2.15	2.3%
Distillate Fuel[9]	2.98	3.04	3.34	3.56	3.78	1.3%
Residual Fuel	1.09	1.08	1.27	1.51	1.61	2.4%
Other[10]	4.24	4.17	4.37	4.66	4.92	1.0%
Total	**17.03**	**17.24**	**18.87**	**20.09**	**20.88**	**1.1%**
Refined Petroleum Products Supplied						
Residential and Commercial	1.12	1.14	1.00	0.95	0.92	-1.3%
Industrial[11]	4.55	4.60	4.81	5.14	5.39	0.9%
Transportation	10.94	11.08	12.66	13.45	13.98	1.4%
Electric Generators[12]	0.42	0.41	0.41	0.55	0.59	2.1%
Total	**17.03**	**17.24**	**18.87**	**20.10**	**20.88**	**1.1%**
Discrepancy[13]	**0.00**	**0.00**	**-0.18**	**-0.17**	**-0.17**	**N/A**
World Oil Price (1993 dollars per barrel)[14]	**18.70**	**16.12**	**19.13**	**21.50**	**24.12**	**N/A**
Domestic Refinery Distillation Capacity	**15.5**	**15.3**	**15.7**	**15.8**	**15.9**	**0.2%**
Capacity Utilization Rate (percent)	**88.0**	**92.0**	**89.7**	**90.0**	**90.0**	**-0.1%**

[1]Includes lease condensate.
[2]Strategic petroleum supply stock additions plus unaccounted for crude oil plus 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 plus other inputs plus refinery processing gain plus 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 byproduct of other processes.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, DC, May 1993). 1993: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) (Washington, DC, June 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A12. Petroleum Product Prices
(1993 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
World Oil Price (dollars per barrel)	**18.70**	**16.12**	**19.13**	**21.50**	**24.12**	**2.4%**
Delivered Sector Product Prices						
Residential						
Distillate Fuel	95.1	90.8	106.7	114.3	120.7	1.7%
Liquefied Petroleum Gas	91.0	89.8	103.3	109.8	117.2	1.6%
Commercial						
Distillate Fuel	67.8	64.0	76.6	83.9	90.1	2.0%
Residual Fuel	39.8	40.0	45.8	52.1	58.3	2.2%
Residual Fuel (dollars per barrel)	16.72	16.80	19.25	21.87	24.47	2.2%
Industrial[1]						
Distillate Fuel	69.2	66.3	76.6	84.1	90.5	1.8%
Liquefied Petroleum Gas	43.5	41.9	62.0	68.3	75.0	3.5%
Residual Fuel	36.0	35.1	43.9	50.0	56.1	2.8%
Residual Fuel (dollars per barrel)	15.11	14.74	18.45	20.99	23.58	2.8%
Transportation						
Distillate Fuel[2]	114.0	111.6	123.3	127.8	131.6	1.0%
Jet Fuel[3]	62.5	57.8	78.2	87.3	92.5	2.8%
Motor Gasoline[4]	116.7	111.7	129.5	135.9	137.7	1.2%
Residual Fuel	33.6	31.0	41.4	47.4	53.8	3.3%
Residual Fuel (dollars per barrel)	14.11	13.00	17.37	19.90	22.59	3.3%
Electric Generators[5]						
Distillate Fuel	66.5	65.5	73.0	76.8	81.9	1.3%
Residual Fuel	37.7	36.9	43.4	49.5	55.4	2.4%
Residual Fuel (dollars per barrel)	15.82	15.49	18.24	20.77	23.26	2.4%
Refined Petroleum Product Prices[6]						
Distillate Fuel	99.8	97.4	110.5	116.4	121.2	1.3%
Jet Fuel	62.5	57.8	78.2	87.3	92.5	2.8%
Liquefied Petroleum Gas	52.6	51.2	70.1	76.8	84.1	3.0%
Motor Gasoline	116.7	111.7	129.2	135.7	137.5	1.2%
Residual Fuel	35.9	34.4	42.7	48.8	54.9	2.8%
Residual Fuel (dollars per barrel)	15.08	14.47	17.94	20.48	23.06	2.8%
Average	**92.9**	**89.4**	**104.2**	**109.6**	**113.0**	**1.4%**

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]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 byproduct of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1992 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, DC, July 1993). 1993 prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). 1992 and 1993 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). **Projections**: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Production						
Dry Gas Production[1]	17.84	18.35	19.08	19.94	20.88	0.8%
Supplemental Natural Gas[2]	0.12	0.13	0.12	0.12	0.08	-3.0%
Net Imports	**1.93**	**2.13**	**2.90**	**3.00**	**3.60**	**3.1%**
Canada	2.03	2.14	2.65	2.69	2.71	1.4%
Mexico	-0.09	-0.04	-0.01	0.00	0.17	N/A
Liquefied Natural Gas	-0.01	0.03	0.25	0.30	0.71	21.5%
Total Supply	**19.88**	**20.61**	**22.09**	**23.06**	**24.55**	**1.0%**
Consumption by Sector						
Residential	4.68	4.96	5.01	4.89	4.89	-0.1%
Commercial	2.78	2.89	2.95	2.94	2.97	0.2%
Industrial[3]	7.41	7.61	8.68	9.01	9.50	1.3%
Electric Generators[4]	2.95	2.94	3.34	3.92	4.72	2.8%
Lease and Plant Fuel[5]	1.17	1.20	1.33	1.38	1.44	1.1%
Pipeline Fuel	0.59	0.61	0.65	0.65	0.65	0.4%
Transportation[6]	0.00	0.01	0.15	0.29	0.42	26.3%
Total	**19.57**	**20.21**	**22.12**	**23.08**	**24.59**	**1.2%**
Discrepancy[7]	**0.31**	**0.40**	**-0.03**	**-0.02**	**-0.03**	**N/A**

[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 byproduct 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. 1992 and 1993 values reflect net storage injections plus 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.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1992 and 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.

Sources: 1992 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1992, Volume 1*, DOE/EIA-0131(92)/1 (Washington, DC, November 1993) with adjustments to end-use sector consumption levels based on Form EIA-867, "Annual Nonutility Power Producer Report." Other 1992 consumption: EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994) with adjustments to end-use sector consumption levels based on Form EIA-867, "Annual Nonutility Power Producers Report." 1993 supply values and consumption as lease, plant, and pipeline fuel: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. 1993 transportation sector consumption: EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. Other 1993 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy Modeling System run AEO95B.D1103942. **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A14. Natural Gas Prices, Margins, and Revenues
(1993 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Source Price						
Average Lower 48 Wellhead Price[1]	1.80	2.02	2.14	3.02	3.39	3.1%
Average Import Price	1.88	2.01	2.01	3.16	3.49	3.3%
Average[2]	**1.81**	**2.02**	**2.12**	**3.04**	**3.41**	**3.1%**
Delivered Prices						
Residential	6.05	6.19	6.06	6.92	7.13	0.8%
Commercial	5.01	5.18	5.08	5.97	6.22	1.1%
Industrial[3]	2.70	2.87	3.05	3.92	4.30	2.4%
Electric Generators[4]	2.45	2.63	2.65	3.45	3.82	2.2%
Transportation[5]	4.15	4.80	6.56	8.60	8.94	3.7%
Average[6]	**3.90**	**4.09**	**4.06**	**4.88**	**5.16**	**1.4%**
Transmission & Distribution Margins by Sector[7]						
Residential	4.25	4.17	3.94	3.89	3.72	-0.7%
Commercial	3.21	3.15	2.96	2.94	2.82	-0.7%
Industrial[3]	0.89	0.85	0.93	0.88	0.90	0.3%
Electric Generators[4]	0.65	0.61	0.53	0.41	0.41	-2.3%
Transportation[5]	2.35	2.78	4.44	5.56	5.53	4.1%
Average[6]	**2.10**	**2.07**	**1.94**	**1.85**	**1.75**	**-1.0%**
Transmission and Distribution Revenue (billion 1993 dollars)						
Residential	19.86	20.66	19.75	19.00	18.21	-0.7%
Commercial	8.92	9.12	8.74	8.64	8.36	-0.5%
Industrial[3]	6.61	6.48	8.07	7.96	8.51	1.6%
Electric Generators[4]	1.91	1.79	1.78	1.63	1.93	0.5%
Transportation[5]	0.00	0.02	0.69	1.59	2.30	31.5%
Total	**37.30**	**38.07**	**39.03**	**38.81**	**39.32**	**0.2%**

[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 byproduct of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average price and margin. 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, 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: 1992 residential delivered price, transportation delivered price, average lower 48 wellhead price, and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1992, Volume 1*, DOE/EIA-0131(92)/1 (Washington, DC, November 1993). 1993 residential delivered price, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). **Other 1992 values, other 1993 values, and projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Crude Oil						
Lower 48 Average Wellhead Price[1] (1993 dollars per barrel)	**17.91**	**15.36**	**18.47**	**20.58**	**22.92**	**2.4%**
Production (million barrels per day)[2]						
U.S. Total	**7.17**	**6.85**	**5.35**	**5.16**	**5.39**	**-1.4%**
Lower 48 Onshore	4.39	4.18	3.53	3.70	3.96	-0.3%
Conventional	3.71	3.55	2.86	2.91	3.01	-1.0%
Enhanced Oil Recovery	0.68	0.62	0.67	0.79	0.95	2.5%
Lower 48 Offshore	1.07	1.09	0.66	0.63	0.66	-2.9%
Alaska	1.71	1.58	1.16	0.83	0.77	-4.2%
U.S. End of Year Reserves (billion barrels)	**24.97**	**23.30**	**17.59**	**16.12**	**16.97**	**-1.8%**
Natural Gas						
Lower 48 Average Wellhead Price[1] (1993 dollars per thousand cubic feet)	**1.80**	**2.02**	**2.14**	**3.02**	**3.39**	**3.1%**
Production (trillion cubic feet)[3]						
U.S. Total	**17.84**	**18.35**	**19.08**	**19.94**	**20.88**	**0.8%**
Lower 48 Onshore	12.74	12.96	13.81	14.72	15.88	1.2%
Associated-Dissolved[4]	2.18	2.21	1.55	1.67	1.80	-1.2%
Non-Associated	10.55	10.75	12.26	13.04	14.08	1.6%
Conventional	8.51	8.68	9.70	10.28	11.05	1.4%
Unconventional	2.04	2.07	2.57	2.77	3.02	2.3%
Tight Sands	1.35	1.36	1.29	1.43	1.84	1.8%
Coal Bed Methane	0.54	0.55	1.13	1.18	1.01	3.6%
Devonian Shale	0.15	0.15	0.15	0.16	0.17	0.7%
Lower 48 Offshore	4.69	4.98	4.76	4.73	4.53	-0.6%
Associated-Dissolved[4]	0.58	0.61	0.37	0.36	0.39	-2.6%
Non-Associated	4.11	4.37	4.40	4.38	4.14	-0.3%
Alaska	0.41	0.41	0.50	0.49	0.47	0.9%
U.S. End of Year Reserves (trillion cubic feet)	**165.02**	**167.78**	**145.67**	**147.48**	**152.48**	**-0.6%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.12**	**0.13**	**0.12**	**0.12**	**0.08**	**-3.0%**
Lower 48 Wells Completed (thousands)	**23.08**	**23.06**	**28.07**	**44.53**	**57.75**	**5.5%**

[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.

Sources: 1992 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92)/1 (Washington, DC, May 1993). 1992 U.S. crude oil reserves, and U.S. natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, DC, October 1993). 1992 crude oil lower 48 average wellhead price: EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993). 1992 natural gas lower 48 average wellhead price, Alaska, total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, DC, November 1993). 1992 and 1993 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1993: Lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) (Washington, DC, June 1994). 1993 natural gas lower 48 average wellhead price, total natural gas production: *Natural Gas Monthly*, DOE/EIA-0130(94/06) (Washington, DC, June 1994). Other 1992 and 1993 values: EIA, Office of Integrated Analysis and Forecasting. Figures for 1992 and 1993 may differ from published data due to internal conversion factors within the AEO95 National Energy Modeling System. **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Production[1]						
East of the Mississippi	589	516	589	591	629	1.2%
West of the Mississippi	409	429	439	485	508	1.0%
Total	**998**	**945**	**1027**	**1076**	**1137**	**1.1%**
Net Imports						
Imports	4	7	13	14	15	4.3%
Exports	103	75	87	100	115	2.5%
Total	**-99**	**-67**	**-74**	**-86**	**-100**	**2.4%**
Total Supply[2]	**899**	**877**	**953**	**990**	**1037**	**1.0%**
Consumption by Sector						
Residential and Commercial	6	6	7	6	6	0.2%
Industrial[3]	74	75	86	93	97	1.6%
Coke Plants	32	31	29	25	22	-2.1%
Electric Generators[4]	780	814	832	868	913	0.7%
Total	**892**	**926**	**954**	**992**	**1039**	**0.7%**
Discrepancy and Stock Change[5]	**6**	**-49**	**0**	**-2**	**-1**	**N/A**
Average Minemouth Price (1993 dollars per short ton)	**21.57**	**19.85**	**20.34**	**21.55**	**22.77**	**0.8%**
Delivered Prices (1993 dollars per short ton)[6]						
Industrial	33.62	32.23	31.32	31.90	33.25	0.2%
Coke Plants	49.15	47.44	45.96	46.64	47.26	0.0%
Electric Generators	30.11	28.60	29.06	30.38	31.43	0.6%
Average[7]	**31.10**	**29.54**	**29.78**	**30.94**	**31.94**	**0.5%**
Average Price to All Users (1993 dollars per million Btu)	1.47	1.41	1.40	1.45	1.50	0.4%
Exports[8]	42.39	41.41	41.03	42.62	43.52	0.3%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Weighted average excludes residential and commercial prices; sectoral prices weighted by consumption tonnage.
[7]Weighted average excluded residential and commercial prices.
[8]Free-alongside-ship (f.a.s.) price at U.S. port-of-exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992 production and minemouth price: Energy Information Administration (EIA), *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993). 1992 imports, exports, consumption, and other prices: EIA, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994). 1993 production and minemouth price: EIA, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). 1993 imports, exports, consumption, and other prices: EIA, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A17. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Electric Utilities and Nonutilities[1] (excluding cogenerators)						
Capability (gigawatts)						
Conventional Hydropower	76.55	76.74	79.27	79.65	79.81	0.2%
Geothermal[2]	2.90	2.96	3.42	3.44	4.57	2.6%
Municipal Solid Waste	2.34	2.59	3.51	4.35	5.14	4.1%
Biomass/Other Waste[3]	1.38	1.50	1.75	1.95	2.73	3.6%
Solar	0.34	0.34	0.54	0.79	1.37	8.5%
Wind[4]	1.75	1.76	3.05	4.18	10.04	10.8%
Total	**85.25**	**85.89**	**91.55**	**94.34**	**103.65**	**1.1%**
Generation (billion kilowatthours)[1]						
Conventional Hydropower	248.77	275.73	303.10	305.22	306.30	0.6%
Geothermal[2]	16.68	17.32	20.55	20.45	28.21	2.9%
Municipal Solid Waste	17.17	17.75	23.58	29.75	35.71	4.2%
Biomass/Other Waste[3]	6.84	7.46	11.09	12.45	17.90	5.3%
Solar	0.75	0.90	1.50	2.52	4.90	10.5%
Wind[4]	2.92	3.05	6.33	9.37	25.22	13.2%
Total	**293.13**	**322.21**	**366.14**	**379.76**	**418.24**	**1.5%**
Consumption						
Conventional Hydropower	2.56	2.84	3.12	3.14	3.16	0.6%
Geothermal[2]	0.35	0.36	0.52	0.57	0.83	5.0%
Municipal Solid Waste	0.28	0.29	0.38	0.48	0.58	4.2%
Biomass/Other Waste[3]	0.09	0.09	0.13	0.14	0.19	4.1%
Solar	0.01	0.01	0.02	0.03	0.05	10.5%
Wind[4]	0.03	0.03	0.07	0.10	0.26	13.2%
Total	**3.32**	**3.63**	**4.24**	**4.46**	**5.06**	**2.0%**
Cogenerators[5]						
Capacity (gigawatts)						
Conventional Hydropower	0.81	0.97	1.29	1.29	1.29	1.7%
Municipal Solid Waste	0.31	0.31	0.51	0.51	0.51	3.0%
Biomass/Other Waste	5.49	5.60	5.62	5.66	5.71	0.1%
Total	**6.61**	**6.87**	**7.41**	**7.46**	**7.51**	**0.5%**
Generation (billion kilowatthours)						
Conventional Hydropower	3.16	3.24	4.48	4.48	4.48	1.9%
Municipal Solid Waste	1.46	1.54	1.89	1.89	1.89	1.2%
Biomass/Other Waste	30.20	30.70	31.71	31.97	32.24	0.3%
Total	**34.81**	**35.48**	**38.08**	**38.34**	**38.61**	**0.5%**
Consumption						
Conventional Hydropower	0.03	0.03	0.03	0.03	0.03	N/A
Municipal Solid Waste	0.02	0.03	0.03	0.03	0.03	1.2%
Biomass/Other Waste	0.64	0.64	0.72	0.78	0.82	1.5%
Total	**0.69**	**0.69**	**0.78**	**0.84**	**0.88**	**1.4%**
Non-electric						
Non-electric Renewable Energy Consumption						
Geothermal[6]	0.01	0.01	0.02	0.03	0.04	7.3%
Biofuels[7]	2.03	2.09	2.32	2.48	2.61	1.3%
Solar Thermal[8]	0.06	0.06	0.08	0.08	0.09	2.3%
Ethanol	0.08	0.07	0.13	0.19	0.23	7.8%
Total	**2.18**	**2.22**	**2.55**	**2.78**	**2.96**	**1.7%**

Table A17. Renewable Energy (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Total Renewable Energy Consumption[9]						
Conventional Hydropower	2.60	2.87	3.16	3.18	3.19	0.6%
Geothermal	0.36	0.37	0.54	0.60	0.86	5.0%
Municipal Solid Waste	0.30	0.31	0.41	0.52	0.61	4.0%
Biofuels/Other Waste	2.76	2.82	3.17	3.40	3.61	1.5%
Solar	0.07	0.07	0.09	0.11	0.14	4.2%
Wind	0.03	0.03	0.07	0.10	0.26	13.2%
Ethanol	0.08	0.07	0.13	0.19	0.23	7.8%
Total	**6.19**	**6.55**	**7.57**	**8.08**	**8.91**	**1.8%**

[1]Grid connected only.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Does not include projections for energy crops.
[4]Includes horizontal-axis wind turbines only.
[5]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification 49). In general, biomass and other waste facilities are cogenerators while the remaining renewables produce only electricity.
[6]Residential and commercial ground-source heat pumps.
[7]Residential and industrial wood and wood waste.
[8]Residential and commercial water heating.
[9]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 using the fossil fuel equivalent of 10,302 Btu per kilowatthour.
N/A = Not available.
Btu = British thermal unit.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 15, 1994. Additional retirements are also determined based on the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1992 and 1993 electric utility capacity: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." 1992 and 1993 nonutility and cogenerator capacity: Form EIA-867, "Annual Nonutility Power Producer Report." 1992 ethanol, 1992 generation, and 1993 generation: EIA, *Annual Energy Review*, DOE/EIA-0384(93) (Washington, DC, July 1994). 1992 nonutility consumption other than ethanol: EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 ethanol: EIA, *Petroleum Supply Annual*, 1993, DOE/EIA-0340(93/1) (Washington, DC, June 1994). 1993 nonutility consumption other than ethanol: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A18. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Residential						
Petroleum	24.9	25.3	22.6	21.3	20.4	-1.3%
Natural Gas	69.4	73.6	74.4	72.6	72.6	-0.1%
Coal	1.5	1.5	1.6	1.5	1.4	-0.3%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A
Total	**95.8**	**100.3**	**98.6**	**95.4**	**94.4**	**-0.4%**
Commercial						
Petroleum	16.1	16.1	13.8	13.4	13.1	-1.2%
Natural Gas	41.5	43.2	43.8	43.7	44.1	0.1%
Coal	2.2	2.2	2.2	2.2	2.2	0.1%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A
Total	**59.8**	**61.5**	**59.9**	**59.4**	**59.5**	**-0.2%**
Industrial[1]						
Petroleum	98.2	95.4	99.1	105.0	108.9	0.8%
Natural Gas[2]	123.9	127.8	144.6	150.1	158.2	1.3%
Coal	63.0	62.4	66.2	67.4	68.0	0.5%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A
Total	**285.1**	**285.6**	**309.9**	**322.5**	**335.1**	**0.9%**
Transportation						
Petroleum	422.8	427.4	480.8	511.1	531.4	1.3%
Natural Gas[3]	8.8	9.0	12.0	13.9	15.8	3.4%
Renewable/Other[4]	0.0	0.0	0.2	0.5	0.8	N/A
Total	**431.6**	**436.4**	**492.9**	**525.5**	**548.1**	**1.3%**
Electric Generators[5]						
Petroleum	20.7	22.9	19.9	27.0	28.8	1.4%
Natural Gas	42.9	41.7	49.2	57.7	69.4	3.0%
Steam Coal	411.9	427.1	440.5	461.6	485.5	0.8%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A
Total	**475.5**	**491.7**	**509.6**	**546.3**	**583.7**	**1.0%**
Total Energy Consumption						
Petroleum	582.8	587.1	636.2	677.8	702.7	1.1%
Natural Gas	286.5	295.2	324.0	338.0	360.1	1.2%
Coal	478.5	493.2	510.5	532.7	557.2	0.7%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A
Other[4]	0.0	0.0	0.2	0.5	0.8	N/A
Total	**1347.8**	**1375.5**	**1470.9**	**1549.0**	**1620.8**	**1.0%**

[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, liquid hydrogen, and lubricants.
[5]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, Table 6 and Table A1, DOE/EIA-0573(94) (Washington, DC, October 1994). 1992 consumption estimates based on: EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). Note that sectoral totals have been adjusted to reflect AEO95 National Energy Modeling System definitions. **Consumption projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A19. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	Reference Case 1992	1993	2000	2005	2010	Annual Growth 1993-2010 (percent)
GDP Implicit Price Deflator (index 1987=1.000)	**1.211**	**1.242**	**1.491**	**1.755**	**2.074**	**3.1%**
Real Gross Domestic Product	**4986**	**5136**	**6126**	**6852**	**7485**	**2.2%**
Real Consumption	3342	3453	4035	4399	4748	1.9%
Real Investment	733	820	1175	1385	1547	3.8%
Real Government Spending	945	939	1003	1077	1143	1.2%
Real Exports	578	598	938	1297	1625	6.1%
Real Imports	611	674	1025	1306	1578	5.1%
Real Disposable Personal Income	**3633**	**3701**	**4371**	**4764**	**5140**	**2.0%**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.077**	**1.097**	**1.306**	**1.469**	**1.598**	**2.2%**
AA Utility Bond Rate (percent)	8.55	7.43	8.41	8.24	7.99	N/A
90-Day U.S. Government Treasury Bill Rate (percent)	3.43	3.00	4.66	4.53	4.37	N/A
Real Yield on Government 10 Year Bonds (percent)	3.62	3.23	4.13	3.50	3.51	N/A
Real 90-Day U.S. Government Treasury Bill Rate (percent)	0.54	0.44	1.61	1.17	1.01	N/A
Real Utility Bond Rate (percent)	5.66	4.87	5.36	4.87	4.64	N/A
Energy Intensity (thousand Btu per 1987 dollar of GDP)	**17.17**	**16.99**	**15.44**	**14.50**	**13.88**	**-1.2%**
Consumer Price Index (1982=1.00)	1.40	1.45	1.81	2.19	2.64	3.6%
Employment Cost Index (1987=1.00)	1.12	1.15	1.44	1.75	2.14	3.7%
Unemployment Rate (percent)	7.55	7.42	6.28	6.00	6.47	N/A
Million Units						
Truck Deliveries, Light-Duty	4.50	5.20	6.35	7.17	7.05	1.8%
Unit Sales of Automobiles	8.38	8.71	9.59	9.92	10.17	0.9%
U.S. Trade-Weighted Exchange Rate	**0.97**	**1.00**	**0.95**	**0.90**	**0.87**	**N/A**
Millions of People						
Population with Armed Forces Overseas	255.8	258.4	275.6	287.1	298.9	0.9%
Population (aged 16 and over)	196.3	198.2	212.8	223.8	235.4	1.0%
Employment, Non-Agriculture	107.9	107.9	120.4	128.9	133.5	1.3%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not available.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992 and 1993: Data Resources Incorporated (DRI), DRI Trend0294. **Projections:** Energy Information Administration, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table A20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
World Oil Price (1993 dollars per barrel)[1]	**18.70**	**16.12**	**19.13**	**21.50**	**24.12**	**2.4%**
Production[2]						
U.S. (50 states)	9.71	9.53	8.24	8.20	8.58	-0.6%
Canada	2.08	2.10	2.17	2.42	2.34	0.6%
OECD Europe[3]	5.08	5.17	6.38	5.22	4.67	-0.6%
OPEC	26.21	27.02	36.01	42.68	46.67	3.3%
Rest of the World[4]	11.56	11.67	12.84	12.05	11.77	0.1%
Total Production	**54.65**	**55.48**	**65.65**	**70.58**	**74.03**	**1.7%**
Net Eurasian Exports	**1.26**	**1.33**	**1.24**	**1.42**	**1.60**	**1.1%**
Total Supply	**55.70**	**56.78**	**66.89**	**72.00**	**75.63**	**1.7%**
Consumption						
U.S. (50 states)	17.03	17.24	18.88	20.10	20.89	1.1%
U.S. Territories	0.21	0.22	0.26	0.29	0.30	1.9%
Canada	1.64	1.69	1.94	2.02	2.08	1.2%
Japan	5.35	5.45	7.02	7.67	8.05	2.3%
Australia & New Zealand	0.82	0.84	0.96	1.03	1.10	1.6%
OECD Europe	13.59	13.48	15.87	16.64	16.97	1.4%
Rest of the World[4]	17.36	18.16	22.27	24.56	26.55	2.3%
Total Consumption	**56.00**	**57.08**	**67.19**	**72.30**	**75.93**	**1.7%**
Discrepancy	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**N/A**
Consumption Aggregations						
OECD	38.64	38.92	44.92	47.75	49.38	1.4%
OPEC	4.91	5.05	5.89	6.51	7.18	2.1%
Rest of the World[4]	12.45	13.11	16.38	18.05	19.37	2.3%
Non-OPEC Production[4]	**28.44**	**28.47**	**29.63**	**27.90**	**27.36**	**-0.2%**
OPEC Summary						
Market Share	0.47	0.47	0.54	0.59	0.61	1.5%
Production Capacity[5]	28.90	31.30	38.40	44.10	47.75	2.5%
Capacity Utilization	0.91	0.86	0.94	0.97	0.98	0.7%

[1]The average cost to domestic refiners of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
[4]Does not include Eurasia.
[5]Maximum sustainable production capacity.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1992 and 1993: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	14.50	11.15	11.33	11.49	10.61	10.92	11.22	11.07	11.42	11.79
Natural Gas Plant Liquids	2.41	2.49	2.57	2.66	2.56	2.69	2.79	2.68	2.81	2.95
Dry Natural Gas	18.90	19.07	19.65	20.32	19.59	20.53	21.32	20.49	21.51	22.57
Coal	20.23	21.79	22.08	22.28	22.85	23.21	23.49	23.93	24.51	25.30
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[1]	7.06	7.83	7.92	8.02	8.25	8.43	8.69	8.79	9.25	9.68
Total	**69.62**	**69.29**	**70.51**	**71.74**	**70.83**	**72.75**	**74.48**	**73.32**	**75.86**	**78.66**
Imports										
Crude Oil[2]	14.79	19.05	19.14	19.06	20.01	19.72	19.42	19.84	19.53	19.15
Petroleum Products[3]	3.79	4.83	5.18	5.66	6.13	7.10	8.27	6.61	8.12	9.82
Natural Gas	2.32	3.17	3.17	3.17	3.31	3.33	3.45	3.55	3.97	4.22
Other Imports[4]	0.50	0.70	0.71	0.73	0.65	0.73	0.95	0.78	1.00	1.12
Total	**21.40**	**27.74**	**28.20**	**28.61**	**30.10**	**30.87**	**32.08**	**30.79**	**32.62**	**34.31**
Exports										
Petroleum[5]	2.11	2.02	1.97	1.87	1.80	1.68	1.60	1.73	1.64	1.56
Natural Gas	0.15	0.21	0.21	0.21	0.27	0.27	0.27	0.31	0.31	0.31
Coal	1.96	2.22	2.22	2.22	2.54	2.54	2.54	2.94	2.89	2.82
Total	**4.21**	**4.45**	**4.40**	**4.31**	**4.61**	**4.49**	**4.42**	**4.98**	**4.83**	**4.69**
Discrepancy[6]	**0.46**	**0.26**	**0.31**	**0.33**	**0.20**	**0.24**	**0.26**	**0.24**	**0.22**	**0.21**
Consumption										
Petroleum Products[7]	33.71	36.10	36.89	37.65	38.05	39.30	40.69	39.03	40.82	42.74
Natural Gas	20.81	22.18	22.78	23.45	22.80	23.76	24.67	23.86	25.30	26.60
Coal	19.43	19.86	20.14	20.36	20.63	21.01	21.30	21.36	21.97	22.83
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[8]	6.80	7.73	7.83	7.94	8.06	8.32	8.78	8.75	9.41	9.95
Total	**87.27**	**92.83**	**94.61**	**96.36**	**96.52**	**99.37**	**102.41**	**99.36**	**103.88**	**108.48**
Net Imports - Petroleum	**16.47**	**21.86**	**22.36**	**22.84**	**24.34**	**25.13**	**26.08**	**24.73**	**26.02**	**27.41**
Prices (1993 dollars per unit)										
World Oil Price (dollars per barrel)[9]	16.12	18.70	19.13	19.52	21.05	21.50	22.06	23.29	24.12	24.99
Gas Wellhead Price (dollars per thousand cubic feet)[10]	2.02	1.98	2.14	2.36	2.68	3.02	3.30	3.01	3.39	3.74
Coal Minemouth Price (dollars per ton)	19.85	20.51	20.34	20.71	21.36	21.55	22.41	22.25	22.77	24.13

