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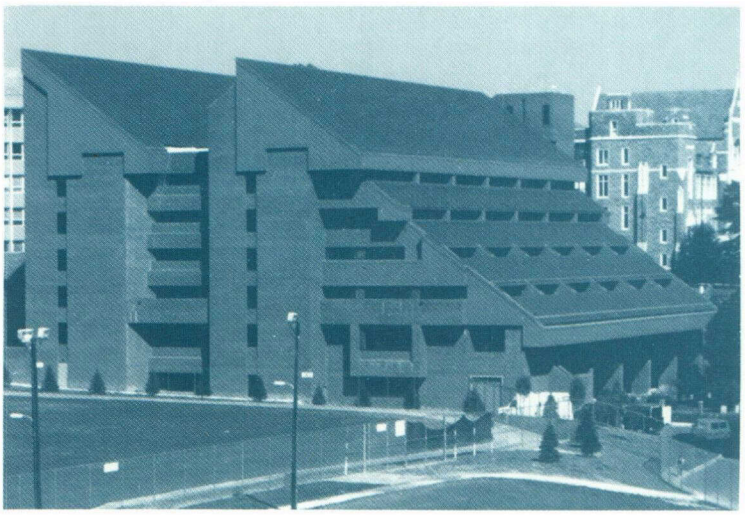
Annual Energy Outlook 1994

With Projections to 2010



Energy Information Administration

For Further Information . . .

The *Annual Energy Outlook* (*AEO*) is prepared by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, under the direction of Mary J. Hutzler (202/586-2222). General questions concerning energy demand or energy markets may be addressed to Mark E. Rodekohr (202/586-1130), Director of the Energy Demand and Integration Division. General questions concerning energy supply and conversion activities may be addressed to Scott Sitzer (202/586-2308), Director of the Energy Supply and Conversion Division. Detailed questions about the forecasts and related model components may be addressed to the following analysts:

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Forecast tables for the five scenarios examined in this report are available via modem on EIA's Electronic Publication System (202/586-2557). A companion document, the *Supplement to the Annual Energy Outlook 1994*, will be available in March 1994. The *Supplement* will include selected regional tables, as well as more detailed information about the assumptions underlying the *AEO* forecasts. The forecast tables in the *AEO94* and its supplement will be available on diskette from the Office of Integrated Analysis and Forecasting in March 1994. Model documentation reports for the National Energy Modeling System (NEMS) are also available from EIA. Quarterly projections of energy supply and demand for 1994 and 1995 are available in the *Short-Term Energy Outlook* (February 1994). To obtain these reports, contact:

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Annual Energy Outlook 1994

With Projections to 2010

January 1994

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Office of Integrated Analysis and Forecasting
U.S. Department of Energy
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PREFACE

The *Annual Energy Outlook 1994* (*AEO94*) 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 for the first time on results from the National Energy Modeling System (NEMS). NEMS is the latest in a series of computer-based energy modeling systems used over the past 2 decades by EIA and its predecessor organization, the Federal Energy Administration, to analyze and forecast energy consumption and supply in the midterm period (about 20 years). Quarterly forecasts of energy supply and demand for 1994 and 1995 are published in the *Short-Term Energy Outlook* (February 1994).

Forecast tables for 2000, 2005, and 2010 for each of the five scenarios examined in the *AEO94* are provided in Appendices A through E. The five scenarios include a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices. Appendix F provides detailed comparisons of the *AEO94* forecasts with those of other organizations. Appendix G briefly describes the NEMS and the major *AEO94* forecast assumptions. Appendix H summarizes the key results for the five scenarios.

The *AEO94* projections are based on Federal, State, and local laws and regulations in effect on October 1, 1993. They include the fuel taxes in the Omnibus Budget Reconciliation Act of 1993, the Clean Air Act Amendments of 1990, and the Energy Policy Act of 1992. Pending legislation, sections of existing legislation for which funds have not been appropriated, and provisions of the Climate Change Action Plan are not reflected in the forecasts.

The *AEO* forecasts 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.

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ADMINISTRATOR'S MESSAGE

Twenty years ago our Nation and the world experienced the oil embargo and price shocks following the 1973 Arab-Israeli war. As oil prices soared, the United States and other countries adopted a wide range of private investment and public policy responses that changed patterns of energy production and consumption. Environmental concerns in recent decades have also had a clear impact on energy supply and use.

In ways that would have been difficult to predict at the time, many of these efforts are having major impacts today. For example, had the consumption patterns of the 1970s continued through the 1990s, total U.S. energy use would be 50 percent higher in 2000 than is projected in this year's *Annual Energy Outlook*. These responses have laid a foundation that will permanently alter our energy future.

The projections to the year 2010 contained in this year's *Outlook* attempt to anticipate the future impacts of energy and environmental policies in place as well as currently known technologies that improve modestly over time.

Although no attempt has been made to include dramatic or "leapfrog" developments, the impacts of technology on both the demand and supply of energy could be, nonetheless, striking:

- If we assume that purchasers of appliances through 2010 select the most energy-efficient technology available in 1991,[1] residential energy demand in 2010 would be about 25 percent less than it would have been if the average technology sold in 1991 had been adopted.
- Because of likely technological advances in the oil and gas industry through 2010, economically recoverable natural gas resources in the United States are up 41 percent and oil up 37 percent from what they would have been if 1990 technology had continued as the industry norm.

Other aspects of the *Annual Energy Outlook* are likely to attract the attention of energy analysts:

- Despite recent sharp drops in the price of oil, the inflation-adjusted level of $28 per barrel projected for 2010 is only about $2 less than that projected last year. This reflects the Energy Information Administration's continuing view that, based on factors currently known, higher prices will eventually be needed to bring forth adequate supplies of oil.
- Net volumes of oil imports into the United States are projected to rise to 60 percent of consumption from the 1992 rate of 38 percent. In a low-priced oil scenario analyzed in this document, the volume of imports goes up to 68 percent, but the total amount spent on these imports goes down.
- Changes in the pattern of energy consumption by fuel in the United States are evolutionary rather than revolutionary, with oil, natural gas, and coal maintaining their dominant positions. Renewable energy, however, is projected to grow at the fastest rate.
- Energy efficiency improvements, fostered in large part by the Energy Policy Act of 1992, utility-sponsored demand-side management programs, and traditional market forces of supply and demand, are expected to keep electricity demand growth well below historical levels. Demand for electricity is expected to grow 1 to 1.5 percent per year to 2010, compared with 3.4 percent per year between 1970 and 1990.

The projections in the *Annual Energy Outlook 1994* represent forecasts based on assumptions about economic conditions, world oil markets, and technology characteristics, as well as laws and regulations in place as of October 1, 1993. Furthermore, the representation of new and emerging technologies may not fully capture issues that would affect technology decisions, such as cost and performance improvements that come with experience, financial risk avoidance, diversification of supply sources, and directions from regulatory commissions. Thus, they should not be construed as absolute predictions of the future, nor do they include the impacts of recent policies such as the Administration's recently announced Climate Change Action Plan and Clean Car Initiatives.

If the past is any guide, there are likely to be short-term events, such as severe weather or supply disruptions, that would noticeably interrupt the smoothness of the projections in the *Outlook*. It is not anticipated, however, that these short-term events would significantly affect the long-term trends. Long-term effects could result from political

[1]The exception is refrigerator efficiencies, which are allowed to increase, based on more stringent efficiency standards pending in the National Appliance Energy Conservation Act of 1987. A more detailed discussion of the efficiency scenarios is provided on page 10.

events, economic shifts, technological breakthroughs, or significant changes in laws and regulations.

This year's *Outlook* is the first generated using the new National Energy Modeling System. This model has been developed by the Office of Integrated Analysis and Forecasting over the past 2 years to improve and update the modeling and analysis capabilities of the Energy Information Administration.

The National Energy Modeling System was developed with extensive input from the energy modeling community and other potential users of model outputs. The National Research Council of the National Academy of Sciences began working on recommendations for a new system in 1990. Since that time, expert reviews, a user group, and a national conference were used to solicit additional valuable input from members of the Department of Energy, other government agencies, business, and academia.

Although this model represents a substantial improvement over previous systems, further model enhancements are planned. For the coming year, these include new or enhanced modules for demand-side management, technology penetration for the electricity generation sector, enhanced oil recovery supply, renewable energy supply, regional macroeconomics, and distribution impacts, as well as enhanced capabilities for environmental analysis.

In addition to these analytical improvements, we will be expanding the accessibility of the models themselves. Each of the component modules of the National Energy Modeling System will be made available in a personal computer version with a user-friendly interface for executing and revising key parameters of the module. Interested users will be able to do their own comparative analysis using our model. Over the next year, we plan to have these personal computer models developed for most of the modules.

The *Annual Energy Outlook 1994* has a different layout with additional emphasis on graphics. We solicit feedback from our customers on the *Outlook* or the modeling system on which it is based. These comments will be used to develop the foundation for future improvements.

Finally, I would like to express a great debt of gratitude to the people of the Office of Integrated Analysis and Forecasting for their very hard work and commitment to quality. Over the past two years the Office has faced the daunting task of developing the National Energy Modeling System and producing its ongoing analytic products such as the *Annual Energy Outlook*. To do either would have been hard. To do both required a herculean effort.

Jay E. Hakes
Administrator
Energy Information Administration

Energy Expenditures Expected to Increase Through 2010

Figure 1. Primary energy expenditures, 1970-2010 (billion 1992 dollars)

Total spending on energy in the United States was about $360 billion in 1990 (Figure 1), about 6 percent of the gross domestic product (GDP) and about 15 percent higher than the national defense budget.

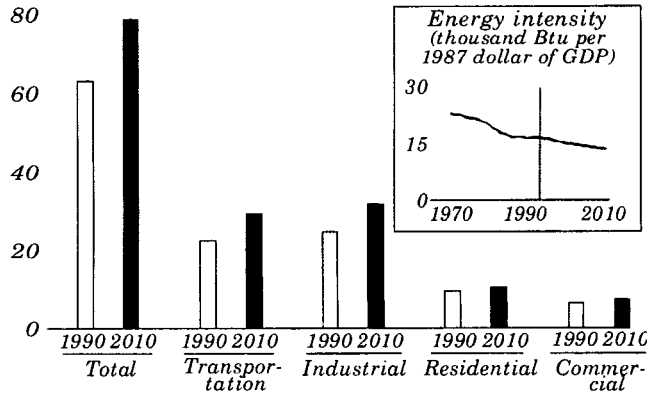
Driven by falling energy prices and consumption, spending on energy declined in 1982-83 and again in 1986. As a share of GDP, energy spending fell through most of the 1980s. Prices for oil and natural gas fell in the 1980s because of excess production capacity, both domestically (for natural gas) and worldwide (for oil), which developed in response to the high prices of the early 1980s but could not be sustained in the face of declining consumption.

Energy spending increases in the forecast as energy prices, particularly those of oil and natural gas, rise after 2000, partly due to diminishing excess capacity and tighter markets. Expenditures on primary energy, which exclude electricity purchases, are expected to increase by 2.5 percent a year through 2010. Primary energy consumption increases to 105 quadrillion Btu in 2010 from 84 quadrillion Btu in 1990.

Spending on petroleum products increases by 2.2 percent annually, due to the increase in the crude oil price and an annual growth in consumption of 1.1 percent. Delivered natural gas prices increase through 2010 at an average annual rate of 1.7 percent. Coupled with an annual growth rate for consumption of 1.3 percent, expenditures on natural gas increase by 3.9 percent a year. Coal expenditures rise by only 1.9 percent a year, with coal consumption and prices increasing slightly.

Energy Consumption Rises, But Efficiency Continues to Improve

Figure 2. End-use energy consumption, 1990 and 2010 (quadrillion Btu)



Total end-use consumption, excluding fuel consumed in electricity generation, is projected to increase from 63 quadrillion Btu in 1990 to 79 in 2010. Industry remains the largest consuming sector, with a 39-percent share of consumption in 1990, growing to 40 percent in 2010 (Figure 2). The transportation sector consumes nearly as much as industry and adds 7 quadrillion Btu from 1990 to 2010, and its share of consumption grows from 35 percent in 1990 to 37 percent in 2010. The residential and commercial sectors both increase by about 1 quadrillion Btu, and their shares of consumption decrease slightly.

Even as consumption increases, energy intensity declines in the forecast at an annual average rate of 1.0 percent, in response to the energy efficiency standards mandated by the Energy Policy Act of 1992 (EPACT), fuel price increases, and continuing changes in the output mix of U.S. industry.

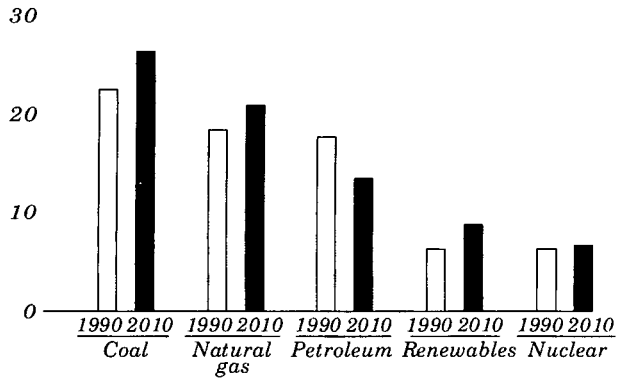
Since 1970, the intensity of energy use in the United States has declined on average by 1.5 percent a year, due to increased efficiency of energy use and the shift to less energy-intensive production and services. (Efficiency measures the use of energy per unit of service provided—for example, heat produced or vehicle-miles traveled.)

EPACT provides additional efficiency standards for new energy-using equipment in the residential and commercial sectors and new motors in the industrial sector. The adoption of more innovative energy-saving technologies is also expected, as growth in demand and higher energy prices accelerate the rate of investment in new technologies.

HIGHLIGHTS

Oil Production Declines—Coal and Natural Gas Increase

Figure 3. Energy production by source, 1990 and 2010 (quadrillion Btu)



Petroleum production continues to decline in the forecast (Figure 3) as the least costly U.S. oil resources are depleted. Imports continue to fill the difference between production and consumption (Table 1). In 2010, the share of net imports in oil consumption could grow to 60 percent, up from 21 percent in the early 1970s and 39 percent in 1990.

Table 1. Net imports of petroleum and natural gas, 1990-2010

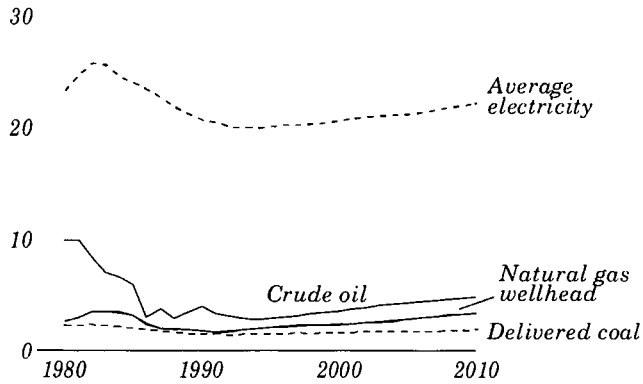
Source	1990	2000	2010
Petroleum (million barrels per day)	*6.68*	*10.94*	*12.80*
Natural gas (trillion cubic feet)	*1.45*	*2.93*	*3.85*

Both coal and natural gas production increase in the forecast, continuing their recent trends. Natural gas production began increasing in the late 1980s, due to renewed growth in consumption and cost reductions associated with improved exploration and development technology. Natural gas imports also grow, accounting for 16 percent of gas consumption in 2010, up from 8 percent in 1990.

Renewable energy production and consumption grow by more than a third over the forecast horizon, with consumption reaching 8.9 quadrillion Btu in 2010. Nuclear power production peaks after 2000, then declines as units are retired, beginning around 2005, but remains slightly higher in 2010 than in 1990. New units do not compensate for the retirements, but improved capacity factors lead to the increase in nuclear generation.

Fuel Prices Rise—Electricity Price Increases Slowest

Figure 4. Energy prices, 1980-2010 (1992 dollars per million Btu)



Crude oil prices, measured as the average refiner acquisition cost of imported crude oil, are forecast to decline through 1994, then rise steadily as excess capacity diminishes worldwide, with an average annual growth rate of 1.0 percent from 1990. In real terms, oil prices are not projected to reach the levels of 1979-85, when prices escalated after the Iranian supply disruption.

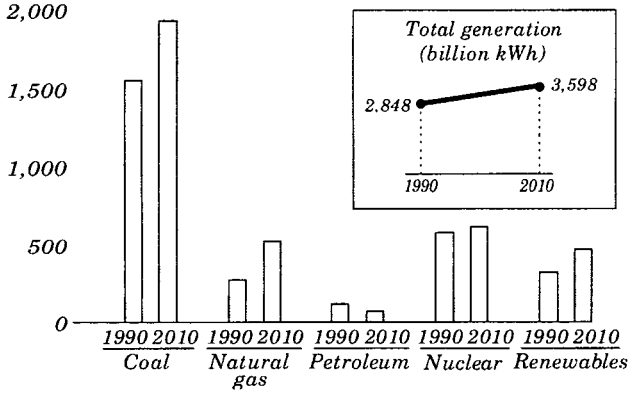
The average wellhead price of natural gas rises steadily over the forecast period at an average annual rate of 3.3 percent. Unlike the price of oil, the price of natural gas in 2010 is likely to approach its historic 1982-84 peak. Gas prices rise as the lowest-cost sources are depleted and demand increases.

Coal prices, having declined in real terms through most of the 1980s due to higher mining productivity and excess capacity, increase at a moderate annual rate of 1.0 percent in the forecast because of the abundance of low-cost domestic reserves and continued productivity improvements.

The average electricity price, declining in real terms through most of the 1980s, increases at an average annual rate of 0.3 percent in the forecast as fuel costs rise. The prices of fuel inputs rise faster, but fuel costs account for only 20 to 25 percent of the total cost of generation. The remaining costs are for operation and maintenance, which are projected to remain stable on a per-kilowatthour basis, and for capital investments, which decline on a per-unit basis.

Coal Continues to Dominate Electricity Production

Figure 5. Electricity generation by fuel, 1990 and 2010 (billion kilowatthours)



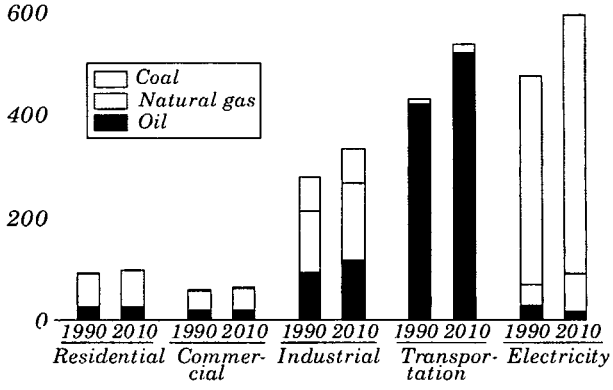
Coal continues as the main fuel for electricity production, contributing over 50 percent of generation through 2010 (Figure 5). Natural gas, used primarily in combined-cycle and gas-fired turbines, contributes an increasing share of electricity generation through 2010. These natural gas technologies are appealing options for new generation capacity, because they emit no sulfur compounds, are less expensive to construct than coal-fired units, and have shorter construction leadtimes.

Generation of electricity from renewable sources grows slightly as a share of total generation, rising to 13 percent in 2010 from 11 percent in 1990; however, renewables have the second fastest growth rate among all sources of generation, behind natural gas. Hydropower remains the dominant source of renewable generation, accounting for considerably more than half of the total. Wind, geothermal, biomass, and municipal solid waste each contribute between 6 and 16 percent of the generation from renewables, and solar energy grows to 1 percent of generation from renewables by 2010.

The increases in the use of renewable sources are due in part to technology improvements and to EPACT. The dramatic cost reductions for both solar and wind technologies in the past decade should increase their adoption, particularly in the geographic regions best suited to their use. Growth in wind energy is projected to increase substantially after 2005, due to higher projected prices for natural gas.

Carbon Emissions Increase, But at a Slower Rate

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



Carbon emissions from fuel combustion increase in the forecast from 1,338 million metric tons in 1990 to 1,632 million in 2010 (Figure 6), assuming no change in current regulations. This is a slower rate of growth than in the 1970s and 1980s, attributable in part to higher market shares for natural gas and renewables. Continued growth in coal and petroleum use offsets some of the potential reductions.

Total carbon emissions grow by an average of 1.0 percent a year through 2010. Because of its dependence on petroleum, the transportation sector contributes an increasing share of emissions, from 32 percent in 1990 to 33 percent in 2010, as transportation emissions grow by 1.1 percent annually.

Electricity generation is the largest source of carbon emissions, increasing by 1.1 percent annually through 2010 (at a faster rate than the total), with its share growing from 36 to 37 percent of the total. This occurs despite the increased use of natural gas and renewables for generation, because of the continued use of coal. Emissions from combustion of natural gas grow from 9 to 12 percent of total utility carbon emissions. Coal remains the largest source of carbon from generation, 85 percent in 2010.

The industrial sector contributes about one-fifth of carbon emissions, and both the residential and commercial sector emissions decline slightly as shares of the total throughout the forecast period.

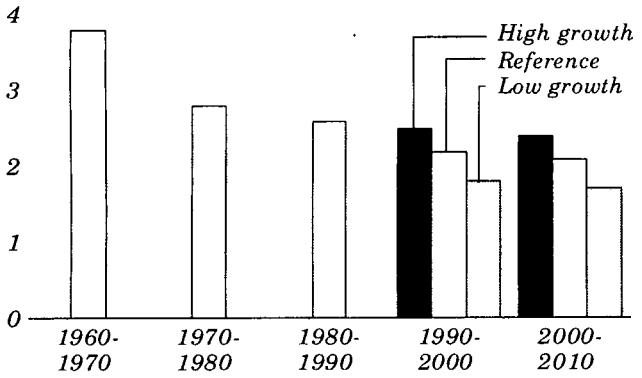
Impacts of the Climate Change Action Plan, which will mitigate the increase in carbon emissions, are not included. These projections consider only those laws and regulations in effect as of October 1, 1993.

CHAPTER 1
KEY ASSUMPTIONS IN THE FORECASTS

Economic growth

One of the biggest influences on energy demand is the growth in economic output, measured by gross domestic product (GDP). The long-run potential for economic growth depends on the capacity to expand aggregate supply, which, in turn, depends on a growing labor force, growth in the capital stock, and improvements in productivity. Over the past 30 years, the 10-year average annual GDP growth has declined each decade, and this decline is assumed to continue in the forecast, though at a slower rate (Figure 7).

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

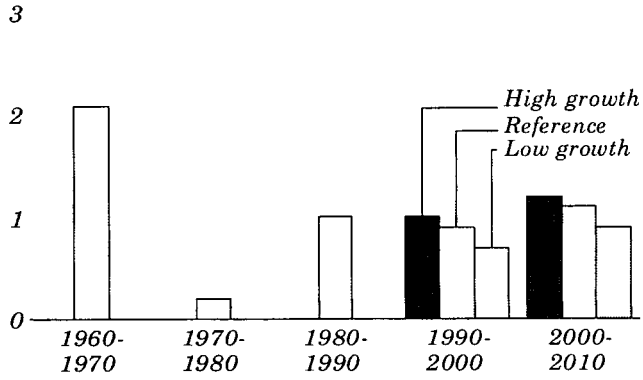


Economic output is assumed to grow in the forecast by 2.1 percent a year, the labor force by 1.1 percent, and productivity by 1.0 percent, with each contributing equally to economic growth. Output of manufacturing industries grows by 2.4 percent a year, with machinery, electronic, and transportation equipment growing at a higher rate. The top six energy-consuming industries grow by 1.7 percent a year.

To capture some of the uncertainty in energy market activity associated with variations in long-term economic growth, two added cases provide lower and higher economic growth rates relative to those of the *AEO94* reference case. The range between those rates is 0.6 percentage points, with the reference case at the midpoint between them.

Productivity (output per person) is a key ingredient for long-run output growth and is assumed to grow in the reference case (Figure 8). Productivity growth, after slowing in the mid-1970s, has recently begun to recover. To maintain the growth in total output, productivity gains must offset the declines in labor force growth expected after 2000.

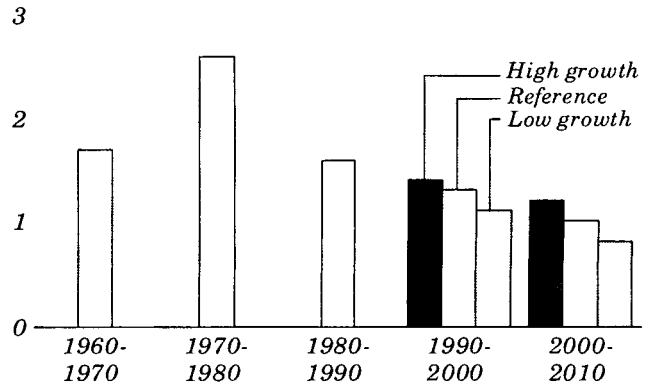
Figure 8. Average annual productivity growth rate by decade, 1960-2010 (percent)



Increasing the pool of funds for investment leads to increased investment and higher capital accumulation, keys for increasing productivity and boosting long-term economic growth. Total savings as a share of GDP are assumed to increase, as inflation-adjusted spending declines and the government deficit is substantially reduced.

Labor force growth depends on labor force participation and population growth. Over the past several decades, labor force participation increased as "baby boomers" came of age and women entered the labor force in increasing numbers. This growth is assumed to continue through 2005 in the forecast's reference case, then to decline slowly as the baby boom cohorts begin to reach retirement age (Figure 9). In the reference case, the total labor growth rate is 1.4 percent for 1995-2000 and 0.8 percent for 2005-2010. The spread in the labor force growth rate between the high and low economic growth cases is 0.3 percentage points.

Figure 9. Average annual labor force growth rate by decade, 1960-2010 (percent)



Population growth in the forecast is 0.9 percent a year. The Census Bureau recently revised its middle series of population projections, leading to upward revisions in all elements contributing to population growth—birth rate, life expectancy, and immigration rates.

Other published forecasts of long-term economic growth range from 1.7 percent to 2.9 percent a year (Table 2). The growth rate in the *AEO94* reference case is close to those of Data Resources, Inc. (DRI) and the Council of Economic Advisors. The WEFA Group (WEFA) projections differ from the others in their labor force participation rates: WEFA forecasts that 70 percent of the population age 16 and over will be in the labor force in 2010, compared with 66 percent in the DRI forecast.

Table 2. Comparative forecasts of economic growth, 1990-2010

	Average annual percentage growth		
Forecast	**Real GDP**	**Labor force**	**Productivity**
AEO94			
Low	1.8	1.0	0.8
Reference	2.1	1.1	1.0
High	2.4	1.3	1.1
DRI			
Low	1.7	1.0	0.7
Base	2.1	1.1	1.0
High	2.5	1.3	1.2
WEFA			
Low	2.1	1.2	1.0
Base	2.5	1.3	1.2
High	2.9	1.5	1.4
Council of Economic Advisors	2.1	NA	NA

NA = not available.

World oil prices

The price of oil in international markets drives U.S. petroleum markets and has powerful spillover effects on the markets for other fuels. International market conditions, particularly crude oil supply by Organization of Petroleum Exporting Countries (OPEC), are major determinants of the world oil price, but U.S. demand and production also affect it.

An innovation in the *AEO94* forecast is the incorporation of a dependence of the world oil price on U.S. oil demand and production. The world oil market component of the National Energy Modeling System adjusts the world price of crude oil, the prices of products available for import into the United States, and production and demand in other regions of the world in response to changes in U.S. oil market conditions. An increase in U.S. oil production or a decline in U.S. demand for oil will lead to a decline in the world oil price. Alternatively, decreased U.S. oil production or increased demand will raise the world oil price.

In the forecast's reference case, the world oil price remains below $20 a barrel until 2000 and then gradually climbs to over $28 a barrel in 2010. To reflect the uncertainty in prices, in a high price case, the world oil price approaches $35 a barrel in 2010, and, in a low price case, it is just over $20 a barrel (Figure 10).

Figure 10. World oil prices, 1970-2010 (1992 dollars per barrel)

The high and low world oil price paths are intended to reflect reasonable upper and lower bounds on world oil prices, under the reference case assumptions for GDP growth rates worldwide and non-OPEC oil production. The price range was derived by varying the assumptions about OPEC output and the level of net oil exports from the former Soviet Union, China, and Eastern Europe. Unforeseeable events, such as the hostilities in the Persian Gulf, could drive prices outside the range, but market forces should bring them back to this range after the end of the exceptional event.

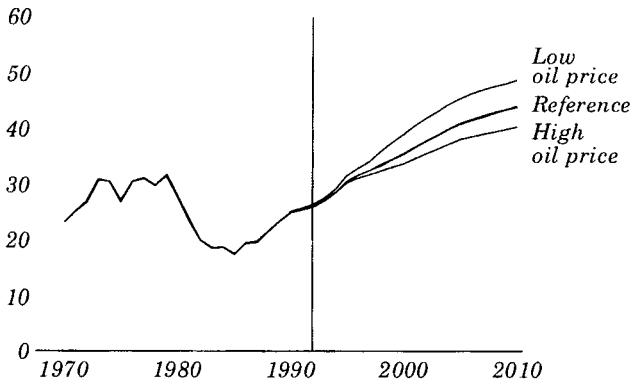
OPEC member nations hold the majority of the world's oil reserves (over 75 percent at the end of 1992) [*1*] and are assumed to be the main source of the additional production needed to meet the world's growing demand for oil. In the reference case, OPEC production increases from 26 million barrels a day in 1992 to 44 million barrels a day in 2010.

Additional factors influencing world oil prices are oil production in non-OPEC countries; net oil exports from the former Soviet Union, China, and Eastern

Europe; and worldwide demand for oil (determined by economic growth rates and other factors). Non-OPEC production is assumed to remain relatively stable: 28 million barrels a day in 1992, rising to 30 million barrels in 1997 and then falling back to 27 million barrels in 2010. Declining production in mature production areas, such as the United States, is offset by increases in the North Sea and Latin America through 2000.

Variation in OPEC's production rate is a key assumption in establishing the low and high world oil price paths. For the low price case, assumptions about OPEC production rates are optimistic, consistent with market conditions in the past several years. For the high price case, OPEC production assumptions are more pessimistic. OPEC production for 2010 is about 11 percent higher in the low price case than in the reference case—and about 8 percent lower in the high price case (Figure 11).

Figure 11. OPEC oil production, 1970-2010 (million barrels per day)



Three out of four other forecasts have world oil prices in the $27-30 range in 2010, with the *AEO94* reference case in the middle. The range between the low and high price cases encompasses the spread of these other forecasts (Table 3).

Table 3. Comparative forecasts of world oil prices

	1992 dollars per barrel		
Forecast	***2000***	***2005***	***2010***
AEO94 reference case	*20.72*	*24.90*	*28.16*
AEO94 low price case	*15.44*	*17.49*	*20.15*
AEO94 high price case	*24.16*	*29.90*	*34.11*
DRI	*22.66*	*26.66*	*29.95*
WEFA	*20.34*	*22.79*	*24.94*
IEA	*26.70*	*29.30*	*29.30*
GRI	*21.01*	*23.82*	*27.02*

Legislation

These forecasts have been prepared on the basis of Federal, State, and local laws and regulations in effect as of October 1, 1993. They incorporate the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents a gallon to the Federal tax on highway fuels—gasoline, diesel fuel, and natural gas. They also incorporate two major pieces of recent legislation: the Clean Air Act Amendments of 1990 (CAAA90) and the Energy Policy Act of 1992 (EPACT). Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts. The Administration's recently announced Climate Change Action Plan is not included.

The main effect of EPACT on energy markets is to reduce demand. The Act requires that minimum building-efficiency standards be set for all new Federal buildings and new buildings that receive federally-backed mortgages. Efficiency standards for electric motors, lights, and residential, commercial, and industrial equipment are also required. Government and private businesses with fleets of automobiles or trucks must phase in vehicles that do not rely on petroleum products.

EPACT exempts certain wholesale electric generators from the Public Utility Holding Company Act of 1935, thus allowing utilities to operate independent wholesale plants outside their service territories. In addition, EPACT improves efficiency in the transmission system by authorizing the Federal Energy Regulatory Commission to order wholesale, but not retail, transmission access case-by-case. EPACT is also expected to increase the use of renewable energy by electric utilities through an investment tax credit.

CAAA90 has its primary impact on the transportation and electric utility sectors. It requires a phased reduction in vehicle emissions of regulated pollutants, with the reduction expected to be met primarily through the use of cleaner burning reformulated gasolines. Electric utilities are required to reduce annual emissions of sulfur dioxide and nitrogen oxides. Utilities can meet the requirements by switching to fuels with lower sulfur content, by using a less polluting fuel such as natural gas, or by installing equipment (scrubbers) that removes sulfur from the flue gas. CAAA90 includes a provision for an emissions allowance trading program.

The projections in the *Annual Energy Outlook 1994* represent forecasts of future energy trends based on legislation and regulations in place on October 1, 1993; data known as of August 1993; and a set of assumptions concerning regulatory and economic conditions, world oil markets, and technology. Short-term phenomena that might occur, including political events and severe weather patterns, are not included in these projections, although it is anticipated that most short-term events would not significantly alter the longer term trends. A number of unexpected events could, however, change the long-term future from the outlook presented here, such as major political events, economic changes, technological breakthroughs, or changes in legislative and regulatory conditions.

Since the assumptions for the *AEO94* projections were finalized, several events or data updates have occurred that, if incorporated, would significantly alter the near-term projections or even the longer term projections in some cases. Estimates of Alaskan crude oil production in the earlier years of the *AEO94* projections are at a level approximately 20 percent lower than the most current conditions might warrant. Recent production enhancements in the two largest fields, Prudhoe Bay and Kuparuk, have maintained levels of production higher than previously anticipated. In addition, production performance from smaller fields has exceeded the levels expected in earlier announcements. As a result, higher levels of Alaskan oil production will be included in the first-quarter *Short-Term Energy Outlook* [2], to be published in February 1994. The *Short-Term Energy Outlook* includes quarterly energy projections through 1995.

The penetration of renewable technologies for electricity generation is another area of uncertainty. The *AEO94* forecasting system uses announced plans for renewable generation capacity as reported on the electricity data forms collected by EIA [3]. New capacity enters the forecasts as economic considerations, such as capital costs, electricity demand, and alternative fuel costs, warrant. Recently, however, regulatory agencies are displaying a greater tendency to avoid new generation capacity that entails large capital investments or long leadtimes, or that contributes to higher emissions levels. Wind generation is one of several viable alternatives to more traditional sources. It is quite possible that considerably more wind capacity may be constructed in the near term than that shown in the *AEO94* projections as a result of these regulatory issues.

More recent data show a marked change in the prospects for nonutility generation of electricity. Data for 1992 reporting current and planned capacity additions [4], which were finalized in December 1993, show approximately a 30-percent increase in cogeneration capacity over 1991 data. Cogeneration for 1992 in the *AEO94* projections is an estimate from the modeling system and reflects the pre-1992 growth rate. Incorporation of the recent 1992 data would increase cogeneration both in the near-term estimates and throughout the forecast.

Other recent events that differ from the projections presented in the *AEO94* include the importation of natural gas from Mexico. Although imports of Mexican natural gas have occurred in the past, the only natural gas trade between the United States and Mexico since 1984 has been the export of gas to Mexico. The *AEO94* forecasts include an assumption that Mexican imports will resume in 2006. Recent trade press articles [5] indicate, however, that a few spot-market purchases of gas have occurred, presumably due to the current depressed prices for crude oil. It is likely that this is a short-lived phenomenon that will not impact the longer term forecasts.

Energy markets are rapidly evolving, as evidenced by these recent shifts in projected trends. Any longer term forecast is likely to include some details that are quickly contradicted by more recent data or events or by the underlying uncertainties of the regulatory environment, weather conditions, and economic growth. None of these events, however, serves to invalidate the longer term trends presented in this report.

NATIONAL ENERGY MODELING SYSTEM

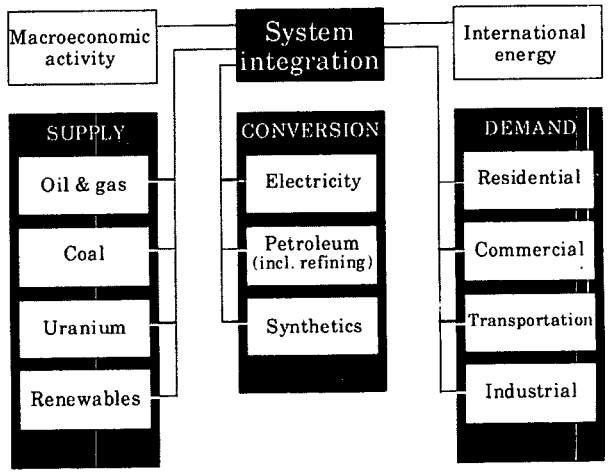
The new National Energy Modeling System (NEMS) generated the projections in the *Annual Energy Outlook 1994*. NEMS uses a unified modeling system to forecast alternative energy futures in the middle term—and thus illustrates the energy, economic, environmental, and energy security consequences for the United States of various energy policies and assumptions.

NEMS is the result of a 2-year development effort by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to enhance and update its policy modeling and analysis capability. Integrated energy modeling systems have been used for EIA's annual reports of energy projections since 1974 and for analytical studies requested by decisionmakers and analysts in the U.S. Congress and the Department of Energy's Office of Policy, Planning, and Program Evaluation. There has been an extensive dialogue between EIA and the community of energy modelers, analysts, and users of EIA projections throughout the NEMS development.

Like its predecessors, 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. The time horizon of NEMS is 25 years—the middle term in which the structure of the economy, the nature of energy markets, and regional demographics are understood sufficiently well to allow for considerable structural and regional detail. The majority of policies proposed today will have their greatest impacts during the middle term.

NEMS was designed to support the analysis of emerging energy issues in the 1990s. Market features formerly analyzed outside the modeling system—such as the international oil market and the penetration of renewable energy sources—are now represented directly in NEMS. Moreover, the component models incorporate sufficient structural detail to allow for the analysis of a variety of energy issues. The enhancements over previous models include a representation of natural gas pipeline transportation capacity and tariffs, an endogenous representation of the impacts of the Clean Air Act compliance options, an embedded refinery model that differentiates several crude oil types, equipment stock models for end-use services in the buildings models, an alternative-fuel vehicle module, a process representation of industrial sector energy use, and emissions reporting.

NEMS Design



Four end-use demand models use fuel price and economic drivers to compute energy demand. Supply and conversion models calculate the prices and production necessary to meet the fuel demands of the end-use and conversion sectors.

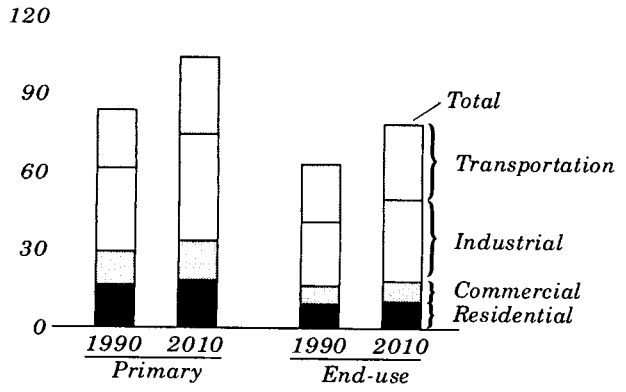
Because of the diversity of energy supply, demand, and conversion in the United States, NEMS is designed to support regional modeling and analysis in order to portray transportation flows, represent the regional differences in energy markets, and provide estimates of policy impacts at the regional level.

The regional detail of the end-use demand models is for the nine Census divisions. Other regional structures include production and consumption regions specific to the supply industries, such as the North American Electric Reliability Council regions and subregions for electricity and the Petroleum Administration for Defense Districts for refineries. Regional results are reported in the *Supplement to the Annual Energy Outlook 1994*.

ENERGY DEMAND BY END USE

Energy consumption in the forecast outpaces population growth as efficiency improvements only partially offset the growing demand for energy services. Primary energy consumption—which includes the energy required to generate and distribute electricity as well as fuels used directly by consumers—is projected to reach 105 quadrillion Btu by 2010, while end-use energy consumption reaches 79 quadrillion Btu (Figure 12).

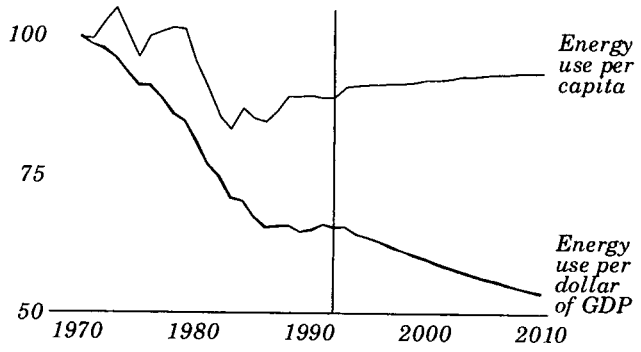
Figure 12. Primary and end-use energy consumption, 1990 and 2010 (quadrillion Btu)



Almost all of the increase in end-use energy consumption over the forecast is in the industrial and transportation sectors. In the reference case, energy consumption in the industrial and transportation sectors is projected to increase by about one-third between 1990 and 2010. Energy use in these sectors also varies with alternative estimates of oil prices and economic growth. In 2010, projected industrial energy use varies by 11 percent across the *AEO94* economic growth cases; transportation energy use varies by over 6 percent across the world oil price cases. Residential and commercial energy consumption changes little over the forecast, as building shell and equipment efficiency improvements largely offset the effect of increases in the number of buildings.

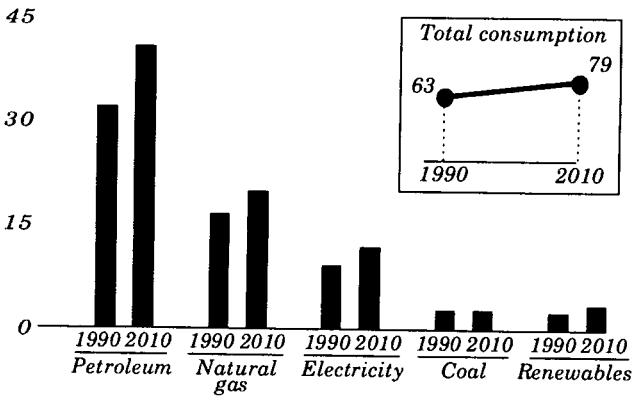
Figure 13 compares historical and projected trends in aggregate end-use energy consumption with trends in population growth and economic activity. Between 1970 and the mid-1980s, total end-use energy consumption remained practically unchanged. Energy intensity, both per dollar of gross domestic product (GDP) and per capita, declined. Since then, relatively stable energy prices and the economic recovery of energy-intensive industries have slowed the decline in energy use per dollar of GDP. Energy use per capita, spurred by low oil prices, has been increasing since the mid-1980's. This trend is projected to continue. Each person is projected to consume over 5 percent more energy in 2010 than in 1990.

Figure 13. End-use energy intensity, 1970-2010 (index, 1970 = 100)



Petroleum products continue to account for more than half of all end-use energy consumption throughout the forecast (Figure 12). Most of the increase in oil use is in the transportation and industrial sectors. End-use natural gas consumption increases by about one-fifth by 2010, mostly in the industrial sector. Electricity consumption is also projected to increase by over one-fourth between 1990 and 2010, despite new efficiency standards for such end uses as refrigerators and fluorescent lights. Projected growth in the use of renewable energy is based on increased use of wood byproducts for energy in the paper industry, with little increase in wood use for heating in the residential sector.

Figure 14. End-use energy consumption by fuel, 1990 and 2010 (quadrillion Btu)



Alternative energy efficiency scenarios

Energy efficiency improvements play a major role in dampening growth in sectoral energy consumption. To highlight the importance of continuing efficiency improvements, this chapter includes end-use scenarios that contrast the projected level of energy consumption in the reference case to consumption levels based on alternative assumptions about efficiency improvements. The results of the analyses are displayed in Figures 17 and 18, 23, 27, and 32, for the residential, commercial, industrial, and transportation end-use sectors, respectively.

In the residential and commercial sectors, two alternative efficiency cases were compared to the reference case—a "best off-the-shelf" case and a "1991 technology" case. In the best off-the-shelf case in the commercial sector, the most energy-efficient natural gas, oil, and electric technologies available in all future years are assumed to be used in new construction and to replace worn-out equipment. In the residential sector, the most efficient technology available in 1991 is chosen in the best off-the-shelf technology case, with the exception of refrigerators, which are assumed to improve in efficiency, based on more stringent efficiency standards pending in the National Appliance Energy Conservation Act of 1987. This high-efficiency equipment scenario provides a benchmark for the amount of energy that could be saved with known technologies [6].

The 1991 technology case assumes that new equipment is purchased at the 1991 shipment-weighted average stock efficiency. Aggregate efficiencies still improve as equipment is purchased for new buildings and to replace worn-out equipment; but the rate of energy efficiency improvement is not as great as in the reference case.

In the industrial and transportation sectors, the 1991 technology cases are contrasted to the reference case to provide a measure of the aggregate energy savings attributable to improved energy efficiency. The industrial-sector estimates keep average process efficiencies (for example, energy consumption per ton of steel produced in blast furnaces) constant at their 1991 levels throughout the forecast. As a result, energy use increases proportionately with projected industrial output. In the transportation sector, average new car, light truck, and aircraft fuel efficiencies are frozen at their 1991 levels; stock turnover still results in increased average fuel efficiency.

Primary versus end-use energy consumption

The distinction between primary (including electricity generation and transmission losses) and delivered end-use energy consumption is illustrated in the table below, which contrasts percentage shares based solely on delivered energy to shares that include electricity generation and transmission losses in the electricity totals.

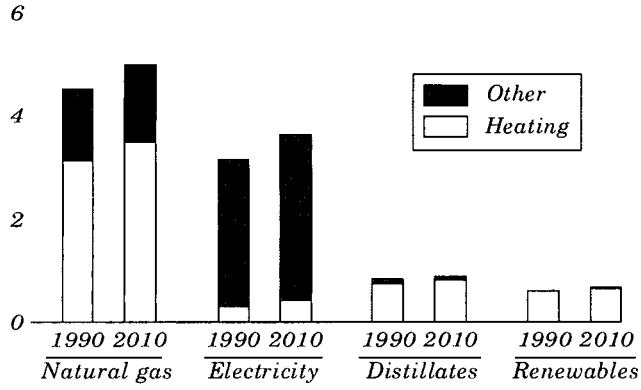
Overall, electric utilities consume about 3.2 Btu for every Btu of electricity delivered to customers. In terms of end-use energy consumption, electricity accounts for only 15 percent of energy consumed by final customers in 2010. In terms of total energy requirements, however, 36 percent of the Nation's energy is used to generate and distribute electricity. This distinction is particularly important in estimating the energy requirements and conservation potential of the residential and commercial sectors, because these sectors depend most heavily on electricity.

Energy consumption in 2010

End-use sector and energy source	*End-use consumption*		*With electricity losses*	
	percent	*Quads*	*percent*	*Quads*
Residential		***10.6***		***18.5***
Electricity	*34*	*3.6*	*62*	*11.6*
Natural gas	*47*	*5.0*	*27*	*5.0*
Petroleum	*12*	*1.3*	*7*	*1.3*
Other	*7*	*0.7*	*4*	*0.7*
Commercial		***7.6***		***15.2***
Electricity	*46*	*3.5*	*73*	*11.2*
Natural gas	*40*	*3.0*	*20*	*3.0*
Petroleum	*11*	*0.8*	*5*	*0.8*
Other	*2*	*0.2*	*1*	*0.2*
Industrial		***31.7***		***41.5***
Electricity	*14*	*4.5*	*35*	*14.3*
Natural gas	*34*	*10.7*	*26*	*10.7*
Petroleum	*34*	*10.8*	*26*	*10.8*
Other	*18*	*5.7*	*13*	*5.7*
Transportation		***29.5***		***29.9***
Electricity	*1*	*0.2*	*2*	*0.6*
Natural gas	*4*	*1.1*	*4*	*1.1*
Petroleum	*95*	*28.1*	*94*	*28.1*
Other	--	*0.1*	--	*0.1*
Total (all sectors)		***79.3***		***105.2***
Electricity	*15*	*11.8*	*36*	*37.7*
Natural gas	*25*	*19.8*	*19*	*19.8*
Petroleum	*52*	*41.1*	*39*	*41.1*
Other	*8*	*6.7*	*6*	*6.7*

Natural Gas Dominates for Heating

Figure 15. Residential energy consumption by fuel and end use, 1990 and 2010 (quadrillion Btu)



Consumption of piped and bottled gas, especially for space heating, continues to dominate the residential energy mix in the forecast (Figure 15). In 1990, gas was the main space heating fuel for 62 percent of single-family households [7]. In 1992, it was reported as the main space heating fuel for 65 percent of all new privately owned single-family homes, its highest market share ever [8].

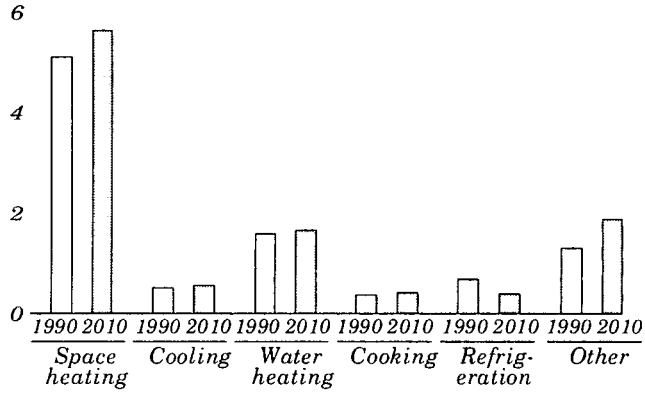
Electricity is one of the most important fuels in the residential sector, because it powers a wide variety of essential services, such as lighting, refrigeration, and laundry equipment. Many of these electricity-dominated services have been targeted by strict Federal Efficiency Standards that, coupled with utility demand-side management (DSM) programs, combine to lower electricity growth.

Primary space heating systems that use distillate fuels were reported to be installed in almost 55 percent of new privately owned single-family homes in the New England Census Division in 1992 and about 18 percent in the Middle Atlantic [9]. This fact, coupled with the forecast for a recovery in housing starts in the Northeast Census Region, leads to stable distillate consumption.

Wood, which accounts for most of the residential use of renewable fuel, is used for both primary and secondary (mainly fireplaces) space heating, with the two uses roughly equally split. Following recent trends, the forecast includes a declining number of homes using wood for primary heating [10]. The decline of wood as a primary fuel is offset by increasing usage intensity (normalizing for weather) and a slight increase in secondary heating usage.

Energy Policy Dampens Growth of Residential Consumption

Figure 16. Residential energy consumption by end use, 1990 and 2010 (quadrillion Btu)



Residential energy consumption per household is projected to decline over the 1990-2010 period, as average consumption growth (0.5 percent a year) falls more than one-third below the growth rate for households. Space heating dominates residential demand (Figure 16), as slow equipment turnover dampens efficiency gains. Refrigerators and freezers are projected to *use less energy* in 2010 than in 1990, due to strict Federal efficiency standards and the development of "Golden Carrot" refrigerators [11].

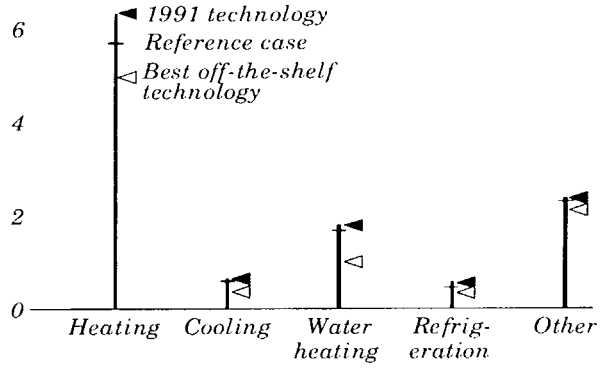
Federal efficiency standards are now in place for most residential appliances, and average stock efficiencies should increase (Table 4). The 1993 Refrigerator/Freezer Standard achieves the greatest savings. Except for refrigerators, average stock efficiencies in 2010 are not expected to reach the level of the best appliances available today, so future efficiency improvements are likely.

Table 4. Residential appliance efficiencies

	Stock average		Best available
Equipment type	**1990**	**2010**	**1991**
Furnace (annual fuel utilization efficiency)			
Natural gas	0.67	0.78	0.97
Distillate oil	0.76	0.81	0.89
Cooling systems (energy efficiency ratios)			
Heat pumps	8.56	10.35	16.40
Central air	8.60	10.11	16.90
Room air	7.47	10.26	12.60
Water heaters (energy factor)			
Electric	0.83	0.91	3.50
Natural gas	0.51	0.56	0.86
Refrigeration (kilowatthours per year)			
Refrigerators	1,188	614	745
Freezers	984	496	383

Appliances Are Becoming Much More Energy-Efficient

Figure 17. Residential energy consumption in three scenarios, 2010 (quadrillion Btu)

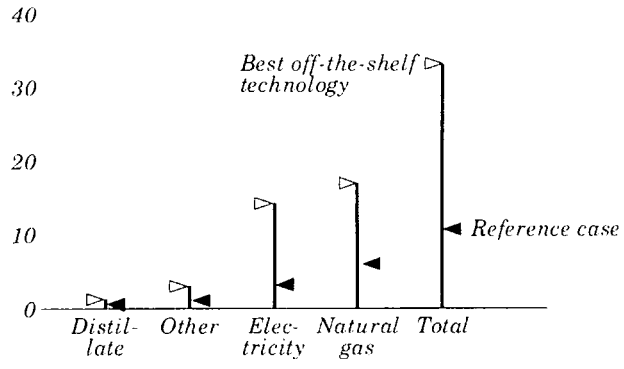


The *AEO94* reference case and two side cases show the relative effects of equipment and building shell efficiency on residential sector energy consumption (Figure 17). The reference case includes many policies to increase residential end-use efficiency, such as the Energy Policy Act of 1992 (EPACT), the National Appliance Energy Conservation Act of 1987 (NAECA), and the "Golden Carrot" refrigerator program of the U.S. Environmental Protection Agency (EPA). The 1991 technology case shows how much energy would be consumed by the residential sector if all new and replacement equipment were purchased at the 1991 shipment-weighted average stock efficiency. In 2010, residential energy consumption in the 1991 technology case would be about 10 percent higher than in the reference case.

The best off-the-shelf technology case is designed to represent full penetration of the most energy-efficient technologies within each service for all new and replacement purchases. This case shows how much energy could be saved if the most efficient technology available in 1991 were purchased. Pending standards were assumed to increase refrigerator efficiency. Almost every end-use service in the sector could realize substantial savings, since current technology permits efficiency levels well above the purchased average. Relative to the reference case, the best off-the-shelf technology case could reduce energy consumption by almost 19 percent a year by 2010 (Figure 18).

Technologies Exist to Achieve Substantial Energy Savings

Figure 18. Cumulative energy savings from efficiency gains in two scenarios, residential sector, 1990-2010 (quadrillion Btu)

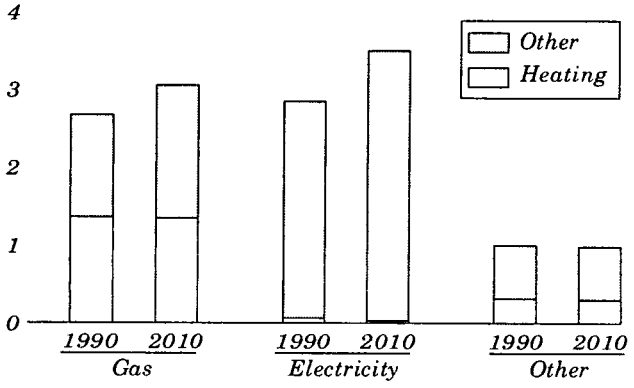


Today's energy-efficient residential appliances could save significant amounts of energy, depending on the market share captured. Both the reference and best off-the-shelf technology cases show great potential for fuel savings relative to the 1991 technology case. As shown in Figure 18, the reference case saves nearly 11 quadrillion Btu between 1990 and 2010, 10 percent more than the delivered energy used to serve the entire residential sector in 1990. Over half of the savings are from natural gas, because its use is concentrated in space heating and water heating, which have had slower increases in efficiency than other end uses. Electricity consumption is cut considerably as well, reflecting the impact of the many different programs designed to reduce its use. Distillate savings are not as dramatic, because the equipment stock has already realized major efficiency gains in the past 15 years.

The best off-the-shelf technology scenario shows that, relative to the 1991 technology case, over 35 quadrillion Btu of energy could be saved if the most energy-efficient technologies were purchased between 1990 and 2010. Again, natural gas realizes most of the savings because of the efficient space heating equipment on today's market. More than 14 quadrillion Btu of electricity could also be saved, a figure that translates into about 45 quadrillion Btu of primary energy, or more than half of the primary energy consumed in the United States in 1990. Super-efficient lighting, heat pump water heaters, and efficient space cooling technologies could contribute significantly to the savings.

Electricity Is the Dominant Fuel for the Commercial Sector

Figure 19. Commercial energy consumption by fuel, 1990 and 2010 (quadrillion Btu)



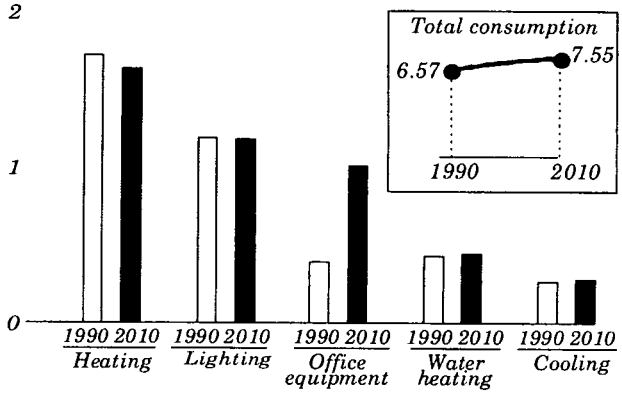
Commercial energy consumption grows in the forecast by 0.7 percent a year, slower than employment (1.2 percent) and commercial floorspace (1.0 percent), as annual average commercial energy intensity (measured in thousand Btu per square foot) declines by 0.3 percent a year. The decline results mainly from continuing penetration of new, higher efficiency equipment and phasing out of old, low-efficiency technologies, as well as fuel switching into higher efficiency technologies, Federal conservation policies such as EPA's Green programs [*12*], improved shell efficiency in new buildings, and equipment efficiency standards in EPACT.

Electricity is the dominant fuel for the majority of services—space cooling, lighting, office equipment, refrigeration, ventilation, and miscellaneous services (Figure 19). It grows in the forecast at the same rate as floorspace, 1.0 percent a year. Natural gas, mainly used for heating, grows by 0.6 percent a year as higher natural gas prices and improved efficiency reduce heating demand.

The changing fuel shares reflect increased use of electricity services and equipment as a result of continuing penetration of new electricity-using technologies (heat pumps for space and water heating); greater use of computers, fax machines, copiers, and other office equipment; increased use of electricity-consuming equipment and appliances in new office buildings; and sensitivity to changes in real energy prices. The real price of electricity remains relatively stable, in contrast to the real increases in the prices of other fuels.

Space Heating Share of Commercial Consumption Still Dominates

Figure 20. Commercial energy consumption by end use, 1990 and 2010 (quadrillion Btu)

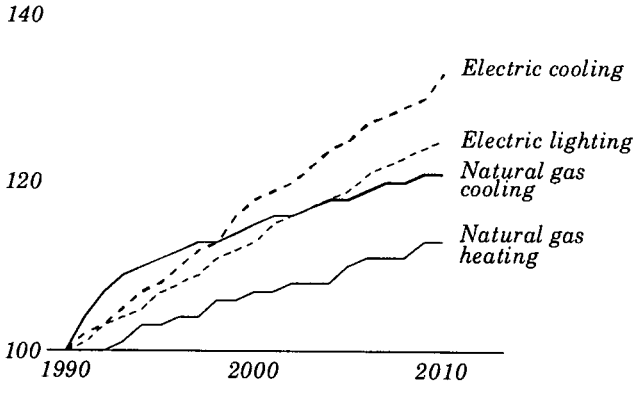


Space heating is the largest commercial energy use in the forecast (Figure 20). Heating uses mainly natural gas, and cooling uses electricity, but cross-penetration is expected to continue.

Lighting consumed more than a quadrillion Btu in 1990, over 40 percent of commercial electricity use. Average installed lighting efficiency is projected to grow by 1.1 percent a year due to EPACT standards for lamps, utility DSM incentives, EPA's Green Lights program [*13*], and the Federal Relighting Initiative [*14*]. Lighting efficiency gains offset the increased demand for lighting in the forecast.

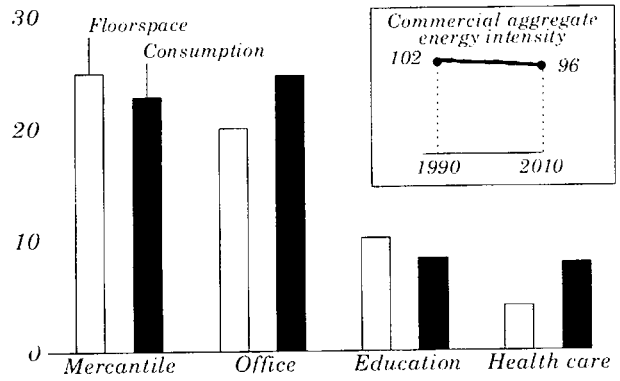
Of other electricity end uses, office equipment is the largest and grows the fastest, as computer, fax machine, and copier use increases. Equipment efficiencies for all end uses show increases in the forecast, from 0.5 percent a year for water heating to 1.4 percent a year for electric space cooling (Figure 21).

Figure 21. Commercial energy efficiency by end use, 1990-2010 (index, 1990 = 100)



Reliance on Energy Varies Across Building Types

Figure 22. Commercial floorspace and energy consumption by building type, 2010 (percent shares)



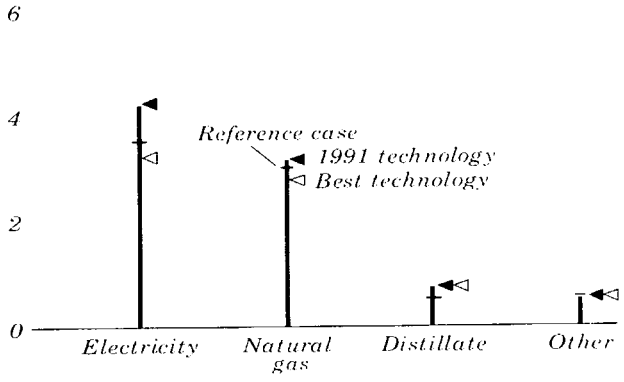
Commercial buildings have diverse uses, but the dominant ones are mercantile and service, office, education, and health care. Net energy consumption, floorspace, and gross energy intensity vary by building type, reflecting the heterogeneity of the sector (Figure 22). For example, health care buildings consume 8 percent of all energy used in commercial buildings in 2010, but they account for only 4 percent of commercial floorspace. Office buildings consume 25 percent of all energy and account for 20 percent of floorspace.

The most energy-intensive buildings are offices, health care, and food services. Gross energy intensity in 2010 is projected to range from 53 million Btu per square foot for warehouse buildings to 196 for food services. The energy intensity of all building types declines (at varying rates) in the forecast in response to efficiency improvements gained through more energy-efficient building shells, technological innovation, and equipment efficiency standards. Mandatory appliance efficiency standards, such as those in EPACT, are projected to move the market toward high-efficiency purchases.

The aggregate commercial sector energy intensity is projected to decline by 0.3 percent a year. In addition to the factors affecting equipment efficiency mentioned above, this decline is driven by the mix of end-use service demands, and the mix and diversity of commercial activity by building type and Census Division.

Technologies Are Available to Achieve Energy Conservation

Figure 23. Commercial energy consumption in three scenarios, 2010 (quadrillion Btu)



For most major energy end uses, an efficiency gap between average commercial stock and the most efficient new units available provides potential for energy savings. Two scenarios illustrate the gap: one keeps technology at 1991 efficiency levels, and the other uses only the most efficient technologies available in all future years (Figure 23).

Electricity consumption rises by 1 percent a year in the reference case, compared with 2 percent in the 1991 technology case, resulting in 6.6 quadrillion Btu of cumulative electricity savings by 2010. Natural gas savings in the reference case are not as large because the available higher efficiency gas technologies have only moderate potential for improvement. Natural gas consumption rises by 0.8 percent a year, compared with 0.6 percent in the reference case. Cumulative gas savings would be 1.8 quadrillion Btu by 2010.

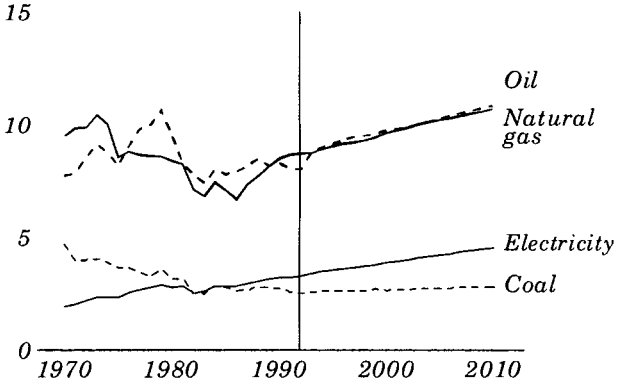
If only the most efficient technologies available were used, potential efficiency improvement and energy savings over the 1991 technology case would be even larger. Cumulative savings by 2010 are 10.1 and 4.4 quadrillion Btu for electricity and natural gas respectively (Table 5), illustrating the potential impact of adopting the best technologies.

Table 5. Cumulative energy savings relative to the 1991 technology case, commercial sector, 2010

	Quadrillion Btu	
Fuel	***Reference case***	***Best technology case***
Electricity	*6.6*	*10.1*
Natural gas	*1.8*	*4.4*

Energy Mix Changes Over Time

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



Industrial consumption of electricity grew by 3 percent a year from 1970 to 1985, while consumption of fossil fuels fell as a result of higher electricity use in manufacturing and the relative decline of such energy-intensive industries as steel. After 1985, fossil fuel consumption began to grow in response to lower fuel prices and modest recoveries in the steel and chemical industries (Figure 24).

Electricity consumption grows in the forecast by 1.7 percent a year. Factors such as lower air pollutant emissions, higher quality products, and more precise controls contribute to the continued penetration of electrotechnologies. However, the increased energy efficiency of electrotechnologies in the energy-intensive industries reduces the growth rate of electricity demand.

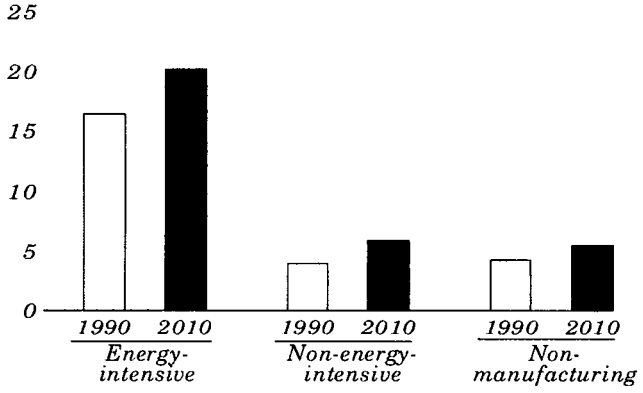
Natural gas consumption is projected to grow by 1.2 percent a year in the forecast and to continue as a major source of energy in the industrial sector. Natural gas also emits less carbon per unit of energy than other fossil fuels. For example, natural gas emits about two-thirds as much carbon per million Btu as residual fuel oil.

Coal consumption is projected to grow by 0.1 percent a year as a result of increased steam coal consumption combined with lower metallurgical coal consumption. The latter falls due to closing of coke ovens, greater use of electric arc furnaces, and improvements in blast furnace technology.

Petroleum consumption is projected to grow by 1.3 percent a year, primarily as a result of rapid growth in the consumption of liquid petroleum gas and petrochemical feedstocks.

Eight Energy-Intensive Industries Consume Most Industrial Energy

Figure 25. Industrial energy consumption by category, 1990 and 2010 (quadrillion Btu)



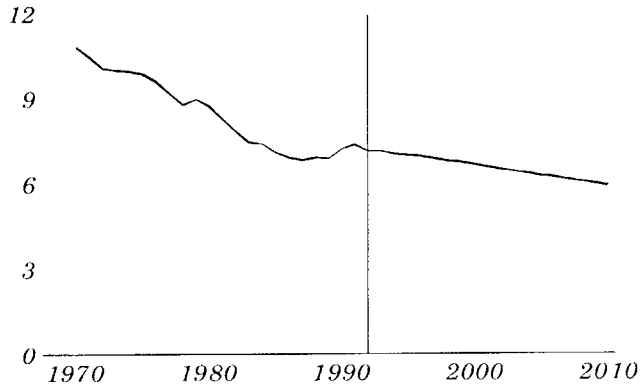
Eight industries—food, paper and allied products, refining, bulk chemicals, glass and glass products, cement, iron and steel, and primary aluminum—constitute two-thirds of industrial energy consumption (Figure 25). These mature industries have historically accounted for the largest share of overall industrial energy consumption, and the trend is expected to continue over the forecast horizon.

Consumption by the energy-intensive industries is projected to grow by 0.9 percent a year, while non-energy-intensive industries grow twice as fast, at 1.9 percent a year. Metal durables, within the non-energy-intensive industries, have the largest projected growth in consumption, 2.1 percent, due to a 3.3-percent annual rate of growth in output. The output growth for metal durables is attributed to a projected return to the investment rates that are typical of the post World War II economy [*15*]. These industries manufacture products such as machine tools, which will see increased demand as a result of increased producer investment.

For the majority of industries, new technologies typically decrease energy consumption. In some instances, environmental issues are a major factor in the choice of technology and processes. For example, in the pulp and paper industry, recycling of waste paper is projected to grow regardless of the energy consequences. This result is supported by government mandates to increase the waste fiber content in pulp and paper products [*16*].

Growth in Industrial Output Exceeds Growth in Energy Use

Figure 26. Industrial energy intensity, 1970-2010 (thousand Btu per 1992 dollar of output)



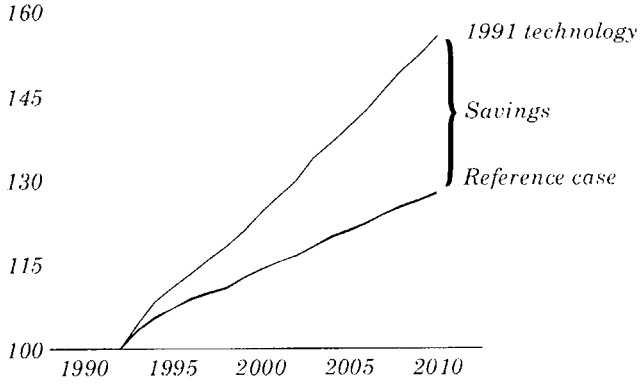
Industrial energy intensity (thousand Btu per dollar of output) fell throughout the 1970s and into the early 1980s (Figure 26). In the latter part of the 1980s, it rose briefly due to lower energy prices, decreased investment in new equipment, and a modest recovery in energy-intensive industries. In the forecast, energy consumption is projected to grow by 1.2 percent a year, and output is projected to grow by 2.2 percent a year.

The forecast indicates decreasing overall energy intensity due to sectoral shifts and increased energy efficiency. Industries with lower energy intensities are projected to grow more rapidly than industries with higher energy intensities. For example, output from the industrial machinery industry is projected to grow by 3.8 percent a year, while output from the iron and steel industry grows by 0.6 percent a year. Efficiency increases can be attributed to housekeeping, equipment changes, process changes, maintenance, and installation of new equipment and retrofits. Growing industries typically install new or retrofit equipment that is less energy intensive than the existing stock.

There have been shifts from low value products to higher value products within some industries [*17*]. For example, the iron and steel industry has shifted to higher value steel and to more energy-efficient processes, such as continuous casting. Contributing to the product shift is an increased international competitiveness that has led to increased imports of energy-intensive products.

Substantial Savings Achieved in Efficient Industrial Technologies

Figure 27. Industrial energy consumption in two scenarios, 1990-2010 (index, 1990 = 100)



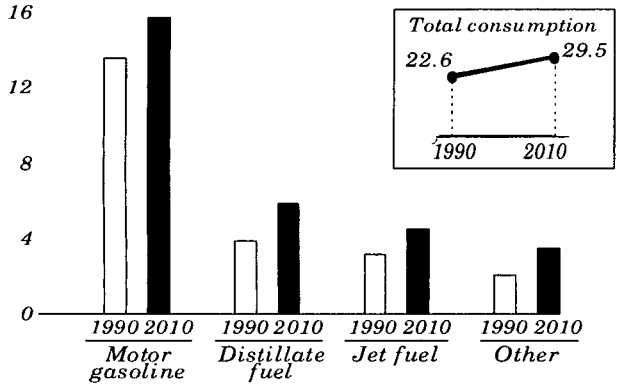
Technology adoption plays a large role in energy consumption for many industries (Figure 27). The reference case embodies expectations of the likely future trends in energy intensity for the energy-intensive industries—based on engineering judgments about the development, cost, and adoption rates for specific technologies. New technologies are added to the existing capital stock only to meet increased demand or to fill gaps created by retirement of existing stock. Otherwise, productive capital equipment is not scrapped and replaced with new technology.

The 1991 technology case presents a situation where there is no change in energy intensity. The difference in energy consumption between the 1991 technology case and the reference case results entirely from adoption of newer technologies. The cumulative avoided energy consumption, 59 quadrillion Btu by 2010, can be attributed to improved production techniques and processes.

In the 1970s and 1980s, efficiency gains were achieved through improved technologies and operating practices in new and existing plants, the closing of inefficient plants, and shifts to more efficient processes. For example, in the cement industry, the shift from the wet clinker process to the dry clinker process lowered energy intensity. Such shifts are projected to continue in the forecast. Technologies such as high-efficiency motors, computerized controls, industry-specific technologies, and cogeneration units further increase energy efficiency.

Petroleum Remains the Dominant Transportation Fuel

Figure 28. Transportation energy consumption by fuel, 1990 and 2010 (quadrillion Btu)



The transportation sector continues in the forecast to rely almost entirely on petroleum fuels through 2010. Motor gasoline is the dominant petroleum product used for transportation (Figure 28). Petroleum's share in total transportation energy consumption is projected to decline from 97 percent in 1990 to 95 percent in 2010, as sales of alternative-fuel light-duty vehicles increase.

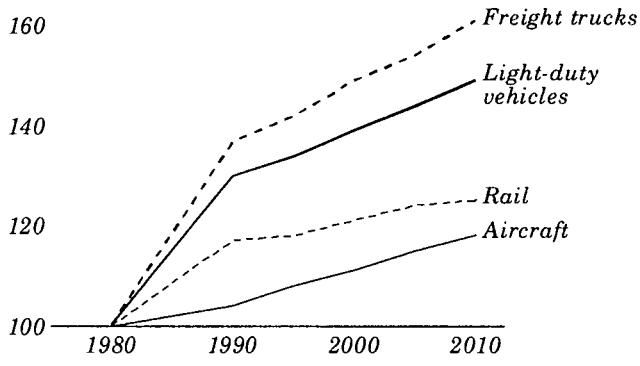
Motor gasoline's share of petroleum transportation consumption declines from 62 percent to 56 percent over the same period, for two reasons. Average fuel efficiencies of new automobiles and light trucks increase at average rates of 0.5 and 0.7 percent a year, respectively, and alternative fuels displace more than 400,000 barrels of motor gasoline a day in 2010. Together, these two factors hold the average annual growth of motor gasoline consumption well below that for other petroleum products.

Distillate fuel use is projected to rise at an annual growth rate of 2.1 percent, based on rising diesel consumption by freight trucks. The increase in diesel use can be attributed to growth in vehicle-miles traveled by heavy-duty trucks, which consume mainly diesel fuel.

Jet fuel consumption rises by 1.8 percent a year as a result of 3.2-percent annual growth in seat-miles traveled and a stock fuel efficiency growth rate of 0.7 percent a year from 1990 to 2010. The rate of increase in jet fuel consumption over the forecast is about half the rate during the 1980s, reflecting lower growth in demand for air travel.

Transportation Fuel Efficiency Continues to Improve

Figure 29. Fuel efficiency by transportation mode, 1980-2010 (index, 1980 = 100)



Fuel efficiency increases for all transportation modes in the forecast between 1990 and 2010, as new fuel-saving technologies replace less fuel-efficient equipment (Figure 29). Between 1990 and 2010, freight truck fuel efficiency rises at the fastest rate, by 18 percent, followed by light-duty vehicle (car, light truck, and van) fuel efficiency at 14 percent, both occurring as a result of rising fuel prices.

Modestly increasing fuel prices and rising income levels will contribute to the sales trend toward larger, higher performance vehicles, which will reduce fuel efficiency improvements over the forecast. These factors, combined with unchanging Corporate Average Fuel Economy standards, will keep fuel efficiency improvements for cars and light trucks below the levels of the 1980s (Table 6).

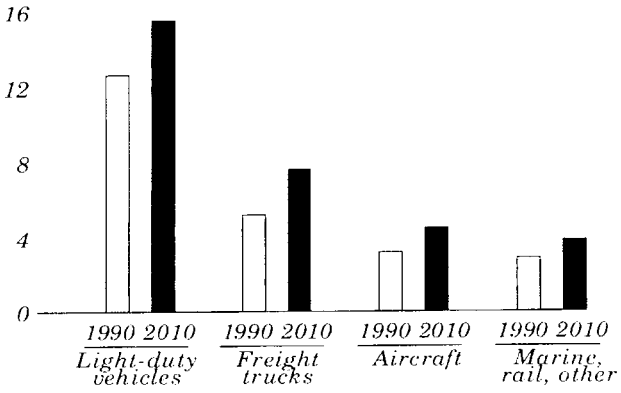
Aircraft fuel efficiency increases by 14 percent, based on increasing sales of fuel-efficient wide-body aircraft relative to less efficient narrow-body aircraft.

Table 6. New car and light truck EPA-rated fuel efficiencies by world oil price case, 1980-2010

	Miles per gallon				
Forecast	***1980***	***1990***	***2000***	***2005***	***2010***
Reference Case					
Cars	*24.3*	*28.2*	*29.5*	*30.6*	*31.4*
Light trucks	*18.5*	*20.9*	*22.4*	*23.4*	*24.2*
High case					
Cars	*24.3*	*28.2*	*30.4*	*31.8*	*32.7*
Light trucks	*18.5*	*20.9*	*23.1*	*24.3*	*25.2*
Low case					
Cars	*24.3*	*28.2*	*28.0*	*28.8*	*29.5*
Light trucks	*18.5*	*20.9*	*21.4*	*22.0*	*22.7*

Light-Duty Vehicles Are Leading Consumers of Transportation Fuels

Figure 30. Transportation energy consumption by mode, 1990 and 2010 (quadrillion Btu)



Light-duty vehicles (cars, light trucks, and vans) are forecast to remain the largest users of transportation fuels in 2010, consuming 15.6 quadrillion Btu in the reference case (Figure 30). There is a 1.6-percent annual increase in vehicle-miles traveled by light-duty vehicles over the forecast period (Table 7) due to modest increases in fuel prices coupled with rising income levels and population increases. But the growth of light-duty vehicle fuel consumption between 1990 and 2010 is only 1 percent annually, with fuel efficiency gains of 0.6 percent a year. Freight trucks consume about half as much fuel as light-duty vehicles in 2010, 7.6 quadrillion Btu, with freight truck fuel consumption growing by 1.9 percent a year.

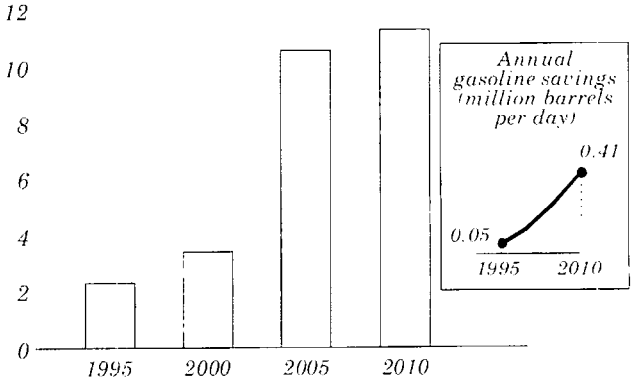
Table 7. Light-duty vehicle use trends, 1990-2010

	Thousand miles per year		
Travel	**1990**	**2000**	**2010**
Per vehicle	10.5	11.1	11.7
Per capita	7.8	8.4	9.1

Air transport fuel use grows by 1.7 percent a year, with consumption rising to 4.5 quadrillion Btu in 2010. Commercial air travel is the fastest growing mode of transportation over the forecast, increasing at an average annual rate of 3.2 percent between 1990 and 2010. Military jet fuel consumption, which currently accounts for 25 percent of total jet fuel consumption, is projected to decline over the forecast, accounting for only 13 percent of jet fuel consumption by 2010.

Alternative-Fuel Vehicles Are Over a Tenth of New Sales by 2010

Figure 31. Alternative-fuel vehicle share of light-duty vehicle sales, 1995-2010 (percent)



Alternative-fuel vehicles in the forecast account for only 2.3 percent of light-duty vehicles sales in 1995, but increase to 10.6 percent in 2005 and 11.4 percent in 2010 (Figure 31). Legislation mandating the use of alternative fuels, including EPACT and State initiatives, is expected to cause most of the initial penetration of alternative-fuel technologies.

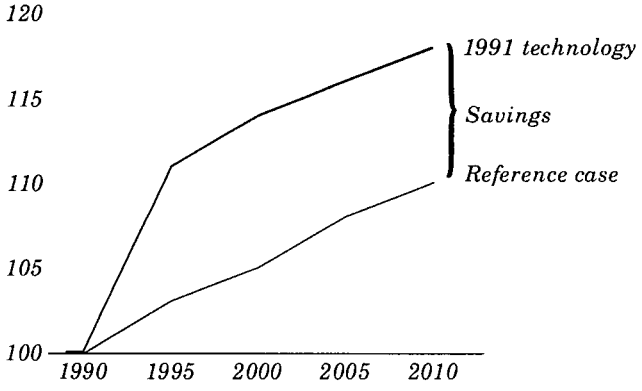
As alternative-fuel light-duty vehicles displace conventional vehicles, the annual motor gasoline savings increase from less than 50,000 barrels a day in 1995 to more than 400,000 barrels a day in 2010. Increasing reliance on alternative-fuel vehicles contributes to a relative reduction in the transportation sector's oil dependency and carbon emissions (2 percent, or approximately 6.6 million metric tons, by 2010). Electric technology vehicles, including both dedicated electric (using only electricity) and electric hybrid (using electricity and gasoline), receive the largest share of alternative-fuel light-duty vehicle sales in 2010, 30 percent (Table 8).

Table 8. Shares of alternative-fuel light-duty vehicle sales by technology type, 2010

Technology	**Percent share**	**Technology**	**Percent share**
Methanol-flex	13.0	*Compressed natural gas*	26.4
Methanol-neat	0.9	*Liquefied petroleum gas*	19.4
Ethanol-flex	8.6	*Dedicated electric*	12.2
Ethanol-neat	0.9	*Electric hybrid*	17.8
		Gas turbine hybrid	0.7

Transportation Energy Intensity Continues to Increase

Figure 32. Transportation energy intensity in two scenarios, 1990-2010 (index, 1990 = 100)

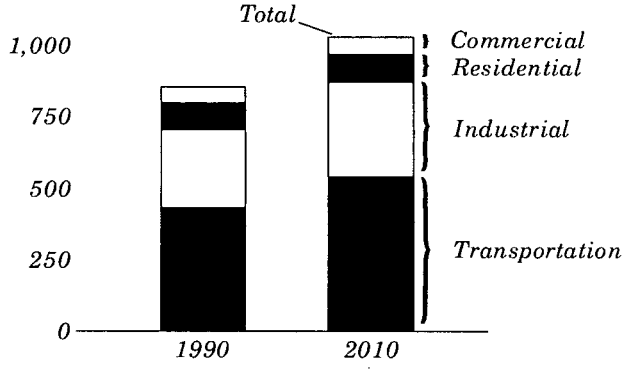


Transportation energy intensity, measured as an index of energy consumption per capita, increases in the forecast (Figure 32). The intensity of energy use increases by 10 percent between 1990 and 2010. Efficiency gains from new technology are more than offset by increases in driving, automobile ownership, freight truck vehicle-miles traveled, airline travel, and waterborne and rail ton-miles traveled. Passenger vehicle highway travel continues to increase faster than the driving-age population over the forecast period as a result of relatively stable fuel prices and growth in real per capita income. Freight travel grows at more than twice the rate of population because of rising industrial output and economic activity. Air travel, represented by revenue passenger-miles, is projected to increase at an annual rate of 3.2 percent, compared with a population growth rate of 0.9 percent. Estimated revenue passenger-miles are a function of jet fuel prices and economic growth. Across the world oil price cases, air travel varies by 5 percent in 2010, while across the economic growth cases it varies by 10 percent (see Tables A7, B7, C7, D7, and E7).

In a frozen technology case, in which no new fuel-efficiency-enhancing technologies are introduced after 1991, the intensity of energy use in the transportation sector would be 7 percent higher than in the reference case by 2010. Actual fuel savings could be even greater than in the reference case, depending on the rate and degree of technology penetration.

Transportation Dependence on Oil Contributes to Carbon Emissions

Figure 33. Carbon emissions from energy use by sector, 1990 and 2010 (million metric tons per year)



The main components of fossil fuels—such as natural gas, petroleum, and coal—are "hydrocarbons," made up of molecules containing hydrogen and carbon atoms. When these fuels are burned, essentially all of the carbon in the fuel chemically combines with the oxygen in the air to form carbon dioxide. On average, hydrocarbon fuels contain at least 75 percent carbon by weight. Thus, for every ton of fossil fuel burned, at least three-quarters of a ton of carbon enters the atmosphere. Of the major fossil fuels, natural gas emits the least carbon per million Btu of energy produced, while coal emits the most.

In the absence of additional efficiency standards, total end-use carbon emissions (excluding emissions from electric utilities) are projected to increase by about 20 percent between 1990 and 2010 (Figure 33) [*18*]. Almost all of this increase occurs in the transportation and industrial sectors. In the transportation sector, carbon emissions are projected to increase by more than 100 million tons in the reference case, as growth in personal and freight travel outpaces projected fuel efficiency improvements. In the industrial sector, carbon emissions are projected to increase by about one-fifth over the forecast—far less than the increase in industrial output. Declining use of coal in steelmaking, as well as fuel efficiency gains in other industries, explains the dampening of carbon emissions in this sector.

Residential and commercial sectors

In sharp contrast to the consumption trends of the 1980s, all the residential sector forecasts project significant growth in aggregate energy consumption. Forecasts of aggregate energy use in the commercial sector vary considerably, principally because of alternative assumptions about the growth in aggregate commercial floorspace.

The *AEO94* forecasts for growth in building sector electricity use are lower than the other estimates shown in Table 9. *AEO94* projects a continued decline in electric space heating in new construction and further revisions to Federal Appliance Efficiency Standards. In addition, the *AEO94* forecast of growth in commercial floorspace and the number of households through 2010 is generally lower than the estimates in the other forecasts.

Table 9. Comparative forecasts of growth in residential and commercial energy demand, 1990-2010

	Average annual percent growth				
Sector	**1980-90**	**AEO94**	**DRI**	**GRI**	**WEFA**
Residential					
Natural gas	-0.7	0.5	0.4	0.6	0.2
Electricity	2.6	0.7	2.2	1.4	1.5
All energy	-0.1	0.5	0.9	0.7	0.7
Households	1.4	0.8	1.0	1.2	1.3
Commercial					
Natural gas	0.1	0.6	0.7	1.3	0.8
Electricity	4.2	1.0	1.9	1.6	1.9
All energy	1.0	0.7	1.0	1.2	1.3
Floorspace	3.8	1.0	0.8	1.4	1.2

Transportation sector

Energy consumption is forecast to grow and be dominated by petroleum products in all of the forecasts listed in Table 10.