[1]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[2]Includes imports of crude oil for the Strategic Petroleum Reserve.
[3]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[4]Includes coal, coal coke (net), and electricity (net).
[5]Includes crude oil and petroleum products.
[6]Balancing item. Includes unaccounted for supply, losses, and gains.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[8]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, net coal coke imports, net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors.
Sources: 1993 natural gas prices: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 coal minemouth price: EIA, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Other 1993 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B2. Energy Consumption by End-Use Sector and Source
(Quadrillion Btu per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Distillate Fuel	0.88	0.78	0.79	0.80	0.73	0.75	0.77	0.71	0.73	0.75
Kerosene	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.06
Liquefied Petroleum Gas	0.39	0.34	0.34	0.34	0.31	0.31	0.32	0.28	0.29	0.29
Natural Gas	5.11	5.10	5.17	5.22	4.97	5.04	5.13	4.91	5.04	5.18
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Renewable Energy[1]	0.72	0.72	0.72	0.74	0.72	0.73	0.75	0.72	0.74	0.77
Electricity	3.39	3.55	3.61	3.68	3.62	3.73	3.85	3.77	3.94	4.12
Total	**10.61**	**10.61**	**10.75**	**10.89**	**10.46**	**10.69**	**10.92**	**10.49**	**10.85**	**11.22**
Commercial										
Distillate Fuel	0.42	0.39	0.39	0.39	0.36	0.37	0.38	0.34	0.35	0.36
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Motor Gasoline[2]	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Residual Fuel	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Natural Gas	2.98	3.02	3.04	3.06	2.99	3.04	3.09	2.99	3.06	3.15
Other[3]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Renewable Energy[4]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Electricity	2.96	3.18	3.22	3.26	3.25	3.34	3.42	3.36	3.50	3.64
Total	**6.77**	**7.01**	**7.08**	**7.14**	**7.03**	**7.17**	**7.31**	**7.12**	**7.34**	**7.58**
Industrial[5]										
Distillate Fuel	1.12	1.20	1.24	1.28	1.27	1.33	1.40	1.30	1.39	1.49
Liquefied Petroleum Gas	1.82	2.00	2.04	2.09	2.16	2.24	2.32	2.27	2.40	2.54
Motor Gasoline[2]	0.19	0.21	0.21	0.22	0.22	0.23	0.24	0.22	0.24	0.26
Petrochemical Feedstocks	1.17	1.28	1.31	1.33	1.38	1.42	1.47	1.44	1.52	1.60
Residual Fuel	0.38	0.46	0.49	0.51	0.51	0.54	0.57	0.51	0.56	0.60
Other Petroleum[6]	3.78	3.78	3.86	3.91	3.92	3.98	4.06	3.95	4.07	4.17
Natural Gas[7]	9.09	10.18	10.32	10.48	10.43	10.71	11.04	10.84	11.28	11.82
Metallurgical Coal	0.84	0.77	0.77	0.75	0.68	0.67	0.66	0.59	0.59	0.58
Steam Coal	1.66	1.83	1.87	1.91	1.94	2.01	2.08	2.01	2.11	2.22
Net Coal Coke Imports	0.02	0.01	0.02	0.03	0.02	0.03	0.04	0.03	0.04	0.05
Renewable Energy	2.12	2.37	2.45	2.52	2.55	2.67	2.78	2.67	2.84	3.03
Electricity	3.35	3.56	3.68	3.80	3.84	4.01	4.19	3.97	4.24	4.53
Total	**25.55**	**27.64**	**28.25**	**28.83**	**28.90**	**29.83**	**30.85**	**29.82**	**31.28**	**32.89**
Transportation										
Distillate Fuel	3.86	4.47	4.59	4.70	4.84	5.02	5.19	5.13	5.43	5.70
Jet Fuel[8]	3.04	3.64	3.74	3.83	3.96	4.13	4.30	4.16	4.46	4.74
Motor Gasoline[2]	13.88	14.77	14.97	15.16	15.14	15.44	15.73	15.01	15.51	15.92
Residual Fuel	1.10	1.29	1.32	1.34	1.46	1.51	1.56	1.58	1.67	1.74
Liquefied Petroleum Gas	0.02	0.08	0.08	0.08	0.16	0.16	0.16	0.25	0.24	0.24
Other Petroleum[9]	0.20	0.22	0.23	0.23	0.23	0.24	0.25	0.23	0.25	0.26
Pipeline Fuel Natural Gas	0.63	0.66	0.67	0.69	0.65	0.67	0.69	0.65	0.67	0.69
Compressed Natural Gas	0.01	0.16	0.16	0.16	0.30	0.29	0.29	0.43	0.43	0.42
Renewables (ethanol)[10]	0.00	0.01	0.01	0.01	0.03	0.03	0.03	0.06	0.06	0.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Methanol[11]	0.00	0.01	0.01	0.01	0.03	0.03	0.03	0.05	0.05	0.05
Electricity	0.06	0.09	0.09	0.09	0.13	0.13	0.13	0.17	0.18	0.18
Total	**22.79**	**25.40**	**25.86**	**26.31**	**26.93**	**27.66**	**28.37**	**27.73**	**28.94**	**30.03**
Electric Generators[12]										
Distillate Fuel	0.01	0.00	0.01	0.01	0.01	0.01	0.05	0.04	0.05	0.08
Residual Fuel	1.07	0.82	0.93	1.05	1.04	1.26	1.58	1.24	1.31	1.60
Natural Gas	3.00	3.07	3.42	3.84	3.46	4.01	4.43	4.04	4.82	5.34
Steam Coal	16.78	17.11	17.36	17.56	17.87	18.19	18.41	18.62	19.13	19.89
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[13]	3.92	4.59	4.60	4.61	4.68	4.80	5.11	5.19	5.65	5.96
Total	**31.30**	**32.56**	**33.27**	**34.02**	**34.03**	**35.23**	**36.55**	**35.49**	**37.32**	**39.25**

Table B2. Energy Consumption by End-Use Sector and Source (Continued)
(Quadrillion Btu per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Primary Energy Consumption										
Distillate Fuel	6.29	6.84	7.02	7.18	7.21	7.49	7.78	7.51	7.95	8.39
Kerosene	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.08
Jet Fuel[8]	3.04	3.64	3.74	3.83	3.96	4.13	4.30	4.16	4.46	4.74
Liquefied Petroleum Gas	2.29	2.48	2.53	2.58	2.69	2.77	2.85	2.86	2.99	3.13
Motor Gasoline[2]	14.14	15.05	15.25	15.45	15.43	15.75	16.04	15.31	15.83	16.26
Petrochemical Feedstocks	1.17	1.28	1.31	1.33	1.38	1.42	1.47	1.44	1.52	1.60
Residual Fuel	2.72	2.74	2.90	3.06	3.17	3.47	3.87	3.50	3.70	4.11
Other Petroleum[14]	3.98	3.99	4.07	4.13	4.14	4.21	4.30	4.17	4.31	4.43
Natural Gas	20.81	22.18	22.78	23.45	22.80	23.76	24.67	23.86	25.30	26.60
Metallurgical Coal	0.84	0.77	0.77	0.75	0.68	0.67	0.66	0.59	0.59	0.58
Steam Coal	18.59	19.09	19.37	19.61	19.95	20.34	20.64	20.77	21.38	22.25
Net Coal Coke Imports	0.02	0.01	0.02	0.03	0.02	0.03	0.04	0.03	0.04	0.05
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[15]	6.78	7.72	7.81	7.92	8.04	8.29	8.74	8.72	9.37	9.90
Total	**87.26**	**92.83**	**94.61**	**96.36**	**96.52**	**99.37**	**102.41**	**99.36**	**103.88**	**108.48**
Electricity Consumption (all sectors)	**9.77**	**10.38**	**10.60**	**10.83**	**10.84**	**11.21**	**11.60**	**11.27**	**11.86**	**12.47**

[1]Includes electricity generated by the sector for self-use from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, and non-electric energy from renewable sources, such as solar thermal water heaters, groundwater heat pumps, and wood.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes liquefied petroleum gas and coal.
[4]Includes commercial sector electricity cogenerated using wood and wood waste, municipal solid waste, and other biomass; non-electric energy from renewable sources, such as active solar and passive solar systems, geothermal heat pumps, and solar water heating systems.
[5]Fuel consumption includes consumption for cogeneration.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes lease and plant fuel.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]Only E85 (85 percent ethanol).
[11]Only M85 (85 percent methanol).
[12]Includes consumption of energy by all electric power generators except cogenerators and generators with standard industrial classification other than 49, both of which produce electricity as a byproduct of other processes.
[13]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports.
[14]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to electric utilities and for self use from renewable sources, non-electric energy from renewable sources, electricity generated from waste heat, net electricity imports, liquid hydrogen, and methanol.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.
Sources: 1993 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 transportation sector compressed natural gas consumption: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. 1993 coal consumption is estimated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 metallurgical consumption is estimated from this source using unpublished data. 1993 residential and commercial coal consumption tonnages are from EIA, *Quarterly Coal Report, October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994) and have been converted to quadrillion Btu using *State Energy Data Report 1992* thermal conversion factors. Other 1993 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B3. Energy Prices by End-Use Sector and Source
(1993 Dollars per Million Btu)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**12.48**	**12.43**	**12.72**	**12.97**	**13.13**	**13.73**	**14.16**	**13.74**	**14.53**	**15.23**
Primary Energy	6.32	6.25	6.41	6.65	6.80	7.18	7.43	7.02	7.42	7.78
Petroleum Products	7.72	8.81	8.97	9.07	9.30	9.54	9.82	9.76	10.06	10.34
Distillate Fuel	6.55	7.51	7.70	7.81	7.95	8.24	8.59	8.36	8.71	9.03
Liquefied Petroleum Gas	10.40	11.84	11.96	12.04	12.57	12.72	12.84	13.31	13.58	13.75
Natural Gas	6.00	5.71	5.88	6.15	6.31	6.71	6.97	6.50	6.92	7.30
Electricity	24.30	23.50	23.93	24.12	23.85	24.66	25.21	24.44	25.67	26.67
Commercial	**12.25**	**12.25**	**12.53**	**12.78**	**12.90**	**13.49**	**13.98**	**13.38**	**14.25**	**14.98**
Primary Energy	4.93	4.84	5.00	5.24	5.43	5.79	6.05	5.69	6.07	6.43
Petroleum Products	4.96	5.60	5.76	5.88	6.09	6.32	6.63	6.55	6.84	7.18
Distillate Fuel	4.61	5.34	5.52	5.64	5.76	6.05	6.38	6.15	6.49	6.80
Residual Fuel	2.67	2.98	3.06	3.14	3.38	3.48	3.58	3.76	3.89	4.04
Natural Gas[1]	5.02	4.76	4.93	5.20	5.40	5.79	6.04	5.63	6.03	6.40
Electricity	21.63	21.08	21.47	21.66	21.50	22.25	22.92	21.90	23.15	24.16
Industrial[2]	**5.02**	**5.11**	**5.28**	**5.44**	**5.66**	**5.95**	**6.24**	**6.00**	**6.42**	**6.80**
Primary Energy	3.32	3.54	3.67	3.81	4.09	4.32	4.56	4.46	4.77	5.06
Petroleum Products	4.34	4.87	4.99	5.09	5.39	5.57	5.83	5.89	6.19	6.48
Distillate Fuel	4.78	5.34	5.52	5.64	5.77	6.06	6.39	6.19	6.53	6.84
Liquefied Petroleum Gas	4.85	7.06	7.18	7.28	7.81	7.91	8.07	8.42	8.69	8.91
Residual Fuel	2.35	2.85	2.93	3.01	3.25	3.34	3.44	3.62	3.75	3.90
Natural Gas[3]	2.79	2.79	2.96	3.16	3.47	3.80	4.09	3.78	4.17	4.52
Metallurgical Coal	1.77	1.72	1.71	1.75	1.74	1.74	1.78	1.75	1.76	1.83
Steam Coal	1.45	1.46	1.45	1.45	1.48	1.48	1.51	1.52	1.53	1.59
Electricity	14.53	14.10	14.34	14.46	14.30	14.78	15.21	14.42	15.22	15.89
Transportation	**7.76**	**8.71**	**9.06**	**9.33**	**9.02**	**9.52**	**10.15**	**9.11**	**9.70**	**10.49**
Primary Energy	7.74	8.69	9.04	9.31	8.99	9.49	10.13	9.07	9.66	10.46
Petroleum Products	7.74	8.71	9.06	9.32	9.00	9.51	10.15	9.09	9.68	10.48
Distillate Fuel[4]	8.05	8.57	8.89	9.08	8.71	9.22	9.64	8.88	9.49	9.92
Jet Fuel[5]	4.28	5.58	5.80	5.98	6.10	6.46	6.81	6.41	6.85	7.35
Motor Gasoline[6]	8.93	10.10	10.54	10.88	10.44	11.07	11.95	10.48	11.21	12.37
Residual Fuel	2.07	2.69	2.76	2.83	3.08	3.17	3.27	3.46	3.59	3.75
Natural Gas[7]	4.65	6.19	6.36	6.62	7.95	8.34	8.59	8.26	8.67	9.03
Electricity	14.85	15.14	15.34	15.27	15.20	15.55	15.57	15.25	15.73	15.92
Total End-Use Energy	**8.05**	**8.36**	**8.61**	**8.83**	**8.80**	**9.24**	**9.68**	**9.09**	**9.64**	**10.24**
Primary Energy	7.68	8.06	8.32	8.53	8.47	8.90	9.37	8.70	9.25	9.85
Electricity	20.08	19.46	19.78	19.92	19.66	20.30	20.81	20.01	21.04	21.87
Electric Generators[8]										
Fossil Fuel Average	1.61	1.61	1.65	1.72	1.79	1.88	2.02	1.91	2.05	2.22
Petroleum Products	2.48	2.85	2.91	2.99	3.24	3.33	3.50	3.63	3.78	4.00
Distillate Fuel	4.72	5.20	5.27	5.35	5.51	5.53	5.91	5.57	5.91	6.28
Residual Fuel	2.46	2.83	2.90	2.97	3.22	3.30	3.42	3.57	3.70	3.88
Natural Gas	2.57	2.44	2.59	2.79	3.15	3.38	3.63	3.43	3.73	4.05
Steam Coal	1.39	1.40	1.39	1.41	1.44	1.45	1.50	1.47	1.50	1.58

Table B3. Energy Prices by End-Use Sector and Source (Continued)
(1993 Dollars per Million Btu)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[9]										
Petroleum Products	6.73	7.64	7.91	8.10	7.98	8.35	8.82	8.16	8.65	9.24
Distillate Fuel[4]	7.02	7.70	7.97	8.13	7.97	8.39	8.77	8.23	8.74	9.12
Jet Fuel	4.28	5.58	5.80	5.98	6.10	6.46	6.81	6.41	6.85	7.35
Liquefied Petroleum Gas	5.94	8.02	8.13	8.21	8.80	8.90	9.04	9.49	9.74	9.92
Motor Gasoline[6]	8.93	10.08	10.52	10.85	10.43	11.05	11.93	10.47	11.20	12.35
Residual Fuel	2.30	2.78	2.85	2.93	3.17	3.26	3.37	3.54	3.67	3.83
Natural Gas	3.97	3.80	3.94	4.14	4.44	4.74	4.98	4.67	5.01	5.33
Coal	1.41	1.41	1.40	1.42	1.44	1.45	1.50	1.47	1.50	1.58
Electricity	20.08	19.46	19.78	19.92	19.66	20.30	20.81	20.01	21.04	21.87

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]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.
[8]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[9]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: Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.
Sources: 1993 prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). 1993 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). 1993 residential natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1993 natural gas delivered prices: EIA, AEO National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. Values for 1993 coal prices have been estimated from EIA, *State Price and Expenditure Report 1992*, DOE/EIA-0376(92) (Washington, DC, December 1994) using consumption quantities aggregated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 electricity prices for commercial, industrial, and transportation: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.
Projections: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Household Characteristics										
Households (millions)										
Single-Family	66.39	70.38	71.78	73.21	72.71	75.21	77.76	74.82	78.56	82.35
Multifamily	24.19	24.05	24.69	25.29	24.45	25.57	26.63	24.99	26.62	28.18
Mobile Homes	5.24	5.29	5.42	5.55	5.24	5.46	5.68	5.19	5.51	5.82
Total	**95.82**	**99.73**	**101.89**	**104.05**	**102.39**	**106.25**	**110.08**	**105.00**	**110.69**	**116.35**
Housing Starts (millions)										
Single-Family	1.13	0.82	1.04	1.25	0.82	1.06	1.31	0.78	1.06	1.33
Multifamily	0.16	0.28	0.39	0.48	0.33	0.43	0.54	0.38	0.50	0.61
Mobile Homes	0.26	0.19	0.22	0.24	0.20	0.22	0.25	0.19	0.23	0.26
Total	**1.55**	**1.29**	**1.64**	**1.97**	**1.34**	**1.72**	**2.10**	**1.35**	**1.78**	**2.20**
Energy Intensity (million Btu per year per household)										
Heating	61.60	57.36	56.75	56.09	53.95	52.64	51.59	51.46	50.02	48.76
Total	**110.72**	**106.35**	**105.55**	**104.70**	**102.18**	**100.57**	**99.22**	**99.90**	**98.06**	**96.41**
Fuel Consumption										
Distillate										
Space Heating	0.80	0.71	0.72	0.72	0.66	0.68	0.69	0.64	0.66	0.68
Water Heating	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.88**	**0.78**	**0.79**	**0.80**	**0.73**	**0.75**	**0.77**	**0.71**	**0.73**	**0.75**
Liquefied Petroleum Gas										
Space Heating	0.26	0.22	0.22	0.22	0.19	0.19	0.20	0.17	0.17	0.18
Water Heating	0.08	0.07	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Cooking[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.39**	**0.34**	**0.34**	**0.34**	**0.31**	**0.31**	**0.32**	**0.28**	**0.29**	**0.29**
Natural Gas										
Space Heating	3.68	3.63	3.67	3.70	3.51	3.53	3.57	3.43	3.50	3.58
Space Cooling	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Water Heating	1.11	1.15	1.17	1.18	1.15	1.19	1.22	1.17	1.22	1.27
Cooking[2]	0.18	0.18	0.18	0.19	0.16	0.17	0.17	0.15	0.16	0.16
Clothes Dryers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[3]	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08
Total	**5.11**	**5.10**	**5.17**	**5.22**	**4.97**	**5.04**	**5.13**	**4.91**	**5.04**	**5.18**
Electricity										
Space Heating	0.37	0.39	0.40	0.41	0.40	0.41	0.43	0.41	0.43	0.45
Space Cooling	0.53	0.53	0.54	0.55	0.53	0.55	0.57	0.55	0.58	0.60
Water Heating	0.36	0.37	0.38	0.38	0.37	0.38	0.39	0.37	0.38	0.40
Refrigeration	0.53	0.45	0.46	0.47	0.40	0.41	0.42	0.37	0.39	0.40
Cooking	0.16	0.17	0.17	0.17	0.17	0.17	0.18	0.17	0.18	0.19
Clothes Dryers	0.19	0.19	0.20	0.20	0.20	0.20	0.21	0.20	0.21	0.22
Freezers	0.14	0.11	0.11	0.11	0.09	0.09	0.09	0.07	0.07	0.08
Lighting	0.32	0.34	0.35	0.36	0.35	0.36	0.37	0.35	0.37	0.39
Other Uses[4]	0.79	0.99	1.01	1.03	1.12	1.16	1.20	1.27	1.34	1.41
Total	**3.39**	**3.55**	**3.61**	**3.68**	**3.62**	**3.73**	**3.85**	**3.77**	**3.94**	**4.12**

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Renewables										
Wood[5]	0.66	0.64	0.65	0.66	0.63	0.65	0.66	0.63	0.65	0.66
Geothermal[6]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Solar[7]	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total	**0.72**	**0.72**	**0.72**	**0.74**	**0.72**	**0.73**	**0.75**	**0.72**	**0.74**	**0.77**
Other Fuels[8]	**0.12**	**0.12**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Fuels										
Space Heating	5.90	5.72	5.78	5.84	5.52	5.59	5.68	5.40	5.54	5.67
Space Cooling	0.53	0.54	0.55	0.57	0.55	0.57	0.59	0.57	0.60	0.63
Water Heating	1.67	1.72	1.74	1.77	1.72	1.77	1.81	1.74	1.80	1.87
Cooking	0.38	0.39	0.40	0.40	0.37	0.38	0.39	0.36	0.37	0.39
Clothes Dryers	0.27	0.27	0.28	0.28	0.27	0.28	0.29	0.28	0.29	0.30
Other Uses	1.85	1.97	2.00	2.04	2.03	2.10	2.17	2.14	2.25	2.36
Total	**10.61**	**10.61**	**10.75**	**10.89**	**10.46**	**10.69**	**10.92**	**10.49**	**10.85**	**11.22**

[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.
[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: 1990 (RECS).*
[6]Includes primary energy displaced by ground-source (geothermal) heat pumps in space heating and cooling applications.
[7]Includes primary energy displaced by solar thermal water heaters.
[8]Includes kerosene and coal.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: Energy Information Administration (EIA), *Short-Term Energy Outlook,* DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Economic Growth Case Comparisons

Table B5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	65.6	70.2	71.0	71.7	72.2	73.9	75.5	74.1	76.8	79.6
New Additions	1.5	1.2	1.4	1.6	1.3	1.5	1.7	1.4	1.6	1.8
Total	**67.0**	**71.4**	**72.4**	**73.3**	**73.5**	**75.3**	**77.2**	**75.4**	**78.4**	**81.4**
Energy Consumption Intensity (Thousand Btu per square feet)	**101.1**	**98.1**	**97.8**	**97.4**	**95.7**	**95.1**	**94.7**	**94.4**	**93.7**	**93.1**
End-Use Consumption										
Electricity										
Space Heating	0.09	0.08	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.07
Space Cooling	0.29	0.29	0.29	0.29	0.28	0.29	0.29	0.28	0.29	0.30
Water Heating	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
Ventilation	0.30	0.31	0.32	0.32	0.31	0.32	0.33	0.32	0.33	0.35
Cooking	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.07	0.07
Lighting	1.06	1.02	1.03	1.04	1.00	1.02	1.05	1.00	1.03	1.07
Refrigeration	0.19	0.19	0.20	0.20	0.19	0.20	0.20	0.19	0.20	0.21
Office Equipment (PC)	0.20	0.25	0.25	0.25	0.28	0.29	0.30	0.32	0.33	0.35
Office Equipment (non-PC)	0.21	0.26	0.26	0.26	0.29	0.29	0.30	0.32	0.33	0.35
Other Uses[1]	0.53	0.69	0.70	0.71	0.72	0.74	0.76	0.76	0.79	0.82
Total Electricity	**2.96**	**3.18**	**3.22**	**3.26**	**3.25**	**3.34**	**3.42**	**3.36**	**3.50**	**3.64**
Natural Gas[2]										
Space Heating	1.33	1.37	1.38	1.39	1.35	1.37	1.39	1.35	1.38	1.41
Space Cooling	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.35	0.36	0.36	0.36	0.35	0.35	0.36	0.34	0.36	0.37
Cooking	0.21	0.23	0.23	0.23	0.22	0.23	0.23	0.23	0.23	0.24
Other Uses[3]	1.08	1.05	1.06	1.06	1.05	1.07	1.08	1.05	1.08	1.10
Total Natural Gas	**2.98**	**3.02**	**3.04**	**3.06**	**2.99**	**3.04**	**3.09**	**2.99**	**3.06**	**3.15**
Distillate										
Space Heating	0.31	0.29	0.29	0.29	0.27	0.27	0.27	0.24	0.25	0.25
Water Heating	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[4]	0.08	0.07	0.08	0.08	0.07	0.08	0.08	0.07	0.08	0.09
Total Distillate	**0.42**	**0.39**	**0.39**	**0.39**	**0.36**	**0.37**	**0.38**	**0.34**	**0.35**	**0.36**
Other Fuels[5]	**0.40**	**0.39**	**0.39**	**0.39**	**0.39**	**0.39**	**0.39**	**0.40**	**0.40**	**0.40**
Renewable Fuels										
Solar	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Renewable Fuels	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Total Consumption	**6.77**	**7.01**	**7.08**	**7.14**	**7.03**	**7.17**	**7.31**	**7.12**	**7.34**	**7.58**

[1]Includes miscellaneous commercial uses such as service station equipment and medical equipment.
[2]Excludes estimated consumption from independent power producer.
[3]Includes miscellaneous commercial uses such as lighting and emergency generators.
[4]Includes miscellaneous commercial uses such as cooking and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 natural gas total fuel consumption: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994) and EIA, AEO National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. Other 1993 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	2559	2943	3048	3150	3271	3427	3601	3479	3728	4003
Nonmanufacturing	889	986	1046	1101	1054	1132	1213	1090	1198	1311
Total	**3448**	**3930**	**4094**	**4251**	**4325**	**4560**	**4814**	**4569**	**4926**	**5315**
Energy Prices (1993 dollars per million Btu)										
Electricity	14.53	14.10	14.34	14.46	14.30	14.78	15.21	14.42	15.22	15.89
Natural Gas	2.79	2.79	2.96	3.16	3.47	3.80	4.09	3.78	4.17	4.52
Steam Coal	1.45	1.46	1.45	1.45	1.48	1.48	1.51	1.52	1.53	1.59
Residual Oil	2.35	2.85	2.93	3.01	3.25	3.34	3.44	3.62	3.75	3.90
Distillate Oil	4.78	5.34	5.52	5.64	5.77	6.06	6.39	6.19	6.53	6.84
Liquefied Petroleum Gas	4.85	7.06	7.18	7.28	7.81	7.91	8.07	8.42	8.69	8.91
Motor Gasoline	8.90	9.01	9.33	9.62	9.61	10.06	10.87	9.84	10.36	11.42
Metallurgical Coal	1.77	1.72	1.71	1.75	1.74	1.74	1.78	1.75	1.76	1.83
Energy Consumption										
Consumption[1] (quadrillion Btu per year)										
Purchased Electricity	3.35	3.56	3.68	3.80	3.84	4.01	4.19	3.97	4.24	4.53
Natural Gas[2]	9.09	10.18	10.32	10.48	10.43	10.71	11.04	10.84	11.28	11.82
Steam Coal	1.66	1.83	1.87	1.91	1.94	2.01	2.08	2.01	2.11	2.22
Metallurgical Coal and Coke[3]	0.86	0.78	0.79	0.78	0.70	0.71	0.70	0.62	0.63	0.63
Residual Fuel	0.38	0.46	0.49	0.51	0.51	0.54	0.57	0.51	0.56	0.60
Distillate	1.12	1.20	1.24	1.28	1.27	1.33	1.40	1.30	1.39	1.49
Liquefied Petroleum Gas	1.82	2.00	2.04	2.09	2.16	2.24	2.32	2.27	2.40	2.54
Petrochemical Feedstocks	1.17	1.28	1.31	1.33	1.38	1.42	1.47	1.44	1.52	1.60
Other Petroleum[4]	3.97	3.98	4.07	4.13	4.14	4.21	4.30	4.17	4.31	4.43
Renewables[5]	2.12	2.37	2.45	2.52	2.55	2.67	2.78	2.67	2.84	3.03
Total	**25.55**	**27.64**	**28.25**	**28.83**	**28.90**	**29.83**	**30.85**	**29.81**	**31.28**	**32.89**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)										
Purchased Electricity	0.97	0.91	0.90	0.89	0.89	0.88	0.87	0.87	0.86	0.85
Natural Gas[2]	2.64	2.59	2.52	2.47	2.41	2.35	2.29	2.37	2.29	2.22
Steam Coal	0.48	0.46	0.46	0.45	0.45	0.44	0.43	0.44	0.43	0.42
Metallurgical Coal and Coke[3]	0.25	0.20	0.19	0.18	0.16	0.15	0.15	0.14	0.13	0.12
Residual Fuel	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.11
Distillate	0.33	0.31	0.30	0.30	0.29	0.29	0.29	0.28	0.28	0.28
Liquefied Petroleum Gas	0.53	0.51	0.50	0.49	0.50	0.49	0.48	0.50	0.49	0.48
Petrochemical Feedstocks	0.34	0.33	0.32	0.31	0.32	0.31	0.31	0.32	0.31	0.30
Other Petroleum[4]	1.15	1.01	0.99	0.97	0.96	0.92	0.89	0.91	0.87	0.83
Renewables[5]	0.62	0.60	0.60	0.59	0.59	0.58	0.58	0.58	0.58	0.57
Total	**7.41**	**7.03**	**6.90**	**6.78**	**6.68**	**6.54**	**6.41**	**6.53**	**6.35**	**6.19**

[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, still gas, motor gasoline, and miscellaneous petroleum products.
[5]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). Coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(94/08) (Washington, DC, August 1994). Natural gas and electricity prices: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. Other prices derived from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994. Other values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Economic Growth Case Comparisons