Table 10. Comparative forecasts of growth in transportation energy demand, 1990-2010

	Average annual percent growth			
Forecast	**1980-90**	**AEO94**	**DRI**	**GRI**
Consumption				
Gasoline	0.9	0.7	0.6	-0.2
Diesel fuel	3.2	2.1	2.0	2.0
Jet fuel	3.6	1.8	1.4	1.2
Residual fuel	-3.0	2.3	2.7	1.5
All energy	1.4	1.4	1.2	0.5
Key indicators				
Car and light truck travel	3.4	1.6	1.7	2.0
Air travel	5.8	3.2	3.0	2.9
Average new car fuel efficiency	3.1	0.5	0.8	1.6
Gasoline prices	-4.5	1.0	1.5	1.2

Average "on-the-road" fuel efficiency for new cars continues to increase but at a slower pace than during the 1980s. Differences in the rate of improvement in fuel efficiency and the rate of increase in gasoline prices across forecasts cause most of the variation in growth rates of gasoline consumption. Growth in travel demand in light-duty vehicles and aircraft moderates substantially relative to the 1980s in all forecasts. The rate of increase in jet fuel consumption is only about half the rate that occurred between 1980 and 1990, reflecting lower growth in demand for air travel.

Industrial sector

All forecasts project total industrial energy demand growth, as opposed to its decline during the 1980s, based on higher levels of industrial output. Forecasts of individual fuels are for more rapid growth or lower rates of decline (Table 11).

Table 11. Comparative forecasts of growth in industrial energy demand, 1990-2010

	Average annual percent growth				
Fuel	**1980-90**	**AEO94**	**DRI**	**GRI**	**WEFA**
Petroleum	-1.4	1.3	1.0	1.5	0.8
Natural gas	0.1	1.2	1.1	1.4	0.6
Coal	-1.4	0.1	0.6	-0.9	-0.4
Electricity	1.5	1.7	2.0	1.9	1.9
All energy	-0.4	1.2	1.9	1.2	0.8

Total end use

Several common themes emerge in a comparison of the *AEO94* reference case with other recent forecasts (Table 12):

- The growth in petroleum consumption is substantially faster than during the 1980s.
- The consumption of natural gas is projected to increase—a turnaround from recent history, reflecting increased gas availability.
- Projected growth in electricity is more modest than it has been historically, reflecting higher efficiency standards.

Table 12. Comparative forecasts of total end-use demand growth, 1990-2010

	Average annual percent growth				
Fuel	**1980-90**	**AEO94**	**DRI**	**GRI**	**WEFA**
Petroleum	0.2	1.2	1.1	0.8	0.8
Natural gas	-0.1	0.9	1.4	1.3	1.3
Coal	-1.4	0.1	0.6	-1.1	-1.1
Electricity	2.4	1.2	2.0	1.6	1.6
All energy	0.4	1.1	1.3	1.0	1.0

Residential and commercial sectors

The energy efficiency forecasts presented here are based on technologies that are either already in the marketplace or are close to commercialization. Technologies that have not reached this stage of development, such as the use of fuel cells in commercial buildings and photovoltaic generation of electricity in private residences, could substantially reduce nonrenewable energy consumption in buildings if they became economically competitive with more conventional technologies in the near future. Following recent historical trends, traditional energy use in the form of wood use as a home heating fuel is projected to increase only slightly in the forecast.

In addition to the mandated efficiency standards detailed in the Energy Policy Act of 1992 (EPACT), the Federal Government is now taking an active nonregulatory role in promoting energy efficiency. So-called "Green Programs" (Green Lights, Energy Star Buildings, Golden Carrot) are based on a partnership between the Federal Government and the private sector. These programs promote the development and market penetration of a new generation of more energy-efficient technologies. For example, the Golden Carrot program provides a monetary award to the manufacturer that can develop and market the most energy-efficient appliance. These efforts have the potential to reduce energy consumption by 2010 well below the levels forecast in the reference case.

Demand-side management programs, which have been increasing in popularity over the past decade, have the potential to both reduce peak demand for energy (thereby reducing required investment in new capacity) and promote consumer purchases of more energy-efficient equipment. The forecasts presented here implicitly assume that demand-side management programs will continue to contribute to efficiency improvements. Even more aggressive demand-side management programs could be implemented over the forecast horizon, however, if energy conservation were seen as a more cost-effective energy supply option than expanding electricity generation and natural gas delivery systems.

Industrial sector

The product mix in the industrial sector directly affects the requirements for purchased energy. Changes in product mix, based on major structural shifts in the pattern of international trade as well as greater consumer acceptance of recycled products, could have a substantial impact on industrial energy use over the forecast. For example, expanded international trade, beyond that assumed in the reference case, may result in greater production of manufacturing equipment and greater reliance on electricity-intensive industries. Recycling could significantly alter fuel use patterns in several energy-intensive industries. In the case of plastics, for example, greater consumer and manufacturer participation in recycling programs could substantially reduce the use of oil as a feedstock for production.

Transportation sector

Alternative-fuel vehicles are projected to increase in importance, particularly in the latter years of the forecast, based on EPACT regulations affecting fuel use in certain categories of fleet vehicles, State-specific regulations mandating the sale of zero emission vehicles, and consumer market acceptance criteria. The rate at which alternative-fuel vehicles enter the market and the specific types of vehicles that gain popularity are subject to considerable uncertainty. For example, California, New York, and Massachusetts now have established timetables to increase sales of alternative-fuel vehicles. Over the forecast horizon, however, many other States now considering similar legislation may opt into such programs and substantially increase the number of vehicles fueled by compressed natural gas, electricity, and alcohol, lowering carbon emissions below the level projected in the reference case.

Mass transit offers a more fuel-efficient (per passenger-mile) and environmentally benign alternative to the use of the personal car. In recent decades reliance on mass transit has been stagnant, and the reference case forecast assumes little increase in the relative importance of mass transit vehicles. New initiatives to promote greater reliance on mass transit have the potential to offset both oil consumption and considerable carbon emissions within the forecast period.

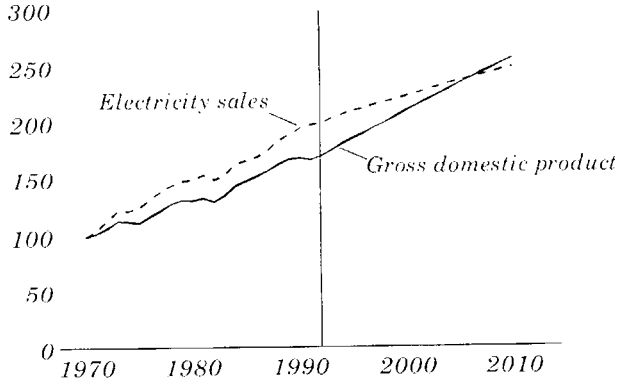
CHAPTER 3

ELECTRICITY

Electricity will continue to play an important role in meeting the Nation's energy needs throughout the foreseeable future. Nonutilities contribute a growing share of electricity production, stimulated by the Energy Policy Act of 1992. (Throughout this chapter the term "nonutilities" excludes cogenerators [*19*].)

Historically, growth in the demand for electricity has been closely tied to economic growth (Figure 34). Until the 1970s and 1980s, the growth in electricity demand tended to outpace economic growth. However, the rapid rise in energy prices in the 1970s and early 1980s, combined with growing market saturation of electric appliances, dampened this relationship—narrowing it to nearly one-to-one by the late 1980s. This trend is expected to continue, with electricity demand actually growing more slowly than the economy over the next two decades.

Figure 34. Electricity sales and economic growth rates, 1970-2010 (index, 1970=100)



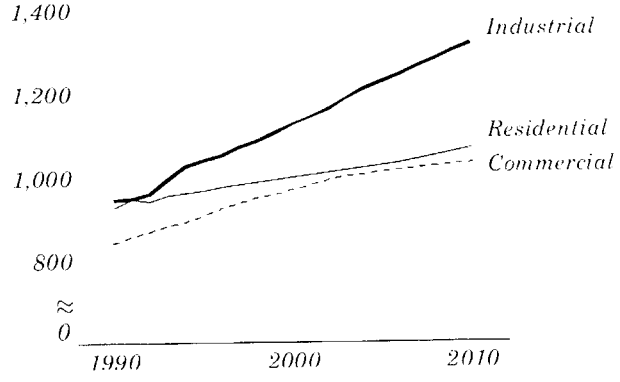
Electricity demand growth is likely to be further dampened by increased utility investments in demand-side management (DSM) programs [*20*] designed to encourage consumers to change their patterns of use or reduce the amount of electricity they consume. Utilities in the United States spent $1.2 billion on DSM programs in 1990 and plan to increase this to nearly $4 billion a year by 1997.

Even with slow growth, electricity will maintain its market share because of its use for space cooling, water heating, lighting, and miscellaneous uses, especially in the residential and commercial sectors. In the industrial sector, the growth of electricity-intensive industries and the broader use of electrical technologies and processes increase electricity's market share slightly.

The demand for electricity grows most rapidly, by more than 14 percent a year, in the transportation sector. However, even so, electricity accounts for less than 0.7 percent of the energy consumed in the transportation sector. Growth in electrically powered public transportation—such as subway and light rail trains—accounts for a large part of the higher demand, but electric vehicles for private use also garner an increasing share. Several States have ordered the conversion of part of their transportation networks to zero emission vehicles. At this time, without a major breakthrough in vehicle emission technology, electric vehicles are the only technology capable of compliance.

Apart from transportation, industrial use of purchased electricity grows the fastest (Figure 35). Industrial demand for electricity grows by 1.7 percent a year, faster than total industrial energy demand. However, the continuing penetration of new, more efficient electrical technologies and processes tends to conceal the substantial growth in this area of the economy.

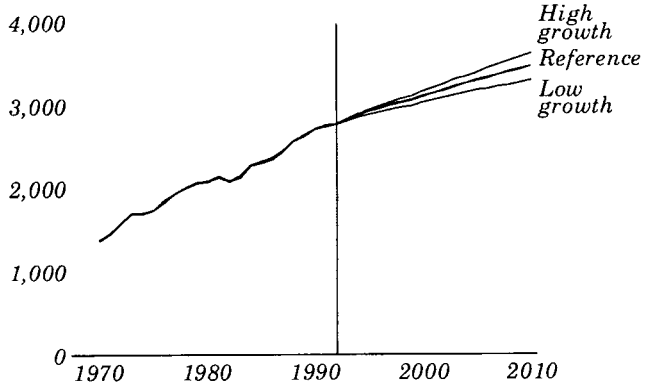
Figure 35. Electricity consumption in the residential, commercial, and industrial sectors, 1990-2010 (billion kilowatthours)



Commercial and residential electricity demand increases slightly over the forecast period. While electricity remains an important energy source in all economic sectors, efficiency gains induced by new appliance efficiency standards, higher energy prices, and utility DSM programs will measurably affect the growth in electricity demand. Energy efficiency improvements continue to dampen the historical link between economic growth and electricity demand over the next 20 years.

Different Growth Assumptions Lead to Varying Demand Forecasts

Figure 36. Electricity demand in three scenarios, 1970-2010 (billion kilowatthours)

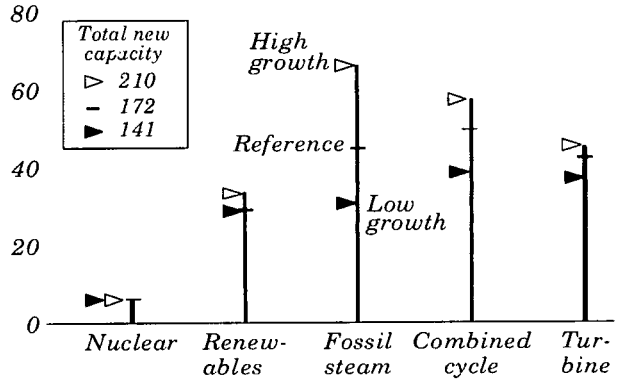


Between 1970 and 1990, electricity demand grew by 3.4 percent a year, exceeding the annual growth rate of 2.7 percent for gross domestic product (GDP) during the same period. Between 1990 and 2010, demand for electricity is expected to grow in the range of 1.0 to 1.5 percent a year (Figure 36)—well below the projected annual GDP growth rates of 1.8 percent and 2.4 percent in the *AEO94* low and high economic growth cases, respectively (see Tables A18, B18, and C18). The decrease in electricity demand growth is due to the emphasis on energy efficiency that occurred in the 1980s. Emphasis on electrical efficiency is expected to continue and expand as economic sectors comply with the directives of the Energy Policy Act of 1992 (EPACT), which directs—and sometimes provides grants to—businesses and municipalities to improve efficiency by such methods as installation of energy-efficient lighting and appliances, upgrading building efficiency standards, and supporting energy efficiency programs for process-oriented industries.

Utility-sponsored DSM programs are also expected to increase significantly in the 1990s. By providing rebates to consumers for installing energy-efficient appliances and by granting reduced rates for interruptible or off-peak service, utilities will be better able to control load distribution and avoid unnecessary construction of new capacity. In 1990, utilities reported to EIA a 23-gigawatt reduction in peak demand as a result of DSM programs. They also reported energy savings of 19 gigawatthours in 1990, increasing to 73 gigawatthours in 1997 [*21*].

Capacity Needs Tied to Economic Growth

Figure 37. New generating capacity by type in three scenarios, 1990-2010 (gigawatts)

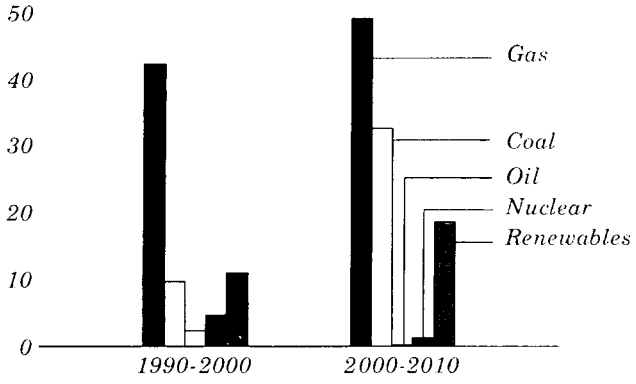


A modest increase in economic growth increases the need for new utility and nonutility generating capacity (Figure 37). The 0.6-percentage-point difference in economic growth across the three economic growth cases yields a 69-gigawatt differential in total capacity needed. Between 1990 and 2010, electric utilities are expected to bring on 110 gigawatts of the capacity needed in the reference case (67 gigawatts have been reported to EIA by utilities). However, utilities are expected to retire 60 gigawatts of capacity (14 have been reported) during the same period, for a net increase of only 50 gigawatts. Spurred by legislative changes intended to make the electricity production market more competitive, nonutility generators are expected to account for a large share of new capacity additions throughout the forecast. Between 1990 and 2010, nonutilities (excluding cogenerators) are projected to add 62 gigawatts of capacity, approximately 55 percent of the net increase in national capacity (see Table A9).

Of the 69 gigawatts of additional capacity needed between the high and low economic growth cases, fully 39 percent is projected to come from combined-cycle and combustion turbine generating technologies needed primarily to meet higher peak and intermediate load requirements. However, stronger economic growth would also be expected to increase the market for new coal-fired and renewable technologies. Across the economic growth cases, coal-fired capacity additions vary by 36 gigawatts, while renewable capacity additions vary by 6.4 gigawatts (see Tables A9, B9, and C9).

Demand Growth Leads to Need for New Capacity

Figure 38. New capacity, utility and nonutility, 1990-2010 (gigawatts)



A projected 172 gigawatts of new capacity will be needed by 2010 to meet the growing demand for electricity and to offset retirements (Figure 38 and Table A9). These capacity needs are in addition to augmentation of existing resources through plant life extension [*22*], repowering [*23*], increased imports, and growing purchases from cogenerators.

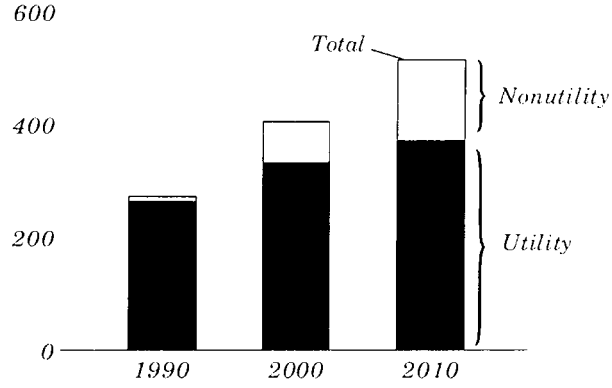
Of the 172 gigawatts of new capacity needed, 53 percent is projected to be gas-fired or oil- and gas-fired combined-cycle and combustion turbine generating technologies. These generating technologies are very flexible, designed primarily to meet peak [*24*] and intermediate load requirements, but able to meet baseload [*25*] requirements if needed. As a result, these plant types are added throughout the forecast period.

New coal-steam [*26*] units are expected to account for 25 percent of all new capacity additions through 2010. Of the 42 gigawatts of planned [*27*] and unplanned [*28*] coal capacity scheduled to come online, 17 gigawatts will replace plants expected to retire. Nevertheless, after 2000 existing baseload capacity will be fully utilized, and utilities are expected to return to constructing coal-fired plants to satisfy part of their baseload requirements. Consequently, 77 percent of the new coal-fired capacity will come online after 2000.

No new additions of nuclear or hydroelectric capacity are expected beyond those already in the construction pipeline. Hydroelectric capacity grows as older plants are upgraded, but the increase is offset by retirements.

Generation from Gas-Fired Plants Increases Dramatically

Figure 39. Electricity generation from gas, excluding cogeneration, 1990 and 2010 (billion kilowatthours)

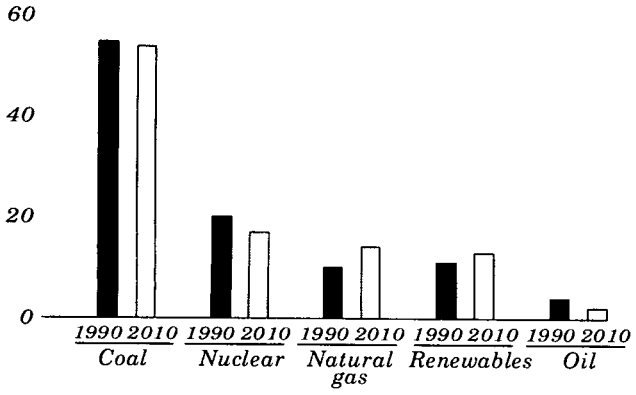


Gas-fired generation is expected to increase steadily throughout the forecast period (Figure 39). It is projected to grow from 273 billion kilowatthours in 1990 to 517 billion kilowatthours in 2010. This increase occurs because of the addition of gas-fired combined-cycle [*29*] and gas-turbine [*30*] technologies to meet electricity demand growth. Both technologies have features which make them attractive when new generating resources are required. They produce almost no emissions of sulfur compounds, and they are less expensive to build and require shorter construction periods than conventional coal and nuclear power plants. The combined-cycle technologies also produce electricity very efficiently, consuming less fuel to produce each kilowatthour of electricity. However, growth in operating costs, resulting from relatively high fuel prices, dampens the penetration of gas-fired plants later in the forecast.

Utility generation by natural gas combined-cycle technology is projected to increase from less than 15 percent of total gas-fired generation in 1990 to more than 55 percent by 2010. Gas turbines are expected to increase their generation share from 5 percent in 1990 to almost 7 percent in 2010. Gas-turbine and combined-cycle generators are also expected to provide a large share of total nonutility generation. Their short leadtimes and relatively low construction costs make them particularly attractive to nonutilities. Nonutility generation by these technologies increases from nearly 9 billion kilowatthours in 1990 to 144 billion in 2010, accounting for 45 percent of the increase in nonutility electricity production.

Coal Still Dominates, Even Though Gas Gains

Figure 40. Fuel shares of electricity generation, 1990 and 2010 (percent)



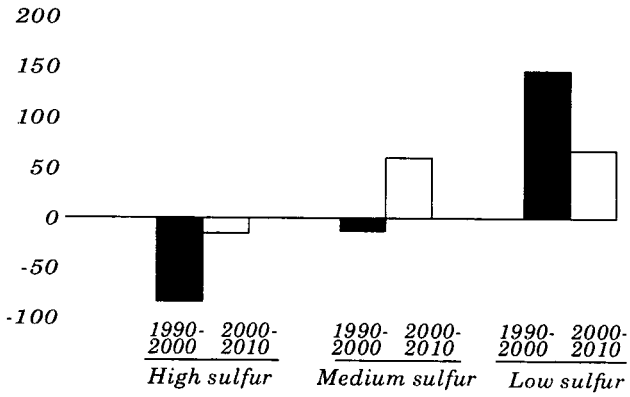
Coal is projected to dominate electricity production in the forecast (Figure 40). Although its growth is only 1.0 percent annually, generation by coal-steam technologies will continue to command a 54-percent share of total generation. Furthermore, nonutility producers are expected to increase their generation from coal from its current share of 2.6 percent of total nonutility generation to nearly 16 percent by 2010.

Nuclear generation is expected to increase through 2005 as plants currently under construction are completed and the performance of existing plants improves. However, between 2005 and 2010 several older nuclear plants are retired, and growing gas-fired generation approaches nuclear energy as the Nation's second most important electricity generating fuel. While gas-fired generation accounted for only 10 percent of total generation in 1990, by 2010 it is expected to provide over 14 percent. In contrast, nuclear energy's share of total generation is expected to decline from 20 percent in 1990 to 17 percent by 2010.

The high price of oil relative to the prices of other generating fuels has historically constrained oil to a small share of the generating market. This trend is expected to continue, and as new gas-fired units come online, generation from oil is projected to decrease from 118 billion kilowatthours in 1990 to 74 billion kilowatthours in 2010. As a result, oil-fired plants account for a diminishing share of total generation, falling from a 4-percent share to a 2-percent share during the forecast period.

Consumption of Low-Sulfur Coal Grows from 1990 to 2000

Figure 41. Change in coal consumption by sulfur content, 1990-2010 (million short tons)



Coal consumption by utilities grows by 1.1 percent a year during the forecast period (Figure 41), but its distribution by sulfur content [*31*] changes substantially as utilities take steps to comply with the Clean Air Act Amendments of 1990 (CAAA90). Under CAAA90, utilities will receive a limited number of tradable allowances annually. Each allowance permits the utility to emit 1 ton of sulfur dioxide (SO_2) in the year issued or any year thereafter. Utilities can choose from a variety of options (fuel switching, emission technology retrofitting, allowance trading, and altering the use of their plants) to keep emissions within these limits (Table 13). The goal is to reduce sulfur emissions from more than 16 million metric tons in 1990 to less than 9 million tons a year in 2000 and after.

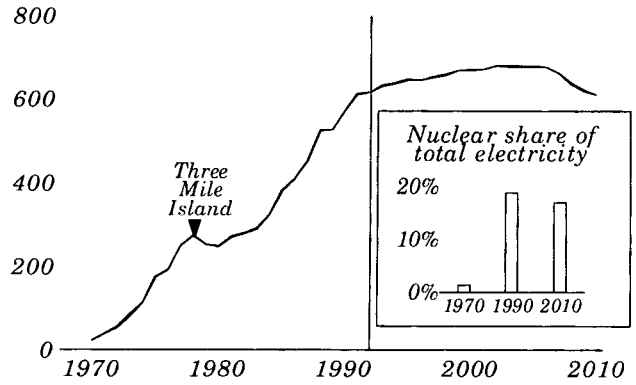
In the short term, 1993-2000, many utilities are projected to switch from high- and medium-sulfur coal to low-sulfur coal as the most economical option for CAAA90 compliance. Demand for low-sulfur coal by utilities rises by more than 148 million short tons between 1990 and 2000. However, because new generating plants must be equipped with the ability to reduce sulfur emissions, the addition of new coal-fired capacity (net of retirements) leads to a resurgence in demand for medium-sulfur coal after 2000.

Table 13. Retrofits and allowance costs, 2000-2010

Forecast	2000	2005	2010
Cumulative retrofits from 1990 (gigawatts of capacity)	23.3	23.3	23.8
Allowance costs (1992 dollars per ton SO_2)	230	290	291

Nuclear Performance Reaches Record Levels

Figure 42. Nuclear electricity generation, 1970-2010 (billion kilowatthours)



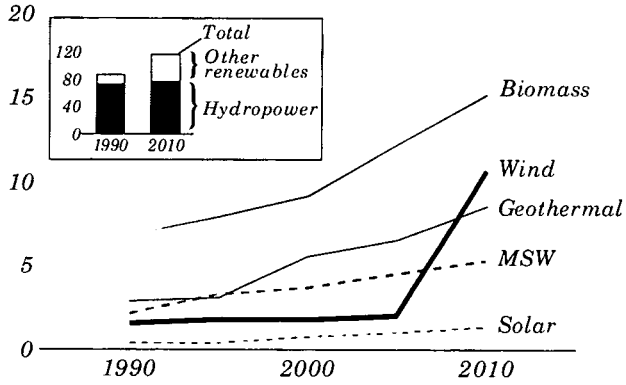
From the beginning of nuclear electricity production in the United States in 1957, to 1979—the year of the accident at the Three Mile Island (TMI) nuclear plant—nuclear power grew in capacity and generation, and as a share of total electricity generation (Figure 42). More recently, nuclear performance has reached record levels each year since 1989. In 1992, nuclear generation was 619 billion net kilowatthours, and the average nuclear capacity factor [*32*] was 70.9 percent; in 1989, these values were 529 net billion kilowatthours and 62.2 percent, respectively.

Completion of equipment upgrades in response to the 1979 accident at TMI, shorter refueling outages, reductions in unplanned outages, and longer fuel cycles contribute to improved performance. The average capacity factor is expected to increase to 72 percent in 1993 and to 74 percent by 2010.

This forecast assumes that all plants operate to their current license terms and that 20 units, totaling 14.2 gigawatts of capacity, retire by 2010. It is also assumed that there will be no age-related degradation in plant performance. Further assumed are the completion of four units totaling 4.8 gigawatts by 2002 and the cancellation of three planned units [*33*] totaling 3.7 gigawatts. No newly ordered plants are assumed to become operational during the forecast period. Given these assumptions, 90.7 gigawatts of nuclear capacity are projected to produce 612 billion kilowatthours of electricity in 2010, about 17 percent of total electricity generation.

Renewables Capacity Other Than Hydro Shows Strong Growth

Figure 43. Generating capacity from renewables other than hydropower, 1990-2010 (gigawatts)

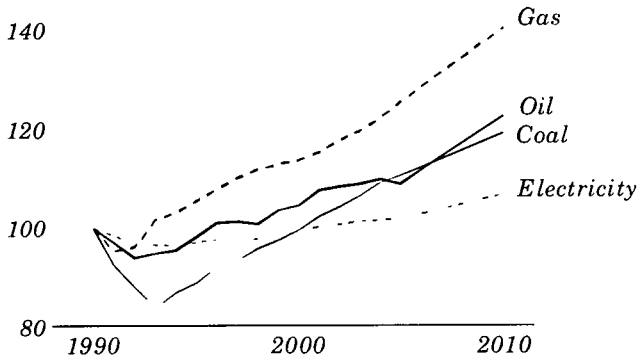


Renewable energy for electricity is dominated by hydropower (Figure 43). Hydroelectric capacity is projected to remain almost flat throughout the forecast: the best resources have already been exploited, and capacity increases from repowering of existing facilities will likely be offset by losses during relicensing [*34*]. Penetration of wind, solar, geothermal, municipal solid waste (MSW), and biomass is projected to more than double, with most of the growth, especially for wind, occurring after 2005.

Wind energy could grow the most (on a percentage basis) due to lower costs and improved technology, and because ample wind resources are available in many regions. Wind energy will most likely be developed on a pilot basis before 2005, but as demand grows and competing fuel prices rise in later years, it will be built to displace generation from higher cost resources. While the United States has ample solar resources, initial penetration of solar energy technologies will most likely be concentrated in the Southwest, where the resources are best [*35*]. MSW electricity generation is a byproduct of waste management; waste disposal methods and related regulations will be the primary factors determining its penetration [*36*]. Geothermal energy is limited geographically to those areas with easily accessible, high-temperature, hydrothermal resources (hot water and steam). In the West, where it is available, it can provide baseload generation [*37*]. Biomass electricity generation by utility, independent, and industrial power producers is the largest single renewables category outside of hydroelectric power [*38*].

Prices for Electricity Grow More Slowly Than Those for Other Fuels

Figure 44. End-use energy prices, 1990-2010 (index, 1990 = 100)



Electricity prices grow more slowly in the forecast than the prices of competing energy forms (Figure 44). Thus, despite efficiency improvements, electricity maintains its share of end-use energy demand. In most cases, regulators base prices on average costs. Averaging yearly changes with historical costs tends to smooth out yearly price changes. This spares consumers the short-term price oscillations of other forms of energy.

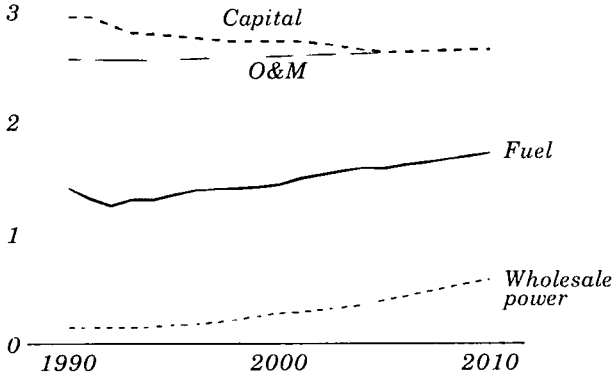
To the extent that natural gas, coal, and petroleum products are inputs to the electricity generating process, the cost of generation will increase. However, electricity prices are not as vulnerable to the effects of fuel price variations as other end-use fuel prices. Faster sales growth for electric utilities allows recovery of increased fixed service costs over a larger sales base and puts downward pressure on the per-unit cost of service.

Gradual depletion of coal reserves also raises the per-unit cost of recovering coal, and increases in the minemouth price of coal will convey directly to the end user. The minemouth price of coal is also projected to increase in the forecast, as labor productivity growth in the labor-intensive mining industry slows.

Oil product pricing is determined primarily by the international market and not by domestic depletion effects. Because natural gas is primarily domestically produced, wellhead price increases are determined largely by resource depletion effects and directly result in end-use price increases.

Offsetting Forces Contribute to Slight Increase in Electricity Prices

Figure 45. Components of electricity price, 1990-2010 (1992 cents per kilowatthour)



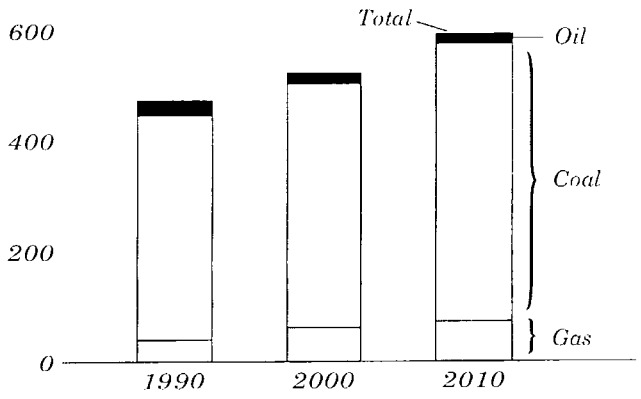
The capital component of electricity price (capital costs divided by sales) declines during the forecast period as fuel costs rise, resulting in only a slight increase in the average electricity price (Figure 45). As sales increase faster than the growth in the capital recovery of equipment investments, the capital component of price declines. More construction of natural-gas-fired plants and utility reliance on life extension and repowering of existing plants slow the growth in costs associated with construction. Natural-gas-fired combined-cycle and turbine facilities have relatively low construction costs, and extending the lives of existing units is much less expensive than constructing new plants.

Increases in fuel costs offset the declining capital component of price, as utilities increase their use of natural gas, a higher cost fuel than coal or nuclear. Increased use of natural gas also contributes to the stability of the operation and maintenance (O&M) component of prices. Natural gas units tend to have lower O&M expenses than coal or nuclear plants. The wholesale power component grows with increased reliance on nonutility power, but its price remains competitive. Nonutility generation increases as the Public Utility Regulatory Policies Act (PURPA) and EPACT exempt selected nonutility producers of electricity from certain restrictions and allow them to compete with other resource options. These new classes of generators, qualifying facilities under PURPA and exempt wholesale generators under EPACT, are expected to satisfy a growing share of the demand for electricity.

ELECTRICITY: COMPARATIVE FORECASTS

Carbon Emissions Grow with Increased Demand

Figure 46. Electric utility carbon emissions by fuel, 1990-2010 (million metric tons per year)



Electricity generation from fossil fuels is the largest single source of carbon emissions in the United States. In 1990 utilities emitted about 477 million metric tons of carbon, and these emissions grow in the forecast by 1.1 percent a year, to almost 596 million metric tons in 2010 (Figure 46 and Table 14). Carbon emissions from coal-fired generating plants grow relatively slowly between 1990 and 2000, but they increase after 2000 as utilities bring more coal plants online to satisfy baseload capacity. As a result of increasing fossil-fuel use, utility carbon emissions increase by 10 percent in 2000 from 1990 levels and by 13 percent in 2010 from 2000 levels.

Although the combustion of petroleum products results in the emission of more carbon into the atmosphere than any other fuel, carbon emissions from oil-fired utility plants fall over the forecast, as relatively expensive oil-fired generation is displaced by growing gas-fired generation. The sharp increase in natural gas generation results in a corresponding increase in this fuel's carbon emissions, but, per unit of generation, it has the lowest carbon content of the fossil fuels.

Table 14. Emissions from U.S. electric power plants, 1990-2010

	Million metric tons per year		
Forecast	**1990**	**2000**	**2010**
Carbon	*476.7*	*525.4*	*595.9*
Sulfur oxides	*14.2*	*10.3*	*9.0*

Comparative Forecasts

Table 15. Comparative forecasts for electricity, 2010

Forecast	AEO94 reference case	DRI	GRI	WEFA	EEI
End-use price (1992 cents per kWh)	*7.60*	*6.50*	*6.18*	*8.01*	*7.18*
Net energy for load (billion kWh)	*3,720*	*4,390*	*4,118*	*4,121*	*4,672*
Sales (billion kWh)	*3,469*	*3,982*	*3,707*	*3,816*	*4,343*
Capability (gigawatts)	*812.3*	*1,044.0*	*925.8*	*877.8*	*924.8*

Sales. EIA's sales projections for 2010 are lower than comparable forecasts (Table 15). EIA's projections incorporate efficiency standards for equipment mandated by EPACT and the latest end-use survey information, which showed increased conservation. These factors result in lower sales projections for 2010. In addition, EIA's projections incorporate new data on the penetration of electric appliances in the residential and commercial sectors. These data show a slightly increased penetration for gas heating appliances relative to electric.

Net energy for load [39]. All the outside projections are higher than the *AEO94* reference case and the high economic growth case in 2010—3,894 billion kilowatthours (see Appendix tables for economic growth cases). EIA's lower projection for net energy for load is based on lower sales.

Capability. EIA has the lowest capability projections for 2010 of the forecasters in Table 15, because of its lower sales forecast. WEFA's, DRI's, and EEI's capability projections are higher because cogeneration capability is reported with nonutility capability, and the DRI and GRI forecasts report nameplate capability rather than net summer capability. (Nameplate capability is typically 5 to 10 percent greater than net summer capability.) NERC's projection of 759.7 gigawatts is slightly above the *AEO94* projection of 740.0 gigawatts in 2000 (see Appendix F).

Prices. The DRI and GRI price projections are lower than EIA's because of lower fuel prices to the electricity sector. WEFA's prices are higher and slightly above EIA's high growth case results, which reach 7.9 cents per kilowatthour in 2010 (see Appendix F).

The demand for electricity and the strategies to meet the demand may differ from the projections presented here. Among the factors that could significantly alter the forecast are the continued development of integrated resource planning (IRP) by utilities, utility DSM programs, the impacts of recent changes in legislation affecting nonutility generators and electricity transmission and distribution, new environmental regulations, the emergence of new generating technologies, and the uncertainty surrounding nuclear power plant refurbishment or retirement.

In recent years, many utilities have developed IRP programs to evaluate the resource options available to meet the demand for electricity. These programs attempt to put all options on a level playing field and allow for the participation of all interested stakeholders when evaluating their 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 the environmental externalities [*40*] associated with particular technologies or evaluating the impacts on the local economy of choosing one technology versus choosing another. The Department of Energy's IRP program is working to develop tools to assist utilities and PUCs in their efforts to implement an IRP process. The continued penetration of IRP programs could alter future utility planning decisions.

Utility investments in DSM programs have grown dramatically in the 1990s. Utilities reported to EIA that, in 1990, DSM programs reduced their peak demand by 25 gigawatts. They also reported that they plan to continue to invest heavily in DSM programs through the turn of the century. However, with the passage of EPACT, which contains stringent efficiency standards for a wide variety of appliances, the future of utility DSM programs targeted at these same appliances is somewhat clouded. The potential for double counting appliance efficiency improvements is high. On the other hand, the new standards may lead utilities to refocus their DSM programs on other areas, and continued technological developments may create new markets for DSM programs.

EPACT also contains provisions which have 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), that can develop non-rate-based generating systems and market the power from them to utilities. Furthermore, EPACT attempts to provide EWGs greater access to utility transmission systems. These provisions will lead to increased growth in nonutility suppliers and restructuring of the electricity industry, but it is unclear to what degree.

The possibility of new environmental legislation and the continued development of advanced generating technologies also make forecasting uncertain. While the Administration's recently announced Climate Change Action Plan primarily involves voluntary compliance, the possibility exists, if the current approach does not achieve the desired reductions, that more stringent carbon reduction regulations will be developed. Efforts to develop generating technologies with reduced environmental impacts are underway. New technologies—particularly for generation from renewable fuels, such as wind and solar plants—might play an important role in reducing the emissions associated with electricity generation.

The current priority in the nuclear power industry is the Advanced Light-Water Reactor Program, a joint initiative of the Department of Energy and the nuclear industry with the goal of making standardized newly designed nuclear plants available for commercial order. Four plant types are involved—two evolutionary plants and two midsized plants. The evolutionary plants are 1,300-megawatt improved versions of the light-water reactor plants currently in operation. The midsized plants are 600-megawatt units that incorporate passive safety design features and modular construction. The current schedule for completion of design certification by the Nuclear Regulatory Commission is 1994 for the evolutionary plants and 1996 for the midsized plants. However, it is assumed that no new orders for nuclear plants will be placed until several issues are satisfactorily resolved: concerns about the disposal of radioactive waste; public concerns about safety; concerns about economic and financial risks; uncertainty about future power plant performance; and uncertainty in the licensing and regulatory processes.

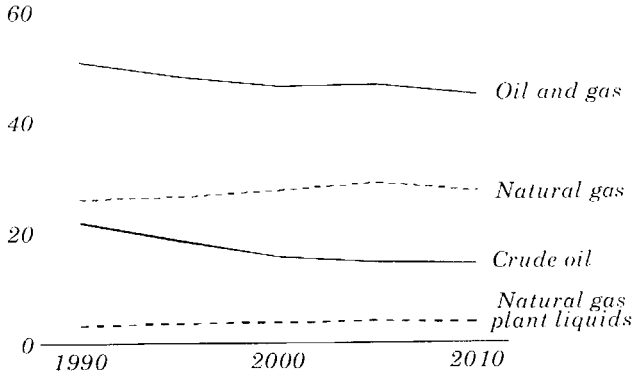
CHAPTER 4

OIL AND NATURAL GAS

Net imports of oil and gas—the difference between domestic consumption and production—are expected to grow from 1990 through 2010. Oil imports, which arrive primarily by ship, represent a much larger share of consumption than gas imports, which arrive primarily by pipeline. Net imports of crude oil and petroleum products represented 39 percent of oil consumption in 1990, but gas imports represented only 8 percent of gas consumption. According to the forecast, in 2010 net imports represent about 60 percent of U.S. oil consumption and 16 percent of U.S. gas consumption.

Oil and gas production is expected to decline from 51 percent of total U.S. energy production in 1990 to 45 percent in 2010—the lowest percentage in more than 50 years (Figure 47). Combined oil and gas production overtook coal production as the number one U.S. energy source in 1948 [*41*] and peaked at 73 percent of U.S. energy production in 1971. During the same period, the number of motor vehicles more than tripled and natural gas pipelines spread nationwide. The decrease in the oil and gas share of production is expected to continue through the projection but to slow around the turn of the century as prices rise and the industry finds ways to exploit its known reserves more intensively.

Figure 47. Oil and gas shares of total energy production, 1990-2010 (percent)

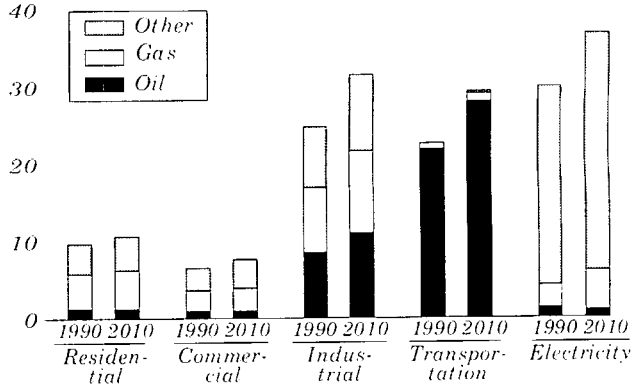


Domestic crude oil production is expected to fall from 7.4 million barrels a day in 1990 to 4.8 million barrels a day in 2006 because of continuing depletion of existing resources at relatively low prices. By 2010, production rises to 5.1 million barrels a day on the strength of rising prices and improved technology.

In contrast, natural gas production is expected to grow through most of the forecast period, reaching 20.4 trillion cubic feet by 2007 and declining slightly to 20.2 trillion cubic feet in 2010. Increased gas production is attributable to rising prices and greater use of unconventional gas recovery technologies.

Natural gas consumption rises at a faster rate than oil consumption through the forecast period. Gas consumption rises from 18.7 trillion cubic feet in 1990 to 24.1 in 2010, with the highest growth rates occurring in the electricity and industrial sectors (Figure 48). Increasing use of gas for electricity generation is expected to be encouraged by demands for a cleaner environment and advances in gas-fired generation technology. Natural gas maintains its position as the leading source of energy for residential space heating throughout the forecast.

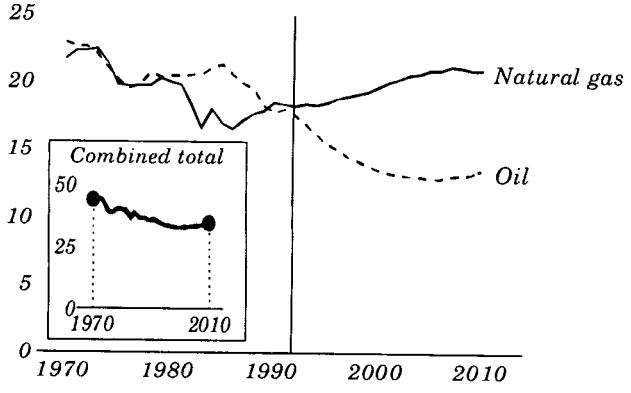
Figure 48. Oil and gas consumption by end-use sector, 1990 and 2010 (quadrillion Btu)



Petroleum product consumption is expected to grow from 17.0 million barrels a day in 1990 to 21.3 million barrels a day in 2010. Gasoline and jet fuel consumption increases considerably as the number of miles traveled continues to grow. Petroleum products remain the leading source of transportation fuel throughout the forecast, slipping only 2 percentage points to 95 percent of the total from 1990 through 2010. (Compressed natural gas represents the largest share of alternative-fuel consumption in the transportation sector by 2010.) The composition of gasoline will change throughout the forecast, as reformulated gasoline joins traditional and oxygenated gasoline in the fuel mix.

Higher Natural Gas Production Offsets Declines in Oil Production

Figure 49. Oil and gas production, 1970-2010 (quadrillion Btu)



Over the past 20 years, domestic oil and natural gas production [*42*] generally declined. The forecast represents in part a departure from this pattern (Figure 49). Oil production is generally projected to decline, due to continuing depletion of existing resources during a period of relatively low prices. It increases slightly after 2006, in response to rising prices and technological gains. Relatively abundant natural gas is available from lower cost sources, allowing production to increase to meet rising demand for most of the forecast.