Table B7. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	1993	Projections 2000 Low Economic Growth	2000 Reference	2000 High Economic Growth	2005 Low Economic Growth	2005 Reference	2005 High Economic Growth	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Key Indicators										
Level of Travel Index (1990 = 1.0)										
Light-Duty Vehicles	1.06	1.19	1.20	1.21	1.29	1.32	1.34	1.38	1.42	1.45
Freight Trucks	1.12	1.27	1.33	1.38	1.38	1.46	1.54	1.44	1.56	1.68
Air	1.05	1.50	1.55	1.59	1.72	1.80	1.88	1.87	2.02	2.17
Rail	1.06	1.11	1.14	1.17	1.18	1.23	1.27	1.24	1.31	1.38
Marine	0.98	1.01	1.04	1.07	1.07	1.11	1.15	1.11	1.18	1.24
Energy Efficiency Indicators										
New Car MPG[1]	27.81	28.81	28.88	28.97	29.70	29.96	30.30	32.36	32.83	33.60
New Light Truck MPG[1]	20.34	21.48	21.52	21.57	22.63	22.74	22.88	23.69	23.80	24.02
Light-Duty Fleet MPG[2]	19.30	20.28	20.33	20.37	20.86	20.96	21.08	21.65	21.82	22.07
Aircraft Efficiency Index	1.02	1.07	1.07	1.07	1.10	1.11	1.11	1.14	1.14	1.15
Freight Truck Efficiency Index	1.01	1.05	1.06	1.06	1.06	1.08	1.09	1.08	1.09	1.11
Rail Efficiency Index	1.01	1.04	1.04	1.04	1.06	1.06	1.06	1.07	1.07	1.07
Domestic Shipping Efficiency Index	1.00	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.01	1.01
Energy Use by Mode (quadrillion Btu per year)										
Light-Duty Vehicles[3]	13.09	14.14	14.31	14.47	14.81	15.09	15.34	15.04	15.50	15.87
Freight Trucks[3]	4.97	5.88	6.06	6.23	6.26	6.51	6.74	6.48	6.88	7.24
Air	3.09	3.68	3.77	3.87	4.00	4.17	4.34	4.21	4.50	4.79
Rail	0.59	0.60	0.61	0.63	0.63	0.65	0.67	0.64	0.68	0.71
Marine	1.63	1.87	1.90	1.93	2.07	2.13	2.19	2.22	2.32	2.42
Pipeline Fuel	0.63	0.66	0.67	0.69	0.65	0.67	0.69	0.65	0.67	0.69
Other[4]	0.16	0.17	0.18	0.19	0.19	0.19	0.20	0.19	0.21	0.22
Total[5]	**22.79**	**25.40**	**25.86**	**26.31**	**26.93**	**27.66**	**28.37**	**27.73**	**28.94**	**30.03**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes light-duty trucks used for freight.
[4]Includes lubricants and aviation gasoline.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Btu = British thermal unit.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1993 values: FAA, *FAA Aviation Forecasts Fiscal Years 1993-2004*, (Washington, DC, February 1993); and EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Generation by Fuel Type										
Electric Utilities										
Coal	1639	1667	1689	1705	1735	1761	1777	1799	1825	1868
Petroleum	100	70	80	91	91	111	143	111	118	148
Natural Gas	259	275	301	341	308	342	366	342	387	420
Nuclear Power	610	652	652	652	653	653	653	596	596	596
Pumped Storage	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
Renewable Sources[1]	277	303	303	303	306	306	306	316	317	317
Total	**2883**	**2964**	**3022**	**3089**	**3090**	**3171**	**3244**	**3162**	**3241**	**3347**
Nonutilities (excluding cogenerators)[2]										
Coal	5	9	9	10	9	12	16	19	44	77
Petroleum	1	0	0	0	0	0	0	0	0	0
Natural Gas	21	26	36	34	35	53	66	54	90	110
Renewable Sources[1]	45	63	64	64	70	73	81	85	101	115
Total	**73**	**98**	**109**	**108**	**115**	**139**	**163**	**158**	**236**	**303**
Cogenerators[3]										
Coal	49	55	55	56	57	58	59	59	60	62
Petroleum	10	38	38	38	40	41	42	43	44	46
Natural Gas	151	175	177	178	192	196	200	209	216	225
Renewable	35	38	38	38	38	38	38	38	39	39
Other[4]	3	4	4	4	5	5	5	5	5	5
Total	**248**	**310**	**313**	**314**	**332**	**338**	**344**	**354**	**365**	**376**
Sales to Utilities	111	137	138	139	145	148	151	154	159	164
Generation for Own Use	137	173	175	176	187	190	193	200	206	212
Net Imports	**28**	**35**	**35**	**36**	**26**	**33**	**53**	**36**	**56**	**67**
Electricity Sales by Sector										
Residential	994	1039	1058	1078	1060	1094	1128	1104	1156	1208
Commercial	868	933	945	957	954	979	1003	984	1026	1066
Industrial	983	1045	1079	1113	1126	1174	1229	1165	1242	1328
Transportation	18	25	25	26	38	38	38	51	52	52
Total	**2862**	**3042**	**3108**	**3173**	**3177**	**3285**	**3399**	**3304**	**3475**	**3654**
End-Use Prices (1993 cents per kilowatthour)[5]										
Residential	8.3	8.0	8.2	8.2	8.1	8.4	8.6	8.3	8.8	9.1
Commercial	7.4	7.2	7.3	7.4	7.3	7.6	7.8	7.5	7.9	8.2
Industrial	5.0	4.8	4.9	4.9	4.9	5.0	5.2	4.9	5.2	5.4
Transportation	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.2	5.4	5.4
All Sectors Average	**6.8**	**6.6**	**6.7**	**6.8**	**6.7**	**6.9**	**7.1**	**6.8**	**7.2**	**7.5**
Price Components (1993 cents per kilowatthour)										
Capital Component	2.8	2.5	2.6	2.6	2.4	2.5	2.6	2.4	2.5	2.6
Fuel Component	1.2	1.1	1.2	1.2	1.3	1.4	1.4	1.4	1.4	1.5
Operation and Maintenance Component	2.7	2.8	2.7	2.7	2.8	2.8	2.7	2.8	2.7	2.7
Wholesale Power Cost	0.1	0.2	0.2	0.2	0.2	0.3	0.4	0.3	0.5	0.6
Total	**6.8**	**6.6**	**6.7**	**6.8**	**6.7**	**6.9**	**7.1**	**6.8**	**7.2**	**7.5**

[1]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[2]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).
[3]Includes generation and cogeneration at facilities whose primary function is not electricity production (standard industrial classification 49). Includes sales to utilities and generation for own use.
[4]Other includes methane and propane and blast furnace gas.
[5]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: Energy Information Administration (EIA), *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **1993 electricity prices for commercial, industrial, and transportation, price components, and projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Utilities										
Capability										
Coal Steam	300.7	297.1	297.1	297.1	300.7	301.1	301.3	304.0	306.4	311.9
Other Fossil Steam[2]	141.3	130.4	130.4	130.4	124.3	124.3	124.3	120.4	120.4	120.4
Combined Cycle	9.7	17.3	17.7	18.4	22.9	23.4	24.4	25.8	27.2	29.1
Combustion Turbine/Diesel	49.2	66.0	65.9	66.7	70.6	71.0	73.4	73.4	77.8	84.2
Nuclear Power	99.0	101.3	101.3	101.3	101.3	101.3	101.3	88.7	88.7	88.7
Pumped Storage	19.1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Renewable Sources[3]	76.8	78.1	78.1	78.1	78.7	78.9	79.0	81.8	81.6	81.8
Total	**695.7**	**710.2**	**710.5**	**712.0**	**718.7**	**720.0**	**723.7**	**714.1**	**722.1**	**736.2**
Cumulative Planned Additions[4]										
Coal Steam	0.00	5.63	5.63	5.63	11.98	11.98	11.98	13.74	13.74	13.74
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.61	7.22	7.22	7.22	11.79	11.79	11.79	12.38	12.38	12.38
Combustion Turbine/Diesel	0.14	16.20	16.20	16.20	22.41	22.41	22.41	22.77	22.77	22.77
Nuclear Power	1.15	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
Pumped Storage	0.30	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Renewable Sources[3]	0.20	1.14	1.14	1.14	1.15	1.15	1.15	1.15	1.15	1.15
Total	**2.40**	**34.97**	**34.97**	**34.97**	**52.11**	**52.11**	**52.11**	**54.82**	**54.82**	**54.82**
Cumulative Unplanned Additions[4]										
Coal Steam	0.00	0.00	0.02	0.01	0.01	0.34	0.54	4.32	6.68	12.24
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.00	1.03	1.42	2.16	2.08	2.56	3.59	4.39	5.79	7.65
Combustion Turbine/Diesel	0.00	0.91	0.74	1.58	0.91	1.23	3.64	3.70	8.05	14.49
Nuclear Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable Sources[3]	0.00	0.14	0.13	0.14	0.39	0.52	0.64	3.27	3.07	3.34
Total	**0.00**	**2.08**	**2.32**	**3.89**	**3.39**	**4.66**	**8.41**	**15.67**	**23.59**	**37.72**
Cumulative Total Additions	**2.40**	**37.06**	**37.29**	**38.86**	**55.50**	**56.77**	**60.52**	**70.50**	**78.41**	**92.54**
Cumulative Retirements[5]	**8.71**	**29.26**	**29.26**	**29.26**	**39.86**	**39.86**	**39.86**	**59.57**	**59.57**	**59.57**
Nonutilities (excludes cogenerators)[6,7]										
Capability										
Coal Steam	0.62	1.81	1.82	1.82	1.81	2.10	2.67	3.11	7.11	12.45
Other Fossil Steam[2]	0.21	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Combined Cycle	2.03	4.19	5.29	4.93	4.90	7.00	8.11	6.30	10.48	12.38
Combustion Turbine/Diesel	1.33	2.35	2.80	3.64	2.47	3.97	7.36	7.66	13.72	21.12
Nuclear Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable Sources[3]	9.11	13.41	13.45	13.51	14.42	15.47	17.98	17.94	22.07	26.59
Total	**13.30**	**22.01**	**23.61**	**24.16**	**23.84**	**28.79**	**36.36**	**35.26**	**53.62**	**72.78**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Cogenerators[7,8]										
Capacity										
Coal	6.90	7.99	8.03	8.06	8.25	8.37	8.48	8.52	8.72	8.93
Petroleum	3.36	5.94	5.96	5.98	6.29	6.37	6.45	6.66	6.81	6.97
Natural Gas	21.06	23.86	24.12	24.30	26.12	26.74	27.33	28.48	29.52	30.72
Renewables	6.92	7.41	7.41	7.42	7.44	7.46	7.48	7.48	7.51	7.53
Other	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**38.25**	**45.23**	**45.54**	**45.78**	**48.14**	**48.96**	**49.77**	**51.16**	**52.59**	**54.18**
Cumulative Additions[4,7]	**7.80**	**23.49**	**25.40**	**26.18**	**28.23**	**34.00**	**42.38**	**42.67**	**62.46**	**83.21**

[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 oil-, gas-, and dual-fired capability.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[4]Cumulative additions after December 31, 1992. Non-zero utility planned additions in 1992 indicate units operational in 1992, but not supplying power to the grid.
[5]Cumulative total retirements from 1990.
[6]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).
[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 capacity based on historic relationships.
[8]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification 49).

Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data as of August 15, 1994. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1993: Net summer capacity at electric utilities, and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capacity for nonutilities and cogeneration and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report."
Projections: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1993	Projections 2000 Low Economic Growth	2000 Reference	2000 High Economic Growth	2005 Low Economic Growth	2005 Reference	2005 High Economic Growth	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	153.4	133.4	133.4	133.4	124.8	124.8	124.8	124.8	124.8	124.8
Gross Domestic Economy Sales	58.5	77.2	75.0	67.2	64.9	59.7	52.1	53.9	49.5	49.5
Gross Domestic Trade	**211.9**	**210.5**	**208.4**	**200.5**	**189.7**	**184.5**	**176.9**	**178.8**	**174.3**	**174.3**
Gross Domestic Firm Power Sales (million 1993 dollars)	7022.3	6897.0	6897.0	6897.0	7038.7	7038.7	7038.7	7676.5	7676.5	7676.5
Gross Domestic Economy Sales (million 1993 dollars)	1194.2	1702.7	1710.7	1644.9	1731.2	1670.3	1598.7	1525.5	1556.7	1680.0
Gross Domestic Sales (million 1993 dollars)	**8216.5**	**8599.8**	**8607.8**	**8542.0**	**8769.9**	**8709.1**	**8637.4**	**9202.0**	**9233.2**	**9356.5**
International Electricity Trade										
Firm Power Imports From Canada and Mexico	14.9	20.9	20.9	22.2	15.1	21.8	41.8	22.2	42.5	52.9
Economy Imports From Canada and Mexico	24.1	28.2	28.2	28.2	30.9	30.9	30.9	34.8	34.8	34.8
Gross Imports From Canada and Mexico	**39.1**	**49.1**	**49.1**	**50.4**	**46.0**	**52.7**	**72.7**	**56.9**	**77.3**	**87.7**
Firm Power Exports To Canada and Mexico	2.5	8.1	8.1	8.1	13.1	13.1	13.1	13.1	13.1	13.1
Economy Exports To Canada and Mexico	8.2	6.4	6.4	6.4	7.0	7.0	7.0	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**10.7**	**14.5**	**14.5**	**14.5**	**20.1**	**20.1**	**20.1**	**20.8**	**20.8**	**20.8**

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: 1993: Interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. International electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1993 firm/economy share: National Energy Board, *Annual Report 1993*. 2000 planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1994. Projections: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Crude Oil										
Domestic Crude Production[1]	6.85	5.27	5.35	5.43	5.01	5.16	5.30	5.23	5.39	5.57
Alaska	1.58	1.15	1.16	1.17	0.83	0.83	0.84	0.76	0.77	0.78
Lower 48 States	5.26	4.11	4.19	4.26	4.19	4.33	4.46	4.47	4.62	4.79
Net Imports	6.69	8.66	8.70	8.66	9.10	8.97	8.83	9.02	8.88	8.70
Other Crude Supply[2]	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**13.61**	**13.92**	**14.05**	**14.09**	**14.11**	**14.13**	**14.13**	**14.25**	**14.27**	**14.27**
Natural Gas Plant Liquids	**1.74**	**1.80**	**1.85**	**1.91**	**1.85**	**1.93**	**2.01**	**1.93**	**2.03**	**2.13**
Other Inputs[3]	**0.19**	**0.23**	**0.23**	**0.24**	**0.23**	**0.23**	**0.23**	**0.23**	**0.23**	**0.23**
Refinery Processing Gain[4]	**0.77**	**0.80**	**0.80**	**0.80**	**0.81**	**0.81**	**0.80**	**0.83**	**0.83**	**0.83**
Net Product Imports[5]	**0.93**	**1.56**	**1.76**	**2.03**	**2.30**	**2.82**	**3.43**	**2.57**	**3.34**	**4.20**
Total Primary Supply[6]	**17.24**	**18.31**	**18.69**	**19.07**	**19.29**	**19.92**	**20.60**	**19.81**	**20.71**	**21.66**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.48	7.99	8.10	8.21	8.20	8.36	8.52	8.14	8.41	8.64
Jet Fuel[8]	1.47	1.76	1.81	1.85	1.91	1.99	2.08	2.01	2.15	2.29
Distillate Fuel[9]	3.04	3.26	3.34	3.42	3.43	3.56	3.70	3.57	3.78	3.98
Residual Fuel	1.08	1.19	1.27	1.33	1.38	1.51	1.69	1.53	1.61	1.79
Other[10]	4.17	4.28	4.37	4.44	4.55	4.66	4.79	4.73	4.92	5.12
Total	**17.24**	**18.48**	**18.87**	**19.25**	**19.47**	**20.09**	**20.78**	**19.97**	**20.88**	**21.83**
Refined Petroleum Products Supplied										
Residential and Commercial	1.14	1.00	1.00	1.01	0.94	0.95	0.96	0.89	0.92	0.93
Industrial[11]	4.60	4.69	4.81	4.91	4.98	5.14	5.31	5.13	5.39	5.65
Transportation	11.08	12.44	12.66	12.87	13.10	13.45	13.80	13.39	13.98	14.50
Electric Generators[12]	0.41	0.36	0.41	0.46	0.46	0.55	0.71	0.56	0.59	0.74
Total	**17.24**	**18.48**	**18.87**	**19.25**	**19.47**	**20.10**	**20.78**	**19.97**	**20.88**	**21.83**
Discrepancy[13]	**0.00**	**-0.18**	**-0.18**	**-0.18**	**-0.18**	**-0.17**	**-0.18**	**-0.16**	**-0.17**	**-0.17**
World Oil Price (1993 dollars per barrel)[14]	**16.12**	**18.70**	**19.13**	**19.52**	**21.05**	**21.50**	**22.06**	**23.29**	**24.12**	**24.99**
Domestic Refinery Distillation Capacity	**15.3**	**15.7**	**15.7**	**15.7**	**15.8**	**15.8**	**15.8**	**15.9**	**15.9**	**15.9**
Capacity Utilization Rate (percent)	**92.0**	**88.9**	**89.7**	**90.0**	**89.9**	**90.0**	**90.0**	**89.9**	**90.0**	**90.0**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil plus 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 production plus other inputs plus refinery processing gain plus 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 byproduct of other processes.
[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: 1993: Energy Information Administration (EIA), *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) (Washington, DC, June 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B12. Petroleum Product Prices
(1993 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (dollars per barrel)	16.12	18.70	19.13	19.52	21.05	21.50	22.06	23.29	24.12	24.99
Delivered Sector Product Prices										
Residential										
Distillate Fuel	90.8	104.2	106.7	108.4	110.2	114.3	119.2	115.9	120.7	125.2
Liquefied Petroleum Gas	89.8	102.2	103.3	103.9	108.5	109.8	110.9	114.9	117.2	118.7
Commercial										
Distillate Fuel	64.0	74.1	76.6	78.2	79.9	83.9	88.5	85.3	90.1	94.4
Residual Fuel	40.0	44.6	45.8	47.0	50.7	52.1	53.6	56.4	58.3	60.5
Residual Fuel (dollars per barrel)	16.80	18.75	19.25	19.74	21.28	21.87	22.51	23.67	24.47	25.39
Industrial[1]										
Distillate Fuel	66.3	74.1	76.6	78.2	80.1	84.1	88.7	85.8	90.5	94.8
Liquefied Petroleum Gas	41.9	61.0	62.0	62.8	67.4	68.3	69.7	72.6	75.0	76.9
Residual Fuel	35.1	42.7	43.9	45.0	48.7	50.0	51.5	54.2	56.1	58.3
Residual Fuel (dollars per barrel)	14.74	17.94	18.45	18.89	20.44	20.99	21.63	22.78	23.58	24.50
Transportation										
Distillate Fuel[2]	111.6	118.8	123.3	125.9	120.9	127.8	133.7	123.2	131.6	137.6
Jet Fuel[3]	57.8	75.3	78.2	80.7	82.4	87.3	91.9	86.6	92.5	99.3
Motor Gasoline[4]	111.7	124.1	129.5	133.6	128.3	135.9	146.8	128.8	137.7	152.0
Residual Fuel	31.0	40.2	41.4	42.4	46.2	47.4	49.0	51.8	53.8	56.1
Residual Fuel (dollars per barrel)	13.00	16.90	17.37	17.81	19.39	19.90	20.57	21.76	22.59	23.56
Electric Generators[5]										
Distillate Fuel	65.5	72.1	73.0	74.2	76.4	76.8	81.9	77.3	81.9	87.1
Residual Fuel	36.9	42.4	43.4	44.5	48.2	49.5	51.2	53.4	55.4	58.1
Residual Fuel (dollars per barrel)	15.49	17.82	18.24	18.70	20.25	20.77	21.52	22.42	23.26	24.41
Refined Petroleum Product Prices[6]										
Distillate Fuel	97.4	106.8	110.5	112.8	110.5	116.4	121.7	114.1	121.2	126.5
Jet Fuel	57.8	75.3	78.2	80.7	82.4	87.3	91.9	86.6	92.5	99.3
Liquefied Petroleum Gas	51.2	69.2	70.1	70.8	75.9	76.8	78.0	81.9	84.1	85.7
Motor Gasoline	111.7	123.8	129.2	133.3	128.1	135.7	146.5	128.6	137.5	151.7
Residual Fuel	34.4	41.6	42.7	43.8	47.5	48.8	50.5	52.9	54.9	57.4
Residual Fuel (dollars per barrel)	14.47	17.46	17.94	18.40	19.94	20.48	21.20	22.23	23.06	24.10
Average	**89.4**	**100.6**	**104.2**	**106.8**	**104.6**	**109.6**	**116.0**	**106.5**	**113.0**	**120.9**

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]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 byproduct of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1993: Prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). Prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). **Projections**: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Dry Gas Production[1]	18.35	18.51	19.08	19.73	19.02	19.94	20.70	19.89	20.88	21.91
Supplemental Natural Gas[2]	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.07	0.08	0.09
Net Imports	**2.13**	**2.90**	**2.90**	**2.90**	**2.98**	**3.00**	**3.12**	**3.19**	**3.60**	**3.84**
Canada	2.14	2.65	2.65	2.65	2.69	2.69	2.69	2.71	2.71	2.71
Mexico	-0.04	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.17	0.17	0.17
Liquefied Natural Gas	0.03	0.25	0.25	0.25	0.29	0.30	0.42	0.30	0.71	0.96
Total Supply	**20.61**	**21.53**	**22.09**	**22.75**	**22.12**	**23.06**	**23.94**	**23.15**	**24.55**	**25.84**
Consumption by Sector										
Residential	4.96	4.95	5.01	5.06	4.83	4.89	4.97	4.76	4.89	5.02
Commercial	2.89	2.93	2.95	2.97	2.90	2.94	2.99	2.90	2.97	3.05
Industrial[3]	7.61	8.58	8.68	8.80	8.79	9.01	9.28	9.13	9.50	9.96
Electric Generators[4]	2.94	3.00	3.34	3.75	3.39	3.92	4.33	3.95	4.72	5.22
Lease and Plant Fuel[5]	1.20	1.30	1.33	1.37	1.33	1.38	1.42	1.39	1.44	1.51
Pipeline Fuel	0.61	0.64	0.65	0.67	0.63	0.65	0.67	0.63	0.65	0.67
Transportation[6]	0.01	0.16	0.15	0.15	0.29	0.29	0.28	0.42	0.42	0.41
Total	**20.21**	**21.54**	**22.12**	**22.78**	**22.15**	**23.08**	**23.96**	**23.18**	**24.59**	**25.85**
Discrepancy[7]	**0.40**	**-0.01**	**-0.03**	**-0.03**	**-0.03**	**-0.02**	**-0.02**	**-0.03**	**-0.03**	**-0.01**

[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 byproduct 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. 1993 values reflect net storage injections plus 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.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.

Sources: 1993 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 transportation sector consumption: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. Other 1993 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy System Modeling runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941. **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B14. Natural Gas Prices, Margins, and Revenue
(1993 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Source Price										
Average Lower 48 Wellhead Price[1]	2.02	1.98	2.14	2.36	2.68	3.02	3.30	3.01	3.39	3.74
Average Import Price	2.01	1.84	2.01	2.39	2.73	3.16	3.36	3.04	3.49	3.86
Average[2]	**2.02**	**1.96**	**2.12**	**2.36**	**2.68**	**3.04**	**3.31**	**3.01**	**3.41**	**3.76**
Delivered Prices										
Residential	6.19	5.89	6.06	6.34	6.51	6.92	7.19	6.70	7.13	7.52
Commercial	5.18	4.91	5.08	5.36	5.57	5.97	6.23	5.80	6.22	6.60
Industrial[3]	2.87	2.88	3.05	3.26	3.57	3.92	4.22	3.90	4.30	4.66
Electric Generators[4]	2.63	2.50	2.65	2.85	3.22	3.45	3.71	3.51	3.82	4.14
Transportation[5]	4.80	6.38	6.56	6.83	8.20	8.60	8.85	8.52	8.94	9.31
Average[6]	**4.09**	**3.91**	**4.06**	**4.27**	**4.57**	**4.88**	**5.13**	**4.81**	**5.16**	**5.49**
Transmission and Distribution Margins by Sector[7]										
Residential	4.17	3.93	3.94	3.97	3.82	3.89	3.88	3.69	3.72	3.76
Commercial	3.15	2.96	2.96	2.99	2.88	2.94	2.93	2.79	2.82	2.84
Industrial[3]	0.85	0.92	0.93	0.90	0.89	0.88	0.91	0.89	0.90	0.90
Electric Generators[4]	0.61	0.54	0.53	0.48	0.54	0.41	0.40	0.50	0.41	0.38
Transportation[5]	2.78	4.43	4.44	4.46	5.52	5.56	5.55	5.51	5.53	5.54
Average	**2.07**	**1.96**	**1.94**	**1.90**	**1.89**	**1.85**	**1.83**	**1.80**	**1.75**	**1.73**
Transmission and Distribution Revenue (billion 1993 dollars)										
Residential	20.66	19.45	19.75	20.13	18.44	19.00	19.29	17.59	18.21	18.88
Commercial	9.12	8.65	8.74	8.89	8.37	8.64	8.76	8.08	8.36	8.65
Industrial[3]	6.48	7.93	8.07	7.89	7.81	7.96	8.48	8.12	8.51	8.95
Electric Generators[4]	1.79	1.63	1.78	1.82	1.83	1.63	1.73	1.96	1.93	1.99
Transportation[5]	0.02	0.69	0.69	0.69	1.58	1.59	1.57	2.31	2.30	2.28
Total	**38.07**	**38.34**	**39.03**	**39.41**	**38.02**	**38.81**	**39.83**	**38.07**	**39.32**	**40.76**

[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 electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average price and margin. 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, and other services. As used here, the term includes the cost of all of these services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1993: Residential delivered price, average lower 48 wellhead price, and average import price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). **Other values, and projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B15. Oil and Gas Supply

Production and Supply	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (1993 dollars per barrel)	15.36	18.07	18.47	18.84	20.17	20.58	21.09	22.17	22.92	23.69
Production (million barrels per day)[2]										
U.S. Total	6.85	5.27	5.35	5.43	5.01	5.16	5.30	5.23	5.39	5.57
Lower 48 Onshore	4.18	3.47	3.53	3.58	3.59	3.70	3.80	3.84	3.96	4.09
Conventional	3.55	2.82	2.86	2.91	2.83	2.91	2.99	2.92	3.01	3.09
Enhanced Oil Recovery	0.62	0.65	0.67	0.68	0.77	0.79	0.81	0.92	0.95	1.00
Lower 48 Offshore	1.09	0.64	0.66	0.68	0.60	0.63	0.66	0.63	0.66	0.70
Alaska	1.58	1.15	1.16	1.17	0.83	0.83	0.84	0.76	0.77	0.78
U.S. End of Year Reserves (billion barrels)	23.30	17.34	17.59	17.84	15.77	16.12	16.44	16.55	16.97	17.44
Natural Gas										
Lower 48 Average Wellhead Price[1] (1993 dollars per thousand cubic feet)	2.02	1.98	2.14	2.36	2.68	3.02	3.30	3.01	3.39	3.74
Production (trillion cubic feet)[3]										
U.S. Total	18.35	18.51	19.08	19.73	19.02	19.94	20.70	19.89	20.88	21.91
Lower 48 Onshore	12.96	13.45	13.81	14.26	13.99	14.72	15.32	15.05	15.88	16.81
Associated-Dissolved[4]	2.21	1.51	1.55	1.59	1.60	1.67	1.75	1.72	1.80	1.88
Non-Associated	10.75	11.95	12.26	12.66	12.39	13.04	13.58	13.32	14.08	14.93
Conventional	8.68	9.44	9.70	10.00	9.72	10.28	10.71	10.45	11.05	11.69
Unconventional	2.07	2.50	2.57	2.66	2.67	2.77	2.87	2.87	3.02	3.24
Tight Sands	1.36	1.25	1.29	1.34	1.33	1.43	1.55	1.66	1.84	2.03
Coal Bed Methane	0.55	1.11	1.13	1.16	1.19	1.18	1.15	1.05	1.01	1.03
Devonian Shale	0.15	0.14	0.15	0.16	0.15	0.16	0.16	0.16	0.17	0.18
Lower 48 Offshore	4.98	4.56	4.76	4.97	4.54	4.73	4.89	4.38	4.53	4.62
Associated-Dissolved[4]	0.61	0.35	0.37	0.38	0.33	0.36	0.38	0.36	0.39	0.41
Non-Associated	4.37	4.21	4.40	4.59	4.21	4.38	4.50	4.01	4.14	4.21
Alaska	0.41	0.50	0.50	0.50	0.49	0.49	0.49	0.47	0.47	0.47
U.S. End of Year Reserves (trillion cubic feet)	167.78	143.94	145.67	147.98	142.00	147.48	152.56	145.12	152.48	157.16
Supplemental Gas Supplies (trillion cubic feet)[5]	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.07	0.08	0.09
Lower 48 Wells Completed (thousands)	23.06	26.39	28.07	30.34	41.30	44.53	47.30	53.03	57.75	61.50

[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.
Sources: 1993 total wells completed: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(94/06) (Washington, DC, June 1994). 1993 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0384(93) (Washington, DC, June 1994). 1993 natural gas lower 48 average wellhead price, and total natural gas production: *Natural Gas Monthly*, DOE/EIA-0130(94/06) (Washington, DC, June 1994). Other 1993 values: EIA, Office of Integrated Analysis and Forecasting. Figures for 1993 may differ from published data due to internal conversion factors within the AEO95 National Energy Modeling System.
Projections: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
East of the Mississippi	516	579	589	588	586	591	597	611	629	644
West of the Mississippi	429	436	439	448	475	485	493	499	508	528
Total	**945**	**1016**	**1027**	**1036**	**1061**	**1076**	**1089**	**1110**	**1137**	**1173**
Net Imports										
Imports	7	13	13	13	14	14	14	15	15	15
Exports	75	87	87	88	100	100	101	117	115	112
Total	**-67**	**-74**	**-74**	**-74**	**-85**	**-86**	**-86**	**-102**	**-100**	**-97**
Total Supply[2]	**877**	**942**	**953**	**961**	**976**	**990**	**1003**	**1008**	**1037**	**1076**
Consumption by Sector										
Residential and Commercial	6	7	7	7	6	6	6	6	6	6
Industrial[3]	75	85	86	89	90	93	96	92	97	102
Coke Plants	31	29	29	28	25	25	25	22	22	22
Electric Generators[4]	814	822	832	839	854	868	877	890	913	948
Total	**926**	**943**	**954**	**962**	**976**	**992**	**1004**	**1010**	**1039**	**1078**
Discrepancy and Stock Change[5]	**-49**	**-1**	**0**	**-1**	**0**	**-2**	**-1**	**-3**	**-1**	**-1**
Average Minemouth Price (1993 dollars per short ton)	**19.85**	**20.51**	**20.34**	**20.71**	**21.36**	**21.55**	**22.41**	**22.25**	**22.77**	**24.13**
Delivered Prices (1993 dollars per short ton)[6]										
Industrial	32.23	31.18	31.32	31.22	31.59	31.90	32.59	33.15	33.25	34.63
Coke Plants	47.44	46.20	45.96	46.85	46.68	46.64	47.83	46.82	47.26	49.00
Electric Generators	28.60	29.17	29.06	29.52	30.05	30.38	31.42	30.68	31.43	33.09
Average[7]	**29.54**	**29.88**	**29.78**	**30.19**	**30.63**	**30.94**	**31.94**	**31.26**	**31.94**	**33.56**
Average Price to All Users (1993 dollars per million Btu)	1.41	1.41	1.40	1.42	1.44	1.45	1.50	1.47	1.50	1.58
Exports[8]	41.41	41.73	41.03	41.64	42.96	42.62	43.22	43.26	43.52	44.78

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports plus net storage withdrawals.
[3]*Includes consumption by cogenerators.*
[4]Includes all electric power generators except cogenerators, which produces electricity as a byproduct of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Weighted average excludes residential and commercial prices; sectoral prices weighted by consumption tonnage.
[7]Weighted average excluded residential and commercial prices.
[8]Free-alongside-ship (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: 1993: Production and minemouth price: Energy Information Administration (EIA), *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Imports, exports, consumption, and other prices: EIA, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B17. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Utilities and Nonutilities[1] (excluding cogenerators)										
Capability (gigawatts)										
Conventional Hydropower	76.74	79.27	79.27	79.27	79.65	79.65	79.65	79.81	79.81	79.81
Geothermal[2]	2.96	3.42	3.42	3.42	3.42	3.44	3.51	4.13	4.57	4.71
Municipal Solid Waste	2.59	3.46	3.51	3.57	4.20	4.35	4.49	4.87	5.14	5.41
Biomass/Other Waste[3]	1.50	1.75	1.75	1.75	1.84	1.95	1.87	1.92	2.73	2.38
Solar	0.34	0.56	0.54	0.54	0.80	0.79	0.82	1.18	1.37	2.85
Wind[4]	1.76	3.05	3.05	3.06	3.25	4.18	6.62	7.82	10.04	13.28
Total	**85.89**	**91.51**	**91.55**	**91.62**	**93.16**	**94.34**	**96.97**	**99.72**	**103.65**	**108.44**
Generation (billion kilowatthours)[1]										
Conventional Hydropower	275.73	303.12	303.10	303.11	305.33	305.22	305.17	306.33	306.30	306.23
Geothermal[2]	17.32	20.28	20.55	20.49	20.46	20.45	21.05	25.27	28.21	29.17
Municipal Solid Waste	17.75	23.29	23.58	23.90	28.67	29.75	30.83	33.64	35.71	37.73
Biomass/Other Waste[3]	7.46	11.20	11.09	11.13	11.73	12.45	11.87	12.17	17.90	15.41
Solar	0.90	1.57	1.50	1.50	2.58	2.52	2.66	4.11	4.90	10.95
Wind[4]	3.05	6.34	6.33	6.34	6.86	9.37	16.09	19.51	25.22	33.15
Total	**322.21**	**365.81**	**366.14**	**366.46**	**375.63**	**379.76**	**387.67**	**401.04**	**418.24**	**432.64**
Consumption										
Conventional Hydropower	2.84	3.12	3.12	3.12	3.15	3.14	3.14	3.16	3.16	3.15
Geothermal[2]	0.36	0.51	0.52	0.52	0.57	0.57	0.59	0.74	0.83	0.89
Municipal Solid Waste	0.29	0.38	0.38	0.39	0.47	0.48	0.50	0.55	0.58	0.61
Biomass/Other Waste[3]	0.09	0.13	0.13	0.13	0.14	0.14	0.14	0.13	0.19	0.16
Solar	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.05	0.11
Wind[4]	0.03	0.07	0.07	0.07	0.07	0.10	0.17	0.20	0.26	0.34
Total	**3.63**	**4.23**	**4.24**	**4.24**	**4.42**	**4.46**	**4.57**	**4.82**	**5.06**	**5.27**
Cogenerators[5]										
Capacity (gigawatts)										
Conventional Hydropower	0.97	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Municipal Solid Waste	0.31	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Biomass/Other Waste	5.60	5.61	5.62	5.62	5.65	5.66	5.68	5.68	5.71	5.74
Total	**6.87**	**7.41**	**7.41**	**7.42**	**7.44**	**7.46**	**7.48**	**7.48**	**7.51**	**7.53**
Generation (billion kilowatthours)										
Conventional Hydropower	3.24	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48
Municipal Solid Waste	1.54	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
Biomass/Other Waste	30.70	31.68	31.71	31.73	31.88	31.97	32.06	32.08	32.24	32.39
Total	**35.48**	**38.06**	**38.08**	**38.11**	**38.26**	**38.34**	**38.43**	**38.45**	**38.61**	**38.76**
Consumption										
Conventional Hydropower	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Biomass/Other Waste	0.64	0.70	0.72	0.74	0.75	0.78	0.81	0.77	0.82	0.87
Total	**0.69**	**0.76**	**0.78**	**0.80**	**0.81**	**0.84**	**0.87**	**0.83**	**0.88**	**0.94**
Non-electric										
Non-electric Renewable Energy Consumption										
Geothermal[6]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Biofuels[7]	2.09	2.25	2.32	2.38	2.38	2.48	2.57	2.47	2.61	2.75
Solar Thermal[8]	0.06	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09
Ethanol	0.07	0.13	0.13	0.15	0.18	0.19	0.21	0.22	0.23	0.24
Total	**2.22**	**2.48**	**2.55**	**2.63**	**2.67**	**2.78**	**2.90**	**2.80**	**2.96**	**3.13**

Economic Growth Case Comparisons

Table B17. Renewable Energy (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Renewable Energy Consumption[9]										
Conventional Hydropower	2.87	3.16	3.16	3.16	3.18	3.18	3.18	3.19	3.19	3.19
Geothermal	0.37	0.53	0.54	0.54	0.60	0.60	0.63	0.77	0.86	0.93
Municipal Solid Waste	0.31	0.41	0.41	0.42	0.50	0.52	0.53	0.58	0.61	0.65
Biofuels	2.82	3.08	3.17	3.25	3.27	3.40	3.52	3.36	3.61	3.79
Solar	0.07	0.09	0.09	0.09	0.11	0.11	0.11	0.13	0.14	0.21
Wind	0.03	0.07	0.07	0.07	0.07	0.10	0.17	0.20	0.26	0.34
Ethanol	0.07	0.13	0.13	0.15	0.18	0.19	0.21	0.22	0.23	0.24
Total	**6.55**	**7.47**	**7.57**	**7.68**	**7.90**	**8.08**	**8.34**	**8.45**	**8.91**	**9.34**

[1]Grid connected only.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Does not include projections for energy crops.
[4]Includes horizontal-axis wind turbines only.
[5]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification 49). In general, biomass and other waste facilities are cogenerators, while the remaining renewables produce only electricity.
[6]Residential and commercial ground-source heat pumps.
[7]Residential and industrial wood and wood waste.
[8]Residential and commercial water heating.
[9]Actual heat rates used to determine fuel consumption for all renewable sources except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined using the fossil fuel equivalent of 10,302 Btu per kilowatthour.
Btu = British thermal unit.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 15, 1994. Additional retirements are also determined based on the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1993: Electric utility capacity: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." Nonutility and cogenerator capacity: Form EIA-867, "Annual Nonutility Power Producer Report." Generation: EIA, *Annual Energy Review*, DOE/EIA-0384(93) (Washington, DC, July 1994). Ethanol: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93/1) (Washington, DC, June 1994). Nonutility consumption other than ethanol: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B18. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	25.3	22.5	22.6	22.8	20.9	21.3	21.6	19.8	20.4	20.9
Natural Gas	73.6	73.4	74.4	75.2	71.6	72.6	73.8	70.7	72.6	74.5
Coal	1.5	1.6	1.6	1.6	1.5	1.5	1.5	1.4	1.4	1.4
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**100.3**	**97.5**	**98.6**	**99.5**	**94.0**	**95.4**	**96.9**	**92.0**	**94.4**	**96.9**
Commercial										
Petroleum	16.1	13.8	13.8	13.9	13.3	13.4	13.5	12.9	13.1	13.4
Natural Gas	43.2	43.4	43.8	44.1	43.1	43.7	44.4	43.0	44.1	45.3
Coal	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**61.5**	**59.4**	**59.9**	**60.2**	**58.6**	**59.4**	**60.2**	**58.1**	**59.5**	**60.9**
Industrial[1]										
Petroleum	95.4	96.3	99.1	101.3	101.9	105.0	108.6	103.7	108.9	114.0
Natural Gas[2]	127.8	142.6	144.6	146.9	146.1	150.1	154.8	152.0	158.2	165.9
Coal	62.4	65.3	66.2	66.8	65.7	67.4	68.9	65.4	68.0	70.5
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**285.6**	**304.2**	**309.9**	**314.9**	**313.7**	**322.5**	**332.3**	**321.1**	**335.1**	**350.4**
Transportation										
Petroleum	427.4	472.3	480.8	489.0	497.4	511.1	524.2	508.5	531.4	552.1
Natural Gas[3]	9.0	11.8	12.0	12.2	13.6	13.9	14.2	15.5	15.8	16.0
Renewable/Other[4]	0.0	0.2	0.2	0.2	0.5	0.5	0.5	0.8	0.8	0.9
Total	**436.4**	**484.2**	**492.9**	**501.4**	**511.5**	**525.5**	**538.9**	**524.9**	**548.1**	**569.0**
Electric Generators[5]										
Petroleum	22.9	17.6	19.9	22.4	22.3	27.0	34.5	27.0	28.8	35.7
Natural Gas	41.7	44.2	49.2	55.2	49.9	57.7	63.7	58.2	69.4	76.9
Steam Coal	427.1	434.4	440.5	445.5	453.6	461.6	467.3	472.5	485.5	505.0
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**491.7**	**496.2**	**509.6**	**523.2**	**525.7**	**546.3**	**565.5**	**557.7**	**583.7**	**617.5**
Total Energy Consumption										
Petroleum	587.1	622.4	636.2	649.3	655.7	677.8	702.4	671.9	702.7	736.0
Natural Gas	295.2	315.5	324.0	333.7	324.3	338.0	351.0	339.4	360.1	378.6
Coal	493.2	503.5	510.5	516.1	523.1	532.7	539.9	541.6	557.2	579.1
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other[4]	0.0	0.2	0.2	0.2	0.5	0.5	0.5	0.8	0.8	0.9
Total	**1375.5**	**1441.5**	**1470.9**	**1499.2**	**1503.5**	**1549.0**	**1593.8**	**1553.8**	**1620.8**	**1694.7**

[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, liquid hydrogen, and lubricants.
[5]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, Table 6 and Table A1, DOE/EIA-0573(94) (Washington, DC, October 1994). Note that sectoral totals have been adjusted to reflect AEO95 National Energy Modeling System definitions.
Consumption projections: EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Economic Growth Case Comparisons

Table B19. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
GDP Implicit Price Deflator (index 1987=1.000)	**1.242**	**1.648**	**1.491**	**1.428**	**2.113**	**1.755**	**1.613**	**2.724**	**2.074**	**1.823**
Real Gross Domestic Product	**5136**	**5924**	**6126**	**6319**	**6518**	**6852**	**7192**	**6949**	**7485**	**8028**
Real Consumption	3453	3943	4035	4121	4250	4399	4549	4499	4748	4996
Real Investment	820	1090	1175	1255	1255	1385	1516	1351	1547	1744
Real Government Spending	939	983	1003	1025	1039	1077	1117	1085	1143	1202
Real Exports	598	899	938	978	1205	1297	1392	1458	1625	1795
Real Imports	674	990	1025	1060	1231	1306	1382	1443	1578	1709
Real Disposable Personal Income	**3701**	**4287**	**4371**	**4451**	**4625**	**4764**	**4913**	**4889**	**5140**	**5396**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.097**	**1.261**	**1.306**	**1.350**	**1.402**	**1.469**	**1.544**	**1.491**	**1.598**	**1.716**
AA Utility Bond Rate (percent)	7.43	10.27	8.41	7.19	10.11	8.24	7.03	10.02	7.99	6.72
90-Day U.S. Government Treasury Bill Rate (percent)	3.00	6.20	4.66	3.47	6.09	4.53	3.33	6.17	4.37	3.02
Real Yield on Government 10 Year Bonds (percent)	3.23	4.27	4.13	3.69	3.71	3.50	3.10	3.92	3.51	3.10
Real 90-Day U.S. Government Treasury Bill Rate (percent)	0.44	1.43	1.61	1.26	0.91	1.17	0.76	0.93	1.01	0.48
Real Utility Bond Rate (percent)	4.87	5.51	5.36	4.98	4.93	4.87	4.46	4.78	4.64	4.18
Energy Intensity (thousand Btu per 1987 dollar of GDP)	**16.99**	**15.67**	**15.44**	**15.25**	**14.81**	**14.50**	**14.24**	**14.30**	**13.88**	**13.51**
Consumer Price Index (1982=1.00)	1.45	2.00	1.81	1.73	2.62	2.19	2.01	3.44	2.64	2.33
Employment Cost Index (1987=1.00)	1.15	1.61	1.44	1.38	2.12	1.75	1.63	2.82	2.14	1.92
Unemployment Rate (percent)	7.42	6.43	6.28	6.24	5.69	6.00	6.28	6.12	6.47	6.79
Million Units										
Truck Deliveries, Light-Duty	5.20	6.06	6.35	6.54	6.67	7.17	7.54	6.21	7.05	7.70
Unit Sales of Automobiles	8.71	9.16	9.59	9.89	9.25	9.92	10.45	9.11	10.17	11.03
U.S. Trade-Weighted Exchange Rate	**1.00**	**0.92**	**0.95**	**0.97**	**0.86**	**0.90**	**0.94**	**0.81**	**0.87**	**0.93**
Millions of People										
Population with Armed Forces Overseas	258.4	271.6	275.6	279.3	279.9	287.1	293.8	288.3	298.9	308.7
Population (aged 16 and over)	198.2	209.7	212.8	215.5	218.4	223.8	228.6	227.7	235.4	242.5
Employment, Non-Agriculture	107.9	117.9	120.4	122.7	125.6	128.9	132.3	128.4	133.5	138.6

GDP = Gross domestic product.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: Data Resources Incorporated (DRI), DRI Trend0294. **Projections:** Energy Information Administration, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Table B20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1993	Projections								
		2000			2005			2010		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (1993 dollars per barrel)[1]	16.12	18.70	19.13	19.52	21.05	21.50	22.06	23.29	24.12	24.99
Production[2]										
U.S. (50 states)	9.53	8.10	8.24	8.39	7.95	8.20	8.42	8.31	8.58	8.86
Canada	2.10	2.16	2.17	2.18	2.41	2.42	2.44	2.32	2.34	2.36
OECD Europe[3]	5.17	6.37	6.38	6.39	5.22	5.22	5.23	4.66	4.67	4.68
OPEC	27.02	35.97	36.01	36.03	42.66	42.68	42.73	46.58	46.67	46.74
Rest of the World[4]	11.67	12.82	12.84	12.86	12.03	12.05	12.09	11.73	11.77	11.82
Total Production	55.48	65.43	65.65	65.84	70.26	70.58	70.91	73.60	74.03	74.46
Net Eurasian Exports	1.33	1.24	1.24	1.24	1.42	1.42	1.42	1.60	1.60	1.60
Total Supply	56.78	66.67	66.89	67.08	71.68	72.00	72.33	75.20	75.63	76.06
Consumption										
U.S. (50 states)	17.24	18.48	18.88	19.25	19.47	20.10	20.75	19.97	20.89	21.83
U.S. Territories	0.22	0.27	0.26	0.26	0.29	0.29	0.29	0.31	0.30	0.30
Canada	1.69	1.95	1.94	1.92	2.04	2.02	2.00	2.11	2.08	2.05
Japan	5.45	7.06	7.02	6.98	7.75	7.67	7.58	8.17	8.05	7.91
Australia & New Zealand	0.84	0.96	0.96	0.95	1.04	1.03	1.03	1.11	1.10	1.09
OECD Europe	13.48	15.94	15.87	15.80	16.75	16.64	16.52	17.13	16.97	16.79
Rest of the World[4]	18.16	22.32	22.27	22.22	24.65	24.56	24.46	26.70	26.55	26.39
Total Consumption	57.08	66.97	67.19	67.38	71.98	72.30	72.63	75.50	75.93	76.36
Discrepancy	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Consumption Aggregations										
OECD	38.92	44.65	44.92	45.16	47.33	47.75	48.17	48.80	49.38	49.97
OPEC	5.05	5.89	5.89	5.89	6.51	6.51	6.51	7.18	7.18	7.18
Rest of the World[4]	13.11	16.43	16.38	16.33	18.14	18.05	17.95	19.51	19.37	19.20
Non-OPEC Production[4]	28.47	29.46	29.63	29.81	27.60	27.90	28.18	27.01	27.36	27.72
OPEC Summary										
Market Share	0.47	0.54	0.54	0.53	0.59	0.59	0.59	0.62	0.61	0.61
Production Capacity[5]	31.30	38.40	38.40	38.40	44.10	44.10	44.10	47.75	47.75	47.75
Capacity Utilization	0.86	0.94	0.94	0.94	0.97	0.97	0.97	0.98	0.98	0.98

[1]The average cost to domestic refiners of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
[4]Does not include Eurasia.
[5]Maximum sustainable production capacity.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
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.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LMAC95.D1103941, AEO95B.D1103942, and HMAC95.D1103941.

Oil Price Case Comparisons

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

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Crude Oil and Lease Condensate	14.50	9.76	11.33	12.07	8.18	10.92	12.12	7.59	11.42	13.12
Natural Gas Plant Liquids	2.41	2.42	2.57	2.60	2.46	2.69	2.73	2.62	2.81	2.85
Dry Natural Gas	18.90	18.77	19.65	19.90	18.83	20.53	20.90	20.02	21.51	21.82
Coal	20.23	21.97	22.08	22.06	23.12	23.21	23.23	24.28	24.51	24.63
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[1]	7.06	7.89	7.92	7.95	8.34	8.43	8.52	8.94	9.25	9.57
Total	**69.62**	**67.77**	**70.51**	**71.54**	**67.90**	**72.75**	**74.47**	**69.82**	**75.86**	**78.37**
Imports										
Crude Oil[2]	14.79	20.84	19.14	18.39	22.83	19.72	18.46	23.56	19.53	17.61
Petroleum Products[3]	3.79	6.47	5.18	4.85	9.56	7.10	6.52	11.64	8.12	7.36
Natural Gas	2.32	3.16	3.17	3.17	3.32	3.33	3.32	3.55	3.97	4.02
Other Imports[4]	0.50	0.71	0.71	0.71	0.76	0.73	0.72	1.02	1.00	0.84
Total	**21.40**	**31.19**	**28.20**	**27.11**	**36.47**	**30.87**	**29.02**	**39.77**	**32.62**	**29.83**
Exports										
Petroleum[5]	2.11	1.73	1.97	2.06	1.43	1.68	1.82	1.35	1.64	1.74
Natural Gas	0.15	0.21	0.21	0.21	0.27	0.27	0.27	0.31	0.31	0.31
Coal	1.96	2.22	2.22	2.22	2.54	2.54	2.54	3.05	2.89	2.90
Total	**4.21**	**4.17**	**4.40**	**4.50**	**4.24**	**4.49**	**4.64**	**4.70**	**4.83**	**4.94**
Discrepancy[6]	**0.46**	**0.13**	**0.31**	**0.37**	**-0.11**	**0.24**	**0.29**	**-0.17**	**0.22**	**0.28**
Consumption										
Petroleum Products[7]	33.71	38.14	36.89	36.54	41.77	39.30	38.68	44.20	40.82	39.92
Natural Gas	20.81	21.89	22.78	23.03	22.05	23.76	24.11	23.38	25.30	25.66
Coal	19.43	20.08	20.14	20.15	20.93	21.01	21.02	21.59	21.97	22.08
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[8]	6.80	7.84	7.83	7.85	8.31	8.32	8.38	9.18	9.41	9.51
Total	**87.27**	**94.92**	**94.61**	**94.53**	**100.02**	**99.37**	**99.15**	**104.71**	**103.88**	**103.53**
Net Imports - Petroleum	**16.47**	**25.58**	**22.36**	**21.18**	**30.96**	**25.13**	**23.15**	**33.85**	**26.02**	**23.24**
Prices (1993 dollars per unit)										
World Oil Price (dollars per barrel)[9]	16.12	13.52	19.13	21.15	14.25	21.50	24.55	14.65	24.12	28.99
Gas Wellhead Price (dollars per thousand cubic feet)[10]	2.02	2.03	2.14	2.16	2.62	3.02	3.07	2.88	3.39	3.51
Coal Minemouth Price (dollars per ton)	19.85	20.40	20.34	20.74	21.56	21.55	22.09	21.39	22.77	23.68

[1]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[2]Includes imports of crude oil for the Strategic Petroleum Reserve.
[3]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[4]Includes coal, coal coke (net), and electricity (net).
[5]Includes crude oil and petroleum products.
[6]Balancing item. Includes unaccounted for supply, losses, and gains.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[8]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, net coal coke imports, net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors.
Sources: 1993 natural gas prices: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 coal minemouth price: EIA, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Other 1993 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C2. Energy Consumption by End-Use Sector and Source
(Quadrillion Btu per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential										
Distillate Fuel	0.88	0.82	0.79	0.78	0.79	0.75	0.73	0.78	0.73	0.69
Kerosene	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Liquefied Petroleum Gas	0.39	0.35	0.34	0.34	0.33	0.31	0.31	0.31	0.29	0.28
Natural Gas	5.11	5.16	5.17	5.17	5.08	5.04	5.05	5.07	5.04	5.06
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Renewable Energy[1]	0.72	0.73	0.72	0.72	0.73	0.73	0.73	0.74	0.74	0.74
Electricity	3.39	3.61	3.61	3.61	3.74	3.73	3.73	3.95	3.94	3.94
Total	**10.61**	**10.79**	**10.75**	**10.74**	**10.79**	**10.69**	**10.66**	**10.97**	**10.85**	**10.82**
Commercial										
Distillate Fuel	0.42	0.42	0.39	0.39	0.41	0.37	0.36	0.41	0.35	0.34
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Motor Gasoline[2]	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Residual Fuel	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Natural Gas	2.98	3.03	3.04	3.04	3.03	3.04	3.04	3.04	3.06	3.06
Other[3]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Renewable Energy[4]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Electricity	2.96	3.23	3.22	3.22	3.35	3.34	3.34	3.51	3.50	3.50
Total	**6.77**	**7.09**	**7.08**	**7.07**	**7.21**	**7.17**	**7.16**	**7.40**	**7.34**	**7.33**
Industrial[5]										
Distillate Fuel	1.12	1.25	1.24	1.24	1.34	1.33	1.33	1.40	1.39	1.39
Liquefied Petroleum Gas	1.82	2.11	2.04	2.04	2.49	2.24	2.23	2.69	2.40	2.39
Motor Gasoline[2]	0.19	0.21	0.21	0.21	0.23	0.23	0.23	0.24	0.24	0.24
Petrochemical Feedstocks	1.17	1.31	1.31	1.30	1.43	1.42	1.42	1.53	1.52	1.51
Residual Fuel	0.38	0.55	0.49	0.44	0.65	0.54	0.49	0.70	0.56	0.47
Other Petroleum[6]	3.78	3.96	3.86	3.79	4.18	3.98	3.85	4.33	4.07	3.97
Natural Gas[7]	9.09	9.90	10.32	10.49	9.98	10.71	10.95	10.46	11.28	11.53
Metallurgical Coal	0.84	0.77	0.77	0.77	0.67	0.67	0.67	0.59	0.59	0.59
Steam Coal	1.66	1.82	1.87	1.88	1.92	2.01	2.03	1.99	2.11	2.15
Net Coal Coke Imports	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Renewable Energy	2.12	2.47	2.45	2.44	2.69	2.67	2.65	2.87	2.84	2.82
Electricity	3.35	3.69	3.68	3.68	4.03	4.01	4.00	4.25	4.24	4.22
Total	**25.55**	**28.07**	**28.25**	**28.31**	**29.64**	**29.83**	**29.88**	**31.11**	**31.28**	**31.32**
Transportation										
Distillate Fuel	3.86	4.66	4.59	4.57	5.13	5.02	4.99	5.55	5.43	5.36
Jet Fuel[8]	3.04	3.80	3.74	3.71	4.23	4.13	4.10	4.57	4.46	4.39
Motor Gasoline[2]	13.88	15.19	14.97	14.86	15.85	15.44	15.21	16.10	15.51	15.08
Residual Fuel	1.10	1.32	1.32	1.31	1.52	1.51	1.50	1.68	1.67	1.66
Liquefied Petroleum Gas	0.02	0.09	0.08	0.09	0.16	0.16	0.17	0.24	0.24	0.27
Other Petroleum[9]	0.20	0.23	0.23	0.23	0.24	0.24	0.24	0.26	0.25	0.25
Pipeline Fuel Natural Gas	0.63	0.64	0.67	0.68	0.64	0.67	0.69	0.64	0.67	0.68
Compressed Natural Gas	0.01	0.16	0.16	0.16	0.30	0.29	0.30	0.43	0.43	0.46
Renewables (ethanol)[10]	0.00	0.00	0.01	0.02	0.01	0.03	0.08	0.01	0.06	0.15
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Methanol[11]	0.00	0.00	0.01	0.02	0.01	0.03	0.06	0.01	0.05	0.11
Electricity	0.06	0.09	0.09	0.09	0.13	0.13	0.13	0.18	0.18	0.18
Total	**22.79**	**26.18**	**25.86**	**25.74**	**28.22**	**27.66**	**27.47**	**29.68**	**28.94**	**28.59**
Electric Generators[12]										
Distillate Fuel	0.01	0.01	0.01	0.01	0.04	0.01	0.01	0.10	0.05	0.05
Residual Fuel	1.07	1.50	0.93	0.87	2.37	1.26	1.16	2.93	1.31	1.20
Natural Gas	3.00	3.00	3.42	3.48	3.03	4.01	4.07	3.73	4.82	4.88
Steam Coal	16.78	17.34	17.36	17.36	18.19	18.19	18.18	18.86	19.13	19.21
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[13]	3.92	4.59	4.60	4.60	4.80	4.80	4.79	5.46	5.65	5.61
Total	**31.30**	**33.41**	**33.27**	**33.27**	**35.40**	**35.23**	**35.18**	**37.45**	**37.32**	**37.31**

Table C2. Energy Consumption by End-Use Sector and Source (Continued)
(Quadrillion Btu per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Primary Energy Consumption										
Distillate Fuel	6.29	7.14	7.02	6.98	7.72	7.49	7.42	8.25	7.95	7.84
Kerosene	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07
Jet Fuel[8]	3.04	3.80	3.74	3.71	4.23	4.13	4.10	4.57	4.46	4.39
Liquefied Petroleum Gas	2.29	2.61	2.53	2.52	3.04	2.77	2.76	3.31	2.99	2.99
Motor Gasoline[2]	14.14	15.47	15.25	15.14	16.16	15.75	15.51	16.42	15.83	15.40
Petrochemical Feedstocks	1.17	1.31	1.31	1.30	1.43	1.42	1.42	1.53	1.52	1.51
Residual Fuel	2.72	3.54	2.90	2.79	4.71	3.47	3.32	5.47	3.70	3.50
Other Petroleum[14]	3.98	4.18	4.07	4.01	4.41	4.21	4.08	4.58	4.31	4.21
Natural Gas	20.81	21.89	22.78	23.03	22.05	23.76	24.11	23.38	25.30	25.66
Metallurgical Coal	0.84	0.77	0.77	0.77	0.67	0.67	0.67	0.59	0.59	0.59
Steam Coal	18.59	19.31	19.37	19.38	20.25	20.34	20.34	20.99	21.38	21.49
Net Coal Coke Imports	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Nuclear Power	6.52	6.96	6.96	6.96	6.97	6.97	6.97	6.36	6.36	6.36
Renewable Energy/Other[15]	6.78	7.82	7.81	7.83	8.28	8.29	8.35	9.14	9.37	9.47
Total	**87.26**	**94.92**	**94.61**	**94.53**	**100.02**	**99.37**	**99.15**	**104.71**	**103.88**	**103.53**
Electricity Consumption (all sectors)	**9.77**	**10.62**	**10.60**	**10.60**	**11.24**	**11.21**	**11.20**	**11.89**	**11.86**	**11.84**

[1]Includes electricity generated by the sector for self-use from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, and non-electric energy from renewable sources, such as solar thermal water heaters, groundwater heat pumps, and wood.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes liquefied petroleum gas and coal.
[4]Includes commercial sector electricity cogenerated using wood and wood waste, municipal solid waste, and other biomass; non-electric energy from renewable sources, such as active solar and passive solar systems, geothermal heat pumps, and solar water heating systems.
[5]Fuel consumption includes consumption for cogeneration.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes lease and plant fuel.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]Only E85 (85 percent ethanol).
[11]Only M85 (85 percent methanol).
[12]Includes consumption of energy by all electric power generators except cogenerators and generators with standard industrial classification other than 49, both of which produce electricity as a byproduct of other processes.
[13]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports.
[14]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to electric utilities and for self use from renewable sources, non-electric energy from renewable sources, electricity generated from waste heat, net electricity imports, liquid hydrogen, and methanol.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.
Sources: 1993 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 transportation sector compressed natural gas consumption: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. 1993 coal consumption is estimated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 metallurgical consumption is estimated from this source using unpublished data. 1993 residential and commercial coal consumption tonnages are from EIA, *Quarterly Coal Report, October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994) and have been converted to quadrillion Btu using *State Energy Data Report 1992* thermal conversion factors. Other 1993 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C3. Energy Prices by End-Use Sector and Source
(1993 Dollars per Million Btu)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential	**12.48**	**12.41**	**12.72**	**12.84**	**13.10**	**13.73**	**13.91**	**13.73**	**14.53**	**14.83**
Primary Energy	6.32	6.10	6.41	6.52	6.53	7.18	7.32	6.65	7.42	7.64
Petroleum Products	7.72	7.83	8.97	9.38	7.94	9.54	10.17	8.12	10.06	11.10
Distillate Fuel	6.55	6.77	7.70	8.03	6.85	8.24	8.73	7.06	8.71	9.54
Liquefied Petroleum Gas	10.40	10.27	11.96	12.54	10.55	12.72	13.64	10.76	13.58	15.07
Natural Gas	6.00	5.74	5.88	5.93	6.26	6.71	6.77	6.38	6.92	7.01
Electricity	24.30	23.69	23.93	24.06	24.20	24.66	24.86	24.98	25.67	26.01
Commercial	**12.25**	**12.26**	**12.53**	**12.65**	**12.91**	**13.49**	**13.68**	**13.48**	**14.25**	**14.51**
Primary Energy	4.93	4.72	5.00	5.10	5.18	5.79	5.93	5.34	6.07	6.29
Petroleum Products	4.96	4.79	5.76	6.11	4.91	6.32	6.85	5.09	6.84	7.72
Distillate Fuel	4.61	4.58	5.52	5.85	4.63	6.05	6.55	4.80	6.49	7.33
Residual Fuel	2.67	2.25	3.06	3.36	2.41	3.48	3.94	2.51	3.89	4.63
Natural Gas[1]	5.02	4.80	4.93	4.98	5.35	5.79	5.85	5.51	6.03	6.12
Electricity	21.63	21.22	21.47	21.60	21.77	22.25	22.48	22.42	23.15	23.44
Industrial[2]	**5.02**	**4.84**	**5.28**	**5.43**	**5.26**	**5.95**	**6.22**	**5.49**	**6.42**	**6.86**
Primary Energy	3.32	3.16	3.67	3.84	3.53	4.32	4.62	3.74	4.77	5.27
Petroleum Products	4.34	3.89	4.99	5.41	4.12	5.57	6.27	4.32	6.19	7.27
Distillate Fuel	4.78	4.58	5.52	5.85	4.67	6.06	6.57	4.86	6.53	7.37
Liquefied Petroleum Gas	4.85	5.63	7.18	7.75	5.92	7.91	8.88	6.14	8.69	10.23
Residual Fuel	2.35	2.10	2.93	3.23	2.25	3.34	3.80	2.34	3.75	4.49
Natural Gas[3]	2.79	2.86	2.96	2.95	3.44	3.80	3.84	3.69	4.17	4.28
Metallurgical Coal	1.77	1.69	1.71	1.73	1.71	1.74	1.76	1.68	1.76	1.81
Steam Coal	1.45	1.39	1.45	1.47	1.41	1.48	1.50	1.43	1.53	1.58
Electricity	14.53	14.21	14.34	14.41	14.52	14.78	14.92	14.76	15.22	15.42
Transportation	**7.76**	**8.15**	**9.06**	**9.37**	**8.09**	**9.52**	**10.00**	**8.00**	**9.70**	**10.52**
Primary Energy	7.74	8.13	9.04	9.34	8.05	9.49	9.98	7.96	9.66	10.49
Petroleum Products	7.74	8.14	9.06	9.36	8.05	9.51	9.99	7.96	9.68	10.52
Distillate Fuel[4]	8.05	7.94	8.89	9.22	7.84	9.22	9.73	7.82	9.49	10.34
Jet Fuel[5]	4.28	4.86	5.80	6.14	4.98	6.46	6.95	5.10	6.85	7.71
Motor Gasoline[6]	8.93	9.62	10.54	10.82	9.55	11.07	11.55	9.43	11.21	12.05
Residual Fuel	2.07	1.90	2.76	3.08	2.07	3.17	3.65	2.17	3.59	4.36
Natural Gas[7]	4.65	6.23	6.36	6.39	7.82	8.34	8.38	7.96	8.67	8.75
Electricity	14.85	15.29	15.34	15.34	15.49	15.55	15.58	15.62	15.73	15.80
Total End-Use Energy	**8.05**	**8.04**	**8.61**	**8.81**	**8.29**	**9.24**	**9.56**	**8.46**	**9.64**	**10.19**
Primary Energy	7.68	7.71	8.32	8.52	7.90	8.90	9.25	8.01	9.25	9.83
Electricity	20.08	19.57	19.78	19.89	19.91	20.30	20.49	20.43	21.04	21.32
Electric Generators[8]										
Fossil Fuel Average	1.61	1.57	1.65	1.68	1.73	1.88	1.95	1.82	2.05	2.16
Petroleum Products	2.48	2.05	2.91	3.23	2.27	3.33	3.79	2.41	3.78	4.54
Distillate Fuel	4.72	4.17	5.27	5.60	4.14	5.53	6.10	4.32	5.91	6.74
Residual Fuel	2.46	2.04	2.90	3.22	2.24	3.30	3.77	2.35	3.70	4.44
Natural Gas	2.57	2.32	2.59	2.65	2.96	3.38	3.53	3.30	3.73	3.97
Steam Coal	1.39	1.40	1.39	1.41	1.46	1.45	1.48	1.43	1.50	1.55