Future domestic oil and natural gas production depends on many uncertain factors—the size and geologic distribution of remaining resources; technological advances in prospect evaluation, drilling, and production; and prices, costs, and other factors affecting industry profitability and expectations.

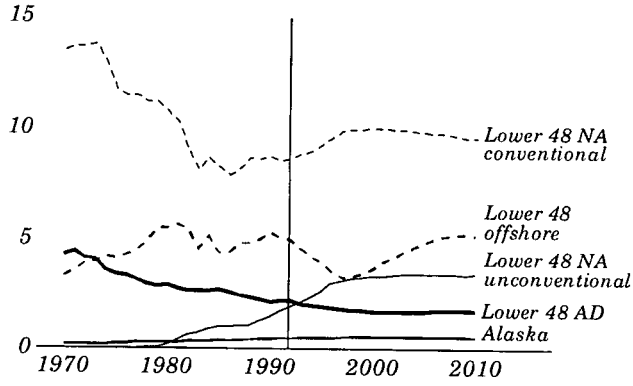
The resource estimates underlying the production projections assume that, given technological innovation by 2010, economically recoverable domestic oil and natural gas resources measured as of 1990 [*43*] will increase by 41 percent for natural gas and 37 percent for oil (Table 16).

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	*82.5*	*122.9*	*851.9*	*1,265.8*
U.S. total	***108.8***	***149.2***	***1,021.2***	***1,435.2***

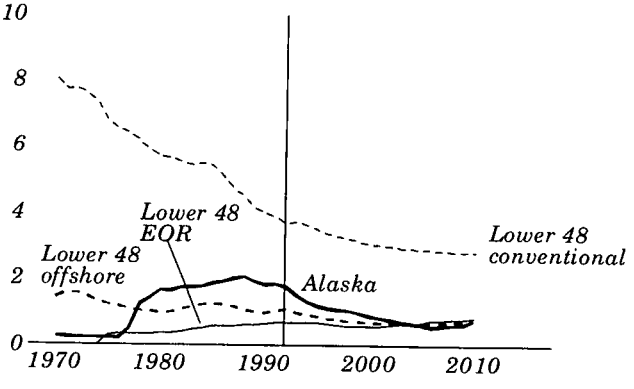
Most Gas Production Components Increase, Oil Components Fall

Figure 50. Gas production by source, 1970-2010 (trillion cubic feet)



The continuing increase in domestic natural gas production [*44*] for most of the forecast is partly attributable to increases in offshore production and increasing use of unconventional gas recovery (UGR) technologies (Figure 50). UGR consists principally of production from reservoirs with low permeability (tight sands) but also includes methane from coalbeds and gas from Devonian shales.

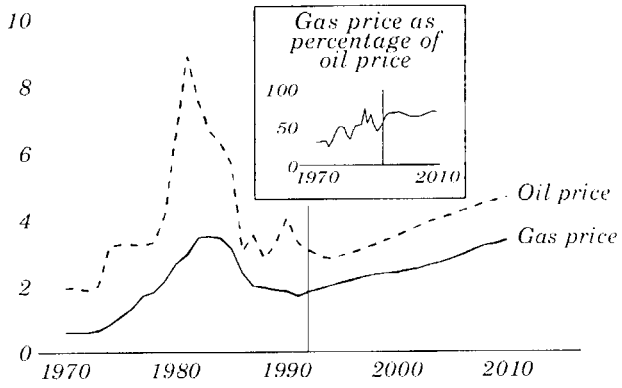
Figure 51. Oil production by source, 1970-2010 (million barrels per day)



The increasing levels of domestic oil production from 2006 to 2010 are attributable to increasing production after 2000 by enhanced oil recovery (EOR) methods [*45*] and from the frontier areas of the lower 48 offshore regions and Alaska (Figure 51). Conventional oil production generally declines in the lower 48 onshore regions because of continuing resource depletion.

Wellhead Prices Turn Upward and Rise Fairly Steadily

Figure 52. Lower 48 oil and gas wellhead prices, 1970-2010 (1992 dollars per million Btu)



Domestic oil and natural gas prices are projected to reverse recent declines (Figure 52). Domestic oil prices are determined largely by the international market. Since U.S. consumption of imported oil represents only a part of world oil demand, changes in U.S. oil consumption have only a limited effect on future world oil prices, which rise largely in response to global supply and demand.

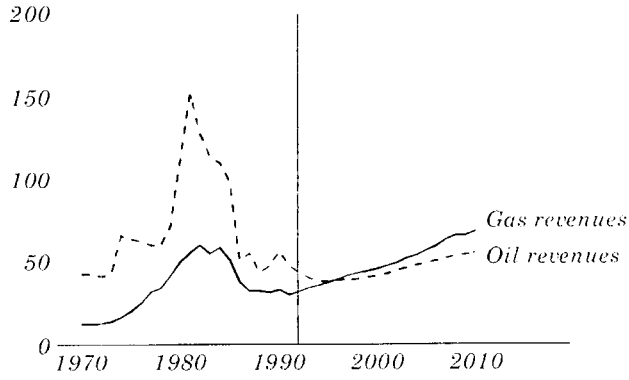
In contrast, domestic natural gas prices are determined largely by competition in U.S. energy markets, because natural gas, unlike oil, is not easily transported to or from countries outside North America. Despite increased competition, the rising domestic demand for natural gas and the effects of domestic depletion lead to rising prices throughout the forecast period.

The world oil price interacts with domestic natural gas markets in complex ways. For example, the crude oil price directly affects the supply of natural gas, because up to roughly one-sixth of domestic gas production is a coproduct of oil production (associated and dissolved natural gas). Crude oil prices indirectly affect the supply of natural gas by influencing the level of crude oil activity. This, in turn, affects exploration and development costs.

The price of crude oil can also affect demand for natural gas, as oil and gas compete as substitute fuels in some end-use sectors. This competition may moderate natural gas demand—and thus natural gas prices—over the forecast period.

Natural Gas Wellhead Revenues Outstrip Those from Oil

Figure 53. Lower 48 oil and gas wellhead revenues, 1970-2010 (billion 1992 dollars)



Despite declining domestic oil production, annual lower 48 revenues from the production of oil are projected to increase over the 1995-2010 period because of increasing world oil prices. Lower 48 natural gas revenues rise more rapidly, driven by the combination of increasing prices and production. They surpass oil revenues by more than 10 percent throughout the 2000-2010 period (Figure 53).

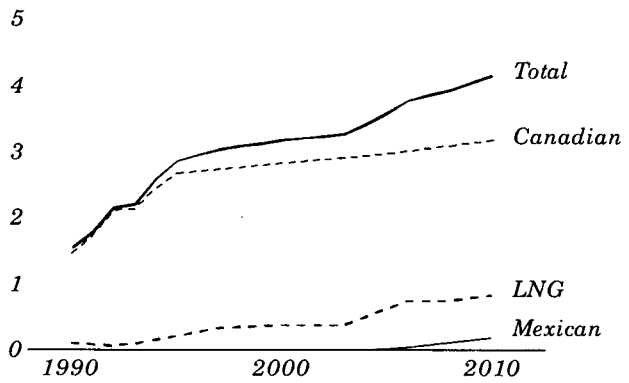
Capital expenditures by the oil and gas industry also increase in the forecast, as depletion effects require more wells to be drilled to sustain equivalent levels of production. Technological improvements help to moderate this trend.

The projected increasing contribution of natural gas revenues to total oil and gas revenues could change the domestic oil and gas industry significantly. The rising share of gas revenues indicates a greater level of involvement by all firms in the industry in exploration for and production of natural gas. The industry's greater focus on this segment could lead to more research and development in the discovery or extraction of gas. For example, firms might investigate refinement of UGR techniques to a much greater extent than otherwise.

Unprecedented growth in gas revenues could also lead to changes in market organization and industry structure, but their direction and magnitude are highly uncertain.

Several Sources Contribute to Higher Natural Gas Imports

Figure 54. Natural gas imports, 1990-2010 (trillion cubic feet)



The diversity of competitively priced supplies is reflected in several sources of higher natural gas imports. Net imports more than double in the forecast, rising from 1.5 trillion cubic feet (Tcf) in 1990 to 3.9 Tcf in 2010 (Figure 54), primarily in response to readily available Canadian supplies and a significant increase in projected pipeline capacity between the United States and Canada (Table 17).

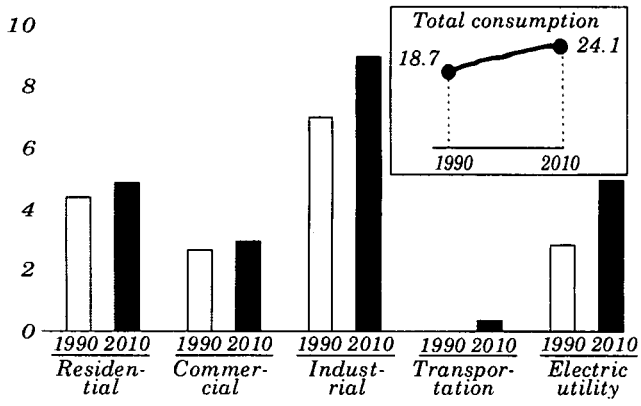
Table 17. Assumed design capacity of Canadian border pipelines

	Billion cubic feet per year			
U.S. region	**1990**	**2000**	**2005**	**2010**
New England	78	333	378	444
Mid-Atlantic	111	278	278	289
West North Central	289	322	389	389
Rocky Mountain	1,011	1,689	1,911	2,056
Pacific	289	378	378	378
Total	***1,778***	***3,000***	***3,333***	***3,556***

Since 1984, U.S. gas trade with Mexico has consisted entirely of exports to Mexico. Gas flows from Mexico to the United States seem inevitable in light of both the recent passage of the North American Free Trade Agreement and Mexico's endowment of recoverable resources. Import activity from Mexico to the United States has been reported in the trade press recently [*46*]. These sales are expected to be short term only. Sustained flows of significant sales volumes from Mexico are projected to resume in 2006, rising rapidly to 0.2 Tcf in 2010. Another source of increased imports is liquefied natural gas (LNG) [*47*].

Natural Gas Markets Expand

Figure 55. Natural gas consumption by sector, 1990 and 2010 (trillion cubic feet)



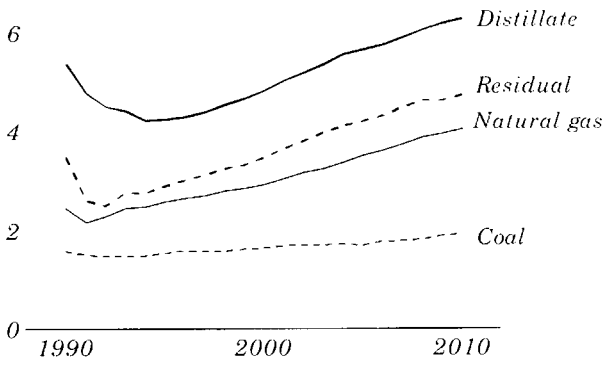
Regulatory policies that increase competition within natural gas markets, advances in gas-fired generation technology, and a growing emphasis on a cleaner environment contribute to an increase in natural gas use in the forecast, from 18.7 Tcf in 1990 to 24.1 Tcf in 2010 (Figure 55). Most of the projected increase is in electricity generation in the electric utility and industrial sectors. In addition to increased gas use in existing generation facilities, a significant part of this increase is for cogenerators, small power producers, independent power producers, and exempt wholesale generators [*48*].

The industrial sector is forecast to increase its natural gas use by 1.2 percent a year between 1990 and 2010. Increased gas use resulting from the increased competitiveness in natural gas markets is partially offset by technological advances in industrial processes and the use of more efficient equipment. A further offsetting factor is the shift from energy-intensive industries, such as iron and steel, to less energy-intensive industries, such as electronics and pharmaceuticals.

Increases of 10 and 12 percent from 1990 to 2010 in residential and commercial consumption, respectively, are attributable to gas conversions, continued gas dominance in new housing, and new uses for natural gas, such as space cooling and gas heat pumps. Although the 0.4 Tcf consumed in the transportation sector by vehicles fueled with compressed natural gas in 2010 is a small percentage of total consumption, it highlights a promising new use for natural gas.

Natural Gas Prices Remain Competitive

Figure 56. Fuel prices for electricity generation, 1990-2010 (1992 dollars per million Btu)



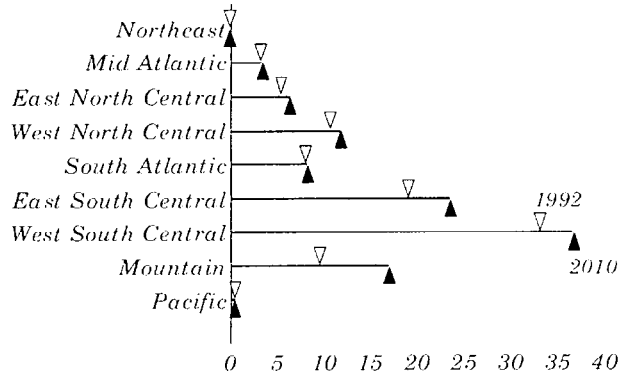
Despite steady increases in its price after 1991, natural gas remains competitive with petroleum products (Figure 56). In the electricity sector, for example, the difference between natural gas and residual fuel oil prices increases. The 2010 margin of $0.67 per million Btu is about the same as the average for 1985-92, although 3 times greater than the 1992 margin and significantly less than in 1990.

Natural gas use for electricity generation is projected to increase through most of the forecast period. Gas consumption for generation by electric utilities declines after 2007, reflecting a projected decline in utilization of gas-fired combined-cycle generation capacity as more coal-fired capacity is added.

Natural gas prices are projected to increase in all sectors in response to higher wellhead prices. Increases in end-use prices are greater in sectors with heating season demands requiring firm service. These increases reflect the elimination of cross-subsidization among customer classes as a result of industry restructuring. Transition costs associated with compliance with Federal Energy Regulatory Commission (FERC) Order 636 increase tariffs slightly through 1998. Capital investment associated with new pipeline capacity pushes up end-use prices throughout the forecast. The post-Order 636 environment offers opportunities to reduce average pipeline tariffs through increases in pipeline capacity utilization and revenue sharing/crediting in interruptible service and capacity release markets. These potential benefits are not directly accounted for in the end-use price forecast [*49*].

More Interregional Pipeline Capacity Needed

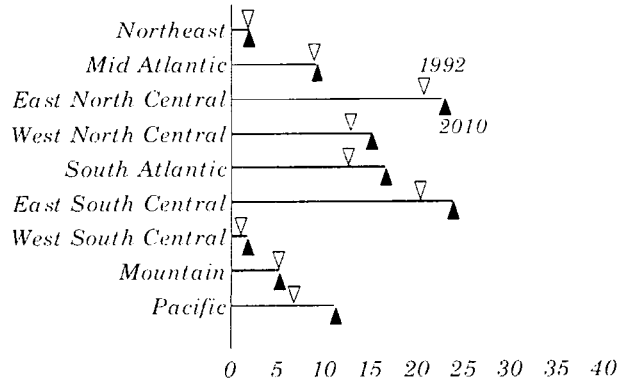
Figure 57. Interregional pipeline capacity exiting Census regions, excluding import/export capacity, 1992 and 2010 (billion cubic feet per day)



Although the Nation's network of pipelines meets current natural gas demand, additional interregional pipeline capacity will be required to support the expansion of natural gas markets. Total interregional pipeline capacity is projected to increase from 89.6 billion cubic feet per day in 1992 to 107.2 billion cubic feet per day in 2010.

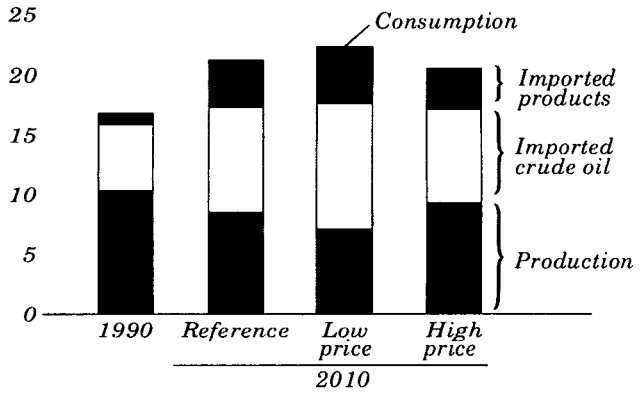
Pipeline expansion is required to increase access to additional sources of supply, especially in the Mountain and East South Central regions of the United States (Figure 57). Capacity exiting the Mountain region increases from 9.6 to 17.0 billion cubic feet per day, while capacity exiting the East South Central region increases from 19.1 to 23.5 billion cubic feet per day. Pipeline expansion is also required to meet growth in gas demand, for example, in Florida and the Pacific region (Figure 58).

Figure 58. Interregional pipeline capacity entering Census regions, excluding import/export capacity, 1992 and 2010 (billion cubic feet per day)



Oil Imports Grow

Figure 59. Oil production and net imports, 1990 and 2010 (million barrels per day)



Generally declining domestic production, along with continuing growth in petroleum consumption, results in higher oil imports in the forecast (Figure 59). Net imports supplied 39 percent [*50*] of U.S. petroleum demand in 1990. By 2010, the projected share is 60 percent in the reference case, compared with 55 percent in the high oil price case and 68 percent in the low oil price case.

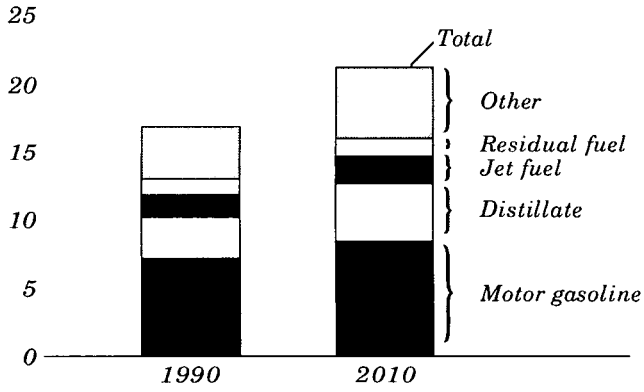
The quality of imported crude oil has been declining for several years, with a trend toward higher sulfur and lower gravity crude oils. This trend is expected to continue as higher quality resources are depleted. The decline in quality will require new refinery investments and increase the cost of producing refined products.

Imports of refined petroleum products are projected to increase between 1990 and 2010 by an average of 7.6 percent a year, mainly due to very small growth in domestic refining capacity. U.S. refinery capacity increases by only 0.3 million barrels a day between 1993 and 2010. Capacity utilization ranges from 87.1 percent in 1990 to 89.9 percent in 2010. All capacity increases are expected to occur at existing refineries.

Refineries are subject to stricter environmental regulations, both on production facilities and on the products they produce. Significant investments will be required to satisfy these regulations, which will increase refining costs and constrain capacity expansion throughout the forecast.

Gasoline, Distillate Fuel Lead Growth in Petroleum Consumption

Figure 60. Petroleum consumption by product, 1990 and 2010 (million barrels per day)



Total petroleum consumption grows in the reference case forecast to 21.3 million barrels a day in 2010, up from 17.0 million barrels a day in 1990. Large increases come from gasoline, distillate fuel, and the "other" category of products [*51*] (Figure 60).

Transportation fuels—gasoline, distillate, and jet fuel—continue to dominate petroleum consumption in the forecast. Gasoline remains the leading petroleum product, but its share of total consumption declines from 43 percent of total petroleum demand in 1990 to 40 percent in 2010. The shares of distillate and jet fuel are forecast to rise from 18 to 20 and 9 to 10 percent, respectively.

Growing demand for lighter products—gasoline, distillate, and jet fuel—will present a challenge to refiners. To produce these lighter products, refiners will need to add more conversion units [*52*], especially because crude quality is expected to decline.

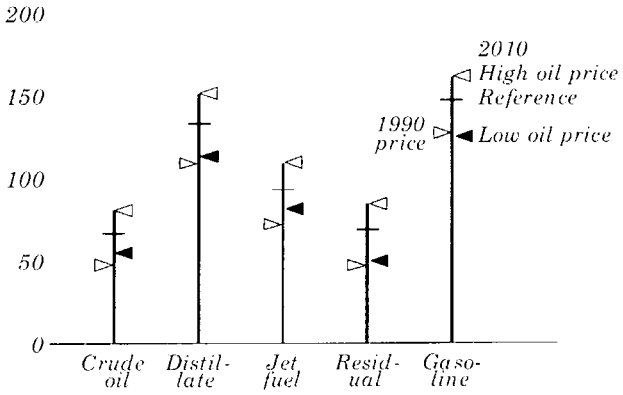
As petroleum demand grows in the forecast, carbon emissions associated with petroleum consumption increase from 583 to 695 million metric tons per year. Carbon emissions from petroleum use in the transportation sector grow around three times as fast as petroleum-related emissions from all other sectors combined (Table 18).

Table 18. Petroleum-related carbon emissions, 1990-2010

	Million metric tons per year		
Source	***1990***	***2000***	***2010***
Transportation	*422.3*	*476.2*	*522.1*
Other sectors	*160.9*	*168.6*	*172.5*

Product Prices Rise as Crude Oil Prices Increase

Figure 61. Oil product prices, 1990 and 2010 (1992 cents per gallon)



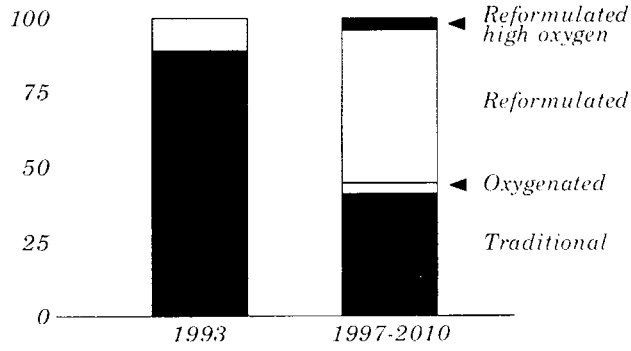
The price of crude oil continues to be the key determinant of petroleum product prices, although costs from recent legislation play a strong role. Prices of all transportation fuels include an additional 4.3-cent-per-gallon tax resulting from the 1993 Omnibus Budget Reconciliation Act. This new tax on jet fuel will commence in 1996.

Demand influences individual product prices. Also, products that require relatively high levels of refinery processing are more costly to produce. Gasoline and distillate fuel, the most expensive petroleum products (Figure 61), have the highest demand and are among the lightest petroleum products, requiring the most refinery processing. Increases in production and distribution costs for gasoline and distillate are expected to rise due to legislation phasing-in cleaner burning fuels.

The Clean Air Act Amendments of 1990 (CAAA90) require the use of cleaner burning fuels, including: oxygenated gasoline in cities that fail to meet national standards for carbon monoxide pollution; low-sulfur diesel fuel used on U.S. highways; and, starting in 1995, a new "reformulated gasoline" in many cities that fail to meet ozone pollution standards. The retail price of reformulated gasoline is expected to be 7 to 8 cents a gallon above that of traditional gasoline. Reformulated gasoline standards will become more restrictive in 2000. The State of California has already adopted motor fuels standards that are even more stringent than Federal standards [*53*] and will implement a statewide requirement for reformulated gasoline in 1996.

Gasoline Projections Reflect New Gasoline Blends

Figure 62. Gasoline supplied by type, 1993 and 1997-2010 (percent)



Production and marketing of gasoline are becoming more complicated as State and Federal standards are imposed in specific areas and during specific seasons. *AEO94* estimates that oxygenated gasoline represented about 11 percent of 1993 U.S. gasoline consumption [*54*]. Requirements for oxygenated gasoline have raised the demand for alcohols and ethers, which are blended with gasoline to increase its oxygen content.

In 1995, the year-round reformulated gasoline program takes effect in nine metropolitan areas with the most severe ozone pollution and in other areas that join the program voluntarily [*55*]. *AEO94* assumes that by 1997 approximately 51 percent of the gasoline produced will be reformulated, and another 4 percent will meet both "oxygenated" and "reformulated" standards (Figure 62).

The phase-in of reformulated gasoline will increase the need for blending oxygenates (alcohols and ethers) with gasoline. Many refineries are adding or expanding units that produce ethers, but much of the oxygenates required must be purchased from nonrefinery producers of ethers or ethanol. Blending with oxygenates will increase the refinery capacity for producing gasoline (Table 19).

Table 19. Oxygenate content of gasoline, 1993-2010

	Million barrels per day		
Gasoline type	***1993***	***2000***	***2010***
Gasoline excluding oxygenates	*7.22*	*7.59*	*7.93*
Oxygenates	*0.23*	*0.43*	*0.49*
Total gasoline	***7.45***	***8.02***	***8.42***

Oil forecasts

Projections of the world oil price (Table 20) differ because of varying expectations about the size of world oil resources, the application of new technology to resource development, the expansion of production capacity in OPEC countries, the market influence of OPEC members, and the future path of oil exploration and production in the Commonwealth of Independent States.

Table 20. Comparative forecasts of oil production and imports, 2010

Forecast	AEO94	DRI	GRI	WEFA
World oil price (1992 dollars per barrel)	*28.16*	*30.03*	*27.27*	*26.84*
Crude oil and natural gas liquids production (million barrels per day)	*7.1*	*7.0*	*8.5*	*6.8*
Total net imports (million barrels per day)	*12.8*	*13.1*	*9.9*	*10.4*

In addition to different oil price projections, several factors affect the projections of domestic production and consumption and, in turn, net imports. All forecasters agree that petroleum net imports will continue to grow as U.S. production declines and demand increases. Private-sector forecasts project the share of petroleum demand provided by imports in 2010 to range from 51 percent in the GRI forecast to 63 percent in the DRI forecast, compared with the *AEO94* reference case forecast of 60 percent. These forecasts reflect different assumptions about conservation, energy efficiency, and the substitution of alternative transportation fuels that lead to differences in the projected rate of demand growth. Although their world oil price forecasts are somewhat different, the DRI forecast and the *AEO94* reference case project the fastest rates of growth in petroleum demand. Demand grows much more slowly in the WEFA forecast.

Projections of domestic production reflect differing forecasts of the size of resources, the costs of development, and the application of new technology. In the *AEO94* reference case, for example, production is projected to decline in the 1990s but increase slightly between 2006 and 2010 because of rising prices and technology improvements. The GRI forecast shows a similar pattern for petroleum production, but the WEFA and DRI forecasts project a decline in production throughout the forecast period.

Natural gas forecasts

The variation in the 2010 natural gas wellhead price reflects the considerable uncertainty surrounding this variable, ranging from $2.89 (AGA) to $3.88 (DRI). The difference of $0.99 from the low to high values is almost 30 percent of $3.47, the *AEO94* reference case value. Several major factors contribute to the variation (Table 21). Less obvious influences include differences in the composition of the recoverable resource base and other aggregate variables or different perceptions of the implication of such factors as technology.

Table 21. Comparative forecasts for natural gas, 2010

Forecast	AEO94	DRI	GRI	AGA	NPC
World oil price (1992 dollars per barrel)	*28.16*	*30.03*	*27.27*	*24.47*	*29.72*
Average wellhead price, lower 48 states (1992 dollars per thousand cubic feet)	*3.47*	*3.88*	*3.22*	*2.89*	*3.77*
U.S. natural gas production (trillion cubic feet)	*20.2*	*21.8*	*21.6*	*21.9*	*20.5*
U.S. natural gas consumption (trillion cubic feet)	*24.1*	*24.8*	*25.3*	*25.4*	*24.0*

The complexities of gas market analysis do not allow easy conclusions regarding the factors that determine specific gas prices. Nevertheless, tentative conclusions can be drawn from some comparisons. The highest gas prices generally correspond to projections that include the highest oil prices (DRI and NPC). Oil is a substitute fuel that competes with gas for market share. Higher oil prices reduce competitive pressure, allowing for higher gas prices. Aggregate production levels are a rough measure of the degree of exploitation of increasingly costly supplies. DRI shows relatively high production volumes and the highest prices. AGA's projection shows the maximum production level, but its price is the lowest, reflecting a more optimistic outlook on the potential recoverable resource base, the use of new technology to maintain recent levels of productivity, and a relatively low oil price.

Natural gas industry restructuring. Complete unbundling of pipeline services, as mandated by FERC Order 636, moves the natural gas industry into uncharted waters. Although marginal cost pricing is currently inconsistent with past and most current practices, which use average cost pricing, a number of recent events point to a trend toward marginal pricing in the gas industry. These events include promulgation of FERC Order 636, which unbundles pipeline services and requires (in most cases) a switch to straight fixed variable rate design from modified fixed variable rate design.

How rapidly competitive forces continue to penetrate the natural gas industry largely depends on implementation of recent FERC rulemaking, the level of activity in capacity release markets, and to what degree changes in Federal regulations are adopted by States in market segments under their jurisdiction. Unbundling in the pipeline industry has spurred some State Public Service Commissions to review and advocate unbundling in local distribution company (LDC) markets. To promote nondistortionary price signals and remove obstacles to competition, cross-subsidization among customer classes is being eliminated, the market is being segmented for marketing purposes, LDC gas services are being unbundled, and gas service prices are being determined through competition. These factors may lead to prices that reflect marginal pricing by customer class. Therefore, the *AEO94* methodology employed in solving for natural gas supply and demand assumes that marginal costs are the basis for determining market-clearing prices throughout the forecast period.

Natural gas storage. Underground storage of natural gas is essential to the U.S. transmission network. Pipeline companies have tended to establish storage facilities in areas where there is a strong seasonal variation in demand, in order to avoid the need for additional pipeline capacity from production areas. During the summer, gas is injected into storage for withdrawal during the heating season.

The role of storage in the future of the natural gas market is expected to expand significantly, especially where there are storage sites available close to market centers. With the increased competitiveness in the natural gas market, large users of natural gas may develop their own storage facilities. Storage may also be a part of futures market arbitrage [*56*].

The *AEO94* projections assume that gas is injected into storage during the off-peak season and withdrawn during the peak season. Some storage facilities (such as salt-dome storage, which is currently a minor share of total storage capacity) can cycle completely up to 10 times a year, as gas is injected and withdrawn in response to demand fluctuations. Depending on the character of future demand, this type of storage could play a significantly larger role.

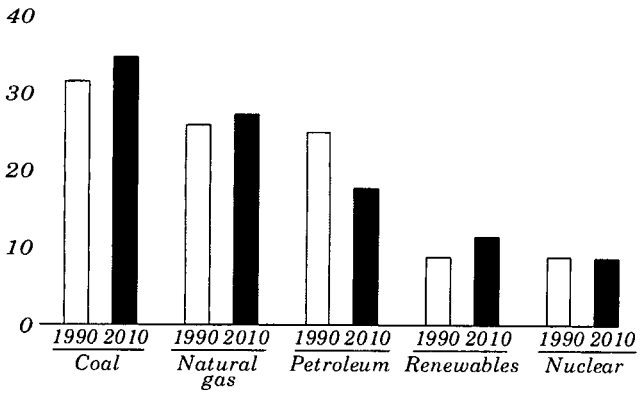
Oil and gas production technology. Benefits to the oil and gas production sector from technological development and penetration are included in the *AEO94* analysis as greater economic incentives and rewards to firms in the industry. Two recent innovations are three-dimensional (3D) reflection seismology and horizontal drilling and completion techniques. 3D seismology, which yields a more complete and coherent image of the subsurface than two-dimensional seismology, can reduce the number of dry holes, especially in the exploration phase, and optimize the location of both appraisal and production wells. Horizontal drilling technology has been applied to the discovery and productive development of oil reserves frequently during the past 5 years, when the advent of improved downhole drilling motors and other necessary supporting equipment, materials, and technologies made this technique commercially viable. Horizontal wells can be more costly to drill and complete for production than vertical wells directed to the same target, but much greater flow rates can serve as an economic offset, possibly yielding higher financial returns. Collectively, these and other technologies are represented in the forecast as a reduction in supply costs and an expansion of recoverable resource targets. Resource estimates are assumed to expand by 37 and 41 percent for oil and gas, respectively.

Gasoline reformulation. Petroleum refiners and marketers face changes in investment requirements due to CAAA90. New regulations requiring higher oxygen content and reformulation of gasoline will affect the refining, gas processing, petrochemical, and ethanol industries and the way they interact. In petrochemicals, increased demand for methanol and certain olefins, with potentially greater supplies of aromatics, will revamp operations and affect feedstock trends and chemical supplies. The impact of the U.S. Environmental Protection Agency's recently released complex model for reformulated gasoline adds further uncertainty.

Coal consumption for electricity generation is the primary use of coal in the United States. The continued growth of coal consumption for that use and the response of the coal industry and electric utilities to the Clean Air Act Amendments of 1990 (CAAA90) are the two major determinants of the *AEO94* coal forecasts. In the industrial sector, steam coal demand will increase in certain energy-intensive process industries; however, domestic coking coal consumption will decline, primarily as a result of changes in domestic steelmaking technology. Coal exports will rise as a result of increases in steam coal demand in both Europe and Asia.

Minemouth prices for coal will rise gradually in all regions, reflecting the interplay of changes in coal mine capacity utilization rates [*57*], smaller gains in labor productivity, and the cost impacts of opening new mines.

Figure 63. Primary energy production by fuel, 1990 and 2010 (percent of total)

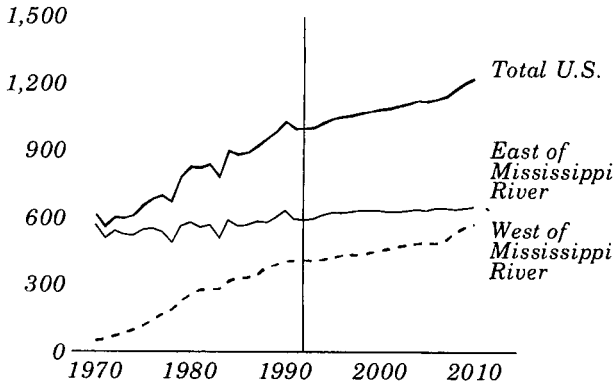


Having surpassed petroleum output levels in 1984, coal now accounts for a greater share of U.S. primary energy production than any other fuel (Figure 63). With projected increases in electricity coal demand and exports, coal's share of U.S. energy production is forecast to increase from 32 percent in 1990 to 35 percent in 2010. By comparison, the share of energy production contributed by natural gas, the second largest source of domestic energy supply, is expected to rise from 26 percent in 1990 to 27 percent in 2010.

Annual coal production is projected to rise to 1,223 million tons [*58*] by 2010, an increase of 194 million tons from 1990. The much slower growth in coal production over the forecast relative to the preceding 20 years (0.9 percent a year compared with 2.6 percent a year) is primarily the result of a smaller projected increase in electricity coal demand.

Continuing a trend that started in the mid-1970s, the share of total U.S. production met by producers west of the Mississippi River is expected to increase over the forecast period, rising from 39 percent in 1990 to 47 percent by 2010.

Figure 64. Coal production by region, 1970-2010 (million short tons)



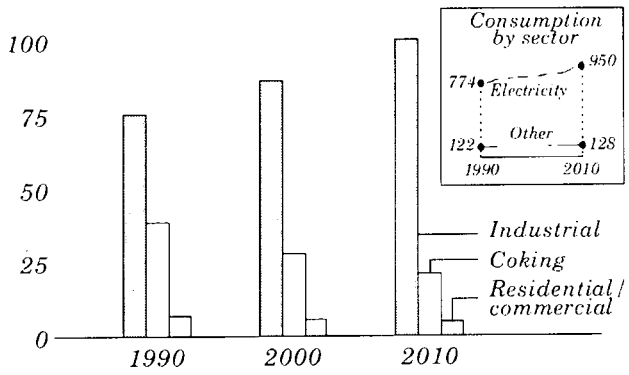
Between 1990 and 2010, western coal production is projected to increase by 44 percent, rising from 399 million tons in 1990 to 573 million tons in 2010 (Figure 64). By contrast, production from mines east of the Mississippi River is projected to rise by only 3 percent, from 630 million tons in 1990 to 650 million tons in 2010.

In the forecast, western producers capture most of the projected gain in production because of their ability to satisfy much of the increased demand for low-sulfur coal at lower delivered cost (minemouth price plus transportation cost) than eastern producers. Eastern production increases by only a small amount over the forecast, because projected declines in high- and medium-sulfur coal production offset most of the gains in low-sulfur coal production.

The uncertainties regarding environmental legislation, transportation costs, coal reserves, and coal-mining productivity—and strong competition from natural gas for market share—will have important implications for the future of the U.S. coal industry.

Electricity, Industrial Uses Increase Domestic Coal Demand

Figure 65. Domestic coal consumption by end use, 1990-2010 (million short tons)



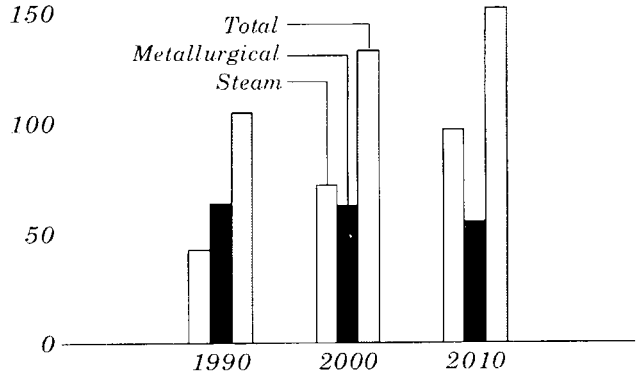
Domestic coal demand is projected to rise by nearly 21 percent, from 895 million tons in 1990 to 1,079 million tons by 2010 (Figure 65). Almost all of this increase is attributable to growth in coal use for electricity generation. In the other demand sectors, an increase in industrial steam coal consumption of 25 million tons between 1990 and 2010 is partially offset by consumption declines of 18 million tons in the coking sector and 2 million tons in the residential/commercial sector.

In the industrial steam coal sector, the higher coal consumption forecast is attributable primarily to increased demand for coal in the chemical and food-processing industries. In these industries, growth in coal use for cogeneration (the production of both electricity and usable heat for industrial processes) is expected to account for some of the projected increase.

The projected decline in domestic coking coal consumption is attributable primarily to the displacement of raw steel production from integrated steel mills (which use coal coke as an energy and raw material input) with: 1) increased steel production from minimills (which use electric arc furnaces and, thus, bypass the use of coal coke); and 2) increased imports of semifinished steels. Also contributing to the decrease in coking coal consumption is an expected reduction in the amount of coke required per ton of pig iron produced, based on energy efficiency improvements and increased supplemental fuel injections (pulverized coal and natural gas) to blast furnaces.

Steam Coal Eclipses Metallurgical Coal in the Export Market

Figure 66. Coal exports, 1990-2010 (million short tons)



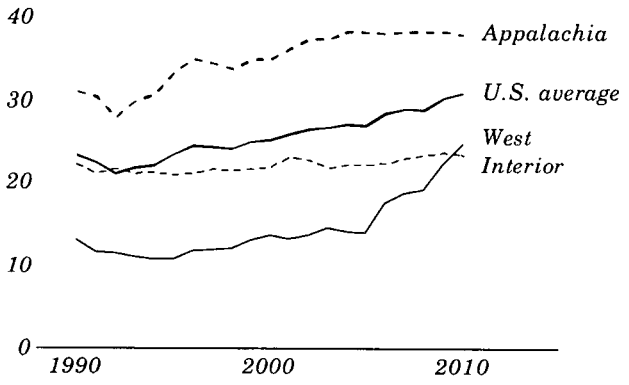
U.S. coal exports rise in the forecast from 106 million tons in 1990 to 152 million tons in 2010 (Figure 66), an increase of 43 percent, attributable primarily to demand for steam coal imports for electricity generation in Europe and Asia. U.S. exports of metallurgical coal decline slightly, corresponding to an overall projected decline in world demand for imports of coking coal.

In Europe, steam coal imports from all sources are projected to rise by 60 percent, from 130 million tons in 1990 to 208 million tons in 2010—because of higher coal demand for electricity generation and declines in coal production in Europe as a result of a reduction in domestic coal subsidies. But increased reliance on natural gas in Europe restrains growth in coal consumption for electricity generation and consequently moderates the need for additional imports of steam coal. U.S. steam coal exports to Europe are projected to increase from 24 million tons in 1990 to 62 million tons in 2010.

Steam coal imports to Asia rise in the forecast by 211 million tons, from 84 million tons in 1990 to 295 million tons in 2010. This increase, met mostly by other coal-exporting countries, is based on current plans to add substantial amounts of coal-fired generating capacity, together with the expectation that imported coal will fuel much of the new generating capacity. U.S. steam coal exports to Asia are projected to increase from 6 million tons in 1990 to 27 million tons in 2010.

Minemouth Coal Prices Rise Slightly

Figure 67. Minemouth coal prices by region, 1990-2010 (1992 dollars per short ton)



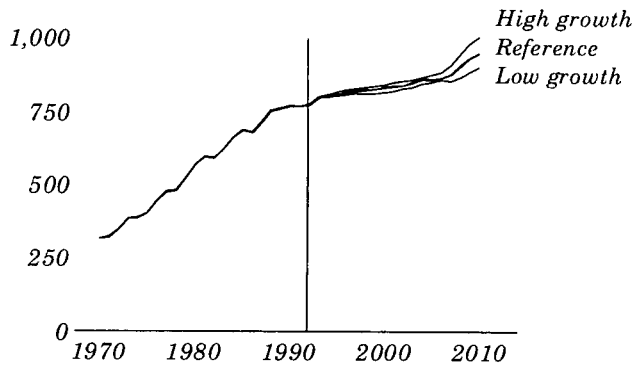
Nationwide, the average minemouth coal price is projected to rise by 1.4 percent a year (in constant dollars) through the forecast (Figure 67), compared with annual growth rates of 1.0 percent for world oil prices and 3.3 percent for the wellhead price of gas. The low rate of increase in the coal price is attributable to several key factors: gains in coal-mining productivity, an abundant coal reserve base, and additional production of low-cost western coal.

During the 1990s, prices increase in Appalachia and the West, as low-sulfur coal production increases, reducing excess production capacity and leading to the opening of new and more costly production capacity. In the Interior region, lower demand for the region's high-sulfur bituminous coal and expected gains in mining productivity slightly reduce the minemouth price.

After 2000, prices increase in all three coal supply regions. In Appalachia and the West, the average price is projected to rise between 2000 and 2010 primarily because of projected increases in coal production of 59 and 94 million tons, respectively. In the Interior region, the average minemouth price of coal is projected to rise slightly between 2000 and 2010. Most of the increase in this supply region can be attributed to reserve depletion effects resulting from the replacement of retired production capacity with new mine capacity.

Electricity Use of Coal Shows Slower Growth

Figure 68. Electricity coal consumption in three scenarios, 1970-2010 (million short tons)

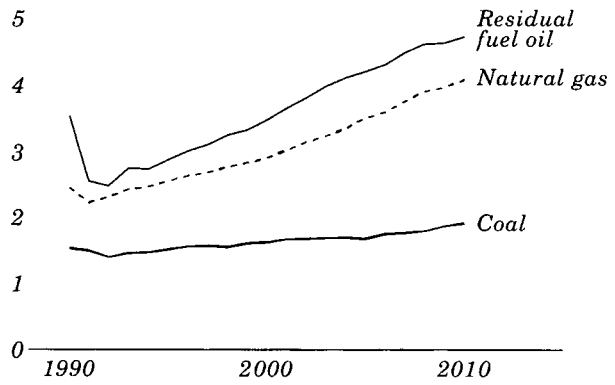


Coal consumption for electricity rises in the forecast from 774 million tons in 1990 to 950 million tons by 2010 (Figure 68). Of the increased domestic distribution of coal to this sector, 132 million tons (or 90 percent) originates from mines west of the Mississippi. Because the western States have abundant reserves of low-cost, low-sulfur coal, western producers are well positioned to meet an anticipated increase in electricity sector demand for this coal as a result of more stringent restrictions on sulfur dioxide emissions. In terms of additional coal-fired generation needed to satisfy demand, fairly equal portions are accounted for by greater utilization of existing plants and generation from new coal-fired capacity added over the forecast. The average utilization rate for existing coal-fired units increases from 59 percent in 1990 to 68 percent by 2010. Together, utilities and nonutilities (excluding cogenerators) increase net coal-fired generating capacity by 26 gigawatts over the forecast period.