Table C3. Energy Prices by End-Use Sector and Source (Continued)
(1993 Dollars per Million Btu)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Average Price to All Users[9]										
Petroleum Products	6.73	6.86	7.91	8.25	6.77	8.35	8.91	6.71	8.65	9.56
Distillate Fuel[4]	7.02	7.02	7.97	8.30	6.99	8.39	8.91	7.05	8.74	9.59
Jet Fuel	4.28	4.86	5.80	6.14	4.98	6.46	6.95	5.10	6.85	7.71
Liquefied Petroleum Gas	5.94	6.55	8.13	8.70	6.83	8.90	9.87	7.09	9.74	11.31
Motor Gasoline[6]	8.93	9.60	10.52	10.80	9.54	11.05	11.53	9.42	11.20	12.04
Residual Fuel	2.30	2.01	2.85	3.16	2.19	3.26	3.73	2.30	3.67	4.42
Natural Gas	3.97	3.85	3.94	3.96	4.43	4.74	4.80	4.61	5.01	5.13
Coal	1.41	1.40	1.40	1.42	1.45	1.45	1.48	1.43	1.50	1.55
Electricity	20.08	19.57	19.78	19.89	19.91	20.30	20.49	20.43	21.04	21.32

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]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.
[8]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[9]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: Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.
Sources: 1993 prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). 1993 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). 1993 residential natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1993 natural gas delivered prices: EIA, AEO National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. Values for 1993 coal prices have been estimated from EIA, *State Price and Expenditure Report 1992*, DOE/EIA-0376(92) (Washington, DC, December 1994) using consumption quantities aggregated from EIA, *State Energy Data Report 1992*, DOE/EIA-0214(92) (Washington, DC, May 1994). 1993 electricity prices for commercial, industrial, and transportation: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.
Projections: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Oil Price Case Comparisons

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

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Household Characteristics										
Households (millions)										
Single-Family	66.39	71.77	71.78	71.78	75.20	75.21	75.22	78.53	78.56	78.57
Multifamily	24.19	24.69	24.69	24.69	25.57	25.57	25.57	26.62	26.62	26.62
Mobile Homes	5.24	5.42	5.42	5.42	5.46	5.46	5.47	5.50	5.51	5.52
Total	**95.82**	**101.88**	**101.89**	**101.89**	**106.23**	**106.25**	**106.25**	**110.64**	**110.69**	**110.70**
Housing Starts (millions)										
Single-Family	1.13	1.04	1.04	1.04	1.06	1.06	1.06	1.06	1.06	1.06
Multifamily	0.16	0.39	0.39	0.39	0.43	0.43	0.43	0.49	0.50	0.50
Mobile Homes	0.26	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.23	0.23
Total	**1.55**	**1.64**	**1.64**	**1.65**	**1.72**	**1.72**	**1.72**	**1.77**	**1.78**	**1.78**
Energy Intensity (million Btu per year per household)										
Heating	61.60	57.07	56.75	56.62	53.60	52.64	52.44	51.06	50.02	49.71
Total	**110.72**	**105.88**	**105.55**	**105.41**	**101.57**	**100.57**	**100.36**	**99.15**	**98.06**	**97.71**
Fuel Consumption										
Distillate										
Space Heating	0.80	0.74	0.72	0.70	0.72	0.68	0.66	0.71	0.66	0.62
Water Heating	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.88**	**0.82**	**0.79**	**0.78**	**0.79**	**0.75**	**0.73**	**0.78**	**0.73**	**0.69**
Liquefied Petroleum Gas										
Space Heating	0.26	0.23	0.22	0.21	0.21	0.19	0.19	0.20	0.17	0.16
Water Heating	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Cooking[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.39**	**0.35**	**0.34**	**0.34**	**0.33**	**0.31**	**0.31**	**0.31**	**0.29**	**0.28**
Natural Gas										
Space Heating	3.68	3.66	3.67	3.67	3.57	3.53	3.54	3.54	3.50	3.52
Space Cooling	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Water Heating	1.11	1.17	1.17	1.17	1.19	1.19	1.19	1.22	1.22	1.22
Cooking[2]	0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.16	0.16	0.16
Clothes Dryers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Total	**5.11**	**5.16**	**5.17**	**5.17**	**5.08**	**5.04**	**5.05**	**5.07**	**5.04**	**5.06**
Electricity										
Space Heating	0.37	0.40	0.40	0.40	0.41	0.41	0.41	0.43	0.43	0.43
Space Cooling	0.53	0.54	0.54	0.54	0.55	0.55	0.55	0.58	0.58	0.57
Water Heating	0.36	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Refrigeration	0.53	0.46	0.46	0.46	0.41	0.41	0.41	0.38	0.39	0.39
Cooking	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.18
Clothes Dryers	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21
Freezers	0.14	0.11	0.11	0.11	0.09	0.09	0.09	0.07	0.07	0.07
Lighting	0.32	0.35	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.37
Other Uses[4]	0.79	1.01	1.01	1.01	1.16	1.16	1.16	1.34	1.34	1.34
Total	**3.39**	**3.61**	**3.61**	**3.61**	**3.74**	**3.73**	**3.73**	**3.95**	**3.94**	**3.94**

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

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Renewables										
Wood[5]	0.66	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.64
Geothermal[6]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Solar[7]	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Total	**0.72**	**0.73**	**0.72**	**0.72**	**0.73**	**0.73**	**0.73**	**0.74**	**0.74**	**0.74**
Other Fuels[8]	**0.12**	**0.12**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Fuels										
Space Heating	5.90	5.81	5.78	5.77	5.69	5.59	5.57	5.65	5.54	5.50
Space Cooling	0.53	0.55	0.55	0.55	0.57	0.57	0.57	0.61	0.60	0.60
Water Heating	1.67	1.74	1.74	1.74	1.76	1.77	1.77	1.80	1.80	1.80
Cooking	0.38	0.40	0.40	0.40	0.38	0.38	0.38	0.37	0.37	0.37
Clothes Dryers	0.27	0.28	0.28	0.28	0.28	0.28	0.28	0.29	0.29	0.29
Other Uses	1.85	2.00	2.00	2.00	2.10	2.10	2.10	2.25	2.25	2.25
Total	**10.61**	**10.79**	**10.75**	**10.74**	**10.79**	**10.69**	**10.66**	**10.97**	**10.85**	**10.82**

[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.
[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: 1990 (RECS).*
[6]Includes primary energy displaced by ground-source (geothermal) heat pumps in space heating and cooling applications.
[7]Includes primary energy displaced by solar thermal water heaters.
[8]Includes kerosene and coal.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Oil Price Case Comparisons

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

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	65.6	71.0	71.0	71.0	73.9	73.9	73.9	76.8	76.8	76.8
New Additions	1.5	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6
Total	**67.0**	**72.4**	**72.4**	**72.4**	**75.3**	**75.3**	**75.3**	**78.4**	**78.4**	**78.4**
Energy Consumption Intensity (Thousand Btu per square feet)	**101.1**	**98.0**	**97.8**	**97.7**	**95.7**	**95.1**	**95.0**	**94.4**	**93.7**	**93.5**
End-Use Consumption										
Electricity										
Space Heating	0.09	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.06	0.06
Space Cooling	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Water Heating	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
Ventilation	0.30	0.32	0.32	0.32	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07
Lighting	1.06	1.04	1.03	1.03	1.03	1.02	1.02	1.04	1.03	1.03
Refrigeration	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Office Equipment (PC)	0.20	0.25	0.25	0.25	0.29	0.29	0.29	0.33	0.33	0.33
Office Equipment (non-PC)	0.21	0.26	0.26	0.26	0.29	0.29	0.29	0.33	0.33	0.33
Other Uses[1]	0.53	0.70	0.70	0.70	0.74	0.74	0.74	0.79	0.79	0.79
Total Electricity	**2.96**	**3.23**	**3.22**	**3.22**	**3.35**	**3.34**	**3.34**	**3.51**	**3.50**	**3.50**
Natural Gas[2]										
Space Heating	1.33	1.37	1.38	1.38	1.35	1.37	1.37	1.35	1.38	1.38
Space Cooling	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.35	0.36	0.36	0.36	0.36	0.35	0.35	0.36	0.36	0.35
Cooking	0.21	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.23	0.23
Other Uses[3]	1.08	1.06	1.06	1.06	1.07	1.07	1.07	1.08	1.08	1.08
Total Natural Gas	**2.98**	**3.03**	**3.04**	**3.04**	**3.03**	**3.04**	**3.04**	**3.04**	**3.06**	**3.06**
Distillate										
Space Heating	0.31	0.32	0.29	0.29	0.31	0.27	0.26	0.31	0.25	0.24
Water Heating	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[4]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Total Distillate	**0.42**	**0.42**	**0.39**	**0.39**	**0.41**	**0.37**	**0.36**	**0.41**	**0.35**	**0.34**
Other Fuels[5]	**0.40**	**0.39**	**0.39**	**0.39**	**0.39**	**0.39**	**0.39**	**0.40**	**0.40**	**0.40**
Renewable Fuels										
Solar	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Renewable Fuels	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Total Consumption	**6.77**	**7.09**	**7.08**	**7.07**	**7.21**	**7.17**	**7.16**	**7.40**	**7.34**	**7.33**

[1]Includes miscellaneous commercial uses such as service station equipment and medical equipment.
[2]Excludes estimated consumption from independent power producer.
[3]Includes miscellaneous commercial uses such as lighting and emergency generators.
[4]Includes miscellaneous commercial uses such as cooking and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 natural gas total fuel consumption: Energy Information Administration (EIA), *Natural Gas Monthly,* DOE/EIA-0130(94/6) (Washington, DC, June 1994) and EIA, AEO National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. Other 1993 values: EIA, *Short-Term Energy Outlook,* DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Key Indicators and Consumption	1993	Projections 2000 Low World Oil Price	2000 Reference	2000 High World Oil Price	2005 Low World Oil Price	2005 Reference	2005 High World Oil Price	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price
Key Indicators										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	2559	3068	3048	3041	3456	3427	3418	3754	3728	3711
Nonmanufacturing	889	1048	1046	1045	1134	1132	1131	1199	1198	1196
Total	**3448**	**4116**	**4094**	**4086**	**4590**	**4560**	**4549**	**4952**	**4926**	**4907**
Energy Prices (1993 dollars per million Btu)										
Electricity	14.53	14.21	14.34	14.41	14.52	14.78	14.92	14.76	15.22	15.42
Natural Gas	2.79	2.86	2.96	2.95	3.44	3.80	3.84	3.69	4.17	4.28
Steam Coal	1.45	1.39	1.45	1.47	1.41	1.48	1.50	1.43	1.53	1.58
Residual Oil	2.35	2.10	2.93	3.23	2.25	3.34	3.80	2.34	3.75	4.49
Distillate Oil	4.78	4.58	5.52	5.85	4.67	6.06	6.57	4.86	6.53	7.37
Liquefied Petroleum Gas	4.85	5.63	7.18	7.75	5.92	7.91	8.88	6.14	8.69	10.23
Motor Gasoline	8.90	8.41	9.33	9.62	8.54	10.06	10.54	8.57	10.36	11.21
Metallurgical Coal	1.77	1.69	1.71	1.73	1.71	1.74	1.76	1.68	1.76	1.81
Energy Consumption										
Consumption[1] (quadrillion Btu per year)										
Purchased Electricity	3.35	3.69	3.68	3.68	4.03	4.01	4.00	4.25	4.24	4.22
Natural Gas[2]	9.09	9.90	10.32	10.49	9.98	10.71	10.95	10.46	11.28	11.53
Steam Coal	1.66	1.82	1.87	1.88	1.92	2.01	2.03	1.99	2.11	2.15
Metallurgical Coal and Coke[3]	0.86	0.79	0.79	0.79	0.71	0.71	0.71	0.63	0.63	0.63
Residual Fuel	0.38	0.55	0.49	0.44	0.65	0.54	0.49	0.70	0.56	0.47
Distillate	1.12	1.25	1.24	1.24	1.34	1.33	1.33	1.40	1.39	1.39
Liquefied Petroleum Gas	1.82	2.11	2.04	2.04	2.49	2.24	2.23	2.69	2.40	2.39
Petrochemical Feedstocks	1.17	1.31	1.31	1.30	1.43	1.42	1.42	1.53	1.52	1.51
Other Petroleum[4]	3.97	4.18	4.07	4.01	4.41	4.21	4.08	4.57	4.31	4.21
Renewables[5]	2.12	2.47	2.45	2.44	2.69	2.67	2.65	2.87	2.84	2.82
Total	**25.55**	**28.07**	**28.25**	**28.31**	**29.64**	**29.83**	**29.88**	**31.11**	**31.28**	**31.32**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)										
Purchased Electricity	0.97	0.90	0.90	0.90	0.88	0.88	0.88	0.86	0.86	0.86
Natural Gas[2]	2.64	2.40	2.52	2.57	2.18	2.35	2.41	2.11	2.29	2.35
Steam Coal	0.48	0.44	0.46	0.46	0.42	0.44	0.45	0.40	0.43	0.44
Metallurgical Coal and Coke[3]	0.25	0.19	0.19	0.19	0.15	0.15	0.15	0.13	0.13	0.13
Residual Fuel	0.11	0.13	0.12	0.11	0.14	0.12	0.11	0.14	0.11	0.10
Distillate	0.33	0.30	0.30	0.30	0.29	0.29	0.29	0.28	0.28	0.28
Liquefied Petroleum Gas	0.53	0.51	0.50	0.50	0.54	0.49	0.49	0.54	0.49	0.49
Petrochemical Feedstocks	0.34	0.32	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.31
Other Petroleum[4]	1.15	1.01	0.99	0.98	0.96	0.92	0.90	0.92	0.87	0.86
Renewables[5]	0.62	0.60	0.60	0.60	0.59	0.58	0.58	0.58	0.58	0.58
Total	**7.41**	**6.82**	**6.90**	**6.93**	**6.46**	**6.54**	**6.57**	**6.28**	**6.35**	**6.38**

[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, still gas, motor gasoline, and miscellaneous petroleum products.
[5]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly,* DOE/EIA-0380(93/1-12) (Washington, DC, 1993). Coal prices: EIA, *Monthly Energy Review,* DOE/EIA-0035(94/08) (Washington, DC, August 1994). Natural gas and electricity prices: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. Other prices derived from EIA, *State Energy Data Report 1992,* DOE/EIA-0214(92) (Washington, DC, May 1994). Other values: EIA, *Short-Term Energy Outlook,* DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C7. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Level of Travel Index (1990 = 1.0)										
Light-Duty Vehicles	1.06	1.21	1.20	1.20	1.32	1.32	1.31	1.42	1.42	1.41
Freight Trucks	1.12	1.34	1.33	1.33	1.47	1.46	1.45	1.57	1.56	1.55
Air	1.05	1.58	1.55	1.53	1.85	1.80	1.78	2.08	2.02	1.99
Rail	1.06	1.13	1.14	1.15	1.20	1.23	1.24	1.27	1.31	1.32
Marine	0.98	1.02	1.04	1.05	1.07	1.11	1.12	1.13	1.18	1.19
Energy Efficiency Indicators										
New Car MPG[1]	27.81	28.40	28.88	29.13	29.25	29.96	30.27	31.53	32.83	33.46
New Light Truck MPG[1]	20.34	21.25	21.52	21.66	22.31	22.74	22.94	23.21	23.80	24.15
Light-Duty Fleet MPG[2]	19.30	20.19	20.33	20.39	20.65	20.96	21.08	21.32	21.82	22.04
Aircraft Efficiency Index	1.02	1.07	1.07	1.07	1.11	1.11	1.11	1.14	1.14	1.14
Freight Truck Efficiency Index	1.01	1.04	1.06	1.06	1.05	1.08	1.09	1.06	1.09	1.11
Rail Efficiency Index	1.01	1.04	1.04	1.04	1.06	1.06	1.06	1.07	1.07	1.07
Domestic Shipping Efficiency Index	1.00	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.01	1.01
Energy Use by Mode (quadrillion Btu per year)										
Light-Duty Vehicles[3]	13.09	14.50	14.31	14.23	15.43	15.09	14.97	15.98	15.50	15.30
Freight Trucks[3]	4.97	6.20	6.06	6.01	6.73	6.51	6.43	7.13	6.88	6.75
Air	3.09	3.84	3.77	3.75	4.27	4.17	4.14	4.61	4.50	4.44
Rail	0.59	0.61	0.61	0.62	0.64	0.65	0.65	0.66	0.68	0.68
Marine	1.63	1.90	1.90	1.90	2.13	2.13	2.13	2.32	2.32	2.32
Pipeline Fuel	0.63	0.64	0.67	0.68	0.64	0.67	0.69	0.64	0.67	0.68
Other[4]	0.16	0.18	0.18	0.18	0.20	0.19	0.19	0.21	0.21	0.20
Total[5]	**22.79**	**26.18**	**25.86**	**25.74**	**28.22**	**27.66**	**27.47**	**29.68**	**28.94**	**28.59**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes light-duty trucks used for freight.
[4]Includes lubricants and aviation gasoline.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Btu = British thermal unit.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). Other 1993 values: FAA, *FAA Aviation Forecasts Fiscal Years 1993-2004* (Washington, DC, February 1993); and EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Generation by Fuel Type										
Electric Utilities										
Coal	1639	1683	1689	1689	1758	1761	1761	1801	1825	1830
Petroleum	100	134	80	74	217	111	102	272	118	108
Natural Gas	259	270	301	308	256	342	351	272	387	393
Nuclear Power	610	652	652	652	653	653	653	596	596	596
Pumped Storage	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
Renewable Sources[1]	277	302	303	303	306	306	306	314	317	320
Total	**2883**	**3040**	**3022**	**3023**	**3188**	**3171**	**3171**	**3254**	**3241**	**3244**
Nonutilities (excluding cogenerators)[2]										
Coal	5	10	9	9	15	12	12	43	44	48
Petroleum	1	0	0	0	0	0	0	1	0	0
Natural Gas	21	25	36	33	45	53	50	101	90	87
Renewable Sources[1]	45	63	64	64	72	73	73	89	101	106
Total	**73**	**98**	**109**	**105**	**132**	**139**	**135**	**234**	**236**	**241**
Cogenerators[3]										
Coal	49	55	55	55	57	58	58	59	60	60
Petroleum	10	39	38	37	43	41	38	49	44	40
Natural Gas	151	161	177	181	170	196	205	185	216	229
Renewable	35	38	38	38	38	38	38	38	39	39
Other[4]	3	4	4	4	5	5	5	5	5	5
Total	**248**	**298**	**313**	**316**	**313**	**338**	**345**	**336**	**365**	**372**
Sales to Utilities	111	136	138	138	145	148	149	156	159	160
Generation for Own Use	137	162	175	178	168	190	196	181	206	212
Net Imports	**28**	**35**	**35**	**35**	**35**	**33**	**32**	**58**	**56**	**41**
Electricity Sales by Sector										
Residential	994	1059	1058	1058	1096	1094	1094	1158	1156	1155
Commercial	868	946	945	944	981	979	978	1029	1026	1024
Industrial	983	1083	1079	1078	1180	1174	1172	1246	1242	1238
Transportation	18	26	25	26	38	38	39	52	52	53
Total	**2862**	**3113**	**3108**	**3106**	**3294**	**3285**	**3282**	**3485**	**3475**	**3470**
End-Use Prices (1993 cents per kilowatthour)[5]										
Residential	8.3	8.1	8.2	8.2	8.3	8.4	8.5	8.5	8.8	8.9
Commercial	7.4	7.2	7.3	7.4	7.4	7.6	7.7	7.7	7.9	8.0
Industrial	5.0	4.8	4.9	4.9	5.0	5.0	5.1	5.0	5.2	5.3
Transportation	5.1	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4
All Sectors Average	**6.8**	**6.7**	**6.7**	**6.8**	**6.8**	**6.9**	**7.0**	**7.0**	**7.2**	**7.3**
Price Components (1993 cents per kilowatthour)										
Capital Component	2.8	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.5
Fuel Component	1.2	1.1	1.2	1.2	1.3	1.4	1.4	1.3	1.4	1.5
Operation and Maintenance Component	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.7	2.7	2.8
Wholesale Power Cost	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.5	0.4
Total	**6.8**	**6.7**	**6.7**	**6.8**	**6.8**	**6.9**	**7.0**	**7.0**	**7.2**	**7.3**

[1]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[2]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).
[3]Includes generation and cogeneration at facilities whose primary function is not electricity production (standard industrial classification other than 49). Includes sales to utilities and generation for own use.
[4]Other includes methane and propane and blast furnace gas.
[5]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: Energy Information Administration (EIA), *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **1993 electricity prices for commercial, industrial, and transportation, price components, and projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electric Utilities										
Capability										
Coal Steam	300.7	297.1	297.1	297.1	301.0	301.1	301.0	303.4	306.4	307.0
Other Fossil Steam[2]	141.3	130.4	130.4	130.4	124.3	124.3	124.3	120.4	120.4	120.4
Combined Cycle	9.7	17.7	17.7	18.0	23.4	23.4	24.0	26.8	27.2	27.7
Combustion Turbine/Diesel	49.2	66.0	65.9	65.9	71.2	71.0	70.9	80.0	77.8	76.7
Nuclear Power	99.0	101.3	101.3	101.3	101.3	101.3	101.3	88.7	88.7	88.7
Pumped Storage	19.1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Renewable Sources[3]	76.8	78.1	78.1	78.1	78.8	78.9	78.9	81.1	81.6	82.1
Total	**695.7**	**710.5**	**710.5**	**710.8**	**720.1**	**720.0**	**720.5**	**720.5**	**722.1**	**722.7**
Cumulative Planned Additions[4]										
Coal Steam	0.00	5.63	5.63	5.63	11.98	11.98	11.98	13.74	13.74	13.74
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.61	7.22	7.22	7.22	11.79	11.79	11.79	12.38	12.38	12.38
Combustion Turbine/Diesel	0.14	16.20	16.20	16.20	22.41	22.41	22.41	22.77	22.77	22.77
Nuclear Power	1.15	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
Pumped Storage	0.30	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Renewable Sources[3]	0.20	1.14	1.14	1.14	1.15	1.15	1.15	1.15	1.15	1.15
Total	**2.40**	**34.97**	**34.97**	**34.97**	**52.11**	**52.11**	**52.11**	**54.82**	**54.82**	**54.82**
Cumulative Unplanned Additions[4]										
Coal Steam	0.00	0.00	0.02	0.00	0.30	0.34	0.29	3.77	6.68	7.37
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.00	1.39	1.42	1.78	2.59	2.56	3.17	5.38	5.79	6.26
Combustion Turbine/Diesel	0.00	0.89	0.74	0.75	1.48	1.23	1.18	10.30	8.05	7.04
Nuclear Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable Sources[3]	0.00	0.10	0.13	0.15	0.43	0.52	0.52	2.63	3.07	3.61
Total	**0.00**	**2.39**	**2.32**	**2.68**	**4.80**	**4.66**	**5.16**	**22.08**	**23.59**	**24.28**
Cumulative Total Additions	**2.40**	**37.36**	**37.29**	**37.65**	**56.91**	**56.77**	**57.27**	**76.90**	**78.41**	**79.10**
Cumulative Retirements[5]	**8.71**	**29.26**	**29.26**	**29.26**	**39.86**	**39.86**	**39.86**	**59.57**	**59.57**	**59.57**
Nonutilities (excludes cogenerators)[6,7]										
Capability										
Coal Steam	0.62	1.81	1.82	1.81	2.49	2.10	2.09	6.89	7.11	7.56
Other Fossil Steam[2]	0.21	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Combined Cycle	2.03	4.49	5.29	4.80	6.35	7.00	6.47	11.32	10.48	9.81
Combustion Turbine/Diesel	1.33	3.14	2.80	2.92	4.52	3.97	4.04	17.54	13.72	14.28
Nuclear Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable Sources[3]	9.11	13.37	13.45	13.45	14.79	15.47	15.45	18.65	22.07	23.28
Total	**13.30**	**23.05**	**23.61**	**23.23**	**28.40**	**28.79**	**28.29**	**54.63**	**53.62**	**55.18**

Table C9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Cogenerators[7,8]										
Capacity										
Coal	6.90	7.99	8.03	8.03	8.23	8.37	8.37	8.48	8.72	8.72
Petroleum	3.36	6.03	5.96	5.86	6.68	6.37	6.02	7.43	6.81	6.18
Natural Gas	21.06	22.23	24.12	24.68	23.45	26.74	27.95	25.61	29.52	31.16
Renewables	6.92	7.40	7.41	7.41	7.43	7.46	7.46	7.45	7.51	7.51
Other	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**38.25**	**43.68**	**45.54**	**46.01**	**45.82**	**48.96**	**49.83**	**49.01**	**52.59**	**53.60**
Cumulative Additions[4,7]	**7.80**	**22.98**	**25.40**	**25.49**	**30.46**	**34.00**	**34.37**	**59.89**	**62.46**	**65.04**

[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 oil-, gas-, and dual-fired capability.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[4]Cumulative additions after December 31, 1992. Non-zero utility planned additions in 1992 indicate units operational in 1992, but not supplying power to the grid.
[5]Cumulative total retirements from 1990.
[6]Electricity was produced solely for sale to an electric utility or another end user, and there is no business activity at the site (standard industrial classification 49).
[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 capacity based on historic relationships.
[8]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification 49).
Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data as of August 15, 1994. Therefore, capacity may differ from other Energy Information Administration sources.
Sources: 1993: Net summer capacity at electric utilities, and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capacity for nonutilities and cogeneration and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Electricity Trade	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	153.4	133.4	133.4	133.4	124.8	124.8	124.8	124.8	124.8	124.8
Gross Domestic Economy Sales	58.5	63.4	75.0	75.5	53.0	59.7	59.6	38.1	49.5	52.1
Gross Domestic Trade	**211.9**	**196.8**	**208.4**	**208.8**	**177.8**	**184.5**	**184.5**	**162.9**	**174.3**	**176.9**
Gross Domestic Firm Power Sales (million 1993 dollars)	7022.3	6897.0	6897.0	6897.0	7038.7	7038.7	7038.7	7676.5	7676.5	7676.5
Gross Domestic Economy Sales (million 1993 dollars)	1194.2	1465.8	1710.7	1734.7	1378.0	1670.3	1709.8	1028.5	1556.7	1707.3
Gross Domestic Sales (million 1993 dollars)	**8216.5**	**8362.8**	**8607.8**	**8631.8**	**8416.7**	**8709.1**	**8748.5**	**8705.0**	**9233.2**	**9383.8**
International Electricity Trade										
Firm Power Imports From Canada and Mexico	14.9	20.9	20.9	20.9	24.2	21.8	21.0	44.3	42.5	27.1
Economy Imports From Canada and Mexico	24.1	28.2	28.2	28.2	30.9	30.9	30.9	34.8	34.8	34.8
Gross Imports From Canada and Mexico	**39.1**	**49.1**	**49.1**	**49.1**	**55.1**	**52.7**	**51.9**	**79.1**	**77.3**	**61.8**
Firm Power Exports To Canada and Mexico	2.5	8.1	8.1	8.1	13.1	13.1	13.1	13.1	13.1	13.1
Economy Exports To Canada and Mexico	8.2	6.4	6.4	6.4	7.0	7.0	7.0	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**10.7**	**14.5**	**14.5**	**14.5**	**20.1**	**20.1**	**20.1**	**20.8**	**20.8**	**20.8**