Compared with the reference case, electricity coal consumption is projected to be 56 million tons higher in 2010 in the high economic growth case and 49 million tons lower in the low economic growth case. These differences in coal consumption are largely attributable to the correlation between economic growth and electricity demand. Most of the variation in total electricity demand in the high and low growth cases is accounted for by changes in coal- and gas-fired generation.

Coal Maintains Price Advantage for Electricity Generation

Figure 69. Electricity fuel prices, 1990-2010 (1992 dollars per million Btu)



Over the forecast, coal maintains its fuel cost advantage over both oil and natural gas (Figure 69). However, in terms of total costs (capital, operating, and fuel), gas-fired combined cycle is expected to remain the most economical choice for power generation. Increases in coal-fired generation will result primarily from increased baseload requirements [*59*].

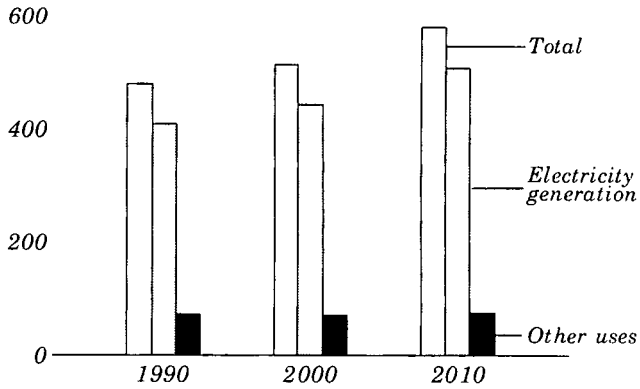
Through 2005, increases in coal consumption for electricity generation occur mainly as the result of increased utilization of existing coal-fired plants. During this period, coal-fired capacity (net of retirements) is expected to remain virtually unchanged. Although coal-fired generation increases by a substantial amount, its share of total generation declines from 55 percent in 1990 to 51 percent in 2005, primarily because generation from gas, nuclear, and renewable fuels also increases by a considerable amount during this period.

During the final 5 years of the forecast, however, 25 gigawatts (net of retirements) of new coal-fired capacity is added, and coal fuels most of the additional electricity generation required to satisfy demand. By 2010, coal's share of total generation recovers to a level of 54 percent.

Nuclear generating capacity, coal's primary competition for baseload power generation over the forecast, is projected to decline by 12 gigawatts between 2000 and 2010. No additional new orders for nuclear units are projected in the forecast period.

Carbon Emissions Rise as Coal Use Increases

Figure 70. Carbon emissions from coal use, 1990-2010 (million metric tons)



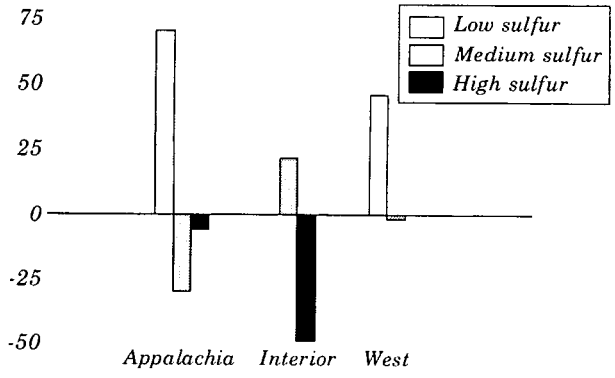
In the reference case, total carbon emissions from coal combustion are projected to rise from 480 million metric tons in 1990 to 514 million metric tons in 2000, an increase of 7 percent (Figure 70). All of this increase is accounted for by electricity coal consumption, as a slight increase in carbon emissions from industrial steam coal consumption is offset by declines in carbon emissions from coal in the coking and residential and commercial sectors. Reflecting higher growth in electricity coal consumption, carbon emissions from coal are projected to increase by 13 percent between 2000 and 2010, rising to 580 million metric tons in 2010.

The share of total U.S. carbon emissions from coal combustion is expected to change little, accounting for 36 percent in both 1990 and 2010. Over the forecast, consumption of coal increases at a slower rate than consumption of petroleum products and natural gas, which accounts for virtually all of the remaining portion of U.S. carbon emissions from end-use energy consumption. Coal's share of carbon emissions remains relatively constant, because of its higher carbon content relative to that of oil and gas.

The combustion of coal produces almost twice the amount of carbon emissions per unit of energy input as does the combustion of natural gas, while average carbon emissions from the combustion of petroleum products fall between coal and gas [*60*]. In the electricity sector, carbon emissions per unit of generation vary even more based on differences in conversion efficiencies of combustion technologies [*61*].

Clean Air Act Amendments of 1990 Increase Demand for Low-Sulfur Coal

Figure 71. Change in U.S. coal production by region and sulfur content, 1990-2000 (million short tons)



The more stringent sulfur dioxide emission restrictions of CAAA90 lead to increased production of low-sulfur coal in Appalachia and the West between 1990 and 2000, displacing primarily high-sulfur coal production in the Interior region (Figure 71). Between 1990 and 2000, low-sulfur coal production for the Nation as a whole is projected to rise by 116 million tons, medium-sulfur coal is projected to decrease by 10 million tons, and high-sulfur coal production declines by 55 million tons.

The addition of new coal-fired capacity has the potential to increase demand for medium-sulfur coal, because new coal-fired capacity must be equipped with the best available control tecnnology (BACT) for reducing sulfur dioxide emissions and thus can use medium-sulfur coal. The tendency to choose medium-sulfur coal or coal blends is most pronounced for new coal-fired plants sited east of the Mississippi River, where most of the Nation's high-sulfur coal reserves are located. Over the forecast, 43 gigawatts of new coal-fired capacity are projected to come online (10 gigawatts between 1990 and 2000 and 33 gigawatts between 2000 and 2010) [62].

Although some of the projected growth in coal production between 2000 and 2010 is in medium-sulfur coal, the siting of most new coal-fired generating capacity near low-sulfur coal reserves leads to a greater increase in low-sulfur coal production. In the same period, low-sulfur coal production is projected to increase by 113 million tons, medium-sulfur coal increases by 56 million tons, and high-sulfur coal decreases by an additional 27 million tons.

Comparative Forecasts

Table 22. Comparative forecasts for coal, 2010

Forecast	AEO94	DRI	GRI	WEFA
Consumption by sector	**Million short tons**			
Electricity	950	1,004	1,077	1,053
Coking plants	21	29	22	28
Industrial/Other	107	204	82	84
Total	**1,079**	**1,237**	**1,182**	**1,165**
Net coal exports	142	136	146	112
Prices	**1992 dollars per short ton**			
Minemouth price	30.87	NA	NA	27.08
Delivered price, electricity	40.32	33.03	24.98	41.13

NA = not available.

The EIA forecast for U.S. coal consumption in 2010 is lower than the consumption levels in the comparative forecasts (Table 22). 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 electricity demand growth projections. The higher forecast for industrial coal consumption by DRI is chiefly attributable to two factors: 1) a greater projected increase in coal consumption for cogeneration; and 2) the accounting of coal consumption by independent power producers and exempt wholesale generators in the industrial rather than the electricity sector. DRI forecasts that coal consumption by cogenerators and nonutilities taken together will rise to 105 million tons by 2010 [63].

The WEFA forecast for U.S. coal exports is the only export forecast that differs significantly from the EIA forecast. The lower forecast for net U.S. coal exports in 2010 by WEFA is attributable to a lower forecast for steam coal exports.

Both DRI and GRI project lower delivered prices of coal to electricity producers in 2010 than does EIA. GRI has the lowest delivered price forecast by far, reflecting continued increases in mining productivity over the forecast and the expectation that reserve depletion will have only a limited effect on mining costs. DRI's small projected increase in the delivered price of coal to electricity producers is attributable to depletion effects and higher transportation costs associated with the use of coal from more distant sources.

Regulations to control utility emissions of air toxics and legislation or policy initiatives to restrain greenhouse gas emissions could significantly affect the costs of coal-fired electricity generation. Also, State actions requiring that the costs of pollution externalities be factored into cost estimates for new generating capacity could reduce the amount of new coal-fired capacity that is built.

In the area of air toxics [*64*], Title III of CAAA90 requires that the Environmental Protection Agency submit its findings and recommendations on utility emissions to Congress by 1995. A decision to regulate emissions could require that utilities equip units with scrubbers, baghouses [*65*], or high-efficiency electrostatic precipitators to remove air toxic pollutants from the combustion gases [*66*].

Another uncertain factor that could substantially affect the future of U.S. coal relates to efforts to stabilize greenhouse gas emissions. In 1993, the Administration developed and released the Climate Change Action Plan, a comprehensive plan for returning net U.S. greenhouse gas emissions to 1990 levels by the year 2000 [*67*]. The plan provides environmental agencies, regulatory agencies, 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 will reduce demand for coal and oil in the electricity sector.

For stabilizing greenhouse gas emissions in the long term, the Climate Change Action Plan requires that measures 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 the Department of Energy's Clean Coal Technology Demonstration Program, as well as other Federal and State initiatives. Current Clean Coal Technology projects include the development of advanced coal technologies such as gasification combined cycle and pressurized fluidized bed combustor, which have the potential to reduce carbon emissions through improvements in conversion efficiencies [*68*].

An uncertainty regarding additions of new electric generating capacity is that some States have required that estimated costs of pollution externalities be factored into capacity planning decisions. Considering these costs favors cleaner burning fuels such as natural gas and renewable fuels over coal. At present, it is unclear how widespread these policies may become.

A considerable amount of uncertainty surrounds several factors that determine the *AEO94* coal price forecasts. Key areas of uncertainty regarding these forecasts relate to estimates of reserve depletion, labor productivity, and transportation rates.

Reserve depletion is one indicator of future mining costs. As new reserves are opened to mining, incremental costs related to the differences in geologic conditions of a new mine compared to those of existing mines can raise mining costs, even when factor input costs, labor productivity, and technology remain constant. Over 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 extent to which reserve depletion will affect future coal prices depends 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.

It is also uncertain how coal mine labor productivity will change over the forecast and how productivity changes will affect minemouth coal prices. Two recent periods show how labor productivity growth can vary. U.S. coal mining productivity declined by an average of 3.2 percent a year between 1970 and 1978 and then increased by an average of 6.6 percent a year between 1978 and 1990 [*69*]. In the *AEO94* forecasts, it is assumed that labor productivity will continue to increase, but at a slower pace than during the recent period. This has the effect of altering production costs and, thus, minemouth coal prices.

Transportation cost is an important determinant of delivered coal prices, particularly for shipments from western fields, where average transportation distances to coal consumers are greater. With the large growth in low-sulfur coal demand associated with CAAA90, the opportunity exists for greater penetration of western coal into markets east of the Mississippi. The extent of penetration will depend largely on the transportation cost structure that western coal producers and their customers face.

LIST OF ACRONYMS

AEO94	*Annual Energy Outlook 1994*
AGA	American Gas Association
BACT	Best available control technology
CAAA90	Clean Air Act Amendments of 1990
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
EWG	Exempt wholesale generator
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GRI	Gas Research Institute
IEA	International Energy Agency
IRP	Integrated resource planning
kWh	Kilowatthour
LDC	Local distribution company
LNG	Liquefied natural gas
MSW	Municipal solid waste
NAECA	National Appliance Energy Conservation Act of 1987
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NPC	National Petroleum Council
O&M	Operation and maintenance
PUC	Public Utility Commission
PURPA	Public Utilities Regulatory Policy Act of 1978
Tcf	Trillion cubic feet
TMI	Three Mile Island
UGR	Unconventional gas recovery
WEFA	The WEFA Group (formerly the Wharton Econometric Forecasting Associates)

NOTES AND SOURCES

Text notes

Page 5

1. Energy Information Administration, *International Energy Outlook 1993*, DOE/EIA-0219(93) (Washington, DC, June 1993).

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2. Energy Information Administration, *Short-Term Energy Outlook*, 1st Quarter, DOE/EIA-0202(94/1Q) (Washington, DC, February 1994).
3. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," for electric utilities and Form EIA-867, "Annual Nonutility Power Producer Report," for nonutilities.
4. Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."
5. "Conoco Inc. Buying 20,000 Mcf/day of Exported Mexican Production," *Inside F.E.R.C.'s Gas Market Report*, Dec. 17, 1993.

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6. The best off-the-shelf technology scenarios emphasize energy consumption savings potential only. The opportunity costs of imposing best off-the-shelf technologies on the market are not addressed.

Page 11

7. Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90) (Washington, DC, May 1992).
8. U.S. Bureau of the Census, *Characteristics of New Housing, 1992* (Washington, DC, June 1993).
9. U.S. Bureau of the Census, *Characteristics of New Housing, 1992* (Washington, DC, June 1993).
10. Energy Information Administration, *Household Energy Consumption and Expenditures 1990*, DOE/EIA-0321(90) (Washington, DC, February 1993).
11. "Golden Carrot" refrigerators are super-efficient refrigerators that were developed by appliance manufacturers in response to incentives offered by a coalition of electric utilities and the U.S. Environmental Protection Agency (EPA).

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12. Green programs are voluntary, nonregulatory programs sponsored by the EPA to encourage U.S. corporations to adopt energy-efficient technologies (e.g., Green Lights, Energy Star Buildings, Energy Star Computers).
13. Green Lights is a voluntary, nonregulatory program sponsored by the EPA to encourage U.S. corporations to adopt energy-efficient lighting.
14. The Federal Energy Management Program's Federal Relighting initiative is a program designed to assist Federal agencies in meeting a DOE energy mandate that requires Federal facilities to use 20 percent less energy by the year 2000, based on 1985 consumption. Through a process of relighting, the initiative will improve lighting and thereby increase productivity.

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15. American Council for Capital Formation, Center for Policy Research, *U.S. Investment Trends: Impact on Productivity, Competitiveness, and Growth* (Washington, DC, April 1991).
16. *Federal Register*, Vol. 58, No. 203 (October 22, 1993), pp. 54911-54919.

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17. U.S. Congress, Office of Technology Assessment, *Industrial Energy Efficiency* (Washington, DC, August 1993), pp. 54-55.

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18. Process emissions from refineries and other industries and emissions resulting from the combustion of wood and wood waste have not been included in these projections. Had these other sources been included total carbon emissions would be about 10 percent higher.

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19. Cogenerators are power producers who use a sequential or simultaneous process to generate heat or steam for a process application and direct excess energy to a turbine to generate electricity.
20. Demand-side management programs are programs instituted by utilities, such as rebates to customers for installation of energy efficient appliances or reduced rates for non-peak-load use of electricity, to encourage customers to reduce their electricity consumption overall or at certain periods.

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21. Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

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22. Life extension is achieved by maintaining or improving the operating status of an electric power plant within acceptable levels of availability and efficiency, beyond the originally anticipated retirement date.
23. Repowering is achieved by investments made in a plant to substantially increase the plant's generating capability, to change generating fuels, or to install a more efficient generating technology at the plant site.
24. Peak load is the maximum load during a specified period of time.
25. Baseload is the minimum amount of power required during a specified period at a steady state.
26. In a coal-steam plant, coal is burned to provide heat for a steam boiler. The steam is then directed to a steam turbine-generator to produce electricity.

27. Planned additions are intended new capacity additions reported by utilities and nonutilities to EIA through Form EIA-860, "Annual Electric Generator Report," and Form EIA-867, "Annual Nonutility Power Producer Report," respectively.
28. Unplanned additions are new utility and nonutility capacity additions projected by EIA to be needed during the forecast period in addition to planned units.
29. Combined-cycle generators produce electricity from a sequential process where otherwise lost waste heat from a gas turbine is directed to heat recovery steam generator or exhaust-fired conventional boiler and utilized by a steam turbine to provide a second generating cycle.
30. A gas turbine is a machine typically composed of an axial-flow compressor and combustion chambers where gas fuel is burned and the hot gases are directed to a turbine where they expand and drive an electricity generator and run the compressor.

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31. The average content of sulfur in coal ranges from 0.3 percent to about 2.5 percent by weight.

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32. The capacity factor is the ratio of the electricity produced by a generating unit, for the period of time considered, to the energy that could have been produced at continuous full-power operation during the same period.
33. Units assumed completed are Watts Bar 1 and 2 and Bellefonte 1 and 2. These units are under construction by the Tennessee Valley Authority (TVA) in Tennessee and Alabama, respectively. Units assumed canceled are WNP 1 and 3 in Washington and Perry 2 in Ohio.
34. Capacity losses during relicensing occur due to required installation of fish ladders and other devices that enhance the environmental characteristics of hydropower generation but diminish overall capacity.
35. The solar projection is for both solar thermal and photovoltaics serving the gird; however, over the time frame of this analysis, photovoltaics are not expected to exceed 0.01 gigawatts of electricity generating capacity.
36. Enhanced recycling or other strategies to minimize the waste stream could limit the amount of waste available for energy generation.
37. Hot dry rock, although not as limited geographically as hydrothermal resources are, is not considered to be economical in the forecast period.
38. Electricity generation from biomass is dominated by industrial cogeneration, which provided over 80 percent of the total in 1990. That share is projected to drop to 57 percent in 2010, as primary electricity generation from biomass grows at a faster pace.

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39. Net energy for load is generation from utilities, net electricity imports, and purchases from nonutilities.

Page 29

40. Emission adders to account for externalities are monetized costs assigned to each ton of emissions (carbon dioxide, nitrogen oxides, and sulfur dioxide particularly) by regulatory authorities in some States.

Page 30

41. American Petroleum Institute, *Basic Petroleum Data Book* (Washington, DC, May 1991), 11:2, Table I:7.

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42. 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) and 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); gas production includes associated gas (natural gas which occurs in crude oil reservoirs as free gas) and dissolved gas (natural gas which occurs in crude oil reservoirs in solution with crude oil).
43. 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.
44. 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).

45. 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.

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46. "Conoco Inc. Buying 20,000 Mcf/day of Exported Mexican Production," *Inside F.E.R.C.'s Gas Market Report*, Dec. 17, 1993.

47. Maximum increases in import capacity for Canadian gas and LNG are provided as model assumptions, as detailed in Appendix G.

48. Cogeneration is represented in the industrial sector.

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49. The General Accounting Office in its report on the cost and benefits of Order 636 [*Natural Gas: Costs, Benefits, and Concerns Related to FERC Order 636*, Final Report of the General Accounting Office, GAO/RCED-94-11, (Washington, DC, November 1993) page 13] stated that the "precise benefits of Order 636 cannot be measured at this time." The benefits of Order 636 are largely a function of the increase in the use of natural gas resulting from greater competition within natural gas markets. The primary benefits of increased gas use cited by GAO include decreased oil imports, improved air quality, and additional domestic employment. Although increased gas consumption would result in higher natural gas wellhead prices, these benefits would not change the cost of services required to move supplies from the wellhead to the burnertip. Increased gas consumption may result in higher utilization of the physical plant comprising the transmission and distribution network. Greater utilization may translate into a lower average cost of providing these services. Additionally, capacity release programs and rate design changes create an environment in which pipeline capacity can be purchased by customers who value it most. It is difficult to quantify and represent the impact the secondary market for pipeline capacity may have on the markup from the wellhead to the burner tip because (1) the operational ground rules for the release programs have been changing over the last year, (2) the value of the capacity is likely to vary significantly from season to season, and (3) the value of the capacity is largely a function of the level of demand for capacity on competing transportation routes. Until the industry has greater experience with these markets, the value of this capacity will not be known. Finally, data on released capacity, volumes moved, and prices of capacity are not readily available.

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50. The sum of crude oil and finished petroleum product imports divided by total demand.

51. "Other" includes liquefied petroleum gases, kerosene, petrochemical feedstocks, asphalt and road oil, petroleum coke, still gas, and other miscellaneous products.

52. Conversion units include catalytic crackers, reformers, isomerization units, and other refinery production units that chemically convert intermediate petroleum products into others.

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53. Standards adopted by the California Air Resources Board (CARB).

54. Estimate based on Census Division level gasoline demand and population-based market share assumptions. Year-to-date data from Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(93/10) (Washington, DC, October 1993), appear to support the annual estimate.

55. Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York, Philadelphia, and San Diego. 1995 opt-ins: Texas, District of Columbia, New Jersey, Maryland, Delaware, New York City, Connecticut, Virginia, New Hampshire, Massachusetts, Pennsylvania, Maine, and Rhode Island.

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56. For a discussion of the role of storage in futures market arbitrage, see *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993), p. 104.

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

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

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

60. 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)—25.12 to 26.35; petroleum products (excluding petroleum coke)—17.09 to 21.44; and natural gas—14.39. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1985-1990*, DOE/EIA-0573 (Washington, DC, September 1993).

61. Of the commercially available generation technologies, gas-fired combined cycle offers the highest conversion efficiency—approximately 41 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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62. Over the forecast period, 42.5 gigawatts of new coal-fired generating capacity is projected to come on line and 16.4 gigawatts retired, resulting in a net increase of 26.1 gigawatts.
63. DRI/McGraw-Hill, *Energy Review*, Spring-Summer 1993 (Lexington, MA, 1993).

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64. Air toxics are pollutants that are hazardous to human health or the environment. Toxic pollutants from utilities that could be regulated in the future include, but are not limited to, arsenic, benzene, chlorine, hydrofluoric and hydrochloric acids, lead, and mercury.
65. A baghouse contains a series of filter bags that trap the ash and dust from combustion gases.
66. John S. Lagarias and Winston Chow, "Cooperation in the Air: PISCES Shows How Industry and Regulators Can Work Together," *Public Utilities Fortnightly*, Vol. 131 (June 1, 1993).
67. The President and The Vice-President, *The Climate Change Action Plan* (Washington, DC, October 1993).
68. The gasification combined cycle and pressurized fluidized bed combustor technologies offer improvements in conversion efficiencies in the range of 40 to 45 percent, which translates into 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).
69. Between 1978 and 1990, the major factors underlying productivity growth were falling coal prices, structural change in the industry, and technological improvements in coal mining. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/ EIA-0559 (Washington, DC, November 1992).

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Table 3. Comparative forecasts of world oil prices (page 6): **AEO94:** Table A1. **DRI:** DRI/McGraw-Hill, "Crude Price Forecast Highlights" (May 1993). **WEFA:** The WEFA Group, *Global Petroleum Quarterly* (June 1993). **IEA:** International Energy Agency, *World Energy Outlook, 1993*. **GRI:** Gas Research Institute, *Gas Research Insights* (March 1993).

Table 4. Residential appliance efficiencies (page 11): American Council for an Energy Efficient Economy (ACEEE), *The Most Energy-Efficient Appliances 1991-1992*; and AEO94 Forecasting System, run AEO94B. D1221934. **Note:** The annual fuel utilization efficiency for furnaces is a measure of overall seasonal performance based on Btu output divided by Btu input. The seasonal energy efficiency ratio for heat pumps and central air conditioners is a measure of seasonal Btu cooling output divided by watthour input for average U.S. climate. The energy efficiency ratio for room air conditioners is a measure of Btu cooling output divided by watthour input. Energy factor for water heaters is measured as Btu output divided by Btu input, based on the use of 64 gallons of hot water per day.

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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					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil and Lease Condensate	15.57	15.22	11.01	10.25	10.80	-1.8%	-1.9%
Natural Gas Plant Liquids	2.17	2.36	2.54	2.70	2.70	1.1%	0.8%
Dry Natural Gas[1]	18.49	18.51	19.63	20.87	20.89	0.6%	0.7%
Coal	22.46	21.62	23.38	24.28	26.47	0.8%	1.1%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[2]	6.20	6.28	7.29	7.82	8.69	1.7%	1.8%
Total	**71.08**	**70.64**	**71.06**	**73.23**	**76.12**	**0.3%**	**0.4%**
Imports							
Crude Oil[3]	12.80	13.24	18.73	19.78	19.62	2.2%	2.2%
Petroleum Products[4]	3.40	2.71	6.90	8.55	9.81	5.4%	7.4%
Natural Gas	1.54	2.15	3.19	3.59	4.16	5.1%	3.7%
Other Imports[5]	0.73	0.96	1.49	1.47	1.61	4.0%	2.9%
Total	**18.46**	**19.07**	**30.31**	**33.39**	**35.21**	**3.3%**	**3.5%**
Exports							
Petroleum	1.82	2.02	2.12	2.12	2.12	0.7%	0.2%
Natural Gas	0.09	0.22	0.24	0.27	0.30	6.4%	1.7%
Coal	2.70	2.68	3.31	3.54	3.75	1.7%	1.9%
Total	**4.61**	**4.92**	**5.68**	**5.92**	**6.17**	**1.5%**	**1.3%**
Discrepancy[6]	**-0.65**	**1.01**	**0.05**	**0.10**	**0.07**	**N/A**	**-13.9%**
Consumption							
Petroleum Products[7]	33.55	33.65	38.23	40.29	42.00	1.1%	1.2%
Natural Gas	19.30	20.15	22.67	24.31	24.89	1.3%	1.2%
Coal	19.01	18.99	20.29	20.95	22.88	0.9%	1.0%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[8]	6.23	6.37	7.34	7.94	8.89	1.8%	1.9%
Total	**84.28**	**85.80**	**95.73**	**100.79**	**105.23**	**1.1%**	**1.1%**
Net Imports - Petroleum	**14.37**	**13.93**	**23.51**	**26.22**	**27.32**	**3.3%**	**3.8%**
Prices (1992 dollars per unit)							
World Oil Price (dollars per barrel)[9]	23.22	18.20	20.72	24.90	28.16	1.0%	2.5%
Gas Wellhead Price (dollars per Mcf)[10]	1.83	1.75	2.42	2.89	3.47	3.3%	3.9%
Coal Minemouth Price (dollars per ton)	23.22	21.03	25.29	27.00	30.87	1.4%	2.2%

[1]Includes synthetic gas.
[2]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, liquid hydrogen, and methanol.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[5]Includes coal, coal coke (net), and electricity (net), methanol, methyl tertiary butyl ether (MTBE), and imports of unfinished oils.
[6]Balancing item. Includes unaccounted for supply, losses, and gains.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and non-petroleum based liquids for blending, such as ethanol.
[8]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, plus 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.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

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

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Distillate Fuel	0.84	0.85	0.90	0.89	0.87	0.2%	0.1%
Kerosene	0.06	0.06	0.06	0.06	0.06	-0.5%	-0.3%
Liquefied Petroleum Gas	0.36	0.41	0.36	0.34	0.33	-0.5%	-1.2%
Natural Gas	4.52	4.83	5.00	4.97	4.99	0.5%	0.2%
Coal	0.06	0.06	0.05	0.05	0.05	-1.3%	-1.2%
Renewable Energy[1]	0.61	0.63	0.65	0.66	0.66	0.4%	0.3%
Electricity	3.15	3.19	3.39	3.49	3.63	0.7%	0.7%
Total	**9.61**	**10.04**	**10.41**	**10.46**	**10.60**	**0.5%**	**0.3%**
Commercial							
Distillate Fuel	0.49	0.49	0.52	0.51	0.49	0.1%	0.1%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.5%	-0.5%
Motor Gasoline[2]	0.11	0.09	0.11	0.11	0.11	0.2%	1.3%
Residual Fuel	0.23	0.23	0.22	0.22	0.22	-0.4%	-0.4%
Natural Gas	2.70	2.89	2.88	2.94	3.01	0.6%	0.2%
Other[3]	0.16	0.16	0.15	0.15	0.15	-0.2%	-0.2%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Electricity	2.86	2.91	3.30	3.44	3.51	1.0%	1.1%
Total	**6.57**	**6.78**	**7.22**	**7.41**	**7.55**	**0.7%**	**0.6%**
Industrial[5]							
Distillate Fuel	1.18	1.19	1.37	1.47	1.56	1.4%	1.5%
Liquefied Petroleum Gas	1.61	1.83	1.99	2.20	2.40	2.0%	1.5%
Motor Gasoline[2]	0.18	0.20	0.23	0.25	0.26	1.8%	1.6%
Petrochemical Feedstocks	1.10	1.23	1.32	1.46	1.59	1.9%	1.5%
Residual Fuel	0.42	0.34	0.46	0.44	0.45	0.4%	1.5%
Other Petroleum[6]	3.82	3.83	4.38	4.43	4.55	0.9%	1.0%
Natural Gas[7]	8.50	8.96	9.61	10.20	10.69	1.2%	1.0%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	1.71	1.65	1.91	2.11	2.24	1.4%	1.7%
Net Coal Coke Imports	0.00	0.03	0.01	0.02	0.02	N/A	-2.6%
Renewable Energy	1.96	1.99	2.40	2.62	2.84	1.9%	2.0%
Electricity	3.23	3.29	3.84	4.18	4.50	1.7%	1.8%
Total	**24.78**	**25.42**	**28.27**	**30.02**	**31.68**	**1.2%**	**1.2%**
Transportation							
Distillate Fuel	3.83	3.76	4.87	5.32	5.82	2.1%	2.5%
Jet Fuel[8]	3.13	3.00	3.72	4.08	4.44	1.8%	2.2%
Motor Gasoline[2]	13.58	13.69	15.03	15.50	15.76	0.7%	0.8%
Residual Fuel	1.03	1.09	1.32	1.49	1.64	2.3%	2.3%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.13	0.20	12.3%	13.8%
Other Petroleum[9]	0.22	0.20	0.21	0.22	0.24	0.3%	0.9%
Pipeline Fuel Natural Gas	0.68	0.61	0.69	0.72	0.73	0.3%	1.0%
Compressed Natural Gas	0.00	0.00	0.13	0.24	0.37	N/A	N/A
Renewables (ethanol)[10]	0.00	0.00	0.01	0.03	0.06	33.4%	33.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	94.9%	74.4%
Methanol[11]	0.00	0.00	0.01	0.03	0.06	38.7%	29.2%
Electricity	0.01	0.01	0.08	0.13	0.19	15.9%	17.8%
Total	**22.50**	**22.38**	**26.16**	**27.91**	**29.50**	**1.4%**	**1.5%**
Electric Utilities[12]							
Distillate Fuel	0.02	0.03	0.08	0.13	0.11	7.7%	8.4%
Residual Fuel	1.23	0.90	0.93	0.97	0.81	-2.1%	-0.6%
Natural Gas	2.88	2.86	4.36	5.24	5.10	2.9%	3.3%
Steam Coal	16.10	16.30	17.49	18.05	19.93	1.1%	1.1%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[13]	3.64	3.20	4.23	4.55	5.21	1.8%	2.7%
Total	**30.07**	**29.69**	**34.30**	**36.24**	**37.74**	**1.1%**	**1.3%**

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

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Primary Energy Consumption							
Distillate Fuel	6.36	6.31	7.72	8.31	8.86	1.7%	1.9%
Kerosene	0.08	0.07	0.07	0.07	0.07	-0.5%	-0.3%
Jet Fuel[8]	3.13	3.00	3.72	4.08	4.44	1.8%	2.2%
Liquefied Petroleum Gas	2.06	2.32	2.49	2.74	3.00	1.9%	1.4%
Motor Gasoline[2]	13.87	13.98	15.37	15.86	16.14	0.8%	0.8%
Petrochemical Feedstocks	1.10	1.23	1.32	1.46	1.59	1.9%	1.5%
Residual Fuel	2.91	2.56	2.94	3.12	3.11	0.3%	1.1%
Other Petroleum[14]	4.04	4.03	4.59	4.65	4.79	0.8%	1.0%
Natural Gas	19.30	20.15	22.67	24.31	24.89	1.3%	1.2%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	17.96	18.05	19.54	20.29	22.31	1.1%	1.2%
Net Coal Coke Imports	0.00	0.03	0.01	0.02	0.02	N/A	-2.6%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[15]	6.22	5.83	7.32	7.92	8.87	1.8%	2.4%
Total	**84.29**	**84.86**	**95.73**	**100.79**	**105.23**	**1.1%**	**1.2%**
Electricity Consumption (all sectors)	**9.25**	**9.45**	**10.62**	**11.25**	**11.84**	**1.2%**	**1.3%**

[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, ground-water 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 co-generated 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 electric utilities, independent power producers, and small power producers that sell power to the grid.

[13]Includes electricity sold to utilities by nonutilities, including cogenerators, from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports. Does not include own use.

[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.

N/A = Not applicable.

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

Sources: 1990 coal consumption: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0118(90) (Washington, D.C. May 1991) and *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas consumption: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). 1990 and 1992 consumption other than coal and natural gas: EIA, *Monthly Energy Review*, DOE/EIA-0035(93/07) (Washington, D.C., July 1993) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. The 1990 values are not final and may be updated in EIA publications. **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A3. Energy Prices by End-Use Sector and Source

(1992 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential	**13.12**	**12.11**	**13.60**	**14.61**	**15.92**	**1.0%**	**1.5%**
Primary Energy	6.72	6.12	7.32	7.94	8.63	1.3%	1.9%
Petroleum Products	9.49	7.78	8.51	9.40	10.14	0.3%	1.5%
Distillate Fuel	8.55	6.68	7.51	8.34	8.94	0.2%	1.6%
Liquefied Petroleum Gas	11.67	10.05	11.13	12.30	13.49	0.7%	1.6%
Natural Gas	6.00	5.72	7.05	7.62	8.30	1.6%	2.1%
Electricity	24.98	23.76	25.39	26.66	28.58	0.7%	1.0%
Commercial	**12.78**	**12.08**	**13.45**	**14.15**	**14.90**	**0.8%**	**1.2%**
Primary Energy	5.27	4.72	5.89	6.50	7.16	1.5%	2.3%
Petroleum Products	6.35	4.94	5.77	6.59	7.24	0.7%	2.1%
Distillate Fuel	6.51	4.76	5.22	6.02	6.63	0.1%	1.9%
Residual Fuel	3.66	2.62	3.56	4.23	4.72	1.3%	3.3%
Natural Gas	5.00	4.74	6.04	6.60	7.27	1.9%	2.4%
Electricity	22.49	21.85	22.38	22.90	23.72	0.3%	0.5%
Industrial	**5.75**	**5.19**	**5.86**	**6.53**	**7.20**	**1.1%**	**1.8%**
Primary Energy	4.09	3.49	4.16	4.84	5.45	1.4%	2.5%
Petroleum Products	5.71	4.42	5.06	6.03	6.80	0.9%	2.4%
Distillate Fuel	6.06	4.87	5.20	6.00	6.65	0.5%	1.7%
Liquefied Petroleum Gas	5.76	4.95	6.41	7.61	8.67	2.1%	3.2%
Residual Fuel	3.31	2.54	3.54	4.28	4.80	1.9%	3.6%
Natural Gas[1]	3.46	3.07	3.85	4.37	4.93	1.8%	2.7%
Metallurgical Coal	1.87	1.79	2.08	2.25	2.20	0.8%	1.1%
Steam Coal	1.64	1.47	1.70	1.80	1.91	0.8%	1.5%
Electricity	15.22	14.87	15.03	15.32	16.11	0.3%	0.4%
Transportation	**8.72**	**7.88**	**8.98**	**9.80**	**10.42**	**0.9%**	**1.6%**
Primary Energy	8.72	7.88	8.96	9.77	10.38	0.9%	1.5%
Petroleum Products	8.81	7.88	8.95	9.77	10.37	0.8%	1.5%
Distillate Fuel[2]	9.03	8.02	9.28	10.19	10.87	0.9%	1.7%
Jet Fuel[3]	6.06	4.52	5.38	6.20	6.91	0.7%	2.4%
Motor Gasoline[4]	9.73	9.09	10.30	11.17	11.79	1.0%	1.5%
Residual Fuel	3.18	2.14	3.23	3.90	4.52	1.8%	4.2%
Natural Gas[5]	3.51	3.93	9.61	10.45	11.08	5.9%	5.9%
Electricity	18.15	17.94	15.33	15.49	15.78	-0.7%	-0.7%
Total End-Use Energy	**8.80**	**8.03**	**9.01**	**9.77**	**10.52**	**0.9%**	**1.5%**
Primary Energy	8.45	7.72	8.67	9.40	10.07	0.9%	1.5%
Electricity	20.79	20.05	20.63	21.16	22.19	0.3%	0.6%
Electric Utilities							
Fossil Fuel Average	1.81	1.59	1.96	2.21	2.45	1.5%	2.5%
Petroleum Products	3.55	2.56	3.58	4.39	4.94	1.7%	3.7%
Distillate Fuel	6.00	4.51	4.84	5.67	6.31	0.3%	1.9%
Residual Fuel	3.52	2.51	3.48	4.22	4.75	1.5%	3.6%
Natural Gas	2.46	2.28	2.92	3.51	4.08	2.6%	3.3%
Steam Coal	1.56	1.41	1.63	1.70	1.92	1.1%	1.7%

Table A3. Energy Prices by End-Use Sector and Source (Continued)
(1992 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Average Price to All Users[6]							
Petroleum Products	7.94	6.84	7.81	8.66	9.33	0.8%	1.7%
Distillate Fuel[2]	8.18	6.98	8.04	8.93	9.64	0.8%	1.8%
Jet Fuel	6.06	4.52	5.38	6.20	6.91	0.7%	2.4%
Liquefied Petroleum Gas	6.45	5.98	7.37	8.56	9.69	2.1%	2.7%
Motor Gasoline[4]	9.73	9.09	10.30	11.17	11.79	1.0%	1.5%
Residual Fuel	3.38	2.37	3.38	4.08	4.64	1.6%	3.8%
Natural Gas	4.20	3.91	4.77	5.26	5.89	1.7%	2.3%
Coal	1.57	1.42	1.64	1.71	1.92	1.0%	1.7%
Electricity	20.79	20.05	20.63	21.16	22.19	0.3%	0.6%

[1]Excludes uses for lease and plant fuel.
[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]Compressed natural gas used as a vehicle fuel.
[6]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption. For each sector, electricity and natural gas prices are derived by dividing total revenues by sales.

Btu = British thermal unit.