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: 1993: Interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. International electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1993 firm/economy share: National Energy Board, *Annual Report 1993*. 2000 planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1994. **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Supply and Disposition	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Domestic Crude Production[1]	6.85	4.61	5.35	5.70	3.86	5.16	5.73	3.58	5.39	6.20
Alaska	1.58	1.02	1.16	1.29	0.69	0.83	0.99	0.40	0.77	1.00
Lower 48 States	5.26	3.59	4.19	4.42	3.17	4.33	4.74	3.18	4.62	5.20
Net Imports	6.69	9.48	8.70	8.35	10.40	8.97	8.39	10.74	8.88	8.00
Other Crude Supply[2]	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**13.61**	**14.09**	**14.05**	**14.06**	**14.27**	**14.13**	**14.11**	**14.32**	**14.27**	**14.19**
Natural Gas Plant Liquids	**1.74**	**1.74**	**1.85**	**1.87**	**1.77**	**1.93**	**1.97**	**1.89**	**2.03**	**2.06**
Other Inputs[3]	**0.19**	**0.21**	**0.23**	**0.23**	**0.20**	**0.23**	**0.22**	**0.22**	**0.23**	**0.25**
Refinery Processing Gain[4]	**0.77**	**0.73**	**0.80**	**0.80**	**0.71**	**0.81**	**0.86**	**0.68**	**0.83**	**0.88**
Net Product Imports[5]	**0.93**	**2.51**	**1.76**	**1.55**	**4.15**	**2.82**	**2.49**	**5.19**	**3.34**	**2.92**
Total Primary Supply[6]	**17.24**	**19.28**	**18.69**	**18.52**	**21.10**	**19.92**	**19.64**	**22.30**	**20.71**	**20.30**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.48	8.22	8.10	8.04	8.58	8.36	8.25	8.72	8.41	8.20
Jet Fuel[8]	1.47	1.84	1.81	1.79	2.04	1.99	1.98	2.21	2.15	2.12
Distillate Fuel[9]	3.04	3.40	3.34	3.32	3.67	3.56	3.53	3.92	3.78	3.72
Residual Fuel	1.08	1.54	1.27	1.22	2.05	1.51	1.45	2.39	1.61	1.53
Other[10]	4.17	4.48	4.37	4.33	4.97	4.66	4.59	5.30	4.92	4.88
Total	**17.24**	**19.48**	**18.87**	**18.71**	**21.31**	**20.09**	**19.80**	**22.52**	**20.88**	**20.44**
Refined Petroleum Products Supplied										
Residential and Commercial	1.14	1.04	1.00	0.99	1.01	0.95	0.93	0.99	0.92	0.88
Industrial[11]	4.60	4.94	4.81	4.75	5.47	5.14	5.04	5.81	5.39	5.29
Transportation	11.08	12.84	12.66	12.58	13.77	13.45	13.31	14.40	13.98	13.72
Electric Generators[12]	0.41	0.66	0.41	0.38	1.05	0.55	0.51	1.32	0.59	0.55
Total	**17.24**	**19.48**	**18.87**	**18.71**	**21.31**	**20.10**	**19.80**	**22.52**	**20.88**	**20.44**
Discrepancy[13]	**0.00**	**-0.19**	**-0.18**	**-0.19**	**-0.20**	**-0.17**	**-0.15**	**-0.22**	**-0.17**	**-0.14**
World Oil Price (1993 dollars per barrel)[14]	**16.12**	**13.52**	**19.13**	**21.15**	**14.25**	**21.50**	**24.55**	**14.65**	**24.12**	**28.99**
Domestic Refinery Distillation Capacity	**15.3**	**15.7**	**15.7**	**15.7**	**16.0**	**15.8**	**15.7**	**16.0**	**15.9**	**15.8**
Capacity Utilization Rate (percent)	**92.0**	**90.0**	**89.7**	**89.8**	**89.9**	**90.0**	**90.0**	**90.0**	**90.0**	**90.0**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil plus 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 production plus other inputs plus refinery processing gain plus 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 byproduct of other processes.
[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: 1993: Energy Information Administration (EIA), *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) (Washington, DC, June 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C12. Petroleum Product Prices
(1993 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price (dollars per barrel)	16.12	13.52	19.13	21.15	14.25	21.50	24.55	14.65	24.12	28.99
Delivered Sector Product Prices										
Residential										
Distillate Fuel	90.8	93.9	106.7	111.3	95.0	114.3	121.1	97.9	120.7	132.3
Liquefied Petroleum Gas	89.8	88.6	103.3	108.2	91.0	109.8	117.8	92.9	117.2	130.1
Commercial										
Distillate Fuel	64.0	63.5	76.6	81.1	64.2	83.9	90.8	66.5	90.1	101.7
Residual Fuel	40.0	33.6	45.8	50.3	36.1	52.1	59.0	37.6	58.3	69.3
Residual Fuel (dollars per barrel)	16.80	14.13	19.25	21.15	15.17	21.87	24.77	15.77	24.47	29.12
Industrial[1]										
Distillate Fuel	66.3	63.5	76.6	81.1	64.7	84.1	91.1	67.4	90.5	102.3
Liquefied Petroleum Gas	41.9	48.6	62.0	66.9	51.1	68.3	76.7	53.0	75.0	88.3
Residual Fuel	35.1	31.5	43.9	48.4	33.6	50.0	56.9	35.0	56.1	67.2
Residual Fuel (dollars per barrel)	14.74	13.23	18.45	20.34	14.13	20.99	23.91	14.68	23.58	28.24
Transportation										
Distillate Fuel[2]	111.6	110.1	123.3	127.8	108.7	127.8	135.0	108.4	131.6	143.4
Jet Fuel[3]	57.8	65.6	78.2	82.8	67.2	87.3	93.8	68.9	92.5	104.1
Motor Gasoline[4]	111.7	118.2	129.5	133.0	117.4	135.9	141.9	115.9	137.7	148.1
Residual Fuel	31.0	28.5	41.4	46.1	31.0	47.4	54.6	32.5	53.8	65.3
Residual Fuel (dollars per barrel)	13.00	11.96	17.37	19.36	13.02	19.90	22.93	13.64	22.59	27.43
Electric Generators[5]										
Distillate Fuel	65.5	57.8	73.0	77.6	57.4	76.8	84.6	59.9	81.9	93.5
Residual Fuel	36.9	30.6	43.4	48.2	33.5	49.5	56.4	35.2	55.4	66.5
Residual Fuel (dollars per barrel)	15.49	12.83	18.24	20.23	14.09	20.77	23.67	14.77	23.26	27.94
Refined Petroleum Product Prices[6]										
Distillate Fuel	97.4	97.3	110.5	115.1	97.0	116.4	123.5	97.8	121.2	133.0
Jet Fuel	57.8	65.6	78.2	82.8	67.2	87.3	93.8	68.9	92.5	104.1
Liquefied Petroleum Gas	51.2	56.5	70.1	75.1	59.0	76.8	85.2	61.2	84.1	97.6
Motor Gasoline	111.7	117.9	129.2	132.7	117.2	135.7	141.7	115.7	137.5	147.9
Residual Fuel	34.4	30.1	42.7	47.4	32.8	48.8	55.8	34.4	54.9	66.2
Residual Fuel (dollars per barrel)	14.47	12.63	17.94	19.89	13.79	20.48	23.43	14.44	23.06	27.80
Average	**89.4**	**91.0**	**104.2**	**108.4**	**89.4**	**109.6**	**116.5**	**88.4**	**113.0**	**124.3**

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]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 byproduct of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1993: Prices for gasoline, distillate, and jet fuel are based on prices in various 1993 issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(93/1-12) (Washington, DC, 1993). Prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, DC, September 1993). **Projections**: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Dry Gas Production[1]	18.35	18.22	19.08	19.32	18.28	19.94	20.29	19.44	20.88	21.19
Supplemental Natural Gas[2]	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.07	0.08	0.08
Net Imports	**2.13**	**2.90**	**2.90**	**2.90**	**3.00**	**3.00**	**3.00**	**3.19**	**3.60**	**3.64**
Canada	2.14	2.65	2.65	2.65	2.69	2.69	2.69	2.71	2.71	2.71
Mexico	-0.04	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.17	0.17	0.17
Liquefied Natural Gas	0.03	0.25	0.25	0.25	0.30	0.30	0.30	0.30	0.71	0.76
Total Supply	**20.61**	**21.24**	**22.09**	**22.33**	**21.39**	**23.06**	**23.41**	**22.70**	**24.55**	**24.91**
Consumption by Sector										
Residential	4.96	5.00	5.01	5.01	4.93	4.89	4.90	4.92	4.89	4.91
Commercial	2.89	2.94	2.95	2.95	2.94	2.94	2.95	2.95	2.97	2.97
Industrial[3]	7.61	8.32	8.68	8.84	8.40	9.01	9.23	8.79	9.50	9.72
Electric Generators[4]	2.94	2.94	3.34	3.40	2.96	3.92	3.98	3.65	4.72	4.77
Lease and Plant Fuel[5]	1.20	1.28	1.33	1.34	1.28	1.38	1.40	1.36	1.44	1.46
Pipeline Fuel	0.61	0.62	0.65	0.66	0.62	0.65	0.67	0.63	0.65	0.66
Transportation[6]	0.01	0.16	0.15	0.16	0.29	0.29	0.29	0.42	0.42	0.44
Total	**20.21**	**21.26**	**22.12**	**22.37**	**21.41**	**23.08**	**23.42**	**22.71**	**24.59**	**24.93**
Discrepancy[7]	**0.40**	**-0.02**	**-0.03**	**-0.03**	**-0.02**	**-0.02**	**-0.01**	**-0.02**	**-0.03**	**-0.03**

[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 byproduct 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. 1993 values reflect net storage injections plus 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.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1993 may differ from published data due to internal conversion factors in the AEO95 National Energy Modeling System.

Sources: 1993 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 transportation sector consumption: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. Other 1993 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO95 National Energy System Modeling runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942. **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C14. Natural Gas Prices, Margins, and Revenue
(1993 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Source Price										
Average Lower 48 Wellhead Price[1]	2.02	2.03	2.14	2.16	2.62	3.02	3.07	2.88	3.39	3.51
Average Import Price	2.01	1.86	2.01	2.18	2.63	3.16	3.24	2.88	3.49	3.56
Average[2]	**2.02**	**2.01**	**2.12**	**2.16**	**2.62**	**3.04**	**3.10**	**2.88**	**3.41**	**3.52**
Delivered Prices										
Residential	6.19	5.92	6.06	6.11	6.46	6.92	6.98	6.58	7.13	7.23
Commercial	5.18	4.94	5.08	5.13	5.51	5.97	6.03	5.68	6.22	6.31
Industrial[3]	2.87	2.95	3.05	3.04	3.55	3.92	3.96	3.80	4.30	4.41
Electric Generators[4]	2.63	2.38	2.65	2.71	3.03	3.45	3.61	3.37	3.82	4.06
Transportation[5]	4.80	6.43	6.56	6.59	8.06	8.60	8.64	8.21	8.94	9.02
Average[6]	**4.09**	**3.96**	**4.06**	**4.07**	**4.57**	**4.88**	**4.94**	**4.75**	**5.16**	**5.28**
Transmission and Distribution Margins by Sector[7]										
Residential	4.17	3.91	3.94	3.95	3.84	3.89	3.89	3.69	3.72	3.71
Commercial	3.15	2.94	2.96	2.97	2.90	2.94	2.93	2.80	2.82	2.79
Industrial[3]	0.85	0.94	0.93	0.88	0.93	0.88	0.86	0.92	0.90	0.89
Electric Generators[4]	0.61	0.37	0.53	0.55	0.41	0.41	0.51	0.49	0.41	0.54
Transportation[5]	2.78	4.42	4.44	4.43	5.44	5.56	5.55	5.33	5.53	5.50
Average	**2.07**	**1.96**	**1.94**	**1.91**	**1.95**	**1.85**	**1.84**	**1.86**	**1.75**	**1.77**
Transmission and Distribution Revenue (billion 1993 dollars)										
Residential	20.66	19.56	19.75	19.82	18.90	19.00	19.06	18.18	18.21	18.20
Commercial	9.12	8.64	8.74	8.76	8.50	8.64	8.64	8.26	8.36	8.30
Industrial[3]	6.48	7.86	8.07	7.79	7.81	7.96	7.95	8.11	8.51	8.67
Electric Generators[4]	1.79	1.08	1.78	1.88	1.21	1.63	2.04	1.80	1.93	2.58
Transportation[5]	0.02	0.69	0.69	0.69	1.57	1.59	1.62	2.24	2.30	2.45
Total	**38.07**	**37.83**	**39.03**	**38.94**	**37.99**	**38.81**	**39.31**	**38.59**	**39.32**	**40.21**

[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 electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average price and margin. 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, and other services. As used here, the term includes the cost of all of these services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1993: Residential delivered price, average lower 48 wellhead price, and average import price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). **Other values, and projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C15. Oil and Gas Supply

Production and Supply	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (1993 dollars per barrel)	15.36	13.32	18.47	20.31	13.99	20.58	23.32	14.35	22.92	27.27
Production (million barrels per day)[2]										
U.S. Total	6.85	4.61	5.35	5.70	3.86	5.16	5.73	3.58	5.39	6.20
Lower 48 Onshore	4.18	3.03	3.53	3.71	2.73	3.70	4.04	2.76	3.96	4.41
Conventional	3.55	2.61	2.86	2.96	2.39	2.91	3.09	2.38	3.01	3.24
Enhanced Oil Recovery	0.62	0.42	0.67	0.75	0.34	0.79	0.95	0.38	0.95	1.17
Lower 48 Offshore	1.09	0.56	0.66	0.71	0.44	0.63	0.70	0.43	0.66	0.79
Alaska	1.58	1.02	1.16	1.29	0.69	0.83	0.99	0.40	0.77	1.00
U.S. End of Year Reserves (billion barrels)	23.30	15.74	17.59	18.51	12.85	16.12	17.44	11.41	16.97	18.57
Natural Gas										
Lower 48 Average Wellhead Price[1] (1993 dollars per thousand cubic feet)	2.02	2.03	2.14	2.16	2.62	3.02	3.07	2.88	3.39	3.51
Production (trillion cubic feet)[3]										
U.S. Total	18.35	18.22	19.08	19.32	18.28	19.94	20.29	19.44	20.88	21.19
Lower 48 Onshore	12.96	13.38	13.81	13.93	13.78	14.72	14.92	14.88	15.88	16.32
Associated-Dissolved[4]	2.21	1.42	1.55	1.60	1.34	1.67	1.78	1.37	1.80	1.95
Non-Associated	10.75	11.97	12.26	12.34	12.45	13.04	13.14	13.51	14.08	14.36
Conventional	8.68	9.47	9.70	9.74	9.85	10.28	10.30	10.80	11.05	11.14
Unconventional	2.07	2.50	2.57	2.60	2.59	2.77	2.84	2.71	3.02	3.22
Tight Sands	1.36	1.25	1.29	1.31	1.25	1.43	1.52	1.49	1.84	2.00
Coal Bed Methane	0.55	1.10	1.13	1.13	1.21	1.18	1.17	1.07	1.01	1.03
Devonian Shale	0.15	0.14	0.15	0.16	0.14	0.16	0.16	0.15	0.17	0.19
Lower 48 Offshore	4.98	4.34	4.76	4.88	4.01	4.73	4.88	4.08	4.53	4.40
Associated-Dissolved[4]	0.61	0.32	0.37	0.39	0.25	0.36	0.40	0.25	0.39	0.45
Non-Associated	4.37	4.02	4.40	4.50	3.76	4.38	4.48	3.83	4.14	3.94
Alaska	0.41	0.50	0.50	0.50	0.49	0.49	0.49	0.47	0.47	0.47
U.S. End of Year Reserves (trillion cubic feet)	167.78	141.80	145.67	146.91	138.70	147.48	149.09	143.01	152.48	152.72
Supplemental Gas Supplies (trillion cubic feet)[5]	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.07	0.08	0.08
Lower 48 Wells Completed (thousands)	23.06	22.82	28.07	30.19	35.05	44.53	47.68	44.20	57.75	63.18

[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.

Sources: 1993 total wells completed: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(94/06) (Washington, DC, June 1994). 1993 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0384(93) (Washington, DC, June 1994). 1993 natural gas lower 48 average wellhead price, and total natural gas production: *Natural Gas Monthly*, DOE/EIA-0130(94/06) (Washington, DC, June 1994). Other 1993 values: EIA, Office of Integrated Analysis and Forecasting. Figures for 1993 may differ from published data due to internal conversion factors within the AEO95 National Energy Modeling System.
Projections: EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Supply, Disposition, and Prices	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production[1]										
East of the Mississippi	516	567	589	590	578	591	601	621	629	634
West of the Mississippi	429	452	439	436	490	485	476	501	508	508
Total	**945**	**1019**	**1027**	**1026**	**1068**	**1076**	**1078**	**1122**	**1137**	**1141**
Net Imports										
Imports	7	13	13	13	14	14	14	15	15	15
Exports	75	88	87	87	99	100	100	123	115	115
Total	**-67**	**-74**	**-74**	**-73**	**-85**	**-86**	**-86**	**-108**	**-100**	**-100**
Total Supply[2]	**877**	**945**	**953**	**953**	**983**	**990**	**992**	**1015**	**1037**	**1041**
Consumption by Sector										
Residential and Commercial	6	7	7	7	6	6	6	6	6	6
Industrial[3]	75	85	86	87	89	93	94	92	97	98
Coke Plants	31	29	29	29	25	25	25	22	22	22
Electric Generators[4]	814	827	832	832	864	868	867	896	913	916
Total	**926**	**947**	**954**	**955**	**985**	**992**	**993**	**1016**	**1039**	**1043**
Discrepancy and Stock Change[5]	**-49**	**-3**	**0**	**-2**	**-2**	**-2**	**-1**	**-1**	**-1**	**-1**
Average Minemouth Price (1993 dollars per short ton)	**19.85**	**20.40**	**20.34**	**20.74**	**21.56**	**21.55**	**22.09**	**21.39**	**22.77**	**23.68**
Delivered Prices (1993 dollars per short ton)[6]										
Industrial	32.23	29.71	31.32	31.76	30.40	31.90	32.40	31.06	33.25	34.42
Coke Plants	47.44	45.23	45.96	46.30	45.81	46.64	47.07	44.98	47.26	48.46
Electric Generators	28.60	29.44	29.06	29.46	30.65	30.38	31.00	30.08	31.43	32.44
Average[7]	**29.54**	**29.95**	**29.78**	**30.18**	**31.02**	**30.94**	**31.54**	**30.49**	**31.94**	**32.97**
Average Price to All Users (1993 dollars per million Btu)	1.41	1.40	1.40	1.42	1.45	1.45	1.48	1.43	1.50	1.55
Exports[8]	41.41	40.12	41.03	41.74	42.24	42.62	42.86	41.07	43.52	44.58

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produces electricity as a byproduct of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Weighted average excludes residential and commercial prices; sectoral prices weighted by consumption tonnage.
[7]Weighted average excluded residential and commercial prices.
[8]Free-alongside-ship (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: 1993: Production and minemouth price: Energy Information Administration (EIA), *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Imports, exports, consumption, and other prices: EIA, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C17. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electric Utilities and Nonutilities[1] (excluding cogenerators)										
Capability (gigawatts)										
Conventional Hydropower	76.74	79.27	79.27	79.27	79.65	79.65	79.65	79.81	79.81	79.81
Geothermal[2]	2.96	3.42	3.42	3.42	3.44	3.44	3.44	4.13	4.57	4.73
Municipal Solid Waste	2.59	3.53	3.51	3.51	4.37	4.35	4.34	5.17	5.14	5.12
Biomass/Other Waste[3]	1.50	1.75	1.75	1.75	1.87	1.95	1.89	2.02	2.73	3.19
Solar	0.34	0.47	0.54	0.54	0.73	0.79	0.79	1.28	1.37	1.35
Wind[4]	1.76	3.00	3.05	3.07	3.51	4.18	4.21	7.38	10.04	11.20
Total	**85.89**	**91.44**	**91.55**	**91.56**	**93.56**	**94.34**	**94.31**	**99.79**	**103.65**	**105.40**
Generation (billion kilowatthours)[1]										
Conventional Hydropower	275.73	303.10	303.10	303.10	305.23	305.22	305.22	306.30	306.30	306.30
Geothermal[2]	17.32	20.55	20.55	20.55	20.43	20.45	20.40	25.23	28.21	29.34
Municipal Solid Waste	17.75	23.66	23.58	23.55	29.93	29.75	29.68	35.94	35.71	35.61
Biomass/Other Waste[3]	7.46	11.08	11.09	11.08	11.95	12.45	12.18	13.06	17.90	21.08
Solar	0.90	1.22	1.50	1.50	2.27	2.52	2.53	4.55	4.90	4.76
Wind[4]	3.05	6.22	6.33	6.36	7.58	9.37	9.42	17.77	25.22	28.31
Total	**322.21**	**365.85**	**366.14**	**366.14**	**377.40**	**379.76**	**379.43**	**402.86**	**418.24**	**425.40**
Consumption										
Conventional Hydropower	2.84	3.12	3.12	3.12	3.14	3.14	3.14	3.16	3.16	3.16
Geothermal[2]	0.36	0.52	0.52	0.52	0.57	0.57	0.57	0.75	0.83	0.89
Municipal Solid Waste	0.29	0.39	0.38	0.38	0.49	0.48	0.48	0.59	0.58	0.58
Biomass/Other Waste[3]	0.09	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.19	0.22
Solar	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.05	0.05	0.05
Wind[4]	0.03	0.06	0.07	0.07	0.08	0.10	0.10	0.18	0.26	0.29
Total	**3.63**	**4.24**	**4.24**	**4.24**	**4.44**	**4.46**	**4.46**	**4.86**	**5.06**	**5.19**
Cogenerators[5]										
Capacity (gigawatts)										
Conventional Hydropower	0.97	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Municipal Solid Waste	0.31	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Biomass/Other Waste	5.60	5.61	5.62	5.62	5.63	5.66	5.67	5.66	5.71	5.72
Total	**6.87**	**7.40**	**7.41**	**7.41**	**7.43**	**7.46**	**7.46**	**7.45**	**7.51**	**7.51**
Generation (billion kilowatthours)										
Conventional Hydropower	3.24	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48
Municipal Solid Waste	1.54	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
Biomass/Other Waste	30.70	31.66	31.71	31.71	31.80	31.97	31.99	31.94	32.24	32.26
Total	**35.48**	**38.03**	**38.08**	**38.09**	**38.17**	**38.34**	**38.36**	**38.31**	**38.61**	**38.64**
Consumption										
Conventional Hydropower	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Biomass/Other Waste	0.64	0.72	0.72	0.72	0.78	0.78	0.77	0.83	0.82	0.82
Total	**0.69**	**0.79**	**0.78**	**0.78**	**0.85**	**0.84**	**0.84**	**0.89**	**0.88**	**0.88**
Non-electric										
Non-electric Renewable Energy Consumption										
Geothermal[6]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Biofuels[7]	2.09	2.33	2.32	2.31	2.50	2.48	2.47	2.63	2.61	2.59
Solar Thermal[8]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Ethanol	0.07	0.12	0.13	0.15	0.13	0.19	0.23	0.17	0.23	0.30
Total	**2.22**	**2.55**	**2.55**	**2.56**	**2.75**	**2.78**	**2.80**	**2.93**	**2.96**	**3.02**

Table C17. Renewable Energy (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Non-electric	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Renewable Energy Consumption[9]										
Conventional Hydropower	2.87	3.16	3.16	3.16	3.18	3.18	3.18	3.19	3.19	3.19
Geothermal	0.37	0.54	0.54	0.54	0.60	0.60	0.60	0.79	0.86	0.93
Municipal Solid Waste	0.31	0.42	0.41	0.41	0.52	0.52	0.51	0.62	0.61	0.61
Biofuels	2.82	3.19	3.17	3.16	3.42	3.40	3.38	3.59	3.61	3.63
Solar	0.07	0.09	0.09	0.09	0.11	0.11	0.11	0.14	0.14	0.14
Wind	0.03	0.06	0.07	0.07	0.08	0.10	0.10	0.18	0.26	0.29
Ethanol	0.07	0.12	0.13	0.15	0.13	0.19	0.23	0.17	0.23	0.30
Total	**6.55**	**7.58**	**7.57**	**7.58**	**8.03**	**8.08**	**8.10**	**8.68**	**8.91**	**9.09**

[1]Grid connected only.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Does not include projections for energy crops.
[4]Includes horizontal-axis wind turbines only.
[5]Includes generators and cogenerators at facilities whose primary function is not electricity production (standard industrial classification 49). In general, biomass and other waste facilities are cogenerators, while the remaining renewables produce only electricity.
[6]Residential and commercial ground-source heat pumps.
[7]Residential and industrial wood and wood waste.
[8]Residential and commercial water heating.
[9]Actual heat rates used to determine fuel consumption for all renewable sources except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined using the fossil fuel equivalent of 10,302 Btu per kilowatthour.

Btu = British thermal unit.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capacity has been estimated for nonutility generators for AEO95. Net summer capacity is used to be consistent with the electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 15, 1994. Additional retirements are also determined based on the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1993: Electric utility capacity: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." Nonutility and cogenerator capacity: Form EIA-867, "Annual Nonutility Power Producer Report." Generation: EIA, *Annual Energy Review*, DOE/EIA-0384(93) (Washington, DC, July 1994). Ethanol: EIA, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93/1) (Washington, DC, June 1994). Nonutility consumption other than ethanol: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C18. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential										
Petroleum	25.3	23.4	22.6	22.3	22.4	21.3	20.7	21.8	20.4	19.4
Natural Gas	73.6	74.2	74.4	74.4	73.1	72.6	72.8	73.1	72.6	72.8
Coal	1.5	1.6	1.6	1.6	1.5	1.5	1.5	1.4	1.4	1.4
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**100.3**	**99.2**	**98.6**	**98.3**	**97.1**	**95.4**	**94.9**	**96.3**	**94.4**	**93.7**
Commercial										
Petroleum	16.1	14.3	13.8	13.7	14.3	13.4	13.2	14.4	13.1	12.9
Natural Gas	43.2	43.7	43.8	43.8	43.6	43.7	43.7	43.8	44.1	44.1
Coal	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**61.5**	**60.2**	**59.9**	**59.7**	**60.2**	**59.4**	**59.2**	**60.5**	**59.5**	**59.3**
Industrial[1]										
Petroleum	95.4	103.5	99.1	96.9	115.1	105.0	101.7	121.3	108.9	105.4
Natural Gas[2]	127.8	138.6	144.6	147.2	139.6	150.1	153.6	146.3	158.2	161.7
Coal	62.4	65.1	66.2	66.4	65.1	67.4	67.9	65.0	68.0	68.9
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**285.6**	**307.2**	**309.9**	**310.4**	**319.8**	**322.5**	**323.2**	**332.6**	**335.1**	**335.9**
Transportation										
Petroleum	427.4	488.0	480.8	477.8	523.9	511.1	505.7	547.9	531.4	521.4
Natural Gas[3]	9.0	11.5	12.0	12.1	13.4	13.9	14.2	15.5	15.8	16.3
Renewable/Other[4]	0.0	0.1	0.2	0.3	0.1	0.5	1.1	0.2	0.8	1.9
Total	**436.4**	**499.5**	**492.9**	**490.3**	**537.5**	**525.5**	**521.0**	**563.7**	**548.1**	**539.6**
Electric Generators[5]										
Petroleum	22.9	32.0	19.9	18.6	51.3	27.0	24.9	64.1	28.8	26.6
Natural Gas	41.7	43.3	49.2	50.1	43.6	57.7	58.6	53.7	69.4	70.2
Steam Coal	427.1	440.1	440.5	440.5	461.7	461.6	461.2	478.7	485.5	487.4
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**491.7**	**515.4**	**509.6**	**509.2**	**556.6**	**546.3**	**544.8**	**596.5**	**583.7**	**584.2**
Total Energy Consumption										
Petroleum	587.1	661.1	636.2	629.2	727.0	677.8	666.3	769.6	702.7	685.7
Natural Gas	295.2	311.2	324.0	327.6	313.3	338.0	343.0	332.4	360.1	365.2
Coal	493.2	509.0	510.5	510.7	530.6	532.7	532.8	547.4	557.2	560.0
Renewable Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other[4]	0.0	0.1	0.2	0.3	0.1	0.5	1.1	0.2	0.8	1.9
Total	**1375.5**	**1481.5**	**1470.9**	**1467.9**	**1571.1**	**1549.0**	**1543.2**	**1649.7**	**1620.8**	**1612.7**

[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, liquid hydrogen, and lubricants.
[5]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, Table 6 and Table A1, DOE/EIA-0573(94) (Washington, DC, October 1994). Note that sectoral totals have been adjusted to reflect AEO95 National Energy Modeling System definitions. **Consumption projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Table C19. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
GDP Implicit Price Deflator (index 1987=1.000)	**1.242**	**1.482**	**1.491**	**1.494**	**1.742**	**1.755**	**1.760**	**2.062**	**2.074**	**2.082**
Real Gross Domestic Product	**5136**	**6163**	**6126**	**6113**	**6904**	**6852**	**6834**	**7537**	**7485**	**7456**
Real Consumption	3453	4064	4035	4024	4442	4399	4384	4795	4748	4723
Real Investment	820	1187	1175	1171	1402	1385	1379	1565	1547	1536
Real Government Spending	939	1009	1003	1001	1085	1077	1074	1151	1143	1138
Real Exports	598	945	938	935	1310	1297	1292	1643	1625	1616
Real Imports	674	1042	1025	1019	1336	1306	1295	1617	1578	1557
Real Disposable Personal Income	**3701**	**4400**	**4371**	**4360**	**4804**	**4764**	**4750**	**5180**	**5140**	**5118**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.097**	**1.315**	**1.306**	**1.303**	**1.481**	**1.469**	**1.465**	**1.609**	**1.598**	**1.591**
AA Utility Bond Rate (percent)	7.43	8.30	8.41	8.46	8.07	8.24	8.29	7.86	7.99	8.06
90-Day U.S. Government Treasury Bill Rate (percent)	3.00	4.60	4.66	4.68	4.48	4.53	4.53	4.43	4.37	4.35
Real Yield on Government 10 Year Bonds (percent)	3.23	4.08	4.13	4.15	3.28	3.50	3.59	3.19	3.51	3.64
Real 90-Day U.S. Government Treasury Bill Rate (percent)	0.44	1.54	1.61	1.63	1.19	1.17	1.17	1.03	1.01	0.90
Real Utility Bond Rate (percent)	4.87	5.24	5.36	5.40	4.78	4.87	4.93	4.45	4.64	4.62
Energy Intensity (thousand Btu per 1987 dollar of GDP)	**16.99**	**15.40**	**15.44**	**15.46**	**14.49**	**14.50**	**14.51**	**13.89**	**13.88**	**13.88**
Consumer Price Index (1982=1.00)	1.45	1.79	1.81	1.82	2.16	2.19	2.20	2.60	2.64	2.66
Employment Cost Index (1987=1.00)	1.15	1.44	1.44	1.44	1.75	1.75	1.75	2.15	2.14	2.14
Unemployment Rate (percent)	7.42	6.09	6.28	6.35	5.82	6.00	6.05	6.36	6.47	6.54
Million Units										
Truck Deliveries, Light-Duty	5.20	6.57	6.35	6.28	7.52	7.17	7.06	7.40	7.05	6.84
Unit Sales of Automobiles	8.71	9.71	9.59	9.54	10.12	9.92	9.86	10.35	10.17	10.06
U.S. Trade-Weighted Exchange Rate	**1.00**	**0.95**	**0.95**	**0.95**	**0.90**	**0.90**	**0.90**	**0.87**	**0.87**	**0.87**
Millions of People										
Population with Armed Forces Overseas	258.4	275.6	275.6	275.6	287.1	287.1	287.1	298.9	298.9	298.9
Population (aged 16 and over)	198.2	212.8	212.8	212.8	223.8	223.8	223.8	235.4	235.4	235.4
Employment, Non-Agriculture	107.9	120.8	120.4	120.3	129.3	128.9	128.8	133.7	133.5	133.3

GDP = Gross domestic product.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1993: Data Resources Incorporated (DRI), DRI Trend0294. **Projections:** Energy Information Administration, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

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

Supply and Disposition	1993	Projections								
		2000			2005			2010		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price (1993 dollars per barrel)[1]	16.12	13.52	19.13	21.15	14.25	21.50	24.55	14.65	24.12	28.99
Production[2]										
U.S. (50 states)	9.53	7.29	8.24	8.64	6.57	8.20	8.87	6.42	8.58	9.54
Canada	2.10	2.03	2.17	2.22	2.19	2.42	2.50	2.07	2.34	2.44
OECD Europe[3]	5.17	6.28	6.38	6.42	5.07	5.22	5.27	4.48	4.67	4.74
OPEC	27.02	40.64	36.01	34.28	51.43	42.68	39.66	58.88	46.67	42.19
Rest of the World[4]	11.67	12.52	12.84	12.95	11.53	12.05	12.22	11.05	11.77	12.03
Total Production	**55.48**	**68.76**	**65.65**	**64.50**	**76.80**	**70.58**	**68.54**	**82.91**	**74.03**	**70.94**
Net Eurasian Exports	**1.33**	**1.84**	**1.24**	**1.24**	**2.52**	**1.42**	**1.42**	**3.20**	**1.60**	**1.60**
Total Supply	**56.78**	**70.60**	**66.89**	**65.74**	**79.32**	**72.00**	**69.96**	**86.11**	**75.63**	**72.54**
Consumption										
U.S. (50 states)	17.24	19.48	18.88	18.70	21.34	20.10	19.80	22.53	20.89	20.44
U.S. Territories	0.22	0.30	0.26	0.25	0.36	0.29	0.27	0.40	0.30	0.28
Canada	1.69	2.14	1.94	1.87	2.42	2.02	1.91	2.65	2.08	1.91
Japan	5.45	7.75	7.02	6.79	9.27	7.67	7.22	10.56	8.05	7.34
Australia & New Zealand	0.84	0.99	0.96	0.95	1.10	1.03	1.01	1.19	1.10	1.07
OECD Europe	13.48	17.09	15.87	15.49	18.80	16.64	16.01	19.85	16.97	16.08
Rest of the World[4]	18.16	23.16	22.27	21.99	26.34	24.56	24.03	29.22	26.55	25.72
Total Consumption	**57.08**	**70.90**	**67.19**	**66.04**	**79.62**	**72.30**	**70.26**	**86.41**	**75.93**	**72.84**
Discrepancy	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**
Consumption Aggregations										
OECD	38.92	47.74	44.92	44.05	53.27	47.75	46.23	57.19	49.38	47.12
OPEC	5.05	5.89	5.89	5.89	6.51	6.51	6.51	7.18	7.18	7.18
Rest of the World[4]	13.11	17.27	16.38	16.10	19.84	18.05	17.52	22.03	19.37	18.53
Non-OPEC Production[4]	**28.47**	**28.12**	**29.63**	**30.22**	**25.36**	**27.90**	**28.88**	**24.03**	**27.36**	**28.75**
OPEC Summary										
Market Share	0.47	0.57	0.54	0.52	0.65	0.59	0.56	0.68	0.61	0.58
Production Capacity[5]	31.30	38.40	38.40	38.40	44.10	44.10	44.10	47.75	47.75	47.75
Capacity Utilization	0.86	1.06	0.94	0.89	1.17	0.97	0.90	1.23	0.98	0.88

[1]The average cost to domestic refiners of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
[4]Does not include Eurasia.
[5]Maximum sustainable production capacity.