Sources: 1990 petroleum prices: *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington,D.C., September 1993). 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, D.C., July 1993). 1992 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 coal prices: EIA, *Quarterly Coal Report*, DOE/EIA-0121(90/4Q) (Washington, D.C., May 1991); EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993), Table A6; and EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 industrial and transportation natural gas delivered prices: EIA, AEO National Energy Modeling System run AEO94B.D1221934. Other 1990 and 1992 natural gas prices: EIA, *Natural Gas Annual*, DOE/EIA-0131 (92)/1 (Washington, DC, November 1993). 1990 electricity prices: EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934. **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

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 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Household Characteristics							
Households (millions)							
Single-Family	64.36	65.60	71.64	75.09	78.70	1.0%	1.0%
Multifamily	24.42	24.27	24.72	25.43	26.37	0.4%	0.5%
Mobile Homes	5.21	5.19	5.31	5.38	5.39	0.2%	0.2%
Total	**93.99**	**95.06**	**101.67**	**105.90**	**110.46**	**0.8%**	**0.8%**
Housing Starts (millions)							
Single-Family	0.90	1.04	1.05	1.08	1.04	0.7%	0.0%
Multifamily	0.30	0.17	0.38	0.39	0.46	2.0%	5.6%
Mobile Homes	0.19	0.21	0.22	0.22	0.21	0.5%	-0.1%
Total	**1.39**	**1.42**	**1.66**	**1.69**	**1.71**	**1.0%**	**1.0%**
Energy Intensity (million Btu per year per household)							
Heating	54.59	58.45	56.55	53.91	51.19	-0.3%	-0.7%
Total	**102.23**	**105.60**	**102.40**	**98.82**	**95.93**	**-0.3%**	**-0.5%**
Fuel Consumption							
Distillate							
Space Heating	0.75	0.77	0.82	0.82	0.80	0.3%	0.2%
Water Heating	0.08	0.08	0.07	0.07	0.07	-0.7%	-0.6%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	1.0%	1.0%
Total	**0.84**	**0.85**	**0.90**	**0.89**	**0.87**	**0.2%**	**0.1%**
Liquefied Petroleum Gas							
Space Heating	0.23	0.27	0.24	0.23	0.22	-0.3%	-1.2%
Water Heating	0.08	0.09	0.07	0.07	0.07	-1.0%	-1.6%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-1.0%	-0.4%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.9%	0.9%
Total	**0.36**	**0.41**	**0.36**	**0.34**	**0.33**	**-0.5%**	**-1.2%**
Natural Gas							
Space Heating	3.12	3.42	3.56	3.52	3.49	0.6%	0.1%
Space Cooling	0.00	0.00	0.00	0.00	0.01	N/A	N/A
Water Heating	1.09	1.10	1.11	1.12	1.16	0.3%	0.3%
Cooking[2]	0.18	0.18	0.19	0.20	0.21	0.8%	0.9%
Clothes Dryers	0.08	0.08	0.07	0.06	0.06	-1.3%	-1.4%
Other Uses[3]	0.06	0.06	0.06	0.07	0.07	1.0%	1.0%
Total	**4.52**	**4.83**	**5.00**	**4.97**	**4.99**	**0.5%**	**0.2%**
Electricity							
Space Heating	0.30	0.33	0.38	0.40	0.41	1.5%	1.1%
Space Cooling	0.52	0.51	0.52	0.53	0.54	0.2%	0.3%
Water Heating	0.34	0.34	0.35	0.35	0.35	0.2%	0.1%
Refrigeration	0.53	0.52	0.45	0.39	0.33	-2.3%	-2.5%
Cooking	0.15	0.15	0.16	0.17	0.18	1.0%	1.0%
Clothes Dryers	0.17	0.18	0.18	0.18	0.18	0.3%	0.2%
Freezers	0.15	0.14	0.11	0.09	0.07	-3.6%	-3.7%
Lighting	0.30	0.30	0.32	0.33	0.34	0.5%	0.7%
Other Uses[4]	0.69	0.72	0.92	1.07	1.23	2.9%	3.0%
Total	**3.15**	**3.19**	**3.39**	**3.49**	**3.63**	**0.7%**	**0.7%**

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 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Renewables							
Wood[5]	0.59	0.61	0.63	0.63	0.63	0.3%	0.1%
Geothermal[6]	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Solar[7]	0.01	0.01	0.01	0.01	0.01	1.1%	1.1%
Total	**0.61**	**0.63**	**0.65**	**0.66**	**0.66**	**0.4%**	**0.3%**
Other Fuels[8]	**0.13**	**0.12**	**0.11**	**0.11**	**0.11**	**-0.9%**	**-0.8%**
Total Fuels							
Space Heating	5.13	5.53	5.75	5.71	5.66	0.5%	0.1%
Space Cooling	0.52	0.51	0.53	0.54	0.56	0.4%	0.5%
Water Heating	1.60	1.67	1.62	1.62	1.67	0.2%	0.0%
Cooking	0.37	0.37	0.39	0.41	0.42	0.7%	0.7%
Clothes Dryers	0.25	0.26	0.25	0.24	0.24	-0.2%	-0.4%
Other Uses	1.73	1.75	1.87	1.95	2.05	0.8%	0.9%
Total	**9.61**	**10.04**	**10.41**	**10.46**	**10.60**	**0.5%**	**0.3%**

[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: 1990: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

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 1990- 2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Total Employment (millions)	**109.8**	**108.4**	**124.5**	**132.8**	**139.6**	**1.2%**	**1.4%**
Total Floorspace (billion square feet)							
Surviving	62.7	64.7	71.0	74.0	77.0	1.0%	1.0%
New Additions	1.5	1.4	1.4	1.5	1.6	0.3%	0.9%
Total	**64.3**	**66.1**	**72.4**	**75.4**	**78.6**	**1.0%**	**1.0%**
Energy Consumption Intensity (Thousand Btu per square feet)	**102.3**	**102.6**	**99.7**	**98.3**	**96.0**	**-0.3%**	**-0.4%**
End-Use Consumption							
Electricity							
Space Heating	0.06	0.06	0.05	0.04	0.04	-2.0%	-2.0%
Space Cooling	0.26	0.26	0.26	0.26	0.26	0.0%	-0.1%
Lighting	1.20	1.20	1.21	1.20	1.19	0.0%	-0.1%
Water Heating	0.03	0.03	0.04	0.05	0.06	4.1%	4.4%
Office Equipment	0.39	0.41	0.78	0.94	1.01	4.8%	5.1%
Other Uses[1]	0.93	0.95	0.96	0.96	0.96	0.2%	0.1%
Total Electricity	**2.86**	**2.91**	**3.30**	**3.44**	**3.51**	**1.0%**	**1.1%**
Natural Gas							
Space Heating	1.36	1.38	1.33	1.30	1.28	-0.3%	-0.4%
Space Cooling	0.01	0.01	0.02	0.02	0.02	3.3%	2.5%
Water Heating	0.37	0.39	0.38	0.38	0.37	0.0%	-0.2%
Other Uses[2]	0.96	1.11	1.14	1.24	1.34	1.7%	1.1%
Total Natural Gas	**2.70**	**2.89**	**2.88**	**2.94**	**3.01**	**0.6%**	**0.2%**
Distillate							
Space Heating	0.31	0.31	0.34	0.33	0.32	0.2%	0.2%
Water Heating	0.03	0.03	0.03	0.03	0.02	-1.1%	-1.2%
Other Uses[2]	0.15	0.15	0.15	0.15	0.15	0.0%	0.0%
Total Distillate	**0.49**	**0.49**	**0.52**	**0.51**	**0.49**	**0.1%**	**0.1%**
Other Fuels[3]	**0.51**	**0.49**	**0.50**	**0.49**	**0.49**	**-0.2%**	**0.0%**
Renewables[4]	**0.01**	**0.01**	**0.03**	**0.03**	**0.03**	**5.2%**	**4.9%**
Total Consumption	**6.57**	**6.78**	**7.22**	**7.41**	**7.55**	**0.7%**	**0.6%**

[1]Includes ventilation, cooking, refrigeration, and other miscellaneous commercial uses.
[2]Includes cooking and other miscellaneous commercial uses.
[3]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[4]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1990 and 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993).
Projections: Energy Information Administration, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A6. Industrial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2536	2552	3186	3616	4076	2.4%	2.6%
Nonmanufacturing	883	875	1061	1158	1246	1.7%	2.0%
Total	**3419**	**3427**	**4247**	**4774**	**5322**	**2.2%**	**2.5%**
Energy Prices (1992 dollars per million Btu)							
Electricity	15.22	14.87	15.03	15.32	16.11	0.3%	0.4%
Natural Gas	3.46	3.07	3.85	4.37	4.93	1.8%	2.7%
Steam Coal	1.64	1.56	1.70	1.80	1.91	0.8%	1.1%
Residual Oil	3.30	2.54	3.54	4.28	4.80	1.9%	3.6%
Distillate Oil	6.02	4.88	5.20	6.00	6.65	0.5%	1.7%
Liquefied Petroleum Gas	5.84	4.95	6.41	7.61	8.67	2.0%	3.2%
Motor Gasoline	10.01	9.07	10.30	11.18	11.80	0.8%	1.5%
Metallurgical Coal	1.87	1.80	2.08	2.25	2.20	0.8%	1.1%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.23	3.29	3.84	4.18	4.50	1.7%	1.8%
Natural Gas[2]	8.50	8.96	9.61	10.20	10.69	1.2%	1.0%
Steam Coal	1.71	1.65	1.91	2.11	2.24	1.4%	1.7%
Metallurgical Coal and Coke[3]	1.05	0.90	0.76	0.67	0.59	-2.8%	-2.3%
Residual Fuel	0.42	0.34	0.46	0.44	0.45	0.4%	1.5%
Distillate	1.18	1.19	1.37	1.47	1.56	1.4%	1.5%
Liquefied Petroleum Gas	1.61	1.83	1.99	2.20	2.40	2.0%	1.5%
Petrochemical Feedstocks	1.10	1.23	1.32	1.46	1.59	1.9%	1.5%
Other Petroleum[4]	4.00	4.03	4.61	4.68	4.81	0.9%	1.0%
Renewables	1.96	1.99	2.40	2.62	2.84	1.9%	2.0%
Total	**24.78**	**25.42**	**28.27**	**30.02**	**31.68**	**1.2%**	**1.2%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.94	0.96	0.90	0.88	0.85	-0.5%	-0.7%
Natural Gas[2]	2.49	2.61	2.26	2.14	2.01	-1.1%	-1.4%
Steam Coal	0.50	0.48	0.45	0.44	0.42	-0.9%	-0.7%
Metallurgical Coal and Coke[3]	0.31	0.26	0.18	0.14	0.11	-4.9%	-4.6%
Residual Fuel	0.12	0.10	0.11	0.09	0.08	-1.8%	-1.0%
Distillate	0.35	0.35	0.32	0.31	0.29	-0.8%	-0.9%
Liquefied Petroleum Gas	0.47	0.53	0.47	0.46	0.45	-0.2%	-0.9%
Petrochemical Feedstocks	0.32	0.36	0.31	0.31	0.30	-0.4%	-1.0%
Other Petroleum[4]	1.17	1.18	1.08	0.98	0.90	-1.3%	-1.5%
Renewables	0.57	0.58	0.56	0.55	0.53	-0.4%	-0.5%
Total	**7.25**	**7.41**	**6.66**	**6.29**	**5.95**	**-1.0%**	**-1.2%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net imports of coal coke.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington,D.C., May 1993). 1990 and 1992 natural gas values: *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

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

Key Indicators and Consumption	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Level of Travel Index (1990 = 1.0)							
Light-Duty Vehicles	1.00	1.01	1.18	1.29	1.38	1.6%	1.7%
Freight Trucks	1.00	1.09	1.34	1.47	1.61	2.4%	2.2%
Air	1.00	1.07	1.45	1.67	1.89	3.2%	3.2%
Rail	1.00	1.04	1.16	1.25	1.34	1.5%	1.4%
Marine	1.00	0.99	1.07	1.13	1.20	0.9%	1.1%
Energy Efficiency Indicators							
New Car MPG[1]	28.20	28.05	29.50	30.60	31.41	0.5%	0.6%
New Light Truck MPG[1]	20.91	20.98	22.41	23.38	24.16	0.7%	0.8%
Light-Duty Fleet MPG[2]	18.90	19.26	20.21	20.90	21.63	0.7%	0.6%
Aircraft Efficiency Index	1.00	1.01	1.07	1.11	1.14	0.7%	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.09	1.13	1.18	0.8%	0.8%
Rail Efficiency Index	1.00	1.00	1.04	1.06	1.07	0.3%	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.01	1.01	1.02	0.1%	0.1%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles[3]	12.74	12.79	14.30	15.03	15.64	1.0%	1.1%
Freight Trucks[3]	5.22	5.31	6.60	7.08	7.58	1.9%	2.0%
Air	3.17	3.04	3.76	4.13	4.48	1.7%	2.2%
Rail	0.51	0.49	0.57	0.60	0.63	1.0%	1.4%
Marine	1.53	1.59	1.88	2.08	2.26	2.0%	2.0%
Pipeline Fuel	0.68	0.61	0.69	0.72	0.73	0.3%	1.0%
Other[4]	0.15	0.15	0.17	0.18	0.19	1.3%	1.5%
Total[5]	**22.50**	**22.38**	**26.16**	**27.91**	**29.50**	**1.4%**	**1.5%**

[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.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Federal Highway Administration, *Highway Statistics 1991*; Oak Ridge National Laboratory, *Transportation Energy Data Book: 12 and 13*, (March 1993); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, February 1993; Energy Information Administration (EIA), *Residential Transportation Energy Consumption Survey 1991*; Argonne National Laboratory, FRATE Model 1990. 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

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

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Generation by Fuel Type							
Coal	1560	1576	1687	1741	1886	1.0%	1.0%
Petroleum	117	89	85	90	74	-2.3%	-1.0%
Natural Gas	264	264	335	392	373	1.7%	1.9%
Nuclear Power	577	619	671	680	612	0.3%	-0.1%
Pumped Storage/Other[1]	-2	-4	-11	-11	-11	9.1%	5.8%
Renewable Sources[2]	293	254	305	309	326	0.5%	1.4%
Total	**2809**	**2798**	**3072**	**3201**	**3260**	**0.7%**	**0.9%**
Nonutilities (excluding cogenerators)[3]							
Generation by Fuel Type							
Coal	1	2	9	9	54	25.0%	22.0%
Petroleum/Other[4]	1	1	1	1	0	-4.6%	-4.9%
Natural Gas	9	16	72	119	144	14.9%	13.0%
Renewable Sources[2]	29	40	69	95	139	8.2%	7.1%
Total	**39**	**60**	**151**	**224**	**338**	**11.3%**	**10.1%**
Cogeneration[5]	**178**	**192**	**210**	**223**	**235**	**1.4%**	**1.1%**
Net Imports	**2**	**28**	**26**	**28**	**30**	**14.5%**	**0.4%**
Electricity Sales by Sector							
Residential	924	936	995	1024	1065	0.7%	0.7%
Commercial	839	850	967	1009	1030	1.0%	1.1%
Industrial	946	973	1126	1226	1318	1.7%	1.7%
Transportation	4	4	25	39	56	14.1%	15.8%
Total	**2713**	**2763**	**3112**	**3298**	**3469**	**1.2%**	**1.3%**
End-Use Prices (1992 cents per kilowatthour)[6]							
Residential	8.5	8.1	8.7	9.1	9.8	0.7%	1.0%
Commercial	7.7	7.5	7.6	7.8	8.1	0.3%	0.5%
Industrial	5.2	5.1	5.1	5.2	5.5	0.3%	0.4%
Transportation	5.1	5.1	5.2	5.3	5.4	0.2%	0.3%
All Sectors Average	**7.1**	**6.8**	**7.0**	**7.2**	**7.6**	**0.3%**	**0.6%**
Price Components (1992 cents per kilowatthour)[6]							
Capital Component	3.0	2.9	2.7	2.6	2.7	-0.5%	-0.4%
Fuel Component	1.4	1.3	1.4	1.6	1.7	1.0%	1.8%
O&M Component	2.6	2.6	2.6	2.6	2.6	0.1%	0.1%
Net Wholesale Power Component	0.1	0.1	0.3	0.4	0.6	7.2%	8.0%
Total	**7.1**	**6.8**	**7.0**	**7.2**	**7.6**	**0.3%**	**0.6%**

[1]Other includes methane and propane and blast furnace gas.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[3]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for delivery to the grid.
[4]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[5]Includes cogeneration at industrial, commercial, and other facilities whose primary function is not electricity production. Includes both sales to utilities and generation for own use.
[6]Prices represent average revenue per kilowatthour.
O&M = Operation and maintenance.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). 1990 Nonutility generation: Form EIA-861, "Annual Electric Utility Report" and the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is filed by nonutilities reporting the electricity delivered, while the EIA-861 is filed by electric utilities reporting the electricity received. Because the Form EIA-861 collects data from the universe of utilities, these data are used for electricity sold to utilities. Own use data is from Form EIA-867. **Prices, 1992 cogeneration, 1992 prices, and all projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Capability							
Coal Steam	299.5	298.7	297.2	299.2	317.1	0.3%	0.3%
Other Fossil Steam[2]	143.9	142.5	129.7	123.5	120.4	-0.9%	-0.9%
Combined Cycle	7.2	7.8	17.6	28.4	35.0	8.2%	8.7%
Combustion Turbine/Diesel	45.6	47.9	64.4	70.4	73.9	2.4%	2.4%
Nuclear Power	99.6	99.0	102.6	103.8	90.7	-0.5%	-0.5%
Pumped Storage/Other[3]	17.6	19.1	20.2	20.2	20.2	0.7%	0.3%
Renewable Sources[4]	76.0	76.2	77.5	78.1	83.4	0.5%	0.5%
Total	**689.4**	**691.2**	**709.2**	**723.5**	**740.7**	**0.4%**	**0.4%**
Cumulative Planned Additions[5]							
Coal Steam	0.00	1.29	8.30	13.35	16.25	N/A	N/A
Other Fossil Steam[2]	0.00	0.95	1.54	1.64	1.64	N/A	N/A
Combined Cycle	0.00	0.67	9.14	14.30	14.99	N/A	N/A
Combustion Turbine/Diesel	0.00	2.50	18.84	24.18	24.55	N/A	N/A
Nuclear Power	0.00	0.00	4.70	5.91	5.91	N/A	N/A
Pumped Storage/Other[3]	0.00	1.41	2.56	2.56	2.56	N/A	N/A
Renewable Sources[4]	0.00	0.28	1.13	1.14	1.14	N/A	N/A
Total	**0.00**	**7.10**	**46.20**	**63.08**	**67.03**	**N/A**	**N/A**
Cumulative Unplanned Additions[5]						N/A	N/A
Coal Steam	0.00	0.00	0.00	0.00	17.79	N/A	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Combined Cycle	0.00	0.00	1.45	7.09	12.94	N/A	N/A
Combustion Turbine/Diesel	0.00	0.00	0.50	2.68	5.93	N/A	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[3]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	0.00	0.00	0.37	0.88	6.22	N/A	N/A
Total	**0.00**	**0.00**	**2.31**	**10.65**	**42.87**	**N/A**	**N/A**
Cumulative Total Utility Additions[5]	**0.00**	**7.10**	**48.52**	**73.72**	**109.91**	**N/A**	**N/A**
Cumulative Utility Retirements	**1.20**	**6.46**	**30.34**	**41.38**	**60.43**	**N/A**	**N/A**
Nonutilities (excludes cogenerators)[6]							
Installed Capability[7]							
Coal Steam	0.09	0.35	1.51	1.53	8.55	25.5%	19.5%
Other Fossil Steam[2]	0.23	0.40	0.83	0.83	0.83	6.6%	4.1%
Combined Cycle	1.27	2.88	9.47	15.93	23.19	15.6%	12.3%
Combustion Turbine/Diesel	0.90	1.48	5.50	9.34	12.85	14.2%	12.7%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[8]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	6.64	7.42	13.52	17.49	26.19	7.1%	7.3%
Total	**9.13**	**12.53**	**30.82**	**45.11**	**71.59**	**10.8%**	**10.2%**
Cogenerators[7,9]	**33.74**	**37.78**	**43.49**	**43.99**	**44.47**	**1.4%**	**0.9%**
Cumulative Nonutility Additions[5,7]	**0.00**	**7.44**	**31.45**	**46.24**	**73.20**	**N/A**	**13.5%**

[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]Other includes methane and propane and blast furnace gas.

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

[5]Cumulative additions after December 31, 1990.

[6]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for sales to the grid.

[7]Nameplate capacity is reported for nonutilities. Nameplate capacity is designated by the manufacturer.

[8]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[9]Includes cogenerators at industrial, commercial, and other facilities whose primary function is not electricity productionN/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992: EIA, *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	146.3	146.3	118.4	115.4	115.4	-1.2%	-1.3%
Gross Domestic Economy Sales	89.0	89.6	86.0	85.8	101.0	0.6%	0.7%
Gross Domestic Trade	**235.4**	**235.9**	**204.4**	**201.2**	**216.4**	**-0.4%**	**-0.5%**
Gross Domestic Firm Power Sales (million 1992 dollars)	6188.8	6407.3	5954.1	6332.2	6906.0	0.5%	0.4%
Gross Domestic Economy Sales (million 1992 dollars)	1720.7	1645.6	2107.4	2586.2	3317.2	3.3%	4.0%
Gross Domestic Sales (million 1992 dollars)	**7909.4**	**8052.8**	**8061.5**	**8918.4**	**10223.2**	**1.3%**	**1.3%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	5.6	14.2	14.4	14.4	14.4	4.8%	0.1%
Economy Imports From Canada and Mexico	16.9	23.8	27.2	29.5	31.9	3.2%	1.6%
Gross Imports From Canada and Mexico	**22.5**	**38.0**	**41.6**	**43.9**	**46.4**	**3.7%**	**1.1%**
Firm Power Exports To Canada and Mexico	1.7	4.7	8.8	8.8	8.8	8.5%	3.6%
Economy Exports To Canada and Mexico	18.8	5.6	6.4	7.0	7.7	-4.4%	1.7%
Gross Exports To Canada and Mexico	**20.5**	**10.3**	**15.2**	**15.7**	**16.4**	**-1.1%**	**2.6%**

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. Electricity trade among utilities in the same region is excluded from these data.

Sources: 1990 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1990 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1990 firm/interruptible share: National Energy Board, *Annual Report 1990.* Planned interregional and international firm power sales (1993 through 2001): DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1992. **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A11. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil[1]	7.36	7.17	5.18	4.84	5.10	-1.8%	-1.9%
Alaska	1.77	1.71	0.87	0.60	0.74	-4.2%	-4.5%
Lower 48 States	5.58	5.46	4.31	4.25	4.35	-1.2%	-1.2%
Natural Gas Plant Liquids	1.56	1.70	1.82	1.94	1.95	1.1%	0.8%
Total	**8.91**	**8.87**	**7.01**	**6.78**	**7.05**	**-1.2%**	**-1.3%**
Net Imports							
Crude Oil (including SPR)[2]	5.78	5.99	8.49	9.00	8.92	2.2%	2.2%
Refined Products[3]	0.90	0.45	2.46	3.27	3.88	7.6%	12.7%
Total	**6.68**	**6.44**	**10.94**	**12.26**	**12.80**	**3.3%**	**3.9%**
Other Inputs[4]	**0.49**	**0.58**	**0.71**	**0.69**	**0.74**	**2.0%**	**1.4%**
Refinery Processing Gain[5]	**0.68**	**0.77**	**0.77**	**0.79**	**0.84**	**1.1%**	**0.5%**
SPR Fill Rate Additions(-)[2]	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**0.0%**	**0.0%**
Total Primary Supply[6]	**16.75**	**16.64**	**19.41**	**20.51**	**21.41**	**1.2%**	**1.4%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.23	7.27	8.02	8.27	8.42	0.8%	0.8%
Jet Fuel[8]	1.52	1.45	1.80	1.97	2.14	1.7%	2.2%
Distillate Fuel	3.02	2.98	3.63	3.91	4.17	1.6%	1.9%
Residual Fuel	1.23	1.09	1.28	1.36	1.36	0.5%	1.2%
Other[9]	3.98	4.24	4.61	4.89	5.21	1.4%	1.2%
Total	**16.99**	**17.03**	**19.34**	**20.40**	**21.30**	**1.1%**	**1.2%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.15	1.16	1.17	1.15	1.13	-0.1%	-0.2%
Industrial[10]	4.32	4.33	5.06	5.35	5.69	1.4%	1.5%
Transportation	10.98	11.01	12.66	13.41	14.08	1.3%	1.4%
Electric Utilities[11]	0.55	0.52	0.44	0.48	0.41	-1.5%	-1.4%
Total	**16.99**	**17.03**	**19.34**	**20.40**	**21.30**	**1.1%**	**1.3%**
Discrepancy[12]	**-0.24**	**-0.39**	**0.08**	**0.11**	**0.11**	**N/A**	**N/A**
World Oil Price (1992 dollars per barrel)[13]	**23.22**	**18.20**	**20.72**	**24.90**	**28.16**	**1.0%**	**2.5%**
Domestic Refinery Distillation Capacity	**15.6**	**15.5**	**15.3**	**15.4**	**15.6**	**0.0%**	**0.0%**
Capacity Utilization Rate (percent)	**87.1**	**87.9**	**89.3**	**89.8**	**89.9**	**0.2%**	**0.1%**

[1]Includes lease condensate.
[2]SPR is the Strategic Petroleum Reserve.
[3]Net imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[4]Includes alcohols, ethers, and imports of unfinished oils.
[5]Represents volumetric gain in refinery distillation and cracking processes.
[6]Total production plus net imports plus other inputs plus refinery processing gain minus SPR additions.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[10]Includes consumption by cogenerators.
[11]Includes consumption by independent power producers.
[12]Balancing item. Includes unaccounted for supply, losses and gains.
[13]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: 1990: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, D.C., May 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A12. Petroleum Product Prices

(1992 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (dollars per barrel)	**23.22**	**18.20**	**20.72**	**24.90**	**28.16**	**1.0%**	**2.5%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	118.5	92.7	104.2	115.7	124.0	0.2%	1.6%
Liquefied Petroleum Gas	106.6	86.7	96.0	106.1	116.4	0.4%	1.6%
Commercial							
Distillate Fuel	90.3	66.0	72.5	83.5	92.0	0.1%	1.9%
Residual Fuel	54.8	39.3	53.3	63.3	70.7	1.3%	3.3%
Residual Fuel (dollars per barrel)	23.02	16.50	22.37	26.58	29.69	1.3%	3.3%
Industrial							
Distillate Fuel	84.1	67.6	72.2	83.3	92.2	0.5%	1.7%
Liquefied Petroleum Gas	52.6	42.7	55.4	65.7	74.8	1.8%	3.2%
Petrochemical Feedstocks	83.7	64.1	50.6	60.7	70.4	-0.9%	0.5%
Residual Fuel	49.5	38.0	53.0	64.1	71.8	1.9%	3.6%
Residual Fuel (dollars per barrel)	20.80	15.95	22.26	26.92	30.17	1.9%	3.6%
Transportation							
Distillate Fuel[1]	125.2	111.2	128.7	141.3	150.7	0.9%	1.7%
Jet Fuel[2]	81.8	61.0	72.6	83.7	93.3	0.7%	2.4%
Motor Gasoline[3]	121.7	113.7	128.8	139.7	147.5	1.0%	1.5%
Residual Fuel	47.6	32.1	48.3	58.4	67.7	1.8%	4.2%
Residual Fuel (dollars per barrel)	19.99	13.47	20.28	24.52	28.43	1.8%	4.2%
Electric Utilities							
Distillate Fuel	83.2	62.6	67.2	78.6	87.5	0.3%	1.9%
Residual Fuel	52.7	37.5	52.0	63.2	71.1	1.5%	3.6%
Residual Fuel (dollars per barrel)	22.14	15.77	21.86	26.55	29.88	1.5%	3.6%
Refined Petroleum Product Prices[4]							
Distillate Fuel	113.9	97.6	111.5	123.8	133.7	0.8%	1.8%
Jet Fuel	81.8	61.0	72.6	83.7	93.3	0.7%	2.4%
Liquefied Petroleum Gas	58.9	51.9	63.6	73.9	83.6	1.8%	2.7%
Motor Gasoline	121.7	113.7	128.8	139.7	147.5	1.0%	1.5%
Petrochemical Feedstocks	83.7	64.1	50.6	60.7	70.4	-0.9%	0.5%
Residual Fuel	50.6	35.5	50.6	61.0	69.4	1.6%	3.8%
Residual Fuel (dollars per barrel)	21.26	14.90	21.25	25.64	29.14	1.6%	3.8%
Average	**102.2**	**90.8**	**103.4**	**113.9**	**122.2**	**0.9%**	**1.7%**

[1]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[2]Kerosene-type jet fuel.
[3]Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[4]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1990 prices: Energy Information Administration (EIA), *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1992 prices for gasoline, distillate, and jet fuel are based on prices in the EIA, *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, D.C., July 1993). 1992 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). **Projections**: EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A13. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Dry Gas Production[1]	17.81	17.84	18.93	20.13	20.19	0.6%	0.7%
Supplemental Natural Gas[2]	0.12	0.12	0.11	0.12	0.07	-2.4%	-2.6%
Net Imports	**1.45**	**1.92**	**2.93**	**3.31**	**3.85**	**5.0%**	**3.9%**
Canada	1.43	2.03	2.67	2.76	2.92	3.6%	2.0%
Mexico	-0.02	-0.10	-0.05	0.00	0.17	N/A	N/A
LNG	0.03	-0.01	0.31	0.55	0.75	17.2%	N/A
Total Supply	**19.38**	**19.88**	**21.97**	**23.56**	**24.11**	**1.1%**	**1.1%**
Consumption by Sector							
Residential	4.39	4.69	4.85	4.83	4.85	0.5%	0.2%
Commercial	2.62	2.80	2.80	2.85	2.93	0.6%	0.2%
Industrial[3]	7.02	7.53	8.01	8.52	9.00	1.2%	1.0%
Electric Utilities[4]	2.79	2.77	4.22	5.06	4.93	2.9%	3.3%
Lease and Plant Fuel[5]	1.24	1.17	1.32	1.38	1.38	0.5%	0.9%
Pipeline Fuel	0.66	0.59	0.67	0.70	0.70	0.3%	1.0%
Transportation[6]	0.00	0.00	0.13	0.24	0.35	N/A	N/A
Total	**18.72**	**19.54**	**21.99**	**23.58**	**24.14**	**1.3%**	**1.2%**
Discrepancy[7]	**0.66**	**0.33**	**-0.02**	**-0.03**	**-0.03**	**N/A**	**N/A**
Average Wellhead Price[8] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.42**	**2.89**	**3.47**	**3.3%**	**3.9%**
Delivered Prices (1992 dollars per thousand cubic feet)							
Residential	6.19	5.89	7.26	7.85	8.55	1.6%	2.1%
Commercial	5.15	4.88	6.22	6.80	7.49	1.9%	2.4%
Industrial[9]	3.57	3.17	3.96	4.50	5.08	1.8%	2.7%
Electric Utilities	2.54	2.36	3.02	3.63	4.22	2.6%	3.3%
Transportation	3.62	4.05	9.90	10.76	11.41	5.9%	5.9%
Average[10]	**4.33**	**4.03**	**4.92**	**5.42**	**6.07**	**1.7%**	**2.3%**

[1]Dry marketed production minus nonhydrocarbon gases removed.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributes with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Reflects natural gas lost, the net 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.
[8]Represents Lower-48 onshore and offshore supplies.
[9]Excludes uses for lease and plant fuel.
[10]Weighted average price. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 industrial and transportation delivered prices: Energy Information Administration (EIA), AEO 1994 National Energy Modeling System run AEO94B.D1221934. Other 1990 and 1992: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Crude Oil							
Lower 48 Average Wellhead Price[1]							
(1992 dollars per barrel)	23.02	17.38	20.19	23.99	26.98	0.8%	2.5%
Production (million barrels per day)[2]							
U.S. Total	7.36	7.17	5.17	4.84	5.10	-1.8%	-1.9%
Lower 48 Onshore	4.63	4.38	3.62	3.59	3.63	-1.2%	-1.0%
Conventional	3.97	3.68	3.05	2.88	2.80	-1.7%	-1.5%
Enhanced Oil Recovery	0.66	0.71	0.57	0.71	0.84	1.2%	1.0%
Lower 48 Offshore	0.95	1.07	0.68	0.65	0.72	-1.4%	-2.1%
Alaska	1.77	1.71	0.87	0.60	0.74	-4.2%	-4.5%
U.S. End of Year Reserves (billion barrels)	27.56	24.97	18.84	17.46	18.31	-2.0%	-1.7%
Natural Gas							
Lower 48 Average Wellhead Price[1]							
(1992 dollars per thousand cubic feet)	1.83	1.75	2.42	2.89	3.47	3.3%	3.9%
Production (trillion cubic feet)[3]							
U.S. Total	17.81	17.84	18.93	20.13	20.19	0.6%	0.7%
Lower 48 Onshore	12.15	12.50	14.87	14.82	14.55	0.9%	0.8%
Associated-Dissolved[4]	2.07	2.11	1.64	1.64	1.67	-1.1%	-1.3%
Non-Associated	10.08	10.39	13.22	13.18	12.88	1.2%	1.2%
Conventional	8.63	8.53	9.95	9.78	9.51	0.5%	0.6%
Unconventional	1.45	1.86	3.27	3.40	3.38	4.3%	3.4%
Tight Sands	1.13	1.19	1.99	2.11	2.15	3.3%	3.3%
Coal Bed Methane	0.19	0.51	0.92	0.93	0.89	8.1%	3.2%
Devonian Shale	0.12	0.16	0.35	0.36	0.33	5.1%	4.2%
Lower 48 Offshore	5.28	4.93	3.57	4.83	5.16	-0.1%	0.3%
Associated-Dissolved[4]	0.63	0.68	0.58	0.57	0.59	-0.3%	-0.8%
Non-Associated	4.65	4.25	2.99	4.26	4.57	-0.1%	0.4%
Alaska	0.38	0.41	0.50	0.49	0.47	1.1%	0.8%
U.S. End of Year Reserves (trillion cubic feet)	169.35	165.02	164.83	156.73	152.38	-0.5%	-0.4%
Supplemental Gas Supplies[5]	0.12	0.12	0.11	0.12	0.07	-2.4%	-2.6%
Total Wells Completed	31.17	23.01	37.51	54.27	76.50	4.6%	6.9%

[1]Represents Lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Dry marketed production minus nonhydrocarbon gases removed.
[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: 1990: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - Energy Information Administration (EIA), *Petroleum Supply Annual 1990*, DOE/EIA-340(90)/1 (Washington, D.C., May 1991); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90) (Washington, D.C., September 1991). 1992: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - EIA, *Petroleum Supply Annual 1992*, DOE/EIA-340(92)/1 (Washington, D.C., May 1993); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, D.C., October 1993). 1990 and 1992: Crude Oil Lower 48 Average Wellhead Prices - EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993); Natural Gas Lower 48 Average Wellhead Prices, Alaska and Total Natural Gas Production, Supplemental Gas Supplies - EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, D.C., November 1993); Total Wells Completed - *Monthly Energy Review*, DOE/EIA-0035(93/11) (Washington, D.C., November 1993). Other 1990 and 1992 values - EIA, Office of Integrated Analysis and Forecasting. Figures for 1990 and 1992 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production[1]							
East of the Mississippi	630	589	630	630	650	0.2%	0.5%
West of the Mississippi	399	409	451	491	573	1.8%	1.9%
Total	**1029**	**998**	**1081**	**1121**	**1223**	**0.9%**	**1.1%**
Net Imports							
Imports	3	4	10	10	11	7.1%	5.9%
Exports	106	103	133	144	152	1.8%	2.2%
Total	**-103**	**-99**	**-123**	**-134**	**-142**	**1.6%**	**2.0%**
Total Supply[2]	**926**	**899**	**958**	**987**	**1081**	**0.8%**	**1.0%**
Consumption by Sector							
Residential and Commercial	7	6	6	6	5	-1.0%	-0.8%
Industrial[3]	76	74	87	94	101	1.5%	1.8%
Coke Plants	39	32	28	24	21	-2.9%	-2.2%
Electricity[4]	774	780	837	862	950	1.0%	1.1%
Total	**895**	**892**	**958**	**987**	**1079**	**0.9%**	**1.1%**
Discrepancy and Stock Change[5]	**31**	**-6**	**0**	**0**	**3**	**-11.3%**	**N/A**
Average Minemouth Price[6] (1992 dollars per short ton)	**23.22**	**21.03**	**25.29**	**27.00**	**30.87**	**1.4%**	**2.2%**
Delivered Prices (1992 dollars per short ton)							
Industrial	35.85	32.78	37.43	40.37	42.30	0.8%	1.4%
Coke Plants	50.93	47.92	55.81	60.38	58.91	0.7%	1.2%
Electricity	32.49	29.36	34.11	35.52	40.32	1.1%	1.8%
Average[7]	**33.59**	**30.32**	**35.05**	**36.60**	**40.88**	**1.0%**	**1.7%**
Average Price to All Users (1992 dollars per million Btu)	**1.58**	**1.42**	**1.64**	**1.71**	**1.92**	**1.0%**	**1.7%**
Exports[8]	45.49	41.34	50.96	54.71	55.95	1.0%	1.7%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Balancing item: the sum of production and net imports, minus total consumption.
[6]Free-on-board price.
[7]Weighted average prices. Weights used are consumption values by sector. Average of Industrial, Coke Plant, and Electricity Sectors.
[8]Free alongside ship price at U.S. port-of-exit.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121 (90/4Q) (Washington, D.C., May 1991); and EIA, *Coal Production 1990*, DOE/EIA-0118(90) (Washington, D.C., September 1991). 1992: EIA, *Quarterly Coal Report*, DOE/EIA-0121(93/2Q) (Washington, D.C., November 1993); and EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, D.C., October 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A16. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Nonelectric	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electricity							
Capability (gigawatts)							
Conventional Hydropower	75.30	75.54	78.29	78.43	78.53	0.2%	0.2%
Geothermal[1]	2.91	2.89	5.54	6.56	8.54	5.5%	6.2%
Municipal Solid Waste	2.13	2.66	3.64	4.43	5.24	4.6%	3.8%
Biomass/Other Waste[2]	6.86	7.29	9.23	12.20	15.17	4.0%	4.2%
Solar[3]	0.36	0.36	0.73	0.98	1.33	6.7%	7.5%
Wind[4]	1.55	1.65	1.76	1.98	10.65	10.1%	10.9%
Total	**89.11**	**90.40**	**99.20**	**104.56**	**119.45**	**1.5%**	**1.6%**
Generation (billion kilowatthours)							
Conventional Hydropower	288.04	247.88	305.07	305.89	306.58	0.4%	1.3%
Geothermal[1]	15.86	16.68	36.01	43.19	57.15	6.6%	7.1%
Municipal Solid Waste	12.32	17.24	20.17	26.04	32.04	5.5%	4.0%
Biomass/Other Waste[2]	34.14	41.73	48.42	65.94	83.63	13.6%	13.8%
Solar[3]	0.70	1.75	2.35	3.36	4.81	10.1%	5.8%
Wind[4]	2.38	2.91	2.91	3.55	29.09	13.3%	13.6%
Total	**353.44**	**328.19**	**414.93**	**447.97**	**513.30**	**1.9%**	**2.5%**
Consumption Equivalent							
Conventional Hydropower	2.98	2.57	3.16	3.17	3.17	0.4%	1.3%
Geothermal[1]	0.16	0.17	0.37	0.45	0.59	6.6%	7.2%
Municipal Solid Waste	0.13	0.18	0.21	0.27	0.33	5.5%	4.1%
Biomass/Other Waste[2]	0.35	0.43	0.50	0.68	0.87	13.6%	17.2%
Solar[3]	0.01	0.01	0.02	0.03	0.05	10.1%	9.3%
Wind[4]	0.02	0.03	0.03	0.04	0.30	13.3%	13.9%
Total	**3.66**	**3.40**	**4.30**	**4.64**	**5.32**	**1.9%**	**2.5%**
Nonelectric Renewable Energy							
Residential, Commercial, and Industrial							
Geothermal	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Biofuels	2.53	2.57	3.00	3.22	3.44	1.6%	1.6%
Solar Thermal	0.02	0.02	0.04	0.04	0.04	3.8%	4.0%
Transportation							
Ethanol	0.06	0.09	0.11	0.12	0.13	3.9%	2.0%
Total	**2.62**	**2.69**	**3.16**	**3.39**	**3.63**	**1.8%**	**1.9%**
Total Renewable Energy	**6.28**	**6.07**	**7.45**	**8.02**	**8.94**	**1.8%**	**1.9%**

[1]Includes hydrothermal resources only (hot water and steam).
[2]Does not include projections for energy crops.
[3]Utility-grid connected generation only.
[4]Includes horizontal-axis wind turbines only.
Btu = British thermal unit.
Note: Includes renewables used in industrial power generation and cogeneration.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 ethanol: Energy Information Administration (EIA), *Weekly Petroleum Status Report*, DOE/EIA-0208(93-01) (Washington, D.C., January 1993). Other 1990 and 1992: EIA, sum of EIA-860 "Annual Electric Generator Report" and EIA-867 "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A17. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Petroleum	24.0	25.7	25.1	24.6	24.0	0.0%	-0.4%
Natural Gas	65.0	69.3	71.9	71.6	71.9	0.5%	0.2%
Coal	1.6	1.4	1.3	1.3	1.2	-1.3%	-0.7%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**90.6**	**96.4**	**98.3**	**97.4**	**97.0**	**0.3%**	**0.0%**
Commercial							
Petroleum	18.1	18.1	18.4	18.2	18.0	0.0%	-0.1%
Natural Gas	38.7	39.9	41.4	42.2	43.3	0.6%	0.4%
Coal	2.3	2.3	2.2	2.2	2.2	-0.4%	-0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	2.6%	0.2%
Total	**59.2**	**60.3**	**62.0**	**62.6**	**63.4**	**0.3%**	**0.3%**
Industrial[1]							
Petroleum	91.9	85.1	106.5	109.6	114.3	1.1%	1.6%
Natural Gas[2]	119.6	123.0	136.1	144.4	151.2	1.2%	1.2%
Coal	67.8	62.2	65.6	68.3	69.7	0.1%	0.6%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**279.3**	**270.4**	**308.2**	**322.3**	**335.2**	**0.9%**	**1.2%**
Transportation							
Petroleum	422.3	428.8	476.2	501.3	522.1	1.1%	1.1%
Natural Gas[3]	9.9	9.8	12.2	14.6	16.7	2.7%	3.0%
Renewable/Other[4]	0.0	0.0	0.3	0.8	1.6	35.4%	31.1%
Total	**432.2**	**438.6**	**488.6**	**516.6**	**540.2**	**1.1%**	**1.2%**
Electric Utilities[5]							
Petroleum	26.8	17.2	18.6	20.0	16.2	-2.5%	-0.3%
Natural Gas	41.2	42.8	62.2	74.7	72.7	2.9%	3.0%
Steam Coal	408.8	414.8	444.6	458.9	506.9	1.1%	1.1%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	5.1%
Total	**476.7**	**474.8**	**525.4**	**553.6**	**595.9**	**1.1%**	**1.3%**
Total Energy Consumption							
Petroleum	583.2	574.9	644.8	673.7	694.6	0.9%	1.1%
Natural Gas	274.4	284.8	323.7	347.5	355.8	1.3%	1.2%
Coal	480.4	480.7	513.8	530.7	579.9	0.9%	1.0%
Renewable Energy	0.0	0.0	0.2	0.5	0.9	33.4%	25.1%
Other[4]	0.0	0.0	0.1	0.4	0.7	38.7%	29.2%
Total	**1338.0**	**1340.5**	**1482.6**	**1552.7**	**1631.9**	**1.0%**	**1.1%**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]Other includes methanol, liquid hydrogen, and lubricants.
[5]Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell electricity to utilities.
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, 1985 - 1990*, DOE/EIA-0573 (Washington, D.C., September 1993), Table 11, p. 15. 1990 consumption estimates: EIA, *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). **Consumption projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A18. Macroeconomic Indicators

(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
GDP Implicit Price Deflator (Index 1987=1.000)	1.132	1.208	1.488	1.749	2.075	3.1%	3.1%
Real Gross Domestic Product	4877	4920	6041	6736	7397	2.1%	2.3%
Real Consumption	3260	3312	3898	4226	4606	1.7%	1.8%
Real Investment	739	712	1137	1308	1449	3.4%	4.0%
Real Government Spending	930	938	998	1068	1129	1.0%	1.0%
Real Exports	510	571	922	1234	1530	5.6%	5.6%
Real Imports	562	614	915	1100	1317	4.4%	4.3%
Real Disposable Personal Income	3517	3584	4202	4563	4970	1.7%	1.8%
Index of Manufacturing Gross Output (Index 1987=1.000)	1.087	1.094	1.366	1.550	1.747	2.4%	2.6%
AA Utility Bond Rate (percent)	9.66	8.55	8.59	8.47	8.26	-0.8%	-0.2%
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	3.43	4.69	4.67	4.49	-2.5%	1.5%
Real Yield on Government 10 Year Bonds (percent)	4.91	3.61	4.41	4.01	3.71	-1.4%	0.1%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	15.85	14.96	14.23	-1.0%	-1.1%
Consumer Price Index (1982=1.00)	1.31	1.40	1.83	2.20	2.65	3.6%	3.6%
Employment Cost Index (1987=1.00)	1.05	1.12	1.46	1.78	2.18	3.7%	3.8%
Unemployment Rate (percent)	5.52	7.40	5.66	5.69	5.92	0.3%	-1.2%
Million Units							
Truck Deliveries, Light-Duty	4.39	4.50	5.66	6.26	6.52	2.0%	2.1%
Unit Sales of Automobiles	9.51	8.35	9.77	10.12	10.38	0.4%	1.2%
U.S. Trade-Weighted Exchange Rate	0.87	0.84	0.84	0.80	0.77	-0.6%	-0.5%
Millions of People							
Population with Armed Forces Overseas	250.3	255.8	275.6	287.1	298.9	0.9%	0.9%
Population (aged 16 and over)	192.7	196.3	212.8	223.8	235.4	1.0%	1.0%
Employment, Non-Agriculture	109.8	108.4	124.5	132.8	139.6	1.2%	1.4%

GDP = Gross domestic product.

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

Sources: 1990 and 1992: Data Resources Incorporated (DRI), DRI Trend0293. **Projections:** Energy Information Administration, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

Table A19. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (1992 dollars per barrel)[1]	**23.22**	**18.20**	**20.72**	**24.90**	**28.16**	**1.0%**	**2.5%**
Production[2]							
U.S. (50 states)	9.59	9.77	8.01	7.81	8.13	-0.8%	-1.0%
Canada	2.03	2.12	2.22	2.52	2.45	1.0%	0.8%
OECD Europe[3]	4.58	5.08	6.42	5.28	4.75	0.2%	-0.4%
OPEC	25.04	26.38	35.54	40.92	44.02	2.9%	2.9%
Rest of the World[4]	11.06	11.00	12.95	12.27	12.07	0.4%	0.5%
Total Production	**52.30**	**54.35**	**65.13**	**68.80**	**71.42**	**1.6%**	**1.5%**
Net Eurasian Exports	**1.88**	**1.58**	**1.24**	**1.42**	**1.60**	**-0.8%**	**0.1%**
Total Supply	**53.60**	**55.93**	**66.37**	**70.22**	**73.02**	**1.6%**	**1.5%**
Consumption							
U.S. (50 states)	16.99	17.03	19.34	20.40	21.30	1.1%	1.2%
U.S. Territories	0.21	0.21	0.25	0.27	0.27	1.4%	1.4%
Canada	1.69	1.64	1.87	1.89	1.89	0.6%	0.8%
Japan	5.14	5.45	6.78	7.14	7.23	1.7%	1.6%
Australia & New Zealand	0.82	0.82	0.95	1.01	1.07	1.3%	1.4%
OECD Europe	12.90	13.61	15.49	15.88	15.95	1.1%	0.9%
Rest of the World[4]	15.78	17.56	21.99	23.93	25.60	2.4%	2.1%
Total Consumption	**53.53**	**56.33**	**66.67**	**70.52**	**73.32**	**1.6%**	**1.5%**
Discrepancy	**-0.07**	**0.40**	**0.30**	**0.30**	**0.30**	**N/A**	**-1.6%**
Consumption Aggregations							
OECD	37.75	38.77	44.68	46.60	47.71	1.2%	1.2%
OPEC	4.61	4.95	5.89	6.51	7.18	2.2%	2.1%
Rest of the World[4]	11.18	12.61	16.10	17.42	18.42	2.5%	2.1%
Non-OPEC Production[4]	**27.26**	**27.97**	**29.59**	**27.88**	**27.40**	**0.0%**	**-0.1%**
OPEC Summary							
Market Share	0.47	0.47	0.53	0.58	0.60	1.3%	1.4%
Production Capacity[5]	29.80	28.90	38.40	44.10	47.75	2.4%	2.8%
Capacity Utilization	0.84	0.91	0.93	0.93	0.92	0.5%	0.1%

[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: 1990: Energy Information Administration (EIA), *International Energy Annual 1991*, DOE/EIA-0219(93); and EIA, International Petroleum Statistics Report, DOE/EIA-0520(93/07). 1992: EIA, *International Energy Annual 1992*, DOE/EIA-0219(94); and EIA, *Monthly Energy Review*, DOE/EIA-0035(93/12). **Projections:** EIA, AEO 1994 National Energy Modeling System run AEO94B.D1221934.