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

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.

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

Sources: 1993: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(94/3Q) (Washington, DC, August 1994). **Projections:** EIA, AEO95 National Energy Modeling System runs LWOP95.D1103941, AEO95B.D1103942, and HWOP95.D1103942.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Crude Oil Equivalency Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1993-2010 (percent)
	1992	1993	2000	2005	2010	
Production						
Crude Oil and Lease Condensate	7.17	6.85	5.35	5.16	5.39	-1.4%
Natural Gas Plant Liquids	1.11	1.14	1.21	1.27	1.33	0.9%
Dry Natural Gas	8.66	8.93	9.26	9.70	10.16	0.8%
Coal	10.17	9.56	10.40	10.96	11.58	1.1%
Nuclear Power	3.11	3.08	3.28	3.29	3.01	-0.1%
Renewable Energy/Other[1]	3.36	3.34	3.73	3.98	4.37	1.6%
Total	**33.59**	**32.89**	**33.23**	**34.37**	**35.84**	**0.5%**
Imports						
Crude Oil[2]	6.10	6.81	8.82	9.08	9.00	1.6%
Petroleum Products[3]	1.76	1.79	2.45	3.35	3.84	4.6%
Natural Gas	1.03	1.09	1.49	1.57	1.88	3.2%
Other Imports[4]	0.20	0.24	0.33	0.35	0.47	4.2%
Total	**9.09**	**9.93**	**13.09**	**14.35**	**15.18**	**2.5%**
Exports						
Petroleum[5]	0.94	1.00	0.93	0.80	0.77	-1.5%
Natural Gas	0.10	0.07	0.10	0.13	0.15	4.5%
Coal	1.26	0.93	1.05	1.20	1.36	2.3%
Total	**2.31**	**1.99**	**2.08**	**2.12**	**2.28**	**0.8%**
Discrepancy[6]	**-0.04**	**0.39**	**0.32**	**0.34**	**0.34**	**-0.9%**
Consumption						
Petroleum Products[7]	15.81	15.92	17.38	18.57	19.28	1.1%
Natural Gas	9.49	9.83	10.73	11.22	11.95	1.2%
Coal	8.89	9.18	9.49	9.93	10.38	0.7%
Nuclear Power	3.11	3.08	3.28	3.29	3.01	-0.1%
Renewable Energy/Other[8]	3.03	3.21	3.69	3.93	4.45	1.9%
Total	**40.33**	**41.22**	**44.57**	**46.94**	**49.07**	**1.0%**
Net Imports - Petroleum	**6.92**	**7.61**	**10.34**	**11.64**	**12.06**	**2.7%**
Prices (1993 dollars per unit)						
World Oil Price (dollars per barrel)[9]	18.70	16.12	19.13	21.50	24.12	2.4%
Gas Wellhead Price (dollars per thousand cubic feet)[10]	1.80	2.02	2.14	3.02	3.39	3.1%
Coal Minemouth Price (dollars per ton)	21.57	19.85	20.34	21.55	22.77	0.8%

[1]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[2]Includes imports of crude oil for the Strategic Petroleum Reserve.
[3]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[4]Includes coal, coal coke (net), and electricity (net).
[5]Includes crude oil and petroleum products.
[6]Balancing item. Includes unaccounted for supply, losses, and gains.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[8]Includes utility and nonutility electricity from hydroelectric, geothermal, 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, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, net coal coke imports, net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1992 and 1993 may differ from published data due to internal conversion factors.

Sources: 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992, Volume 1*, DOE/EIA-0131(92)/1 (Washington, DC, November 1993). 1992 coal minemouth prices: EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993). Other 1992 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). 1993 natural gas prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(94/6) (Washington, DC, June 1994). 1993 coal minemouth price: EIA, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994). Other 1993 values: EIA, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994). **Projections:** EIA, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table E1. 1993 Average Household Expenditures for Energy by Household Characteristic
(1993 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2203**	**1201**	**787**	**343**	**71**	**1002**
Households by Income Quintile						
1st	1400	895	550	289	56	505
2nd	1752	990	645	292	53	762
3rd	2252	1143	771	306	66	1110
4th	2508	1320	891	357	73	1188
5th	3103	1673	1084	480	108	1431
Households by Race						
African American	1954	1148	664	442	42	806
All Others	2235	12078	803	330	74	1027
Households by Census Division						
New England	2501	1541	804	353	384	959
Middle Atlantic	2397	1549	783	517	249	848
South Atlantic	2204	1196	654	506	36	1008
East North Central	2092	1071	634	413	24	1021
East South Central	2099	1164	950	186	28	935
West North Central	2333	1175	958	211	6	1159
West South Central	2228	1225	950	275	0	1002
Mountain	2203	1004	651	348	5	1200
Pacific	2012	921	683	233	5	1091

Source: Energy Information Administration, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table E2. 2000 Average Household Expenditures for Energy by Household Characteristics
(1993 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2359**	**1175**	**784**	**321**	**70**	**1184**
Households by Income Quintile						
1st	1478	876	549	270	56	603
2nd	1868	968	643	274	52	899
3rd	2431	1118	766	287	65	1313
4th	2693	1291	885	332	74	1402
5th	3324	1637	1081	449	107	1687
Households by Race						
African American	2077	1113	659	412	42	964
All Others	2396	1183	800	309	74	1213
Households by Census Division						
New England	2670	1529	773	359	398	1141
Middle Atlantic	2580	1530	793	483	254	1051
South Atlantic	2308	1150	636	478	36	1158
East North Central	2270	1049	640	387	22	1222
East South Central	2189	1122	927	170	25	1066
West North Central	2508	1130	916	208	5	1379
West South Central	2507	1207	942	265	0	1300
Mountain	2340	977	652	321	4	1364
Pacific	2197	939	715	219	5	1258

Source: Energy Information Administration, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table E3. 2005 Average Household Expenditures for Energy by Household Characteristic
(1993 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2447**	**1219**	**806**	**344**	**69**	**1227**
Households by Income Quintile						
1st	1534	909	564	289	55	625
2nd	1939	1006	661	295	51	932
3rd	2519	1159	787	309	64	1360
4th	2790	1339	911	355	73	1452
5th	3448	1701	1115	482	105	1747
Households by Race						
African American	2157	1155	678	437	41	1002
All Others	2485	1228	823	332	73	1257
Households by Census Division						
New England	2738	1579	791	402	386	1159
Middle Atlantic	2696	1585	827	506	252	1111
South Atlantic	2413	1196	642	517	37	1217
East North Central	2369	1091	637	433	21	1278
East South Central	2248	1144	943	179	23	1104
West North Central	2572	1147	921	220	5	1426
West South Central	2596	1245	970	275	0	1351
Mountain	2448	1065	702	359	4	1384
Pacific	2284	1006	755	247	5	1278

Source: Energy Information Administration, AEO95 National Energy Modeling System run AEO95B.D1103942.

Table E4. 2010 Average Household Expenditures for Energy by Household Characteristic
(1993 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2463**	**1266**	**857**	**341**	**68**	**1197**
Households by Income Quintile						
1st	1550	940	598	287	55	610
2nd	1952	1043	701	293	50	909
3rd	2530	1204	834	307	63	1326
4th	2806	1391	968	352	72	1415
5th	3474	1771	1190	478	103	1703
Households by Race						
African American	2168	1192	719	433	40	976
All Others	2502	1276	875	329	72	1226
Households by Census Division						
New England	2732	1639	850	406	384	1092
Middle Atlantic	2739	1642	895	499	248	1096
South Atlantic	2426	1229	673	519	37	1197
East North Central	2380	1131	682	428	21	1249
East South Central	2270	1199	998	179	22	1071
West North Central	2566	1192	963	223	5	1374
West South Central	2596	1281	1007	274	0	1315
Mountain	2418	1086	729	353	4	1333
Pacific	2327	1070	818	248	5	1257

Source: Energy Information Administration, AEO95 National Energy Modeling System run AEO95B.D1103942.

Detailed Comparative Forecasts

Table F1. Comparison of Electricity Forecasts
(Billion Kilowatthours, Except Where Noted)

Projection	EIA *AEO95*			Other Forecasts					
	Reference	Low Economic Growth	High Economic Growth	WEFA	GRI	DRI	NERC	EEI	NERA
2000									
Average End-Use Price									
(1993 cents per kilowatthour)	**6.70**	**6.60**	**6.80**	**7.52**	**6.37**	**6.50**	**N/A**	**7.01**	**N/A**
Residential	8.20	8.00	8.20	9.03	7.51	7.70	N/A	8.62	N/A
Commercial	7.30	7.20	7.40	8.18	6.96	6.90	N/A	7.59	N/A
Industrial	4.90	4.80	4.90	5.33	4.75	4.80	N/A	5.11	N/A
Net Energy for Load	**3,305**	**3,235**	**3,373**	**3,485**	**3,562**	**3,496**	**3,479**	**3,481**	**3,770**
Coal	1,689	1,667	1,705	1,727	1,759	1,733	1,777	1,836	1,730
Petroleum	80	70	91	128	150	87	65	93	170
Natural Gas	301	275	341	403	367	352	334	448	460
Nuclear	652	652	652	601	625	668	684	686	650
Hydroelectric/Other[a]	301	301	301	354	296	325	282	349	380
Nonutility Sales to Grid	247	235	247	214	315	285	268	N/A	300
Net Imports	35	35	36	59	50	46	69	70	80
Electricity Sales	**3,108**	**3,042**	**3,173**	**3,227**	**3,246**	**3,200**	**N/A**	**3,266**	**3,510**
Residential	1,058	1,039	1,078	1,113	1,122	1,113	N/A	1,052	1,130
Commercial/Other[b]	970	958	983	1,004	981	1,025	N/A	1,000	1,120
Industrial	1,079	1,045	1,113	1,110	1,143	1,062	N/A	1,214	1,260
Capability (gigawatts)[c,d,e]	**734.1**	**732.2**	**736.2**	**747.0**	**808.0**	**787.0**	**707.3**	**753.0**	**783.9**
Coal Steam	298.9	298.9	298.9	306.5	340.0	335.8	294.4	309.1	331.4
Oil and Gas	222.3	220.5	224.3	235.0	250.0	245.2	220.9	232.2	240.9
Nuclear	101.3	101.3	101.3	101.4	107.0	111.3	101.8	102.7	111.6
Hydroelectric/Other[a]	111.6	111.5	111.6	104.1	111.0	94.6	91.4	108.9	100.0
2010									
Average End-Use Price									
(1993 cents per kilowatthour)	**7.20**	**6.80**	**7.50**	**8.22**	**5.48**	**6.40**	**N/A**	**7.02**	**N/A**
Residential	8.80	8.30	9.10	9.99	6.22	7.30	N/A	9.04	N/A
Commercial	7.90	7.50	8.20	8.86	5.73	6.70	N/A	7.51	N/A
Industrial	5.20	4.90	5.40	5.80	4.52	5.00	N/A	5.10	N/A
Net Energy for Load	**3,692**	**3,510**	**3,881**	**4,121**	**4,290**	**4,184**	**N/A**	**4,173**	**N/A**
Coal	1,825	1,799	1,868	2,136	2,246	1,887	N/A	2,095	N/A
Petroleum	118	111	148	204	164	113	N/A	147	N/A
Natural Gas	387	342	420	496	389	476	N/A	648	N/A
Nuclear	596	596	596	566	553	694	N/A	619	N/A
Hydroelectric/Other[a]	315	314	315	362	305	325	N/A	571	N/A
Nonutility Sales to Grid	395	312	467	285	575	637	N/A	N/A	N/A
Net Imports	56	36	67	71	58	53	N/A	93	N/A
Electricity Sales	**3,475**	**3,304**	**3,654**	**3,816**	**3,910**	**3,816**	**N/A**	**3,910**	**N/A**
Residential	1,156	1,104	1,208	1,308	1,330	1,363	N/A	1,170	N/A
Commercial/Other[b]	1,078	1,035	1,118	1,210	1,223	1,201	N/A	1,147	N/A
Industrial	1,242	1,165	1,328	1,298	1,357	1,253	N/A	1,593	N/A
Capability (gigawatts)[c,d,e]	**775.3**	**749.4**	**809.0**	**877.8**	**967.0**	**849.6**	**N/A**	**901.0**	**N/A**
Coal Steam	313.5	307.1	324.4	365.4	448.0	349.0	N/A	359.6	N/A
Oil and Gas	249.9	233.8	267.5	304.4	300.0	295.2	N/A	290.4	N/A
Nuclear	88.7	88.7	88.7	101.0	102.0	110.8	N/A	90.7	N/A
Hydroelectric/Other[a]	123.7	119.7	128.4	107.0	117.0	94.6	N/A	160.3	N/A

[a]Other includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power, plus a small quantity of petroleum coke. For nonutility generators, other also includes waste heat, blast furnace gas, and coke oven gas.

[b]Other includes sales of electricity to government, railways, and street lighting authorities.

[c]For DRI and GRI, capability represents nameplate capacity; for the others, capability represents net summer capability.

[d]WEFA's, DRI's, and EEI's capacity projections include cogeneration.

[e]DRI and NERC do not provide nonutility capacity by plant type. The total nonutility capacity in 2000 is 86.8, and 41.2 gigawatts for DRI, and NERC, respectively. In 2010, the projections are 164.8 gigawatts for DRI.

[f]The NERA projection does not include nonutility capacity.

N/A = not available.

Sources: EIA: AEO95 Forecasting System runs AEO95B.D1103942(Reference Case), LMAC95.D1103941(Low Economic Growth Case), and HMAC95.D1103941(High Economic Growth Case). **WEFA:** The WEFA Group, *Coal and Electricity Report* (Summer 1993). **GRI:** Gas Research Institute, *GRI Projection of U.S. Energy Supply and Demand*, 1995 Edition. **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Sum. 1994). **NERC:** North American Electric Reliability Council, *Electricity Supply and Demand 1994-2003* (June 1994). **EEI:** Edison Electric Institute, *Electricity for the American Economy* (draft report). **NERA:** National Economic Research Association, *NERA Energy Outlook* (Dec. 1993).

Detailed Comparative Forecasts

Table F2. Comparison of Petroleum Forecasts
(Million Barrels per Day, Except Where Noted)

Projection	EIA *AEO95*			Other Forecasts				
	Reference	Low World Oil Price	High World Oil Price	WEFA	GRI	DRI	AGA	IPAA
2000								
World Oil Price								
(1993 dollars per barrel)	**19.13**	**13.52**	**21.15**	**18.75**[a]	**18.58**[a]	**19.88**[a]	**21.51**[a]	**N/A**
Crude Oil and NGL Production	**7.20**	**6.35**	**7.57**	**8.61**	**8.01**	**7.81**	**N/A**	**7.61**
Crude Oil	5.35	4.61	5.70	6.02	6.22	6.02	N/A	5.70
Natural Gas Liquids	1.85	1.74	1.87	2.59	1.79	1.79	N/A	1.91
Total Net Imports	**10.46**	**11.99**	**9.90**	**9.01**	**9.62**	**10.20**	**N/A**	**9.79**
Petroleum Demand	**18.87**	**19.48**	**18.71**	**18.40**	**17.63**	**19.22**	**N/A**	**18.72**
Motor Gasoline	8.10	8.22	8.04	N/A	7.56	8.13	N/A	7.81
Jet Fuel	1.81	1.84	1.79	N/A	1.69	1.70	N/A	1.71
Distillate Fuel	3.34	3.40	3.32	N/A	3.55	3.72	N/A	3.44
Residual Fuel	1.27	1.54	1.22	N/A	1.51	1.09	N/A	1.23
Other	4.37	4.48	4.33	N/A	3.32	4.58	N/A	4.54
2010								
World Oil Price								
(1993 dollars per barrel)	**24.12**	**14.65**	**28.99**	**21.36**[a]	**20.54**[a]	**28.07**[a]	**24.45**[a]	**N/A**
Crude Oil and NGL Production	**7.42**	**5.47**	**8.26**	**7.57**	**8.37**	**6.94**	**N/A**	**7.18**
Crude Oil	5.39	3.58	6.20	4.71	6.50	5.17	N/A	5.23
Natural Gas Liquids	2.03	1.89	2.06	2.86	1.87	1.77	N/A	1.95
Total Net Imports	**12.22**	**15.93**	**10.92**	**10.90**	**10.88**	**12.91**	**N/A**	**11.49**
Petroleum Demand	**20.88**	**22.52**	**20.44**	**19.50**	**19.25**	**21.13**	**N/A**	**20.00**
Motor Gasoline	8.41	8.72	8.20	N/A	7.74	8.57	N/A	7.95
Jet Fuel	2.15	2.21	2.12	N/A	1.97	1.91	N/A	1.95
Distillate Fuel	3.78	3.92	3.72	N/A	4.15	4.53	N/A	3.80
Residual Fuel	1.61	2.39	1.53	N/A	1.56	1.19	N/A	1.37
Other	4.92	5.30	4.88	N/A	3.83	4.93	N/A	4.94

[a]Refiner's acquisition cost.
N/A = not available.
Sources: EIA: AEO95 Forecasting System, runs AEO95B.D1103942 (Reference Case), LWOP95.d1103941 (Low World Oil Price Case), and HWOP95.D1103942 (High World Oil Price Case). **WEFA:** The WEFA Group, *Long-term Economic Outlook* (Third Quarter 1994). **GRI:** Gas Research Institute, *Draft of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1995 Edition (Oct. 1994). **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Summer 1994). **AGA:** American Gas Association, An Overview of The *1994 AGA-TERA Base Case* (January 1994). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Forecast 1994-2000* (Mar. 1994).

Table F3. Comparison of Natural Gas Forecasts
(Trillion Cubic Feet, Except Where Noted)

Projection	EIA *AEO95*			Other Forecasts			
	Reference	Low Economic Growth	High Economic Growth	WEFA	GRI	DRI	AGA
2000							
Wellhead Price (1993 dollars per thousand cubic feet)	**2.29**	**2.12**	**2.50**	**2.55**	**2.53[a]**	**2.44**	**2.60[a]**
Dry Gas Production	**19.08**	**18.51**	**19.73**	**19.0**	**19.7**	**20.1**	**19.8**
Net Imports	**2.90**	**2.90**	**2.90**	**N/A**	**3.3**	**2.8**	**3.0**
Consumption	**22.12**	**21.54**	**22.78**	**19.6**	**23.0**	**22.5**	**22.9**
Residential	5.01	4.95	5.06	4.9	5.1	5.0	5.1
Commercial	2.95	2.93	2.97	3.0[b]	3.1[b]	3.0	3.4
Industrial	8.68[b]	8.58[b]	8.80[b]	7.8[b]	9.7[b]	10.1[c]	10.4[b]
Electric Generators	3.34	3.00	3.75	3.7	4.1	3.6	4.2
Other	2.19	2.10	2.13	.1	1.0	.8	.2
End-Use Prices							
Residential	6.06	5.89	6.34	6.56	6.62	6.56	6.38
Commercial	5.08	4.91	5.36	5.59	5.65[b]	5.58	5.25
Industrial	3.05	2.88	3.26	3.95	3.32[b]	3.62	3.02
Electric Generators	2.65	2.50	2.85	3.26	3.12	2.96	3.02
Transportation	6.56	6.38	6.83	N/A	N/A	N/A	N/A
2010							
Wellhead Price (1993 dollars per thousand cubic feet)	**3.37**	**3.04**	**3.72**	**3.47**	**2.71[a]**	**3.56**	**3.09[a]**
Dry Gas Production	**20.88**	**19.89**	**21.91**	**19.0**	**23.2**	**22.6**	**21.9**
Net Imports	**3.60**	**3.19**	**3.84**	**N/A**	**3.7**	**3.8**	**3.3**
Consumption	**24.59**	**23.18**	**25.85**	**20.7**	**26.9**	**25.9**	**25.3**
Residential	4.87	4.76	5.02	5.1	5.7	5.0	5.4
Commercial	2.97	2.90	3.05	3.2[b]	3.7[b]	3.2	4.0
Industrial	9.50[b]	9.13[b]	9.96[b]	8.0[b]	11.8[b]	12.1[c]	10.7[b]
Electric Generators	4.72	3.95	5.22	4.3	4.6	4.5	5.6
Other	2.51	2.44	2.59	.4	1.5	1.1	.9
End-Use Prices							
Residential	7.13	6.70	7.52	7.30	6.33	7.48	6.95
Commercial	6.22	5.80	6.60	6.47	5.44	6.55	5.52
Industrial	4.30	3.90	4.66	4.64	3.44	4.81	3.61
Electric Generators	3.82	3.51	4.14	4.00	3.20	4.09	3.44
Transportation	8.94	8.52	9.31	N/A	N/A	N/A	N/A

[a]Average acquisition price.
[b]Includes gas consumed in cogeneration.
[c]Includes lease and plant fuels.
N/A = not available.

Sources: EIA: AEO95 Forecasting System, runs AEO95B.D1103942 (Reference Case), LMAC95.D1103941 (Low Economic Growth Case), and HMAC95.D1103941 (High Economic Growth Case). **WEFA:** The WEFA Group, *Natural Gas Service Long Term Forecast* (Summer 1994). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1995 Edition (August 1994). **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Summer 1994). **AGA:** American Gas Association, *1994 AGA-TERA Base Case* (January 1994).

Table F4. Comparison of Coal Forecasts
(Million Short Tons, Except Where Noted)

Projection	EIA *AEO95*			Other Forecasts		
	Reference	Low Economic Growth	High Economic Growth	DRI	GRI	WEFA
2000						
Production	**1027**	**1016**	**1036**	**1085**	**1106**	**1060**
Consumption by Sector						
Electricity	832	822	839	849	864	847
Coking Plants	29	29	28	32	26	32
Industrial/Other	93	92	96	101	105	79
Total	**954**	**943**	**962**	**982**	**995**	**958**
Net Coal Exports	**74**	**74**	**74**	**103**	**109**	**102**
Minemouth Price (1993 dollars per short ton)	**20.34**	**20.51**	**20.71**	**N/A**	**16.29**	**25.71**
Average Delivered Price: Electricity (1993 dollars per short ton)	**29.06**	**29.17**	**29.52**	**28.52**	**27.62**	**35.27**
2010						
Production	**1137**	**1110**	**1173**	**1226**	**1426**	**1278**
Consumption by Sector						
Electricity	913	890	948	927	1160	1053
Coking Plants	22	22	22	29	19	28
Industrial/Other	103	98	108	151	106	84
Total	**1039**	**1010**	**1078**	**1107**	**1285**	**1165**
Net Coal Exports	**100**	**102**	**97**	**116**	**136**	**112**
Minemouth Price (1993 dollars per short ton)	**22.77**	**22.25**	**24.13**	**N/A**	**15.85**	**27.86**
Average Delivered Price: Electricity (1993 dollars per short ton)	**31.43**	**30.68**	**33.09**	**31.88**	**25.64**	**42.32**

N/A = not available.

Sources: EIA: AEO95 Forecasting System, runs AEO95B.D1103942 (Reference Case), LMAC95.D1103941 (Low Economic Growth Case), and HMAC95.D1103941 (High Economic Growth Case). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1994). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1995 Edition. **WEFA:** The WEFA Group, *Coal and Electricity Report* (Summer 1993).

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 1995 (AEO95)* are generated with the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). In addition to developing the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed using a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years in the future. In order to represent the regional differences in energy markets, the component models of NEMS function at the regional level: the 9 Census divisions for the end-use demand models; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990 (CAAA90), and the costs of compliance with other regulations. The calculation and reporting of carbon emissions are centralized in the Integrating Module.

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules, macroeconomic feedback mechanism within NEMS, and a mechanism to evaluate detailed macroeconomic and interindustry impacts associated with energy events. Key macroeconomic variables include Gross Domestic Product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module is a response surface representation of the Data Resources, Inc., Quarterly Model of the U.S. Economy.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as the changes in the efficiency of energy use for residential end-uses and in light-duty vehicle fuel efficiency. Average expenditures estimates are provided for households by income group, race, Census division, and other characteristics.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, subject to delivered energy prices, availability of renewable sources of energy, and macroeconomic variables representing interest rates, population, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, subject to delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing GDP, employment, interest rates, and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and analyses of both building shell and appliance standards.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 35 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of output for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the 8 energy intensive industries, 7 are modeled in the Industrial Demand Module with components for boiler/steam/ cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, and compressed natural gas by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternatively-fueled vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas, costs of generation by centralized renewables, macroeconomic variables for costs of capital and domestic investment, and electricity load shapes and demand. There are four primary submodules—capacity planning, fuel dispatching, finance and pricing, and load and demand-side management. Nonutility generation and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module. All CAAA90 compliance options are explicitly represented in the capacity expansion and dispatch decisions. Both new generating technologies and renewable technologies compete directly in these decisions. The competition between utility and nonutility generation and several options for wholesale pricing are included.

Renewable Fuels Module

The Renewable Fuels Module includes submodules that provide explicit representation of the supply of hydroelectric power, wood, municipal solid waste, wind energy, solar energy, and geothermal energy. (The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of dispersed renewables.) This module provides costs and performance criteria to the Electricity Market Module and also interacts with the Petroleum Market Module to represent the production and pricing of alcohol fuels derived from renewable sources.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from tight gas formations, Devonian shale, and coalbeds. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports with Canada and Mexico and liquefied natural gas imports and exports. The crude oil supply curves are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. The supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas, the production of domestic natural gas, and the availability and price of natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline capacity expansion requirements. There is an explicit representation of core and noncore markets for natural gas transmission, and the key components of pipeline and distributor tariffs for transmission services are included for the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for the 5 Petroleum Administration for Defense Districts, using the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

The Coal Market Module represents mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to capacity utilization and fuel costs, as well as reserve depletion, labor productivity, and factor input costs. Twenty-six coal types are represented, differentiated by thermal grade, sulfur content, and mining process. Production and distribution are computed for 16 supply and 23 demand regions, by the transportation modes of barge, rail, and truck. Transportation rates are constructed using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market is represented by a linear program which computes trade in 4 types of coal for 16 export and 20 import regions.

Major assumptions for the *Annual Energy Outlook 1995*

Assumptions on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in *AEO95*. These assumptions are presented in Chapter 1. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are presented in the *Supplement to the Annual Energy Outlook 1995*, along with regional results and other details of the projections.

Building sector assumptions

The buildings sector includes both residential and commercial structures. Both the National Appliance Energy Conservation Act of 1987 (NAECA), the Energy Policy Act of 1992 (EPACT), and the Climate Change Action Plan (CCAP) contain provisions which impact future buildings sector energy use. The provisions with the most significant effect are minimum equipment efficiency standards. These standards require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels which change over time. The manufacture of equipment that does not meet the standards is prohibited.

Residential assumptions. The NAECA minimum standards [*1*] for the major types of equipment in the residential sector are:

- Heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992
- Room air conditioners—an 8.6 energy efficiency ratio in 1990
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993
- Electric water heaters—a 0.88 energy factor in 1990
- Natural gas water heaters—a 0.54 energy factor in 1990.

Building codes relevant to CCAP are represented by an increase in the shell integrity of new construction over time. By the year 2000, heating and cooling shell efficiency in new construction improves by 7 percent relative to 1994.

Other programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs, which are cooperative efforts between the EPA and energy appliance manufacturers, encourage the development and production of highly energy-efficient equipment. One of the best known examples of these programs is the "golden carrot refrigerator," a very efficient design that is projected to be available by 1998 and to consume less than two-thirds of the energy specified in the 1993 standard.

In addition to the *AEO95* reference case, two side cases were developed to examine the effect of equipment and building standards on residential energy use. The *1993 technology case* assumes that all future equipment purchases are made at the efficiency level consistent with 1993 shipments, with the exception that 1994 standards for clothes dryers are included. The *best technology case* assumes that all future equipment purchases are characterized by those with the highest efficiency as of 1993.

Commercial assumptions. Minimum 1994 equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*2*]. Minimum standards for representative equipment types produced after January 1, 1994, are:

- Central air-conditioning heat pumps—a 9.7 seasonal energy efficiency rating

- Gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard
- Fluorescent reflector lamps—a 75.0 lumens per watt lighting efficacy standard.

The CCAP programs recognized in the *AEO95* reference case include enhanced efficiency standards for central air-conditioning units, the expansion of the EPA Green Lights and Energy Star Buildings programs, and improvements to building shells from advanced insulation methods and technologies. The minimum efficiency standard for air-conditioning units is assumed to rise to a seasonal energy efficiency rating of 10.0 in 1998. The EPA green programs are designed to facilitate cost-justified retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module via discount parameters for controlling cost-based equipment retrofit decisions for various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO95* version of the commercial module includes end-use-specific segmentation of discount rates. Existing building shell efficiency is assumed to increase by 1 percent over the 1990 average by the year 2000, saving a proportional amount of space heating and cooling energy.

In addition to the reference case, two side cases and a calculation of commercial consumption based on constant energy intensity were also developed to examine the effect of technologies and building standards on commercial energy use. The *1993 technology case* assumes that all future equipment choices are made from the menu of equipment available in 1993. However, the choice of specific equipment type and efficiency is still made endogenously. For example, if the price of a particular fuel rises relative to other fuels, shifts to competing technologies using different fuels could occur, or more efficient 1993 models of the same technology might be chosen. The *best technology case* assumes that all future equipment choices are made from a menu of technologies that includes only the most efficient models available in a particular year. For example, in the best technology case, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. Building shells are also assumed to become 6 percent more efficient by 2010 in the best technology case.