HIGH ECONOMIC GROWTH CASE PROJECTIONS

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

Supply, Disposition, and Prices	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil and Lease Condensate	15.57	15.22	11.09	10.37	10.92	-1.8%	-1.8%
Natural Gas Plant Liquids	2.17	2.36	2.64	2.82	2.85	1.4%	1.0%
Dry Natural Gas[1]	18.49	18.51	20.36	21.84	22.06	0.9%	1.0%
Coal	22.46	21.62	23.75	24.84	27.83	1.1%	1.4%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[2]	6.20	6.28	7.40	8.03	9.10	1.9%	2.1%
Total	**71.08**	**70.64**	**72.44**	**75.21**	**79.32**	**0.6%**	**0.6%**
Imports							
Crude Oil[3]	12.80	13.24	18.92	20.15	19.61	2.2%	2.2%
Petroleum Products[4]	3.40	2.71	7.27	8.89	10.64	5.9%	7.9%
Natural Gas	1.54	2.15	3.19	3.59	4.16	5.1%	3.7%
Other Imports[5]	0.73	0.96	1.55	1.60	1.87	4.8%	3.8%
Total	**18.46**	**19.07**	**30.93**	**34.24**	**36.28**	**3.4%**	**3.6%**
Exports							
Petroleum	1.82	2.02	2.12	2.12	2.12	0.7%	0.2%
Natural Gas	0.09	0.22	0.24	0.27	0.30	6.4%	1.7%
Coal	2.70	2.68	3.31	3.54	3.75	1.7%	1.9%
Total	**4.61**	**4.92**	**5.68**	**5.92**	**6.17**	**1.5%**	**1.3%**
Discrepancy[6]	**-0.65**	**1.01**	**0.04**	**0.11**	**0.07**	**N/A**	**-13.7%**
Consumption							
Petroleum Products[7]	33.55	33.65	39.04	41.40	43.39	1.3%	1.4%
Natural Gas	19.30	20.15	23.40	25.28	26.05	1.5%	1.4%
Coal	19.01	18.99	20.64	21.50	24.23	1.2%	1.4%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[8]	6.23	6.37	7.44	8.14	9.26	2.0%	2.1%
Total	**84.28**	**85.80**	**97.73**	**103.63**	**109.50**	**1.3%**	**1.4%**
Net Imports - Petroleum	**14.37**	**13.93**	**24.07**	**26.93**	**28.13**	**3.4%**	**4.0%**
Prices (1992 dollars per unit)							
World Oil Price (dollars per barrel)[9]	23.22	18.20	21.32	25.45	28.81	1.1%	2.6%
Gas Wellhead Price (dollars per Mcf)[10]	1.83	1.75	2.56	3.32	3.88	3.8%	4.5%
Coal Minemouth Price (dollars per ton)	23.22	21.03	26.86	27.45	32.95	1.8%	2.5%

[1]Includes synthetic gas.

[2]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, liquid hydrogen, and methanol.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Imports of finished petroleum products. Does not include imports of unfinished oils or blending components.

[5]Includes coal, coal coke (net), and electricity (net), methanol, methyl tertiary butyl ether (MTBE), and imports of unfinished oils.

[6]Balancing item. Includes unaccounted for supply, losses, and gains.

[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and non-petroleum based liquids for blending, such as ethanol.

[8]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, plus 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.

Mcf = Thousand cubic feet.

N/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B2. Energy Consumption by End-Use Sector and Source

(Quadrillion Btu per Year)

Sector and Source	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Distillate Fuel	0.84	0.85	0.90	0.90	0.89	0.3%	0.2%
Kerosene	0.06	0.06	0.06	0.06	0.06	-0.5%	-0.1%
Liquefied Petroleum Gas	0.36	0.41	0.36	0.34	0.33	-0.5%	-1.2%
Natural Gas	4.52	4.83	5.07	5.07	5.15	0.7%	0.4%
Coal	0.06	0.06	0.05	0.05	0.05	-1.3%	-1.3%
Renewable Energy[1]	0.61	0.63	0.66	0.67	0.68	0.5%	0.4%
Electricity	3.15	3.19	3.45	3.59	3.78	0.9%	0.9%
Total	**9.61**	**10.04**	**10.56**	**10.68**	**10.93**	**0.6%**	**0.5%**
Commercial							
Distillate Fuel	0.49	0.49	0.52	0.52	0.51	0.2%	0.2%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.5%	-0.5%
Motor Gasoline[2]	0.11	0.09	0.11	0.11	0.11	0.2%	1.3%
Residual Fuel	0.23	0.23	0.22	0.22	0.22	-0.4%	-0.4%
Natural Gas	2.70	2.89	2.90	2.96	3.06	0.6%	0.3%
Other[3]	0.16	0.16	0.15	0.15	0.15	-0.2%	-0.2%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Electricity	2.86	2.91	3.34	3.53	3.65	1.2%	1.3%
Total	**6.57**	**6.78**	**7.28**	**7.53**	**7.75**	**0.8%**	**0.7%**
Industrial[5]							
Distillate Fuel	1.18	1.19	1.42	1.55	1.68	1.8%	1.9%
Liquefied Petroleum Gas	1.61	1.83	2.04	2.28	2.52	2.3%	1.8%
Motor Gasoline[2]	0.18	0.20	0.24	0.26	0.29	2.2%	2.0%
Petrochemical Feedstocks	1.10	1.23	1.35	1.51	1.67	2.1%	1.7%
Residual Fuel	0.42	0.34	0.48	0.48	0.47	0.6%	1.9%
Other Petroleum[6]	3.82	3.83	4.43	4.54	4.68	1.0%	1.1%
Natural Gas[7]	8.50	8.96	9.84	10.51	11.28	1.4%	1.3%
Metallurgical Coal	1.04	0.87	0.75	0.65	0.58	-2.9%	-2.3%
Steam Coal	1.71	1.65	1.97	2.22	2.41	1.7%	2.1%
Net Coal Coke Imports	0.00	0.03	0.02	0.02	0.02	N/A	-1.7%
Renewable Energy	1.96	1.99	2.48	2.74	3.02	2.2%	2.3%
Electricity	3.23	3.29	3.96	4.37	4.76	2.0%	2.1%
Total	**24.78**	**25.42**	**28.97**	**31.14**	**33.38**	**1.5%**	**1.5%**
Transportation							
Distillate Fuel	3.83	3.76	5.03	5.56	6.15	2.4%	2.8%
Jet Fuel[8]	3.13	3.00	3.81	4.23	4.65	2.0%	2.5%
Motor Gasoline[2]	13.58	13.69	15.21	15.75	16.05	0.8%	0.9%
Residual Fuel	1.03	1.09	1.35	1.54	1.72	2.6%	2.6%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.13	0.20	12.3%	13.7%
Other Petroleum[9]	0.22	0.20	0.22	0.23	0.25	0.6%	1.2%
Pipeline Fuel Natural Gas	0.68	0.61	0.71	0.75	0.80	0.8%	1.5%
Compressed Natural Gas	0.00	0.00	0.13	0.24	0.36	N/A	N/A
Renewables (ethanol)[10]	0.00	0.00	0.01	0.03	0.06	33.5%	33.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	95.6%	75.1%
Methanol[11]	0.00	0.00	0.01	0.03	0.06	38.7%	29.2%
Electricity	0.01	0.01	0.08	0.13	0.19	15.9%	17.9%
Total	**22.50**	**22.38**	**26.65**	**28.63**	**30.49**	**1.5%**	**1.7%**
Electric Utilities[12]							
Distillate Fuel	0.02	0.03	0.12	0.14	0.12	8.0%	8.7%
Residual Fuel	1.23	0.90	1.01	0.98	0.75	-2.5%	-1.0%
Natural Gas	2.88	2.86	4.74	5.75	5.41	3.2%	3.6%
Steam Coal	16.10	16.30	17.78	18.48	21.11	1.4%	1.4%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[13]	3.64	3.20	4.24	4.62	5.40	2.0%	2.9%
Total	**30.07**	**29.69**	**35.11**	**37.28**	**39.35**	**1.4%**	**1.6%**

Table B2. Energy Consumption by End-Use Sector and Source (Continued)

(Quadrillion Btu per Year)

Sector and Source	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Primary Energy Consumption							
Distillate Fuel	6.36	6.31	7.99	8.66	9.34	1.9%	2.2%
Kerosene	0.08	0.07	0.07	0.07	0.07	-0.5%	-0.2%
Jet Fuel[8]	3.13	3.00	3.81	4.23	4.65	2.0%	2.5%
Liquefied Petroleum Gas	2.06	2.32	2.54	2.82	3.12	2.1%	1.7%
Motor Gasoline[2]	13.87	13.98	15.56	16.13	16.45	0.9%	0.9%
Petrochemical Feedstocks	1.10	1.23	1.35	1.51	1.67	2.1%	1.7%
Residual Fuel	2.91	2.56	3.06	3.21	3.16	0.4%	1.2%
Other Petroleum[14]	4.04	4.03	4.65	4.77	4.93	1.0%	1.1%
Natural Gas	19.30	20.15	23.40	25.28	26.05	1.5%	1.4%
Metallurgical Coal	1.04	0.87	0.75	0.65	0.58	-2.9%	-2.3%
Steam Coal	17.96	18.05	19.89	20.85	23.65	1.4%	1.5%
Net Coal Coke Imports	0.00	0.03	0.02	0.02	0.02	N/A	-1.7%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[15]	6.22	5.83	7.43	8.12	9.24	2.0%	2.6%
Total	**84.29**	**84.86**	**97.73**	**103.63**	**109.50**	**1.3%**	**1.4%**
Electricity Consumption (all sectors)	**9.25**	**9.45**	**10.84**	**11.63**	**12.39**	**1.5%**	**1.5%**

[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, ground-water 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 co-generated 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 electric utilities, independent power producers, and small power producers that sell power to the grid.

[13]Includes electricity sold to utilities by nonutilities, including cogenerators, from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports. Does not include own use.

[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.

N/A = Not applicable.

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

Sources: 1990 coal consumption: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0118(90) (Washington, D.C. May 1991) and *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas consumption: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). 1990 and 1992 consumption other than coal and natural gas: EIA, *Monthly Energy Review*, DOE/EIA-0035(93/07) (Washington, D.C., July 1993) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. The 1990 values are not final and may be updated in EIA publications. **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B3. Energy Prices by End-Use Sector and Source

(1992 Dollars per Million Btu)

Sector and Source	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential	**13.12**	**12.11**	**13.87**	**15.19**	**16.83**	**1.3%**	**1.8%**
Primary Energy	6.72	6.12	7.45	8.29	8.98	1.5%	2.1%
Petroleum Products	9.49	7.78	8.65	9.55	10.42	0.5%	1.6%
Distillate Fuel	8.55	6.68	7.65	8.50	9.27	0.4%	1.8%
Liquefied Petroleum Gas	11.67	10.05	11.27	12.44	13.63	0.8%	1.7%
Natural Gas	6.00	5.72	7.19	8.02	8.68	1.9%	2.3%
Electricity	24.98	23.76	25.86	27.54	30.28	1.0%	1.4%
Commercial	**12.78**	**12.08**	**13.72**	**14.68**	**15.55**	**1.0%**	**1.4%**
Primary Energy	5.27	4.72	6.02	6.83	7.50	1.8%	2.6%
Petroleum Products	6.35	4.94	5.91	6.75	7.51	0.8%	2.4%
Distillate Fuel	6.51	4.76	5.36	6.19	6.94	0.3%	2.1%
Residual Fuel	3.66	2.62	3.72	4.33	4.82	1.4%	3.4%
Natural Gas	5.00	4.74	6.17	6.99	7.63	2.1%	2.7%
Electricity	22.49	21.85	22.75	23.51	24.50	0.4%	0.6%
Industrial	**5.75**	**5.19**	**6.01**	**6.75**	**7.54**	**1.4%**	**2.1%**
Primary Energy	4.09	3.49	4.28	5.02	5.70	1.7%	2.8%
Petroleum Products	5.71	4.42	5.20	6.18	7.06	1.1%	2.6%
Distillate Fuel	6.06	4.87	5.33	6.18	6.95	0.7%	2.0%
Liquefied Petroleum Gas	5.76	4.95	6.58	7.76	8.86	2.2%	3.3%
Residual Fuel	3.31	2.54	3.67	4.39	5.01	2.1%	3.9%
Natural Gas[1]	3.46	3.07	3.97	4.66	5.26	2.1%	3.0%
Metallurgical Coal	1.87	1.79	2.14	2.20	2.16	0.7%	1.0%
Steam Coal	1.64	1.47	1.78	1.80	1.96	0.9%	1.6%
Electricity	15.22	14.87	15.26	15.66	16.77	0.5%	0.7%
Transportation	**8.72**	**7.88**	**9.10**	**10.03**	**10.86**	**1.1%**	**1.8%**
Primary Energy	8.72	7.88	9.08	10.00	10.82	1.1%	1.8%
Petroleum Products	8.81	7.88	9.08	10.00	10.81	1.0%	1.8%
Distillate Fuel[2]	9.03	8.02	9.41	10.46	11.34	1.1%	1.9%
Jet Fuel[3]	6.06	4.52	5.52	6.43	7.23	0.9%	2.6%
Motor Gasoline[4]	9.73	9.09	10.43	11.43	12.34	1.2%	1.7%
Residual Fuel	3.18	2.14	3.32	4.00	4.69	2.0%	4.5%
Natural Gas[5]	3.51	3.93	9.74	10.73	11.59	6.2%	6.2%
Electricity	18.15	17.94	15.33	15.61	16.10	-0.6%	-0.6%
Total End-Use Energy	**8.80**	**8.03**	**9.17**	**10.06**	**11.01**	**1.1%**	**1.8%**
Primary Energy	8.45	7.72	8.82	9.66	10.52	1.1%	1.7%
Electricity	20.79	20.05	20.94	21.71	23.16	0.5%	0.8%
Electric Utilities							
Fossil Fuel Average	1.81	1.59	2.06	2.34	2.62	1.9%	2.8%
Petroleum Products	3.55	2.56	3.80	4.53	5.18	1.9%	4.0%
Distillate Fuel	6.00	4.51	4.98	5.83	6.62	0.5%	2.1%
Residual Fuel	3.52	2.51	3.66	4.34	4.96	1.7%	3.9%
Natural Gas	2.46	2.28	3.03	3.88	4.43	3.0%	3.8%
Steam Coal	1.56	1.41	1.70	1.73	2.06	1.4%	2.1%

Table B3. Energy Prices by End-Use Sector and Source (Continued)

(1992 Dollars per Million Btu)

Sector and Source	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Average Price to All Users[6]							
Petroleum Products	7.94	6.84	7.93	8.86	9.72	1.0%	2.0%
Distillate Fuel[2]	8.18	6.98	8.15	9.16	10.06	1.0%	2.0%
Jet Fuel	6.06	4.52	5.52	6.43	7.23	0.9%	2.6%
Liquefied Petroleum Gas	6.45	5.98	7.51	8.68	9.83	2.1%	2.8%
Motor Gasoline[4]	9.73	9.09	10.43	11.43	12.34	1.2%	1.7%
Residual Fuel	3.38	2.37	3.52	4.19	4.81	1.8%	4.0%
Natural Gas	4.20	3.91	4.86	5.56	6.22	2.0%	2.6%
Coal	1.57	1.42	1.71	1.74	2.05	1.3%	2.1%
Electricity	20.79	20.05	20.94	21.71	23.16	0.5%	0.8%

[1]Excludes uses for lease and plant fuel.

[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]Compressed natural gas used as a vehicle fuel.

[6]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption. For each sector, electricity and natural gas prices are derived by dividing total revenues by sales.

Btu = British thermal unit.

Sources: 1990 petroleum prices: *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington,D.C., September 1993). 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, D.C., July 1993). 1992 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 coal prices: EIA, *Quarterly Coal Report*, DOE/EIA-0121(90/4Q) (Washington, D.C., May 1991); EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993), Table A6; and EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 industrial and transportation natural gas delivered prices: EIA, AEO National Energy Modeling System run HMAC94.D1221932. Other 1990 and 1992 natural gas prices: EIA, *Natural Gas Annual*, DOE/EIA-0131 (92)/1 (Washington, DC, November 1993). 1990 electricity prices: EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932. **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B4. Residential Sector Key Indicators and End-Use Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Household Characteristics							
Households (millions)							
Single-Family	64.36	65.60	72.96	77.29	81.94	1.2%	1.2%
Multifamily	24.42	24.27	25.28	26.36	27.72	0.6%	0.7%
Mobile Homes	5.21	5.19	5.42	5.58	5.67	0.4%	0.5%
Total	**93.99**	**95.06**	**103.66**	**109.23**	**115.33**	**1.0%**	**1.1%**
Housing Starts (millions)							
Single-Family	0.90	1.04	1.22	1.28	1.27	1.7%	1.1%
Multifamily	0.30	0.17	0.46	0.48	0.55	3.0%	6.7%
Mobile Homes	0.19	0.21	0.24	0.24	0.23	1.1%	0.6%
Total	**1.39**	**1.42**	**1.92**	**2.00**	**2.06**	**2.0%**	**2.1%**
Energy Intensity (million Btu per year per household)							
Heating	54.59	58.45	56.14	53.00	50.18	-0.4%	-0.8%
Total	**102.23**	**105.60**	**101.90**	**97.78**	**94.77**	**-0.4%**	**-0.6%**
Fuel Consumption							
Distillate							
Space Heating	0.75	0.77	0.83	0.82	0.81	0.4%	0.3%
Water Heating	0.08	0.08	0.08	0.07	0.07	-0.5%	-0.5%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	1.2%	1.2%
Total	**0.84**	**0.85**	**0.90**	**0.90**	**0.89**	**0.3%**	**0.2%**
Liquefied Petroleum Gas							
Space Heating	0.23	0.27	0.24	0.23	0.22	-0.3%	-1.2%
Water Heating	0.08	0.09	0.07	0.07	0.07	-1.0%	-1.6%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-1.0%	-0.4%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	1.1%	1.1%
Total	**0.36**	**0.41**	**0.36**	**0.34**	**0.33**	**-0.5%**	**-1.2%**
Natural Gas							
Space Heating	3.12	3.42	3.61	3.57	3.58	0.7%	0.2%
Space Cooling	0.00	0.00	0.00	0.01	0.01	N/A	N/A
Water Heating	1.09	1.10	1.13	1.15	1.21	0.5%	0.5%
Cooking[2]	0.18	0.18	0.20	0.21	0.22	1.1%	1.1%
Clothes Dryers	0.08	0.08	0.07	0.06	0.06	-1.3%	-1.4%
Other Uses[3]	0.06	0.06	0.07	0.07	0.07	1.2%	1.2%
Total	**4.52**	**4.83**	**5.07**	**5.07**	**5.15**	**0.7%**	**0.4%**
Electricity							
Space Heating	0.30	0.33	0.39	0.41	0.42	1.6%	1.3%
Space Cooling	0.52	0.51	0.53	0.54	0.56	0.4%	0.5%
Water Heating	0.34	0.34	0.36	0.36	0.37	0.3%	0.3%
Refrigeration	0.53	0.52	0.46	0.40	0.34	-2.1%	-2.3%
Cooking	0.15	0.15	0.16	0.17	0.18	1.2%	1.2%
Clothes Dryers	0.17	0.18	0.18	0.18	0.19	0.4%	0.4%
Freezers	0.15	0.14	0.11	0.09	0.07	-3.3%	-3.4%
Lighting	0.30	0.30	0.33	0.34	0.35	0.8%	0.9%
Other Uses[4]	0.69	0.72	0.94	1.10	1.28	3.2%	3.3%
Total	**3.15**	**3.19**	**3.45**	**3.59**	**3.78**	**0.9%**	**0.9%**

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Renewables							
Wood[5]	0.59	0.61	0.63	0.64	0.64	0.4%	0.2%
Geothermal[6]	0.01	0.01	0.02	0.02	0.03	8.6%	8.1%
Solar[7]	0.01	0.01	0.01	0.01	0.01	1.4%	1.4%
Total	**0.61**	**0.63**	**0.66**	**0.67**	**0.68**	**0.5%**	**0.4%**
Other Fuels[8]	**0.13**	**0.12**	**0.12**	**0.11**	**0.11**	**-0.8%**	**-0.8%**
Total Fuels							
Space Heating	5.13	5.53	5.82	5.79	5.79	0.6%	0.3%
Space Cooling	0.52	0.51	0.54	0.56	0.58	0.6%	0.7%
Water Heating	1.60	1.67	1.65	1.66	1.73	0.4%	0.2%
Cooking	0.37	0.37	0.40	0.42	0.44	0.9%	1.0%
Clothes Dryers	0.25	0.26	0.25	0.24	0.25	0.0%	-0.2%
Other Uses	1.73	1.75	1.91	2.01	2.14	1.1%	1.1%
Total	**9.61**	**10.04**	**10.56**	**10.68**	**10.93**	**0.6%**	**0.5%**

[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: 1990: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

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

Key Indicators and Consumption	High Economic Growth Case					Annual Growth 1990- 2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Total Employment (millions)	**109.8**	**108.4**	**126.3**	**135.5**	**143.7**	**1.4%**	**1.6%**
Total Floorspace (billion square feet)							
Surviving	62.7	64.7	71.8	75.7	79.8	1.2%	1.2%
New Additions	1.5	1.4	1.6	1.7	1.9	0.9%	1.6%
Total	**64.3**	**66.1**	**73.4**	**77.4**	**81.6**	**1.2%**	**1.2%**
Energy Consumption Intensity							
(Thousand Btu per square feet)	102.3	102.6	**99.2**	**97.4**	**94.9**	**-0.4%**	**-0.4%**
End-Use Consumption							
Electricity							
Space Heating	0.06	0.06	0.05	0.04	0.04	-1.9%	-1.9%
Space Cooling	0.26	0.26	0.26	0.26	0.27	0.1%	0.1%
Lighting	1.20	1.20	1.22	1.22	1.23	0.1%	0.1%
Water Heating	0.03	0.03	0.04	0.05	0.06	4.4%	4.8%
Office Equipment	0.39	0.41	0.79	0.97	1.05	5.1%	5.4%
Other Uses[1]	0.93	0.95	0.98	0.99	1.01	0.4%	0.3%
Total Electricity	**2.86**	**2.91**	**3.34**	**3.53**	**3.65**	**1.2%**	**1.3%**
Natural Gas							
Space Heating	1.36	1.38	1.35	1.31	1.30	-0.2%	-0.3%
Space Cooling	0.01	0.01	0.02	0.02	0.02	3.4%	2.7%
Water Heating	0.37	0.39	0.39	0.38	0.38	0.1%	0.0%
Other Uses[2]	0.96	1.11	1.15	1.24	1.35	1.7%	1.1%
Total Natural Gas	**2.70**	**2.89**	**2.90**	**2.96**	**3.06**	**0.6%**	**0.3%**
Distillate							
Space Heating	0.31	0.31	0.34	0.34	0.34	0.5%	0.4%
Water Heating	0.03	0.03	0.03	0.03	0.03	-0.9%	-1.1%
Other Uses[2]	0.15	0.15	0.15	0.15	0.15	0.0%	0.0%
Total Distillate	**0.49**	**0.49**	**0.52**	**0.52**	**0.51**	**0.2%**	**0.2%**
Other Fuels[3]	**0.51**	**0.49**	**0.50**	**0.49**	**0.49**	**-0.2%**	**0.0%**
Renewables[4]	**0.01**	**0.01**	**0.03**	**0.03**	**0.03**	**5.2%**	**4.9%**
Total Consumption	**6.57**	**6.78**	**7.28**	**7.53**	**7.75**	**0.8%**	**0.7%**

[1]Includes ventilation, cooking, refrigeration, and other miscellaneous commercial uses.
[2]Includes cooking and other miscellaneous commercial uses.
[3]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[4]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1990 and 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993).
Projections: Energy Information Administration, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

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

Key Indicators and Consumption	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2536	2552	3306	3806	4358	2.7%	3.0%
Nonmanufacturing	883	875	1116	1240	1360	2.2%	2.5%
Total	**3419**	**3427**	**4423**	**5046**	**5718**	**2.6%**	**2.9%**
Energy Prices (1992 dollars per million Btu)							
Electricity	15.22	14.87	15.26	15.66	16.77	0.5%	0.7%
Natural Gas	3.46	3.07	3.97	4.66	5.26	2.1%	3.0%
Steam Coal	1.64	1.56	1.78	1.80	1.96	0.9%	1.3%
Residual Oil	3.30	2.54	3.67	4.39	5.01	2.1%	3.8%
Distillate Oil	6.02	4.88	5.33	6.18	6.95	0.7%	2.0%
Liquefied Petroleum Gas	5.84	4.95	6.58	7.76	8.86	2.1%	3.3%
Motor Gasoline	10.01	9.07	10.43	11.42	12.34	1.1%	1.7%
Metallurgical Coal	1.87	1.80	2.14	2.20	2.16	0.7%	1.0%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.23	3.29	3.96	4.37	4.76	2.0%	2.1%
Natural Gas[2]	8.50	8.96	9.84	10.51	11.28	1.4%	1.3%
Steam Coal	1.71	1.65	1.97	2.22	2.41	1.7%	2.1%
Metallurgical Coal and Coke[3]	1.05	0.90	0.76	0.68	0.60	-2.8%	-2.2%
Residual Fuel	0.42	0.34	0.48	0.48	0.47	0.6%	1.9%
Distillate	1.18	1.19	1.42	1.55	1.68	1.8%	1.9%
Liquefied Petroleum Gas	1.61	1.83	2.04	2.28	2.52	2.3%	1.8%
Petrochemical Feedstocks	1.10	1.23	1.35	1.51	1.67	2.1%	1.7%
Other Petroleum[4]	4.00	4.03	4.67	4.80	4.97	1.1%	1.2%
Renewables	1.96	1.99	2.48	2.74	3.02	2.2%	2.3%
Total	**24.78**	**25.42**	**28.97**	**31.14**	**33.38**	**1.5%**	**1.5%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.94	0.96	0.90	0.87	0.83	-0.6%	-0.8%
Natural Gas[2]	2.49	2.61	2.23	2.08	1.97	-1.2%	-1.5%
Steam Coal	0.50	0.48	0.44	0.44	0.42	-0.9%	-0.7%
Metallurgical Coal and Coke[3]	0.31	0.26	0.17	0.13	0.10	-5.2%	-4.9%
Residual Fuel	0.12	0.10	0.11	0.10	0.08	-1.9%	-1.0%
Distillate	0.35	0.35	0.32	0.31	0.29	-0.8%	-0.9%
Liquefied Petroleum Gas	0.47	0.53	0.46	0.45	0.44	-0.3%	-1.0%
Petrochemical Feedstocks	0.32	0.36	0.31	0.30	0.29	-0.5%	-1.2%
Other Petroleum[4]	1.17	1.18	1.06	0.95	0.87	-1.5%	-1.7%
Renewables	0.57	0.58	0.56	0.54	0.53	-0.4%	-0.5%
Total	**7.25**	**7.41**	**6.55**	**6.17**	**5.84**	**-1.1%**	**-1.3%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net imports of coal coke.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington,D.C., May 1993). 1990 and 1992 natural gas values: *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

HIGH ECONOMIC GROWTH CASE PROJECTIONS

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

Key Indicators and Consumption	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Level of Travel Index (1990 = 1.0)							
Light-Duty Vehicles	1.00	1.01	1.18	1.30	1.40	1.7%	1.8%
Freight Trucks	1.00	1.09	1.39	1.55	1.72	2.7%	2.5%
Air	1.00	1.07	1.49	1.73	1.99	3.5%	3.5%
Rail	1.00	1.04	1.20	1.30	1.41	1.7%	1.7%
Marine	1.00	0.99	1.10	1.18	1.27	1.2%	1.4%
Energy Efficiency Indicators							
New Car MPG[1]	28.20	28.05	29.67	30.91	32.02	0.6%	0.7%
New Light Truck MPG[1]	20.91	20.98	22.53	23.59	24.59	0.8%	0.9%
Light-Duty Fleet MPG[2]	18.90	19.26	20.27	21.01	21.85	0.7%	0.7%
Aircraft Efficiency Index	1.00	1.01	1.07	1.11	1.15	0.7%	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.09	1.14	1.19	0.9%	0.9%
Rail Efficiency Index	1.00	1.00	1.04	1.06	1.07	0.3%	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.01	1.01	1.02	0.1%	0.1%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles[3]	12.74	12.79	14.45	15.25	15.88	1.1%	1.2%
Freight Trucks[3]	5.22	5.31	6.83	7.42	8.02	2.2%	2.3%
Air	3.17	3.04	3.85	4.27	4.69	2.0%	2.4%
Rail	0.51	0.49	0.58	0.62	0.66	1.3%	1.7%
Marine	1.53	1.59	1.92	2.14	2.37	2.2%	2.2%
Pipeline Fuel	0.68	0.61	0.71	0.75	0.80	0.8%	1.5%
Other[4]	0.15	0.15	0.18	0.19	0.21	1.6%	1.8%
Total[5]	**22.50**	**22.38**	**26.65**	**28.63**	**30.49**	**1.5%**	**1.7%**

[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.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Federal Highway Administration, *Highway Statistics 1991*; Oak Ridge National Laboratory, *Transportation Energy Data Book: 12 and 13*, (March 1993); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, February 1993; Energy Information Administration (EIA), *Residential Transportation Energy Consumption Survey 1991*; Argonne National Laboratory, FRATE Model 1990. 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

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

Supply, Disposition, and Prices	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Generation by Fuel Type							
Coal	1560	1576	1714	1781	1990	1.2%	1.3%
Petroleum	117	89	94	91	68	-2.7%	-1.5%
Natural Gas	264	264	354	398	371	1.7%	1.9%
Nuclear Power	577	619	671	680	612	0.3%	-0.1%
Pumped Storage/Other[1]	-2	-4	-11	-11	-11	9.1%	5.8%
Renewable Sources[2]	293	254	306	311	324	0.5%	1.4%
Total	**2809**	**2798**	**3127**	**3250**	**3354**	**0.9%**	**1.0%**
Nonutilities (excluding cogenerators)[3]							
Generation by Fuel Type							
Coal	1	2	9	9	71	26.6%	23.8%
Petroleum/Other[4]	1	1	1	1	0	-4.7%	-5.0%
Natural Gas	9	16	91	178	186	16.4%	14.6%
Renewable Sources[2]	29	40	70	99	158	8.9%	7.9%
Total	**39**	**60**	**171**	**287**	**415**	**12.5%**	**11.3%**
Cogeneration[5]	**178**	**192**	**215**	**230**	**246**	**1.6%**	**1.4%**
Net Imports	**2**	**28**	**26**	**28**	**30**	**14.5%**	**0.4%**
Electricity Sales by Sector							
Residential	924	936	1012	1053	1108	0.9%	0.9%
Commercial	839	850	979	1035	1071	1.2%	1.3%
Industrial	946	973	1162	1281	1396	2.0%	2.0%
Transportation	4	4	25	39	57	14.2%	15.8%
Total	**2713**	**2763**	**3178**	**3408**	**3631**	**1.5%**	**1.5%**
End-Use Prices (1992 cents per kilowatthour)[6]							
Residential	8.5	8.1	8.8	9.4	10.3	1.0%	1.4%
Commercial	7.7	7.5	7.8	8.0	8.4	0.4%	0.6%
Industrial	5.2	5.1	5.2	5.3	5.7	0.5%	0.7%
Transportation	5.1	5.1	5.2	5.3	5.5	0.3%	0.4%
All Sectors Average	**7.1**	**6.8**	**7.1**	**7.4**	**7.9**	**0.5%**	**0.8%**
Price Components (1992 cents per kilowatthour)[6]							
Capital Component	3.0	2.9	2.7	2.7	2.8	-0.3%	-0.1%
Fuel Component	1.4	1.3	1.5	1.6	1.8	1.2%	2.0%
O&M Component	2.6	2.6	2.6	2.6	2.6	0.1%	0.1%
Net Wholesale Power Component	0.1	0.1	0.3	0.5	0.7	8.2%	9.2%
Total	**7.1**	**6.8**	**7.1**	**7.4**	**7.9**	**0.5%**	**0.8%**

[1]Other includes methane and propane and blast furnace gas.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[3]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for delivery to the grid.
[4]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[5]Includes cogeneration at industrial, commercial, and other facilities whose primary function is not electricity production. Includes both sales to utilities and generation for own use.
[6]Prices represent average revenue per kilowatthour.
O&M = Operation and maintenance.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). 1990 Nonutility generation: Form EIA-861, "Annual Electric Utility Report" and the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is filed by nonutilities reporting the electricity delivered, while the EIA-861 is filed by electric utilities reporting the electricity received. Because the Form EIA-861 collects data from the universe of utilities, these data are used for electricity sold to utilities. Own use data is from Form EIA-867. **Prices, 1992 cogeneration, 1992 prices, and all projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Capability							
Coal Steam	299.5	298.7	297.2	299.3	335.9	0.6%	0.7%
Other Fossil Steam[2]	143.9	142.5	129.7	123.5	120.4	-0.9%	-0.9%
Combined Cycle	7.2	7.8	17.7	31.1	36.9	8.5%	9.0%
Combustion Turbine/Diesel	45.6	47.9	64.7	72.1	74.0	2.4%	2.4%
Nuclear Power	99.6	99.0	102.6	103.8	90.7	-0.5%	-0.5%
Pumped Storage/Other[3]	17.6	19.1	20.2	20.2	20.2	0.7%	0.3%
Renewable Sources[4]	76.0	76.2	77.5	78.9	83.1	0.4%	0.5%
Total	**689.4**	**691.2**	**709.6**	**728.9**	**761.1**	**0.5%**	**0.5%**
Cumulative Planned Additions[5]							
Coal Steam	0.00	1.29	8.30	13.35	16.25	N/A	N/A
Other Fossil Steam[2]	0.00	0.95	1.54	1.64	1.64	N/A	N/A
Combined Cycle	0.00	0.67	9.14	14.30	14.99	N/A	N/A
Combustion Turbine/Diesel	0.00	2.50	18.84	24.18	24.55	N/A	N/A
Nuclear Power	0.00	0.00	4.70	5.91	5.91	N/A	N/A
Pumped Storage/Other[3]	0.00	1.41	2.56	2.56	2.56	N/A	N/A
Renewable Sources[4]	0.00	0.28	1.13	1.14	1.14	N/A	N/A
Total	**0.00**	**7.10**	**46.20**	**63.08**	**67.03**	**N/A**	**N/A**
Cumulative Unplanned Additions[5]						N/A	N/A
Coal Steam	0.00	0.00	0.00	0.17	36.63	N/A	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Combined Cycle	0.00	0.00	1.56	9.76	14.82	N/A	N/A
Combustion Turbine/Diesel	0.00	0.00	0.76	4.47	6.05	N/A	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[3]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	0.00	0.00	0.37	1.70	5.84	N/A	N/A
Total	**0.00**	**0.00**	**2.68**	**16.10**	**63.34**	**N/A**	**N/A**
Cumulative Total Utility Additions[5]	**0.00**	**7.10**	**48.89**	**79.18**	**130.38**	**N/A**	**N/A**
Cumulative Utility Retirements	**1.20**	**6.46**	**30.34**	**41.38**	**60.43**	**N/A**	**N/A**
Nonutilities (excludes cogenerators)[6]							
Installed Capability[7]							
Coal Steam	0.09	0.35	1.51	1.51	11.26	27.2%	21.3%
Other Fossil Steam[2]	0.23	0.40	0.83	0.83	0.83	6.6%	4.1%
Combined Cycle	1.27	2.88	11.37	25.00	28.77	16.9%	13.6%
Combustion Turbine/Diesel	0.90	1.48	7.95	12.86	15.66	15.4%	14.0%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[8]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	6.64	7.42	13.90	18.61	32.47	8.3%	8.5%
Total	**9.13**	**12.53**	**35.55**	**58.81**	**88.99**	**12.1%**	**11.5%**
Cogenerators[7,9]	**33.74**	**37.78**	**43.48**	**43.96**	**44.37**	**1.4%**	**0.9%**
Cumulative Nonutility Additions[5,7]	**0.00**	**7.44**	**36.16**	**59.90**	**90.50**	**N/A**	**14.9%**

[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]Other includes methane and propane and blast furnace gas.

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

[5]Cumulative additions after December 31, 1990.

[6]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for sales to the grid.

[7]Nameplate capacity is reported for nonutilities. Nameplate capacity is designated by the manufacturer.

[8]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[9]Includes cogenerators at industrial, commercial, and other facilities whose primary function is not electricity productionN/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992: EIA, *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	146.3	146.3	118.4	115.4	115.4	-1.2%	-1.3%
Gross Domestic Economy Sales	89.0	89.6	80.8	98.3	106.1	0.9%	0.9%
Gross Domestic Trade	**235.4**	**235.9**	**199.1**	**213.8**	**221.6**	**-0.3%**	**-0.3%**
Gross Domestic Firm Power Sales (million 1992 dollars)	6188.8	6407.3	5954.1	6332.2	6906.0	0.5%	0.4%
Gross Domestic Economy Sales (million 1992 dollars)	1720.7	1645.6	2135.8	3240.1	3797.6	4.0%	4.8%
Gross Domestic Sales (million 1992 dollars)	7909.4	8052.8	**8089.9**	**9572.3**	**10703.6**	**1.5%**	**1.6%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	5.6	14.2	14.4	14.4	14.4	4.8%	0.1%
Economy Imports From Canada and Mexico	16.9	23.8	27.2	29.5	31.9	3.2%	1.6%
Gross Imports From Canada and Mexico	**22.5**	**38.0**	**41.6**	**43.9**	**46.4**	**3.7%**	**1.1%**
Firm Power Exports To Canada and Mexico	1.7	4.7	8.8	8.8	8.8	8.5%	3.6%
Economy Exports To Canada and Mexico	18.8	5.6	6.4	7.0	7.7	-4.4%	1.7%
Gross Exports To Canada and Mexico	**20.5**	**10.3**	**15.2**	**15.7**	**16.4**	**-1.1%**	**2.6%**

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. Electricity trade among utilities in the same region is excluded from these data.

Sources: 1990 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1990 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1990 firm/interruptible share: National Energy Board, *Annual Report 1990.* Planned interregional and international firm power sales (1993 through 2001): DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1992. **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

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

Supply and Disposition	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil[1]	7.36	7.17	5.22	4.90	5.16	-1.8%	-1.8%
Alaska	1.77	1.71	0.88	0.60	0.75	-4.2%	-4.5%
Lower 48 States	5.58	5.46	4.34	4.30	4.41	-1.2%	-1.2%
Natural Gas Plant Liquids	1.56	1.70	1.89	2.03	2.05	1.4%	1.1%
Total	**8.91**	**8.87**	**7.12**	**6.93**	**7.21**	**-1.1%**	**-1.1%**
Net Imports							
Crude Oil (including SPR)[2]	5.78	5.99	8.58	9.17	8.91	2.2%	2.2%
Refined Products[3]	0.90	0.45	2.64	3.43	4.28	8.1%	13.3%
Total	**6.68**	**6.44**	**11.21**	**12.60**	**13.19**	**3.5%**	**4.1%**
Other Inputs[4]	**0.49**	**0.58**	**0.75**	**0.76**	**0.88**	**3.0%**	**2.4%**
Refinery Processing Gain[5]	**0.68**	**0.77**	**0.76**	**0.79**	**0.84**	**1.0%**	**0.5%**
SPR Fill Rate Additions(-)[2]	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**0.0%**	**0.0%**
Total Primary Supply[6]	**16.75**	**16.64**	**19.82**	**21.07**	**22.10**	**1.4%**	**1.6%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.23	7.27	8.12	8.41	8.58	0.9%	0.9%
Jet Fuel[8]	1.52	1.45	1.84	2.04	2.25	2.0%	2.5%
Distillate Fuel	3.02	2.98	3.76	4.07	4.39	1.9%	2.2%
Residual Fuel	1.23	1.09	1.33	1.40	1.38	0.6%	1.3%
Other[9]	3.98	4.24	4.69	5.03	5.41	1.5%	1.4%
Total	**16.99**	**17.03**	**19.74**	**20.96**	**22.00**	**1.3%**	**1.4%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.15	1.16	1.18	1.16	1.14	0.0%	-0.1%
Industrial[10]	4.32	4.33	5.17	5.55	5.95	1.6%	1.8%
Transportation	10.98	11.01	12.89	13.76	14.53	1.4%	1.6%
Electric Utilities[11]	0.55	0.52	0.50	0.49	0.38	-1.8%	-1.8%
Total	**16.99**	**17.03**	**19.74**	**20.96**	**22.00**	**1.3%**	**1.4%**
Discrepancy[12]	**-0.24**	**-0.39**	**0.08**	**0.11**	**0.10**	**N/A**	**N/A**
World Oil Price (1992 dollars per barrel)[13]	**23.22**	**18.20**	**21.32**	**25.45**	**28.81**	**1.1%**	**2.6%**
Domestic Refinery Distillation Capacity	**15.6**	**15.5**	**15.4**	**15.6**	**15.6**	**0.0%**	**0.1%**
Capacity Utilization Rate (percent)	**87.1**	**87.9**	**89.7**	**90.0**	**90.0**	**0.2%**	**0.1%**

[1]Includes lease condensate.
[2]SPR is the Strategic Petroleum Reserve.
[3]Net imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[4]Includes alcohols, ethers, and imports of unfinished oils.
[5]Represents volumetric gain in refinery distillation and cracking processes.
[6]Total production plus net imports plus other inputs plus refinery processing gain minus SPR additions.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[10]Includes consumption by cogenerators.
[11]Includes consumption by independent power producers.
[12]Balancing item. Includes unaccounted for supply, losses and gains.
[13]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: 1990: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, D.C., May 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B12. Petroleum Product Prices

(1992 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (dollars per barrel)	**23.22**	**18.20**	**21.32**	**25.45**	**28.81**	**1.1%**	**2.6%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	118.5	92.7	106.1	117.9	128.5	0.4%	1.8%
Liquefied Petroleum Gas	106.6	86.7	97.3	107.3	117.6	0.5%	1.7%
Commercial							
Distillate Fuel	90.3	66.0	74.3	85.9	96.3	0.3%	2.1%
Residual Fuel	54.8	39.3	55.7	64.9	72.2	1.4%	3.4%
Residual Fuel (dollars per barrel)	23.02	16.50	23.41	27.24	30.32	1.4%	3.4%
Industrial							
Distillate Fuel	84.1	67.6	73.9	85.7	96.4	0.7%	2.0%
Liquefied Petroleum Gas	52.6	42.7	56.8	66.9	76.5	1.9%	3.3%
Petrochemical Feedstocks	83.7	64.1	52.1	62.2	72.3	-0.7%	0.7%
Residual Fuel	49.5	38.0	54.9	65.7	75.0	2.1%	3.8%
Residual Fuel (dollars per barrel)	20.80	15.95	23.04	27.59	31.48	2.1%	3.8%
Transportation							
Distillate Fuel[1]	125.2	111.2	130.5	145.1	157.3	1.1%	1.9%
Jet Fuel[2]	81.8	61.0	74.6	86.8	97.6	0.9%	2.6%
Motor Gasoline[3]	121.7	113.7	130.5	142.9	154.4	1.2%	1.7%
Residual Fuel	47.6	32.1	49.7	60.0	70.2	2.0%	4.5%
Residual Fuel (dollars per barrel)	19.99	13.47	20.89	25.18	29.49	2.0%	4.5%
Electric Utilities							
Distillate Fuel	83.2	62.6	69.1	80.9	91.8	0.5%	2.1%
Residual Fuel	52.7	37.5	54.8	64.9	74.2	1.7%	3.9%
Residual Fuel (dollars per barrel)	22.14	15.77	23.03	27.28	31.18	1.7%	3.9%
Refined Petroleum Product Prices[4]							
Distillate Fuel	113.9	97.6	113.1	127.1	139.5	1.0%	2.0%
Jet Fuel	81.8	61.0	74.6	86.8	97.6	0.9%	2.6%
Liquefied Petroleum Gas	58.9	51.9	64.8	74.9	84.8	1.8%	2.8%
Motor Gasoline	121.7	113.7	130.5	142.9	154.4	1.2%	1.7%
Petrochemical Feedstocks	83.7	64.1	52.1	62.2	72.3	-0.7%	0.7%
Residual Fuel	50.6	35.5	52.7	62.7	72.0	1.8%	4.0%
Residual Fuel (dollars per barrel)	21.26	14.90	22.11	26.32	30.25	1.8%	4.0%
Average	**102.2**	**90.8**	**105.0**	**116.5**	**127.2**	**1.1%**	**1.9%**

[1]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.

[2]Kerosene-type jet fuel.

[3]Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.