Industrial sector assumptions

Compared to the building sector, there are relatively few regulations which target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1997 [*3*]. These standards have been incorporated into the Industrial Demand Module through the analysis of process efficiencies for new industrial processes. These standards are expected to lead to significant improvements in efficiency since it has been estimated that electric motors account for about 60 percent of industrial process electricity use.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. It was estimated that full implementation of these programs would reduce industrial electricity consumption by 55 billion kilowatthours and non-electric consumption by 370 trillion Btu by 2000. However, the programs were not fully funded. The energy savings were revised in proportion to the funding received. Consequently, electricity consumption is reduced by 6 billion kilowatthours, and non-electric energy consumption is reduced by 43 trillion Btu. The non-electric energy is assumed to be steam coal.

High efficiency and 1993 technology cases. Over the 1970-1990 period, industrial energy intensity fell by 1.9 percent annually. This was due to energy conservation and the changing composition of industrial output. The *high efficiency case* replicates the 1.9-percent annual decline from 1995 through 2010. This is twice the rate of decline anticipated in the reference case (0.9 percent). For this exercise the composition of industrial output remained the same as in the reference case.

The *1993 technology case* holds the energy efficiency of new plant and equipment constant over the forecast. New equipment and processes, however, typically are more energy efficient than those used in existing plants. As a result, the average energy intensity declines as old equipment is retired and new production capacity is added.

Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for the two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The projections appearing in this report assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally-fueled automobile fleet operators—Federal, State, and local governments, and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*4*]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 2002. Purchases of alternative-fuel vehicles by State and local governments must realize 20 percent of total purchases by 2002 and 70 percent by 2005. Private fuel-provider companies are required to purchase 30 percent alternative-fuel vehicles in 1996, increasing to 90 percent by 1999.

In addition to these requirements, the State of California has adopted a Low Emission Vehicle Program, which requires that 10 percent of all new vehicles sold by 2000 meet the "zero emissions requirements." At present, only electric-dedicated vehicles meet these requirements. Both Massachusetts and New York have also adopted this program. Other states could opt-in for adoption, but these projections assume that only the three states that have formally adopted the California program will participate.

The projections assume that these regulations represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of these vehicles, should vehicle cost, fuel efficiency, range, and performance characteristics make them desirable. In fact, the projections indicate that more than the minimum will be purchased, as shown in Figure 32.

Projections for both vehicle-miles traveled [*5*] and ton-miles traveled [*6*] are calculated endogenously and are based on the assumption that modal shares, for example, personal automobile travel versus mass transit, remain stable over the forecast and track recent historical patterns. Other important factors affecting the forecast of vehicle-miles traveled are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 70 percent by 2010; and the proportion of the driving-age population over the age of 60, which increases from 21.6 percent in 1990 to 24.1 percent in 2010.

Climate Change Action Plan. There are four CCAP programs that focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy; (3) promote telecommuting; and (4) develop fuel economy labels for tires. The combined assumed effect of the Federal subsidy, system efficiency, and telecommuting policies is a 1.3-percent reduction in vehicle-miles traveled (190 trillion Btu). The fuel economy tire labeling program improved new fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 40 trillion Btu.

High efficiency and 1993 technology cases. Over the 1970-1990 period, transportation energy efficiency rose by 1.9 percent annually for light-duty vehicles, 1.5 percent for freight trucks, 1.6 percent for rail locomotives and marine vessels, and 2.1 percent for aircraft. In the high efficiency case, fuel efficiency improvements from new technology more than offset the increasing travel in each transportation mode. As a result, the total energy consumption in the transportation sector was 10 percent lower than in the reference case. The 1993 technology case assumed that new vehicle fuel efficiencies did not increase beyond their 1993 levels over the forecast. As a result, transportation sector energy use is estimated to be 5 percent higher than in the reference case in 2010.

Both cases were run with only the Transportation Demand Module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand was captured.

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. There are 22 fossil, renewable, and nuclear generating technologies included in these projections. Technologies represented include those currently available as well as those that are assumed to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production expressed by the percent heat rate, are used for decisionmaking where it is assumed that the selection of new plants to be built is based on least cost. The levelized lifetime cost, including fuel costs, is evaluated and is used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the *Supplement to the Annual Energy Outlook 1995*.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions by 2000. Utilities are assumed to comply with the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. The costs for FGD equipment average approximately $179 per kilowatt, in 1993 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

The provisions of EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators [7]. These entities are included among nonutility producers and are assumed to have a capital structure which is highly leveraged, compared with that of investor-owned regulated utilities.

Prices for electricity are assumed to be regulated at the State level. Prices for the residential, commercial, industrial, and transportation sectors are developed by classifying costs into four categories: fuel, fixed operation and maintenance, variable operation and maintenance, and capital. These costs are allocated to each of the four customer classes using the proportion of sales to the class and each class's contribution to system peak load requirements. These allocated costs are divided by the sales to each sector to obtain electricity prices to the sector.

Energy efficiency and demand-side management. Improvements in energy efficiency induced by growing energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. Utilities have reported plans to increase their expenditures on demand-side management programs to more than $4 billion per year by 1997.

Nuclear power. It is assumed that two nuclear generating units currently under construction will be operational by 2010: Watts Bar 1 in 1995 and Watts Bar 2 in 1997. Bellefonte 1 and 2 are assumed not to be completed. These four units are owned by the Tennessee Valley Authority (TVA). TVA is in the process of developing an Integrated Resource Plan for completion by late 1995 to determine long-term energy needs in the region, and the most economical way to meet them. In recent months the chairman of TVA has made several statements that make the completion of these nuclear units highly uncertain. In particular, he stated that completion of the unfinished units may not be economically feasible, and has had cost estimates developed for the conversion of the Bellefonte units to coal or natural gas facilities. In addition, TVA has, for the first time, issued requests for proposals totalling four gigawatts of power, suggesting that purchased power may be a preferable option to the completion of the nuclear units.

It is assumed that no newly-ordered nuclear power plants will be operational through 2010 for the following reasons:

- Concerns about the disposal of radioactive waste
- Public concerns about safety
- Concern about economic and financial risk
- Uncertainty in the licensing and regulatory processes.

In the reference case, nuclear units are assumed to operate until their license expiration, typically 40 years from the date of first operation. Two side cases were developed with alternate retirement dates for nuclear units. The *low nuclear case* assumes that all reactors retire 5 years earlier than their license expiration dates, while the *high nuclear case* assumes 5 years of operation past the license expiration dates for all reactors.

The average nuclear capacity factor is expected to increase from 71 percent currently to 74 percent by 2000, and remain at that level through 2010. Capacity factor assumptions are developed at a regional level, based on historical performance of individual units.

Renewable fuels assumptions

Energy Policy Act of 1992. The Renewable Fuels Module incorporates the provisions of EPACT that support the development of renewable energy forms. EPACT provides a renewable electricity production credit of 1.5 cents per kilowatthour for electricity produced by wind, applied to plants that become operational between January 1, 1994, and June 30, 1999 [*8*]. The credit extends for 10 years after the date of initial operation. EPACT also includes provisions that allow an investment tax credit of 10 percent for solar and geothermal technologies that generate electric power [*9*]. This credit is included as a 10-percent reduction to the capital costs in the Renewable Fuels Module.

State mandates. *AEO95* includes EIA estimates of mandated capacities (net summer capability) for renewables, as follows:

- Wind—California (U.S. supply only), 927 megawatts; Minnesota, 380 megawatts; New York, 6 megawatts
- Geothermal—California, 159 megawatts
- Biomass wood—Minnesota, 119 megawatts.

Several energy supply actions under the CCAP encourage States to promote the demonstration and use of renewable energy systems.

Renewable resources. The major source of renewable energy for electricity generation is hydroelectric power. Environmental and other restrictions are assumed to limit the growth of hydroelectric power, which grows slightly. The total resources for most other renewables are theoretically large, for example, the amount of sunlight. However, total resources are not always the relevant measure. Regional characterization is required in order to properly represent the resource. For example, while the capability to produce solar thermal energy is present in all regions of the United States, it is assumed that solar energy technologies will penetrate first in those regions where its economics are most favorable. Wind energy resource potential, while large, is constrained by land-use and environmental factors that result in the exclusion of some land area within suitable wind classes. The geographic distribution of available wind resources is based on a resource assessment study by the Pacific Northwest Laboratory [*10*]. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Capacity in 1992 totaled 2.9 gigawatts [*11*]. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically producible since biomass fuels have a low Btu value per weight of fuel. Municipal solid waste resources are limited by the amount of the waste that is disposed of by other methods such as recycling or landfills and the impact of waste minimization as a strategy for managing the waste problem.

Non-electric renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [*12*] (RECS) and data from the *Characteristics of New Housing: 1992*, published by the Bureau of the Census [*13*]. The RECS data provide a benchmark for Btu of wood use in 1990. The Census data are used to develop the forecasts of new housing units utilizing wood. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump consumption is also based on the latest RECS and Census data; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Solar thermal consumption for water heating is also represented by displaced primary energy relative to an electric water heater.

Exogenous projections of active and passive solar technologies and geothermal heat pumps in the commercial sector are based on projections from the National Renewable Energy Laboratory [*14*]. Industrial use of renewable energy is primarily the use of wood and wood byproducts in the paper and lumber industries as well as a small amount of hydropower for electricity generation.

Oil and gas supply assumptions

Domestic oil and gas economically recoverable resources. The projections are based on analyses of estimates of the economically recoverable resource base from the U.S. Geological Survey and the Minerals Management Service of the Department of the Interior, the National Petroleum Council, the Office of Fossil Energy of the Department of Energy, and the Potential Gas Committee [*15*]. Economically recoverable resources are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional or nonconventional techniques, under specified economic conditions. Estimates were developed on a regional basis. Total unproved oil resources are assumed to be 86 billion barrels with 1990 technology and 129 billion barrels with 2010 technology. Total unproved gas resources are assumed to be 852 trillion cubic feet with 1990 technology and 1,449 trillion cubic feet with 2010 technology.

The CCAP includes a program promoting the capture of methane from coal mining activities to reduce carbon emissions. That methane would be marketed as part of the domestic natural gas supply. The *AEO95* assumption for this program is that it begins in 1995, reaching a maximum annual production level of 19.1 billion cubic feet by 2000. The volumes of recoverable methane from the program are not included in the economically recoverable gas estimates discussed previously in this appendix.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that the recoverable resource target will expand and the effective cost of supply activities will be reduced. The projections assume that the total volumes of unproved domestic oil and natural gas resources that are economically recoverable will increase over the 1990-2010 period at average annual rates of roughly 2.1 and 2.6 percent respectively in response to technological innovation, as indicated by the volumes cited above. The increase is due to both the development and deployment of new technologies, for example, three-dimensional seismology, and horizontal drilling and completion techniques. Drilling, operating, and lease equipment costs are expected to decline at assumed rates that vary somewhat by cost and fuel categories, ranging from roughly 1 to 3 percent, with most of them generally at 2 percent.

AEO95 includes sensitivity test results based on variation in the technology assumptions. The assumed average annual rates for expansion of the recoverable oil and gas resource estimates were varied by plus or minus 50 percent. This change modifies the outlook by altering the productivity for drilling, which indirectly affects the unit supply cost. The analysis is based on the oil and gas wellhead prices from the reference case. The analysis was conducted as a supply-side sensitivity only, without any market interactions from the consuming sectors.

Leasing and drilling restrictions. The projections of crude oil and natural gas supply assume that current restrictions on leasing and drilling will continue to be enforced throughout the forecast period. At present, drilling is prohibited along the entire East Coast, the west coast of Florida, and the West Coast except for the area off the Southern California. In Alaska, drilling is prohibited in a number of areas including the Arctic National Wildlife Refuge. The projections also assume that coastal leasing and drilling activities will be reduced in response to the restrictions of CAAA90, which requires that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska and imports. The Alaska Natural Gas Transportation System is assumed to come online no earlier than 2005 and only after the border price reaches $3.64, in 1993 dollars per thousand cubic feet. Pipeline import volumes from Canada are constrained by the pipeline design capacity, which is assumed to increase from 2.3 trillion cubic feet in 1990 to 4.2 trillion cubic feet in 2010. The liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have an operating capacity of 311 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen when economically justified, but not before 1996 and 1998, respectively, expanding total liquefied natural gas operating capacity to 794 billion cubic feet.

Natural gas transmission and distribution assumptions. The projections reflect the assumptions that the provisions of Order 636 have been fully implemented, and that all interstate pipeline companies have completed the switch from modified fixed variable (MFV) to straight fixed variable (SFV) rate design. Approved transition costs are assumed to be consistent with the revised cost estimate published by the Federal Energy Regulatory Commission (FERC) in the November 1993 GAO report. Gas supply realignment (GSR) costs are recovered from 1994 through 1998, with 90 percent assigned to firm markets and 10 percent to interruptible markets as stipulated in FERC Order 636. Account 191 costs are collected in 1994 and 1995 from firm customers only.

Consistent with the industry restructuring, the methodology employed in solving for the market equilibrium assumes that marginal costs are the basis for determining market-clearing prices for noncore markets and that average cost of service rates are the basis for core market prices.

Firm transportation rates for pipeline services are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base (the test for determining whether or not to build new capacity is done based on incremental rates, however). Distribution markups to firm service customers are based on historical data and are assumed to decline 1 percent per year. Although the market is perceived to be changing from current history, this assumption is consistent with current regulatory policy and with EIA's definition of a reference case.

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above that included in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety. (Refurbishment costs include any expenditures for repair and/or replacement of existing pipe).

Prices for use in compressed natural gas (CNG) vehicles are phased from EIA's *Natural Gas Annual* historical transportation prices to what is assumed to be a retail market price in 2005. The linear phase-in begins in 1994 and continues through 2005, after which the price is assumed to be the firm industrial price plus a markup to cover the cost of dispensing the fuel (plus taxes). The phase-in period represents the transition from a market where users must obtain and dispense their own supplies (as in the case of fleet vehicles) to a market in which retail outlets are readily available to all customers. Federal taxes of $0.49 (1993 dollars) per thousand cubic feet plus corresponding State taxes are levied starting in 1994.

Provisions of the CCAP are assumed to have no impact on the transmission and distribution segment of the industry. Although regulatory changes that are recommended in the CCAP may be considered by the FERC in the near future, they go beyond the current FERC regulatory policy and thus are not considered in the reference case.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*16*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of these costs because demand for these products is less price-responsive than for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for new fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. These additional costs are determined in the representation of refinery operations by incorporating specifications and demands for these fuels. Demands for traditional, reformulated, oxygenated, and high-oxygen reformulated gasolines are disaggregated from composite gasoline consumption based on market share assumptions for each Census Division, which are detailed in the *Supplement to Annual Energy Outlook 1995*. The expected oxygenated gasoline market shares assume wintertime participation of 39 carbon monoxide nonattainment areas and year-round participation of Minnesota beginning in 1995.

Starting in 1995, reformulated gasoline is assumed to be consumed in the nine serious ozone nonattainment areas required by CAAA90 and in areas in 12 States and the District of Columbia that had opted into the program as of January 1994 [*17*]. Nonattainment areas in Wisconsin will join the program in June 1995 and are assumed to opt in beginning in 1996, along with Atlanta, Georgia. The State of Georgia, which had been considering joining the reformulated gasoline program, has recently adopted tighter restrictions on Reid vapor pressure (Rvp) in the Atlanta area in lieu of reformulated gasoline.

Reformulated gasoline reflects "Simple Model" standards between 1995 and 1997 and meets the "Complex Model" definition beginning in 1998 as required by the EPA. *AEO95* projections also reflect California's statewide requirement for severely reformulated gasoline beginning in 1996. In accordance with the Renewable Oxygenate Standard, renewable oxygenates, such as ethanol and ethyl tertiary butyl ether (ETBE), are blended into 15 percent of reformulated gasoline in 1995 and 30 percent starting in 1996. Throughout the forecast, traditional gasoline in blended according to 1990 baseline specifications, to reflect CAAA90 "anti-dumping" requirements aimed at preventing traditional gasoline from becoming more polluting.

Due to recent tax trend analysis, *AEO95* assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 increase with inflation, while Federal taxes remain at 1994 levels. This differs from previous forecasts, which have assumed that both State and Federal taxes increase with inflation.

Coal market assumptions

Resource base. Estimates of recoverable coal reserves are based on the EIA Demonstrated Reserve Base (DRB) of in-ground coal resources of the United States. Resource estimates from the DRB are correlated with coal quality data from other sources to create a Coal Reserves Data Base. Estimates are developed on a regionally disaggregated basis.

In certain coal-producing regions, the DRB estimates have been augmented by a portion of inferred resources. The extent of augmentation varies by State and coal type, based on the recency of DRB estimates and the amount of inferred coal that meets criteria related to seam thickness, depth, and overburden. The purpose of this change is to represent expected additions to demonstrated reserves that would occur in later years of the forecast. The effect of the change is to reduce somewhat mine-mouth and delivered prices in that period.

Productivity. Technological advances in the coal industry, such as continuous mining, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue, but to decline in magnitude over the forecast horizon. Different rates of improvement are assumed by region and by mine type, surface and deep. On a national basis, labor productivity is assumed to improve at a rate of 3.9 percent per year, declining from an annual rate of 7.7 percent in 1993 to 2.2 percent in 2010. In the alternative cases that were run to examine the impacts of different labor productivity assumptions, the annual growth rates for productivity were increased and decreased by 50 percent in each region for each year after 1995. For example, a 4-percent productivity rate specific to a given year, mine type, and region in the reference case rate was set to 6 percent in the *high productivity case* and to 2 percent in the *low productivity case*.

Notes

1. Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction.*
2. National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.
3. National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.
4. National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.
5. Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.
6. Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.
7. National Energy Policy Act of 1992, P.L. 102-486, Title VII, Subtitle A, Section 711, and Title XXVIII, Sections 2801 and 2802.
8. National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1914.
9. National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.
10. Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, (PNL-7789), prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 (August 1991).
11. Energy Information Administration, EIA-861, "Annual Electric Utility Report," and EIA-867, "Annual Nonutility Power Producer Report."
12. Energy Information Administration, *Household Energy Consumption and Expenditures 1990*, (DOE/EIA-0321(90)) (Washington, DC, 1993).
13. U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1992*, (Washington, DC, 1993).
14. National Renewable Energy Laboratory, "Baseline Projections of Renewables Use in the Buildings Sector," prepared for the U.S. Department of Energy under Contract DE-AC02-83CH10093 (December 1992).
15. Mast, Richard F., et al., United States Department of the Interior, Geological Survey and Minerals Management Service, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment*, United States Government Printing Office, 1989; Cooke, Larry W., United States Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051, July 1991; National Petroleum Council, Committee on Natural Gas, *The Potential for Natural Gas in the United States, Volume II, Source and Supply*, Washington, DC, December 1992; Fisher, William L., et al., Oil Resources Panel convened by the U.S. Department of Energy, *An Assessment of the Oil Resource Base of the United States*, October 1992; Potential Gas Committee, *Potential Supply of Natural Gas in the United States (December 31, 1992)*, Potential Gas Agency, Colorado School of Mines, May 1993.
16. Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993).
17. Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, and San Diego. 1995 opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Additional 1996 opt-ins are Atlanta (Georgia) and areas of Wisconsin.

High Electricity Demand Case

Over the next 15 years, consumers in all sectors of the economy are expected to use more electricity. If history is any indicator, as the economy grows, so will the demand for electricity. However, over the past 30 years this relationship has changed dramatically. As discussed on page 26 of this report, the ratio of growth in the demand for electricity to economic growth declined through the 1960s and 1970s and has hovered near 1 for the past 10 years or so (see Figure 36 on page 26). The question is how this relationship will change over the next decade and a half.

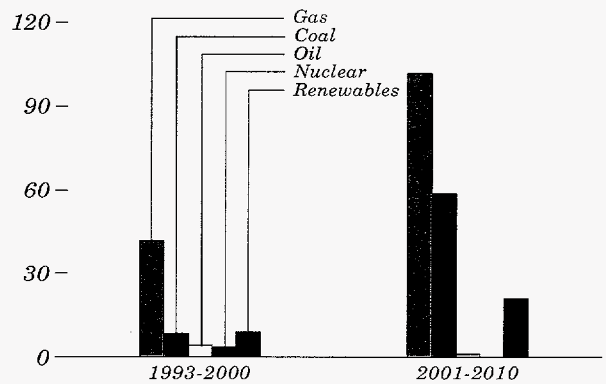
Demographic trends, together with the improving efficiencies of new electric appliances and equipment, suggest that growth in the demand for electricity will continue to slow relative to economic growth. For example, the population over age 16—a major driver of residential electricity consumption—is projected to increase by 1.0 percent a year between 1993 and 2010, slower than the 1.9-percent and 1.1-percent annual growth rates seen in the 1970s and 1980s, respectively. A similar story is seen for commercial floorspace, the growth of which is also expected to slow relative to historical growth rates. Adding this information to the improving efficiencies of new electric appliances and equipment makes stronger growth unlikely. The major projections presented in this report reflect these underlying trends.

On the other hand, if the rate of penetration of more efficient appliances into the market is slower than expected, or if unanticipated new uses of electricity emerge, demand growth could retain its recent historical relationship to economic growth. For instance, if electric vehicles enter the market faster than expected, the demand for electricity could increase at a faster rate than shown in the reference case. Table H1 shows the key results of a high electricity demand case, which assumes that electricity demand will continue to grow at the same rate as the economy through 2000 before slowing.

The results of the high demand case are substantially different from the reference case. In 2010, electricity sales are 14 percent higher than in the reference case; coal and gas production are 10 and 6 percent higher, respectively; and carbon emissions are 97 million metric tons higher. Electricity prices are only 3 percent higher, while gas and coal prices to utilities are 9 and 10 percent higher, respectively. It should be noted, however, that changes in other sectors of the economy, which were not analyzed here, would partially reduce these differences. For instance, if a new electric technology penetrated in the industrial sector, electricity demand would rise, but the demand for other fuels in the industrial sector could fall. Also, rising use of natural gas for electricity generation leads to higher gas prices, which would tend to reduce the demand for gas in other areas.

A major effect of stronger growth in electricity demand would be on the need for additional generating capacity. Figure H1 shows the projected capacity additions in the high electricity demand case. Relative to the reference case, the difference of 0.8 percentage point in the annual growth rate of electricity demand leads to the need for 114 gigawatts of additional capacity—a 14-percent increase in total capacity—in 2010. In terms of generating plants, this difference means that additional capacity equivalent to 380 new plants (assuming a capacity of 300 megawatts per plant) would be needed to meet demand in 2010.

Figure H1. Utility and nonutility capacity additions by fuel type in the high electricity demand case, 1993-2000 and 2001-2010 (gigawatts)



Source: AEO95 Forecasting System, run NEWDEM. D1213942.

High Electricity Demand Case

Table H1. Results of the high electricity demand case, 2000 and 2010

		2000		2010		Annual growth, 1993-2010	
	1993	Reference case	High demand	Reference case	High demand	Reference case	High demand
Electricity sales (billion kilowatthours)	**2,862**	**3,108**	**3,396**	**3,475**	**3,960**	**1.1**	**1.9**
Electricity prices (1993 cents per kilowatthour)	**6.8**	**6.7**	**6.7**	**7.2**	**7.4**	**0.3**	**0.5**
Generation by fuel (billion kilowatthours)							
Coal	1,693	1,753	1,814	1,929	2,177	0.8	1.5
Natural gas	431	514	638	693	878	2.8	4.3
Renewables	357	405	410	457	489	1.5	1.9
Other	722	772	839	761	806	0.3	0.6
Total	**3,204**	**3,444**	**3,700**	**3,842**	**4,351**	**1.1**	**1.8**
Generating capacity (gigawatts)							
Coal[1]	301	299	299	314	351	0.2	0.9
Combined-cycle / combustion turbine[1]	63	92	101	129	195	4.3	6.9
Renewables[1]	86	92	93	104	114	1.1	1.7
Nuclear power[1]	99	101	101	89	89	-0.6	-0.6
Cogenerators	38	46	46	53	53	2.0	2.0
Other	161	151	151	141	141	-0.8	-0.8
Total	**747**	**780**	**790**	**828**	**942**	**0.6**	**1.4**
Energy production							
Coal (million short tons)	945	1,027	1,057	1,137	1,256	1.1	1.7
Natural gas (trillion cubic feet)	18.4	19.1	20.6	20.9	22.2	0.8	1.1
Carbon emissions (million metric tons)	**1,376**	**1,471**	**1,526**	**1,621**	**1,718**	**1.0**	**1.3**
Prices to utilities (1993 dollars per million Btu)							
Coal	1.39	1.39	1.44	1.50	1.65	0.5	1.0
Natural gas	2.57	2.59	3.01	3.73	4.06	2.2	2.7

[1]Excludes cogenerators.

Notes: Other includes non-coal fossil steam, pumped storage, methane, propane, and blast furnace gas. Totals may not equal sum of components due to independent rounding.

Source: AEO95 Forecasting System, run NEWDEM.D1213942.

Conversion Factors

Table I1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.646
Consumption	million Btu per short ton	21.143
Coke Plants	million Btu per short ton	26.799
Industrial	million Btu per short ton	22.250
Residential and Commercial	million Btu per short ton	23.105
Electric Utilities	million Btu per short ton	20.787
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.188
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.948
Petroleum Products		
Consumption	million Btu per barrel	5.800
Motor Gasoline	million Btu per barrel	5.253
Jet Fuel (Kerosene)	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas	million Btu per barrel	3.624
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks	million Btu per barrel	5.630
Unfinished Oils	million Btu per barrel	5.825
Imports	million Btu per barrel	5.652
Exports	million Btu per barrel	5.761
Natural Gas Plant Liquids		
Production	million Btu per barrel	3.805
Natural Gas		
Production, Dry	Btu per cubic foot	1,030
Consumption	Btu per cubic foot	1,030
Non-electric Utilities	Btu per cubic foot	1,031
Electric Utilities	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,018
Exports	Btu per cubic foot	1,018
Electricity Consumption	Btu per kilowatthour	3,412
Electricity Component		
Plant Generation Efficiency (heat rate)		
Fossil Fuel Steam	Btu per kilowatthour	10,302
Nuclear Energy	Btu per kilowatthour	10,678
Geothermal	Btu per kilowatthour	21,000

[1]Coal and geothermal conversion factors vary from year to rear. 1992 values are reported.
Source: Energy Information Administration, AEO95 National Energy Modeling System.

Table I2. Metric Conversion Factors

United States Unit	multiplied by	Conversion Factor	equals	Metric Unit
Mass				
Pounds (lb)	X	0.453 592 37	=	kilograms (kg)
Short Tons (2000 lb)	X	0.907 184 7	=	metric tons (t)
Length				
Miles	X	1.609 344	=	kilometers (km)
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules (j)
Kilowatthours	X	3.6	=	megajoules (MJ)
Volume				
Barrels of Oil (bbl)	X	0.158 987 3	=	cubic meters (m^3)
Cubic Feet (ft^3)	X	0.028 316 85	=	cubic meters (m^3)
Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.

[a]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam, London, 1956.

[2]*Annual Energy Outlook* tables use the fossil fuel heat rate.

Source: Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), Table B1.

Table I3. Metric Prefixes

Unit Multiple	Prefix	Symbol
10^3	kilo	k
10^6	mega	M
10^9	giga	G
10^{12}	tera	T
10^{15}	peta	P
10^{18}	exa	E

Source: Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), Table B2, and EIA, Office of Statistical Standards.

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Annual Energy Outlook 1995 Diskettes

These diskettes contain the forecast tables for Appendices A, B, and C in the *Annual Energy Outlook 1995* (*AEO95*) in worksheet (.WK1) format, so they can be viewed using most spreadsheet packages. They come on 3.5-inch disks and will be available early in January 1995.

Supplement to the Annual Energy Outlook 1995 Diskettes

These diskettes contain the Detailed Tables in Part II of the *Supplement to the Annual Energy Outlook 1995* (*AEO95 Supplement*) in worksheet (.WK1) format, so they can be viewed using most spreadsheet packages. They come on 3.5-inch disks and will be available early in February 1995.

PC Version of the National Energy Modeling System

The National Energy Modeling System, used for the forecasts in *AEO95*, will be available for execution on a personal computer. The system allows execution of the individual NEMS modules on a standalone basis. The *AEO95* version is scheduled for release in April 1995.

To receive any of the items above please either:

a) Send a letter with your business address, phone number, and which of the above items you would like, to:

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The Energy Information Administration National Energy Modeling System/Annual Energy Outlook Conference Schedule

Arlington Renaissance Hotel, Arlington, VA February 28, 1995

15 a.m. Opening Remarks — Jay Hakes, Administrator, Energy Information Administration

30 a.m. Keynote Address — William Hogan, Kennedy School of Government, Harvard University

15-10:00 a.m. Overview of the *Annual Energy Outlook 1995* — Jay Hakes, Administrator & Mary J. Hutzler, Director, Office of Integrated Analysis & Forecasting, Energy Information Administration

:15 a.m. - 12:45 p.m. Parallel Morning Sessions

The Role of Gas in a Restructured Utility Market

Moderator: Andy S. Kydes, Senior Modeling Analyst Energy Information Administration

- Electricity & gas market restructuring as a result of deregulation
- Operating in today's competitive environment
- Current trends & their effects on future prices, efficiencies, & technologies

International Markets

Moderator: Scott Sitzer, Director, Energy Supply & Conversion Division, Energy Information Administration

- Oil, gas, & coal markets

End-Use Technologies & Efficiency

Moderator: Arthur Andersen, Director, Energy Demand & Integration Division, Energy Information Administration

- Alternative fuel vehicle modeling
- Technology choice in the residential & commercial sectors
- Industrial sector technology modeling

2:00 p.m. - 5:00 p.m. Parallel Afternoon Sessions

IV. Scenario Design

- Identification of emerging energy issues

National Energy Modeling System PC Models

- Demonstration of PC User Interface for the National Energy Modeling System

V. Technological Innovation, Risks, & Penetration for Electric Utility Generators

- Effects of structural change on technological innovation
- Technology innovation impacts on technology choice
- Technological modeling in tne National Energy Modeling System
- Conceptual issues for longer term analysis
- Demonstration of PC electric utility technologies data base

5:00 p.m. Adjourn

Hotel Reservations

The conference will be held at the Arlington Renaissance Hotel adjacent to the Ballston Metro subway station and convenient to key points in the Washington, DC metropolitan area.

For room reservations at the NEMS/AEO Conference contact the Arlington Renaissance Hotel directly by February 2, 1995.

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Energy Information Administration
(202)586-9648

Conference Registration

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lan to attend the following parallel sessions:
oose one morning and one afternoon session.)

rning:
____ I. Role of Gas in a Restructured Market
____ II. International Markets
____ III. End-Use Technologies & Efficiency

ernoon:
____ IV. Scenario Design & NEMS PC Models
____ V. Technological Innovation, Risks, & Adoption (Electric Utility Generators)

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