[4]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1990 prices: Energy Information Administration (EIA), *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1992 prices for gasoline, distillate, and jet fuel are based on prices in the EIA, *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, D.C., July 1993). 1992 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). **Projections**: EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B13. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Dry Gas Production[1]	17.81	17.84	19.63	21.06	21.31	0.9%	1.0%
Supplemental Natural Gas[2]	0.12	0.12	0.11	0.12	0.08	-2.0%	-2.2%
Net Imports	**1.45**	**1.92**	**2.93**	**3.31**	**3.85**	**5.0%**	**3.9%**
Canada	1.43	2.03	2.67	2.76	2.92	3.6%	2.0%
Mexico	-0.02	-0.10	-0.05	0.00	0.17	N/A	N/A
LNG	0.03	-0.01	0.31	0.55	0.75	17.2%	N/A
Total Supply	**19.38**	**19.88**	**22.67**	**24.50**	**25.24**	**1.3%**	**1.3%**
Consumption by Sector							
Residential	4.39	4.69	4.92	4.92	5.00	0.7%	0.4%
Commercial	2.62	2.80	2.81	2.88	2.97	0.6%	0.3%
Industrial[3]	7.02	7.53	8.19	8.77	9.38	1.5%	1.2%
Electric Utilities[4]	2.79	2.77	4.59	5.56	5.23	3.2%	3.6%
Lease and Plant Fuel[5]	1.24	1.17	1.36	1.43	1.57	1.2%	1.7%
Pipeline Fuel	0.66	0.59	0.69	0.72	0.77	0.8%	1.5%
Transportation[6]	0.00	0.00	0.13	0.23	0.35	N/A	N/A
Total	**18.72**	**19.54**	**22.70**	**24.52**	**25.27**	**1.5%**	**1.4%**
Discrepancy[7]	**0.66**	**0.33**	**-0.03**	**-0.03**	**-0.03**	**N/A**	**N/A**
Average Wellhead Price[8] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.56**	**3.32**	**3.88**	**3.8%**	**4.5%**
Delivered Prices (1992 dollars per thousand cubic feet)							
Residential	6.19	5.89	7.40	8.26	8.94	1.9%	2.3%
Commercial	5.15	4.88	6.35	7.20	7.86	2.1%	2.7%
Industrial[9]	3.57	3.17	4.08	4.80	5.42	2.1%	3.0%
Electric Utilities	2.54	2.36	3.14	4.01	4.58	3.0%	3.7%
Transportation	3.62	4.05	10.03	11.05	11.94	6.1%	6.2%
Average[10]	**4.33**	**4.03**	**5.01**	**5.74**	**6.41**	**2.0%**	**2.6%**

[1]Dry marketed production minus nonhydrocarbon gases removed.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributes with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Reflects natural gas lost, the net 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.
[8]Represents Lower-48 onshore and offshore supplies.
[9]Excludes uses for lease and plant fuel.
[10]Weighted average price. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 industrial and transportation delivered prices: Energy Information Administration (EIA), AEO 1994 National Energy Modeling System run HMAC94.D1221932. Other 1990 and 1992: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B14. Oil and Gas Supply

Production and Supply	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Crude Oil							
Lower 48 Average Wellhead Price[1] (1992 dollars per barrel)	23.02	17.38	20.74	24.49	27.57	0.9%	2.6%
Production (million barrels per day)[2]							
U.S. Total	7.36	7.17	5.21	4.90	5.16	-1.8%	-1.8%
Lower 48 Onshore	4.63	4.38	3.65	3.63	3.67	-1.2%	-1.0%
Conventional	3.97	3.68	3.08	2.92	2.83	-1.7%	-1.4%
Enhanced Oil Recovery	0.66	0.71	0.57	0.71	0.84	1.2%	1.0%
Lower 48 Offshore	0.95	1.07	0.68	0.67	0.74	-1.3%	-2.0%
Alaska	1.77	1.71	0.88	0.60	0.75	-4.2%	-4.5%
U.S. End of Year Reserves (billion barrels)	27.56	24.97	18.92	17.58	18.43	-2.0%	-1.7%
Natural Gas							
Lower 48 Average Wellhead Price[1] (1992 dollars per thousand cubic feet)	1.83	1.75	2.56	3.32	3.88	3.8%	4.5%
Production (trillion cubic feet)[3]							
U.S. Total	17.81	17.84	19.63	21.06	21.31	0.9%	1.0%
Lower 48 Onshore	12.15	12.50	15.13	15.36	14.95	1.0%	1.0%
Associated-Dissolved[4]	2.07	2.11	1.66	1.65	1.69	-1.0%	-1.2%
Non-Associated	10.08	10.39	13.48	13.71	13.27	1.4%	1.4%
Conventional	8.63	8.53	10.14	10.20	9.89	0.7%	0.8%
Unconventional	1.45	1.86	3.33	3.51	3.38	4.3%	3.4%
Tight Sands	1.13	1.19	2.03	2.19	2.20	3.4%	3.5%
Coal Bed Methane	0.19	0.51	0.94	0.95	0.83	7.7%	2.7%
Devonian Shale	0.12	0.16	0.36	0.36	0.35	5.3%	4.4%
Lower 48 Offshore	5.28	4.93	4.00	5.22	5.29	0.0%	0.4%
Associated-Dissolved[4]	0.63	0.68	0.58	0.58	0.60	-0.3%	-0.7%
Non-Associated	4.65	4.25	3.42	4.64	4.69	0.0%	0.5%
Alaska	0.38	0.41	0.50	0.49	1.07	5.3%	5.5%
U.S. End of Year Reserves (trillion cubic feet)	169.35	165.02	165.16	159.87	165.84	-0.1%	0.0%
Supplemental Gas Supplies[5]	0.12	0.12	0.11	0.12	0.08	-2.0%	-2.2%
Total Wells Completed	31.17	23.01	39.08	58.60	81.71	4.9%	7.3%

[1]Represents Lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Dry marketed production minus nonhydrocarbon gases removed.
[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: 1990: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - Energy Information Administration (EIA), *Petroleum Supply Annual 1990*, DOE/EIA-340(90)/1 (Washington, D.C., May 1991); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90) (Washington, D.C., September 1991). 1992: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - EIA, *Petroleum Supply Annual 1992*, DOE/EIA-340(92)/1 (Washington, D.C., May 1993); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, D.C., October 1993). 1990 and 1992: Crude Oil Lower 48 Average Wellhead Prices - EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993); Natural Gas Lower 48 Average Wellhead Prices, Alaska and Total Natural Gas Production, Supplemental Gas Supplies - EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, D.C., November 1993); Total Wells Completed - *Monthly Energy Review*, DOE/EIA-0035(93/11) (Washington, D.C., November 1993). Other 1990 and 1992 values - EIA, Office of Integrated Analysis and Forecasting. Figures for 1990 and 1992 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production[1]							
East of the Mississippi	630	589	644	640	672	0.3%	0.7%
West of the Mississippi	399	409	450	504	615	2.2%	2.3%
Total	**1029**	**998**	**1094**	**1144**	**1287**	**1.1%**	**1.4%**
Net Imports							
Imports	3	4	10	10	11	7.1%	5.9%
Exports	106	103	133	144	152	1.8%	2.2%
Total	**-103**	**-99**	**-123**	**-134**	**-142**	**1.6%**	**2.0%**
Total Supply[2]	**926**	**899**	**971**	**1010**	**1145**	**1.1%**	**1.4%**
Consumption by Sector							
Residential and Commercial	7	6	6	6	5	-1.0%	-0.8%
Industrial[3]	76	74	89	100	109	1.8%	2.2%
Coke Plants	39	32	28	24	22	-2.9%	-2.2%
Electricity[4]	774	780	847	879	1006	1.3%	1.4%
Total	**895**	**892**	**971**	**1009**	**1142**	**1.2%**	**1.4%**
Discrepancy and Stock Change[5]	**31**	**-6**	**1**	**1**	**4**	**-10.2%**	**N/A**
Average Minemouth Price[6] (1992 dollars per short ton)	**23.22**	**21.03**	**26.86**	**27.45**	**32.95**	**1.8%**	**2.5%**
Delivered Prices (1992 dollars per short ton)							
Industrial	35.85	32.78	39.11	40.00	43.35	1.0%	1.6%
Coke Plants	50.93	47.92	57.32	58.98	57.81	0.6%	1.0%
Electricity	32.49	29.36	35.60	36.33	43.17	1.4%	2.2%
Average[7]	**33.59**	**30.32**	**36.55**	**37.25**	**43.46**	**1.3%**	**2.0%**
Average Price to All Users (1992 dollars per million Btu)	**1.58**	**1.42**	**1.71**	**1.74**	**2.05**	**1.3%**	**2.1%**
Exports[8]	45.49	41.34	53.04	54.44	55.48	1.0%	1.6%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Balancing item: the sum of production and net imports, minus total consumption.
[6]Free-on-board price.
[7]Weighted average prices. Weights used are consumption values by sector. Average of Industrial, Coke Plant, and Electricity Sectors.
[8]Free alongside ship price at U.S. port-of-exit.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121 (90/4Q) (Washington, D.C., May 1991); and EIA, *Coal Production 1990*, DOE/EIA-0118(90) (Washington, D.C., September 1991). 1992: EIA, *Quarterly Coal Report*, DOE/EIA-0121(93/2Q) (Washington, D.C., November 1993); and EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, D.C., October 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B16. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Nonelectric	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electricity							
Capability (gigawatts)							
Conventional Hydropower	75.30	75.54	78.31	78.44	78.58	0.2%	0.2%
Geothermal[1]	2.91	2.89	5.57	6.56	8.54	5.5%	6.2%
Municipal Solid Waste	2.13	2.66	3.70	4.58	5.50	4.9%	4.1%
Biomass/Other Waste[2]	6.86	7.29	9.41	12.47	15.59	4.2%	4.3%
Solar[3]	0.36	0.36	0.73	0.98	1.33	6.7%	7.5%
Wind[4]	1.55	1.65	2.07	3.78	16.30	12.5%	13.6%
Total	**89.11**	**90.40**	**99.78**	**106.81**	**125.84**	**1.7%**	**1.9%**
Generation (billion kilowatthours)							
Conventional Hydropower	288.04	247.88	305.19	306.09	306.88	0.4%	1.3%
Geothermal[1]	15.86	16.68	36.16	43.21	57.18	6.6%	7.1%
Municipal Solid Waste	12.32	17.24	20.64	27.16	34.02	5.8%	4.3%
Biomass/Other Waste[2]	34.14	41.73	49.33	67.33	85.68	13.8%	14.0%
Solar[3]	0.70	1.75	2.36	3.37	4.82	10.1%	5.8%
Wind[4]	2.38	2.91	3.84	9.11	44.81	15.8%	16.4%
Total	**353.44**	**328.19**	**417.52**	**456.27**	**533.39**	**2.1%**	**2.8%**
Consumption Equivalent							
Conventional Hydropower	2.98	2.57	3.16	3.17	3.18	0.4%	1.3%
Geothermal[1]	0.16	0.17	0.37	0.45	0.59	6.6%	7.2%
Municipal Solid Waste	0.13	0.18	0.21	0.28	0.35	5.8%	4.5%
Biomass/Other Waste[2]	0.35	0.43	0.51	0.70	0.89	13.8%	17.3%
Solar[3]	0.01	0.01	0.02	0.03	0.05	10.1%	9.3%
Wind[4]	0.02	0.03	0.04	0.09	0.46	15.8%	16.7%
Total	**3.66**	**3.40**	**4.32**	**4.72**	**5.52**	**2.1%**	**2.8%**
Nonelectric Renewable Energy							
Residential, Commercial, and Industrial							
Geothermal	0.01	0.01	0.02	0.02	0.03	8.6%	8.1%
Biofuels	2.53	2.57	3.08	3.34	3.63	1.8%	1.9%
Solar Thermal	0.02	0.02	0.04	0.04	0.04	3.9%	4.1%
Transportation							
Ethanol	0.06	0.09	0.12	0.13	0.16	4.9%	3.1%
Total	**2.62**	**2.69**	**3.25**	**3.53**	**3.85**	**2.1%**	**2.2%**
Total Renewable Energy	**6.28**	**6.07**	**7.57**	**8.25**	**9.36**	**2.1%**	**2.1%**

[1]Includes hydrothermal resources only (hot water and steam).
[2]Does not include projections for energy crops.
[3]Utility-grid connected generation only.
[4]Includes horizontal-axis wind turbines only.
Btu = British thermal unit.
Note: Includes renewables used in industrial power generation and cogeneration.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 ethanol: Energy Information Administration (EIA), *Weekly Petroleum Status Report*, DOE/EIA-0208(93-01) (Washington, D.C., January 1993). Other 1990 and 1992: EIA, sum of EIA-860 "Annual Electric Generator Report" and EIA-867 "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B17. Carbon Emissions by End-Use Sector and Source

(Million Metric Tons per Year)

Sector and Source	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Petroleum	24.0	25.7	25.3	24.8	24.3	0.1%	-0.3%
Natural Gas	65.0	69.3	73.0	72.9	74.1	0.7%	0.4%
Coal	1.6	1.4	1.3	1.3	1.2	-1.3%	-0.8%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**90.6**	**96.4**	**99.5**	**99.0**	**99.6**	**0.5%**	**0.2%**
Commercial							
Petroleum	18.1	18.1	18.5	18.4	18.3	0.0%	0.0%
Natural Gas	38.7	39.9	41.6	42.5	43.9	0.6%	0.5%
Coal	2.3	2.3	2.2	2.2	2.2	-0.4%	-0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	2.6%	0.2%
Total	**59.2**	**60.3**	**62.4**	**63.1**	**64.3**	**0.4%**	**0.4%**
Industrial[1]							
Petroleum	91.9	85.1	108.7	113.8	119.2	1.3%	1.9%
Natural Gas[2]	119.6	123.0	139.5	149.1	159.7	1.5%	1.5%
Coal	67.8	62.2	67.1	71.4	74.0	0.4%	1.0%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**279.3**	**270.4**	**315.3**	**334.2**	**352.8**	**1.2%**	**1.5%**
Transportation							
Petroleum	422.3	428.8	483.6	512.5	536.7	1.2%	1.3%
Natural Gas[3]	9.9	9.8	12.5	14.9	17.7	2.9%	3.3%
Renewable/Other[4]	0.0	0.0	0.3	0.8	1.6	35.4%	31.1%
Total	**432.2**	**438.6**	**496.3**	**528.1**	**555.7**	**1.3%**	**1.3%**
Electric Utilities[5]							
Petroleum	26.8	17.2	20.7	20.3	15.0	-2.8%	-0.7%
Natural Gas	41.2	42.8	67.7	82.1	77.1	3.2%	3.3%
Steam Coal	408.8	414.8	452.0	469.8	537.0	1.4%	1.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	5.4%
Total	**476.7**	**474.8**	**540.4**	**572.2**	**629.1**	**1.4%**	**1.6%**
Total Energy Consumption							
Petroleum	583.2	574.9	656.7	689.8	713.5	1.0%	1.2%
Natural Gas	274.4	284.8	334.2	361.5	372.4	1.5%	1.5%
Coal	480.4	480.7	522.7	544.6	614.3	1.2%	1.4%
Renewable Energy	0.0	0.0	0.2	0.5	0.9	33.4%	25.2%
Other[4]	0.0	0.0	0.1	0.4	0.7	38.7%	29.2%
Total	**1338.0**	**1340.5**	**1513.9**	**1596.7**	**1701.8**	**1.2%**	**1.3%**

[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 consumption of energy by electric utilities, independent power producers, and small power producers that sell electricity to utilities.
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, 1985 - 1990*, DOE/EIA-0573 (Washington, D.C., September 1993), Table 11, p. 15. 1990 consumption estimates: EIA, *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). **Consumption projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B18. Macroeconomic Indicators

(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
GDP Implicit Price Deflator (index 1987=1.000)	1.132	1.208	1.412	1.596	1.813	2.4%	2.3%
Real Gross Domestic Product	4877	4920	6233	7048	7864	2.4%	2.6%
Real Consumption	3260	3312	3967	4328	4758	1.9%	2.0%
Real Investment	739	712	1229	1462	1678	4.2%	4.9%
Real Government Spending	930	938	1018	1100	1179	1.2%	1.3%
Real Exports	510	571	964	1324	1685	6.2%	6.2%
Real Imports	562	614	945	1166	1436	4.8%	4.8%
Real Disposable Personal Income	3517	3584	4259	4647	5089	1.9%	2.0%
Index of Manufacturing Gross Output (index 1987=1.000)	1.087	1.094	1.417	1.631	1.868	2.7%	3.0%
AA Utility Bond Rate (percent)	9.66	8.55	7.36	7.24	6.90	-1.7%	-1.2%
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	3.43	3.48	3.43	3.12	-4.3%	-0.5%
Real Yield on Government 10 Year Bonds (percent)	4.91	3.61	3.86	3.58	3.29	-2.0%	-0.5%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	15.68	14.70	13.92	-1.1%	-1.2%
Consumer Price Index (1982=1.00)	1.31	1.40	1.74	2.02	2.33	2.9%	2.9%
Employment Cost Index (1987=1.00)	1.05	1.12	1.39	1.64	1.93	3.1%	3.1%
Unemployment Rate (percent)	5.52	7.40	5.51	5.69	5.96	0.4%	-1.2%
Million Units							
Truck Deliveries, Light-Duty	4.39	4.50	5.86	6.58	7.07	2.4%	2.5%
Unit Sales of Automobiles	9.51	8.35	10.16	10.69	11.22	0.8%	1.7%
U.S. Trade-Weighted Exchange Rate	0.87	0.84	0.86	0.84	0.83	-0.2%	-0.1%
Millions of People							
Population with Armed Forces Overseas	250.3	255.8	279.6	294.1	309.0	1.1%	1.1%
Population (aged 16 and over)	192.7	196.3	215.7	228.9	242.8	1.2%	1.2%
Employment, Non-Agriculture	109.8	108.4	126.3	135.5	143.7	1.4%	1.6%

GDP = Gross domestic product.

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

Sources: 1990 and 1992: Data Resources Incorporated (DRI), DRI Trend0293. **Projections:** Energy Information Administration, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

Table B19. International Petroleum Supply and Disposition Summary

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (1992 dollars per barrel)[1]	**23.22**	**18.20**	**21.32**	**25.45**	**28.81**	**1.1%**	**2.6%**
Production[2]							
U.S. (50 states)	9.59	9.77	8.11	7.97	8.31	-0.7%	-0.9%
Canada	2.03	2.12	2.23	2.54	2.47	1.0%	0.9%
OECD Europe[3]	4.58	5.08	6.42	5.30	4.76	0.2%	-0.4%
OPEC	25.04	26.38	35.52	40.89	44.06	2.9%	2.9%
Rest of the World[4]	11.06	11.00	12.98	12.30	12.11	0.5%	0.5%
Total Production	**52.30**	**54.35**	**65.26**	**69.00**	**71.71**	**1.6%**	**1.6%**
Net Eurasian Exports	**1.88**	**1.58**	**1.24**	**1.42**	**1.60**	**-0.8%**	**0.1%**
Total Supply	**53.60**	**55.93**	**66.50**	**70.42**	**73.31**	**1.6%**	**1.5%**
Consumption							
U.S. (50 states)	16.99	17.03	19.74	20.97	22.00	1.3%	1.4%
U.S. Territories	0.21	0.21	0.25	0.27	0.27	1.3%	1.3%
Canada	1.69	1.64	1.86	1.87	1.87	0.5%	0.7%
Japan	5.14	5.45	6.72	7.04	7.12	1.6%	1.5%
Australia & New Zealand	0.82	0.82	0.94	1.00	1.06	1.3%	1.4%
OECD Europe	12.90	13.61	15.38	15.75	15.82	1.0%	0.8%
Rest of the World[4]	15.78	17.56	21.91	23.81	25.47	2.4%	2.1%
Total Consumption	**53.53**	**56.33**	**66.80**	**70.72**	**73.61**	**1.6%**	**1.5%**
Discrepancy	**-0.07**	**0.40**	**0.30**	**0.30**	**0.30**	**N/A**	**-1.6%**
Consumption Aggregations							
OECD	37.75	38.77	44.89	46.90	48.14	1.2%	1.2%
OPEC	4.61	4.95	5.89	6.51	7.18	2.2%	2.1%
Rest of the World[4]	11.18	12.61	16.02	17.31	18.29	2.5%	2.1%
Non-OPEC Production[4]	**27.26**	**27.97**	**29.75**	**28.10**	**27.64**	**0.1%**	**-0.1%**
OPEC Summary							
Market Share	0.47	0.47	0.53	0.58	0.60	1.2%	1.4%
Production Capacity[5]	29.80	28.90	38.40	44.10	47.75	2.4%	2.8%
Capacity Utilization	0.84	0.91	0.92	0.93	0.92	0.5%	0.1%

[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: 1990: Energy Information Administration (EIA), *International Energy Annual 1991*, DOE/EIA-0219(93); and EIA, International Petroleum Statistics Report, DOE/EIA-0520(93/07). 1992: EIA, *International Energy Annual 1992*, DOE/EIA-0219(94); and EIA, *Monthly Energy Review*, DOE/EIA-0035(93/12). **Projections:** EIA, AEO 1994 National Energy Modeling System run HMAC94.D1221932.

LOW ECONOMIC GROWTH CASE PROJECTIONS

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

Supply, Disposition, and Prices	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil and Lease Condensate	15.57	15.22	10.94	10.15	10.66	-1.9%	-2.0%
Natural Gas Plant Liquids	2.17	2.36	2.47	2.55	2.57	0.9%	0.5%
Dry Natural Gas[1]	18.49	18.51	19.07	19.75	19.83	0.4%	0.4%
Coal	22.46	21.62	23.02	23.96	25.22	0.6%	0.9%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[2]	6.20	6.28	7.19	7.70	8.48	1.6%	1.7%
Total	**71.08**	**70.64**	**69.90**	**71.41**	**73.33**	**0.2%**	**0.2%**
Imports							
Crude Oil[3]	12.80	13.24	18.74	19.66	19.22	2.1%	2.1%
Petroleum Products[4]	3.40	2.71	6.37	7.87	9.10	5.0%	7.0%
Natural Gas	1.54	2.15	3.19	3.59	4.16	5.1%	3.7%
Other Imports[5]	0.73	0.96	1.44	1.39	1.48	3.6%	2.4%
Total	**18.46**	**19.07**	**29.73**	**32.52**	**33.96**	**3.1%**	**3.3%**
Exports							
Petroleum	1.82	2.02	2.12	2.12	2.12	0.7%	0.2%
Natural Gas	0.09	0.22	0.24	0.27	0.30	6.4%	1.7%
Coal	2.70	2.68	3.31	3.54	3.75	1.7%	1.9%
Total	**4.61**	**4.92**	**5.68**	**5.92**	**6.17**	**1.5%**	**1.3%**
Discrepancy[6]	**-0.65**	**1.01**	**-0.02**	**0.14**	**0.13**	**N/A**	**-10.6%**
Consumption							
Petroleum Products[7]	33.55	33.65	37.50	39.18	40.51	0.9%	1.0%
Natural Gas	19.30	20.15	22.12	23.19	23.82	1.1%	0.9%
Coal	19.01	18.99	19.87	20.67	21.69	0.7%	0.7%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[8]	6.23	6.37	7.24	7.81	8.67	1.7%	1.7%
Total	**84.28**	**85.80**	**93.93**	**98.14**	**101.26**	**0.9%**	**0.9%**
Net Imports - Petroleum	**14.37**	**13.93**	**22.99**	**25.42**	**26.20**	**3.0%**	**3.6%**
Prices (1992 dollars per unit)							
World Oil Price (dollars per barrel)[9]	23.22	18.20	20.20	24.31	27.31	0.8%	2.3%
Gas Wellhead Price (dollars per Mcf)[10]	1.83	1.75	2.31	2.51	2.93	2.4%	2.9%
Coal Minemouth Price (dollars per ton)	23.22	21.03	25.13	27.01	29.97	1.3%	2.0%

[1]Includes synthetic gas.

[2]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, liquid hydrogen, and methanol.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Imports of finished petroleum products. Does not include imports of unfinished oils or blending components.

[5]Includes coal, coal coke (net), and electricity (net), methanol, methyl tertiary butyl ether (MTBE), and imports of unfinished oils.

[6]Balancing item. Includes unaccounted for supply, losses, and gains.

[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and non-petroleum based liquids for blending, such as ethanol.

[8]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, plus 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.

Mcf = Thousand cubic feet.

N/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C2. Energy Consumption by End-Use Sector and Source

(Quadrillion Btu per Year)

Sector and Source	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Distillate Fuel	0.84	0.85	0.89	0.88	0.86	0.1%	0.1%
Kerosene	0.06	0.06	0.06	0.06	0.06	-0.7%	-0.4%
Liquefied Petroleum Gas	0.36	0.41	0.36	0.34	0.33	-0.5%	-1.2%
Natural Gas	4.52	4.83	4.93	4.88	4.84	0.3%	0.0%
Coal	0.06	0.06	0.05	0.05	0.05	-1.2%	-1.2%
Renewable Energy[1]	0.61	0.63	0.64	0.64	0.65	0.3%	0.1%
Electricity	3.15	3.19	3.33	3.39	3.48	0.5%	0.5%
Total	**9.61**	**10.04**	**10.27**	**10.23**	**10.25**	**0.3%**	**0.1%**
Commercial							
Distillate Fuel	0.49	0.49	0.51	0.50	0.48	-0.1%	-0.1%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.5%	-0.5%
Motor Gasoline[2]	0.11	0.09	0.11	0.11	0.11	0.2%	1.3%
Residual Fuel	0.23	0.23	0.22	0.22	0.22	-0.4%	-0.4%
Natural Gas	2.70	2.89	2.86	2.91	2.98	0.5%	0.2%
Other[3]	0.16	0.16	0.15	0.15	0.15	-0.2%	-0.2%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Electricity	2.86	2.91	3.26	3.36	3.38	0.8%	0.8%
Total	**6.57**	**6.78**	**7.16**	**7.30**	**7.36**	**0.6%**	**0.5%**
Industrial[5]							
Distillate Fuel	1.18	1.19	1.31	1.39	1.45	1.0%	1.1%
Liquefied Petroleum Gas	1.61	1.83	1.94	2.12	2.28	1.8%	1.2%
Motor Gasoline[2]	0.18	0.20	0.22	0.23	0.24	1.4%	1.1%
Petrochemical Feedstocks	1.10	1.23	1.29	1.41	1.51	1.6%	1.2%
Residual Fuel	0.42	0.34	0.48	0.45	0.43	0.1%	1.3%
Other Petroleum[6]	3.82	3.83	4.33	4.33	4.35	0.6%	0.7%
Natural Gas[7]	8.50	8.96	9.38	9.94	10.31	1.0%	0.8%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-3.0%	-2.3%
Steam Coal	1.71	1.65	1.84	2.01	2.12	1.1%	1.4%
Net Coal Coke Imports	0.00	0.03	0.01	0.01	0.01	N/A	-6.0%
Renewable Energy	1.96	1.99	2.32	2.51	2.68	1.6%	1.7%
Electricity	3.23	3.29	3.72	4.01	4.24	1.4%	1.4%
Total	**24.78**	**25.42**	**27.58**	**29.05**	**30.19**	**1.0%**	**1.0%**
Transportation							
Distillate Fuel	3.83	3.76	4.70	5.09	5.48	1.8%	2.1%
Jet Fuel[8]	3.13	3.00	3.64	3.97	4.25	1.5%	2.0%
Motor Gasoline[2]	13.58	13.69	14.87	15.27	15.41	0.6%	0.7%
Residual Fuel	1.03	1.09	1.30	1.44	1.56	2.1%	2.0%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.13	0.20	12.3%	13.8%
Other Petroleum[9]	0.22	0.20	0.21	0.21	0.22	0.1%	0.6%
Pipeline Fuel Natural Gas	0.68	0.61	0.66	0.69	0.69	0.0%	0.6%
Compressed Natural Gas	0.00	0.00	0.13	0.24	0.37	N/A	N/A
Renewables (ethanol)[10]	0.00	0.00	0.01	0.03	0.05	33.3%	33.3%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	94.3%	73.8%
Methanol[11]	0.00	0.00	0.01	0.03	0.06	38.7%	29.2%
Electricity	0.01	0.01	0.08	0.13	0.19	15.8%	17.7%
Total	**22.50**	**22.38**	**25.69**	**27.25**	**28.49**	**1.2%**	**1.3%**
Electric Utilities[12]							
Distillate Fuel	0.02	0.03	0.05	0.10	0.11	8.0%	8.6%
Residual Fuel	1.23	0.90	0.86	0.86	0.88	-1.7%	-0.2%
Natural Gas	2.88	2.86	4.15	4.52	4.63	2.4%	2.7%
Steam Coal	16.10	16.30	17.14	17.87	18.87	0.8%	0.8%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[13]	3.64	3.20	4.22	4.55	5.19	1.8%	2.7%
Total	**30.07**	**29.69**	**33.63**	**35.20**	**36.25**	**0.9%**	**1.1%**

Table C2. Energy Consumption by End-Use Sector and Source (Continued)

(Quadrillion Btu per Year)

Sector and Source	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Primary Energy Consumption							
Distillate Fuel	6.36	6.31	7.47	7.96	8.38	1.4%	1.6%
Kerosene	0.08	0.07	0.07	0.07	0.07	-0.6%	-0.4%
Jet Fuel[8]	3.13	3.00	3.64	3.97	4.25	1.5%	2.0%
Liquefied Petroleum Gas	2.06	2.32	2.44	2.66	2.87	1.7%	1.2%
Motor Gasoline[2]	13.87	13.98	15.20	15.61	15.76	0.6%	0.7%
Petrochemical Feedstocks	1.10	1.23	1.29	1.41	1.51	1.6%	1.2%
Residual Fuel	2.91	2.56	2.85	2.96	3.09	0.3%	1.0%
Other Petroleum[14]	4.04	4.03	4.54	4.54	4.57	0.6%	0.7%
Natural Gas	19.30	20.15	22.12	23.19	23.82	1.1%	0.9%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-3.0%	-2.3%
Steam Coal	17.96	18.05	19.12	20.02	21.12	0.8%	0.9%
Net Coal Coke Imports	0.00	0.03	0.01	0.01	0.01	N/A	-6.0%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[15]	6.22	5.83	7.23	7.79	8.66	1.7%	2.2%
Total	**84.29**	**84.86**	**93.93**	**98.14**	**101.26**	**0.9%**	**1.0%**
Electricity Consumption (all sectors)	**9.25**	**9.45**	**10.39**	**10.89**	**11.28**	**1.0%**	**1.0%**

[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, ground-water 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 co-generated 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 electric utilities, independent power producers, and small power producers that sell power to the grid.

[13]Includes electricity sold to utilities by nonutilities, including cogenerators, from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports. Does not include own use.

[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.

N/A = Not applicable.

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

Sources: 1990 coal consumption: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0118(90) (Washington, D.C. May 1991) and *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas consumption: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). 1990 and 1992 consumption other than coal and natural gas: EIA, *Monthly Energy Review*, DOE/EIA-0035(93/07) (Washington, D.C., July 1993) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. The 1990 values are not final and may be updated in EIA publications. **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C3. Energy Prices by End-Use Sector and Source
(1992 Dollars per Million Btu)

Sector and Source	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential	**13.12**	**12.11**	**13.29**	**13.89**	**14.88**	**0.6%**	**1.2%**
Primary Energy	6.72	6.12	7.20	7.60	8.09	0.9%	1.6%
Petroleum Products	9.49	7.78	8.35	9.24	9.88	0.2%	1.3%
Distillate Fuel	8.55	6.68	7.38	8.12	8.66	0.1%	1.5%
Liquefied Petroleum Gas	11.67	10.05	10.87	12.26	13.24	0.6%	1.5%
Natural Gas	6.00	5.72	6.94	7.22	7.69	1.2%	1.7%
Electricity	24.98	23.76	24.81	25.41	26.86	0.4%	0.7%
Commercial	**12.78**	**12.08**	**13.14**	**13.54**	**13.99**	**0.5%**	**0.8%**
Primary Energy	5.27	4.72	5.78	6.17	6.65	1.2%	1.9%
Petroleum Products	6.35	4.94	5.63	6.44	7.02	0.5%	2.0%
Distillate Fuel	6.51	4.76	5.10	5.83	6.37	-0.1%	1.6%
Residual Fuel	3.66	2.62	3.40	4.10	4.56	1.1%	3.1%
Natural Gas	5.00	4.74	5.93	6.20	6.66	1.4%	1.9%
Electricity	22.49	21.85	21.88	22.12	22.58	0.0%	0.2%
Industrial	**5.75**	**5.19**	**5.69**	**6.26**	**6.82**	**0.8%**	**1.5%**
Primary Energy	4.09	3.49	4.04	4.64	5.16	1.2%	2.2%
Petroleum Products	5.71	4.42	4.88	5.85	6.55	0.7%	2.2%
Distillate Fuel	6.06	4.87	5.07	5.83	6.39	0.3%	1.5%
Liquefied Petroleum Gas	5.76	4.95	6.14	7.49	8.40	1.9%	3.0%
Residual Fuel	3.31	2.54	3.40	4.12	4.63	1.7%	3.4%
Natural Gas[1]	3.46	3.07	3.74	4.09	4.53	1.3%	2.2%
Metallurgical Coal	1.87	1.79	2.09	2.26	2.24	0.9%	1.3%
Steam Coal	1.64	1.47	1.71	1.80	1.89	0.7%	1.4%
Electricity	15.22	14.87	14.69	14.79	15.37	0.0%	0.2%
Transportation	**8.72**	**7.88**	**8.86**	**9.63**	**10.20**	**0.8%**	**1.4%**
Primary Energy	8.72	7.88	8.84	9.61	10.16	0.8%	1.4%
Petroleum Products	8.81	7.88	8.84	9.60	10.15	0.7%	1.4%
Distillate Fuel[2]	9.03	8.02	9.11	9.89	10.46	0.7%	1.5%
Jet Fuel[3]	6.06	4.52	5.25	6.04	6.66	0.5%	2.2%
Motor Gasoline[4]	9.73	9.09	10.19	11.02	11.61	0.9%	1.4%
Residual Fuel	3.18	2.14	3.09	3.77	4.35	1.6%	4.0%
Natural Gas[5]	3.51	3.93	9.50	10.27	10.85	5.8%	5.8%
Electricity	18.15	17.94	15.09	15.06	15.20	-0.9%	-0.9%
Total End-Use Energy	**8.80**	**8.03**	**8.84**	**9.44**	**10.07**	**0.7%**	**1.3%**
Primary Energy	8.45	7.72	8.51	9.12	9.69	0.7%	1.3%
Electricity	20.79	20.05	20.19	20.36	21.06	0.1%	0.3%
Electric Utilities							
Fossil Fuel Average	1.81	1.59	1.92	2.09	2.30	1.2%	2.1%
Petroleum Products	3.55	2.56	3.41	4.24	4.74	1.5%	3.5%
Distillate Fuel	6.00	4.51	4.70	5.46	6.07	0.1%	1.7%
Residual Fuel	3.52	2.51	3.34	4.10	4.56	1.3%	3.4%
Natural Gas	2.46	2.28	2.84	3.19	3.56	1.9%	2.5%
Steam Coal	1.56	1.41	1.62	1.70	1.86	0.9%	1.5%

Table C3. Energy Prices by End-Use Sector and Source (Continued)

(1992 Dollars per Million Btu)

Sector and Source	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Average Price to All Users[6]							
Petroleum Products	7.94	6.84	7.69	8.51	9.11	0.7%	1.6%
Distillate Fuel[2]	8.18	6.98	7.89	8.68	9.28	0.6%	1.6%
Jet Fuel	6.06	4.52	5.25	6.04	6.66	0.5%	2.2%
Liquefied Petroleum Gas	6.45	5.98	7.11	8.49	9.47	1.9%	2.6%
Motor Gasoline[4]	9.73	9.09	10.19	11.02	11.62	0.9%	1.4%
Residual Fuel	3.38	2.37	3.24	3.94	4.46	1.4%	3.6%
Natural Gas	4.20	3.91	4.69	4.98	5.42	1.3%	1.8%
Coal	1.57	1.42	1.63	1.71	1.86	0.9%	1.5%
Electricity	20.79	20.05	20.19	20.36	21.06	0.1%	0.3%

[1]Excludes uses for lease and plant fuel.

[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]Compressed natural gas used as a vehicle fuel.

[6]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption. For each sector, electricity and natural gas prices are derived by dividing total revenues by sales.

Btu = British thermal unit.

Sources: 1990 petroleum prices: *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington,D.C., September 1993). 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, D.C., July 1993). 1992 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 coal prices: EIA, *Quarterly Coal Report*, DOE/EIA-0121(90/4Q) (Washington, D.C., May 1991); EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993), Table A6; and EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 industrial and transportation natural gas delivered prices: EIA, AEO National Energy Modeling System run LMAC94.D1221932. Other 1990 and 1992 natural gas prices: EIA, *Natural Gas Annual*, DOE/EIA-0131 (92)/1 (Washington, DC, November 1993). 1990 electricity prices: EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932. **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

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

Key Indicators and Consumption	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Household Characteristics							
Households (millions)							
Single-Family	64.36	65.60	70.30	72.80	75.31	0.8%	0.8%
Multifamily	24.42	24.27	24.16	24.49	24.99	0.1%	0.2%
Mobile Homes	5.21	5.19	5.18	5.18	5.10	-0.1%	-0.1%
Total	**93.99**	**95.06**	**99.64**	**102.46**	**105.40**	**0.6%**	**0.6%**
Housing Starts (millions)							
Single-Family	0.90	1.04	0.86	0.87	0.81	-0.6%	-1.4%
Multifamily	0.30	0.17	0.30	0.31	0.35	0.7%	4.1%
Mobile Homes	0.19	0.21	0.20	0.20	0.18	-0.3%	-0.9%
Total	**1.39**	**1.42**	**1.36**	**1.37**	**1.34**	**-0.2%**	**-0.3%**
Energy Intensity (million Btu per year per household)							
Heating	54.59	58.45	57.10	54.83	52.41	-0.2%	-0.6%
Total	**102.23**	**105.60**	**103.04**	**99.86**	**97.28**	**-0.2%**	**-0.5%**
Fuel Consumption							
Distillate							
Space Heating	0.75	0.77	0.82	0.80	0.79	0.2%	0.1%
Water Heating	0.08	0.08	0.07	0.07	0.07	-0.8%	-0.7%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.8%	0.8%
Total	**0.84**	**0.85**	**0.89**	**0.88**	**0.86**	**0.1%**	**0.1%**
Liquefied Petroleum Gas							
Space Heating	0.23	0.27	0.24	0.23	0.22	-0.3%	-1.2%
Water Heating	0.08	0.09	0.07	0.07	0.07	-1.1%	-1.7%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-1.0%	-0.4%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.7%	0.7%
Total	**0.36**	**0.41**	**0.36**	**0.34**	**0.33**	**-0.5%**	**-1.2%**
Natural Gas							
Space Heating	3.12	3.42	3.52	3.47	3.40	0.4%	0.0%
Space Cooling	0.00	0.00	0.00	0.00	0.01	N/A	N/A
Water Heating	1.09	1.10	1.09	1.08	1.11	0.1%	0.0%
Cooking[2]	0.18	0.18	0.19	0.19	0.20	0.6%	0.6%
Clothes Dryers	0.08	0.08	0.07	0.06	0.06	-1.3%	-1.4%
Other Uses[3]	0.06	0.06	0.06	0.07	0.07	0.8%	0.7%
Total	**4.52**	**4.83**	**4.93**	**4.88**	**4.84**	**0.3%**	**0.0%**
Electricity							
Space Heating	0.30	0.33	0.37	0.38	0.39	1.3%	0.9%
Space Cooling	0.52	0.51	0.51	0.51	0.52	0.0%	0.1%
Water Heating	0.34	0.34	0.34	0.34	0.34	0.0%	-0.1%
Refrigeration	0.53	0.52	0.44	0.38	0.32	-2.5%	-2.7%
Cooking	0.15	0.15	0.16	0.16	0.17	0.7%	0.7%
Clothes Dryers	0.17	0.18	0.18	0.17	0.18	0.1%	0.0%
Freezers	0.15	0.14	0.11	0.09	0.07	-3.8%	-3.9%
Lighting	0.30	0.30	0.31	0.32	0.32	0.3%	0.4%
Other Uses[4]	0.69	0.72	0.91	1.03	1.18	2.7%	2.8%
Total	**3.15**	**3.19**	**3.33**	**3.39**	**3.48**	**0.5%**	**0.5%**

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

Key Indicators and Consumption	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Renewables							
Wood[5]	0.59	0.61	0.62	0.62	0.61	0.2%	0.0%
Geothermal[6]	0.01	0.01	0.01	0.02	0.02	7.0%	6.4%
Solar[7]	0.01	0.01	0.01	0.01	0.01	0.9%	0.9%
Total	**0.61**	**0.63**	**0.64**	**0.64**	**0.65**	**0.3%**	**0.1%**
Other Fuels[8]	**0.13**	**0.12**	**0.11**	**0.11**	**0.10**	**-0.9%**	**-0.9%**
Total Fuels							
Space Heating	5.13	5.53	5.69	5.62	5.52	0.4%	0.0%
Space Cooling	0.52	0.51	0.52	0.52	0.53	0.1%	0.2%
Water Heating	1.60	1.67	1.59	1.57	1.60	0.0%	-0.2%
Cooking	0.37	0.37	0.39	0.39	0.40	0.5%	0.5%
Clothes Dryers	0.25	0.26	0.24	0.23	0.24	-0.3%	-0.5%
Other Uses	1.73	1.75	1.84	1.89	1.96	0.6%	0.6%
Total	**9.61**	**10.04**	**10.27**	**10.23**	**10.25**	**0.3%**	**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: 1990: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

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

Key Indicators and Consumption	Low Economic Growth Case					Annual Growth 1990- 2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Total Employment (millions)	**109.8**	**108.4**	**122.0**	**129.6**	**134.8**	**1.0%**	**1.2%**
Total Floorspace (billion square feet)							
Surviving	62.7	64.7	70.2	72.3	74.2	0.8%	0.8%
New Additions	1.5	1.4	1.2	1.3	1.4	-0.5%	0.0%
Total	**64.3**	**66.1**	**71.5**	**73.6**	**75.6**	**0.8%**	**0.7%**
Energy Consumption Intensity (Thousand Btu per square feet)	**102.3**	**102.6**	**100.1**	**99.2**	**97.4**	**-0.2%**	**-0.3%**
End-Use Consumption							
Electricity							
Space Heating	0.06	0.06	0.05	0.04	0.04	-2.0%	-2.1%
Space Cooling	0.26	0.26	0.26	0.25	0.25	-0.2%	-0.3%
Lighting	1.20	1.20	1.20	1.17	1.16	-0.2%	-0.2%
Water Heating	0.03	0.03	0.04	0.05	0.05	3.9%	4.1%
Office Equipment	0.39	0.41	0.77	0.91	0.96	4.6%	4.8%
Other Uses[1]	0.93	0.95	0.95	0.93	0.92	-0.1%	-0.2%
Total Electricity	**2.86**	**2.91**	**3.26**	**3.36**	**3.38**	**0.8%**	**0.8%**
Natural Gas							
Space Heating	1.36	1.38	1.32	1.29	1.26	-0.4%	-0.5%
Space Cooling	0.01	0.01	0.02	0.02	0.02	3.0%	2.2%
Water Heating	0.37	0.39	0.38	0.37	0.36	-0.2%	-0.4%
Other Uses[2]	0.96	1.11	1.14	1.24	1.34	1.7%	1.0%
Total Natural Gas	**2.70**	**2.89**	**2.86**	**2.91**	**2.98**	**0.5%**	**0.2%**
Distillate							
Space Heating	0.31	0.31	0.34	0.33	0.31	0.0%	-0.1%
Water Heating	0.03	0.03	0.03	0.03	0.02	-1.2%	-1.3%
Other Uses[2]	0.15	0.15	0.15	0.15	0.15	0.0%	0.0%
Total Distillate	**0.49**	**0.49**	**0.51**	**0.50**	**0.48**	**-0.1%**	**-0.1%**
Other Fuels[3]	**0.51**	**0.49**	**0.50**	**0.49**	**0.49**	**-0.2%**	**0.0%**
Renewables[4]	**0.01**	**0.01**	**0.03**	**0.03**	**0.03**	**5.2%**	**4.9%**
Total Consumption	**6.57**	**6.78**	**7.16**	**7.30**	**7.36**	**0.6%**	**0.5%**

[1]Includes ventilation, cooking, refrigeration, and other miscellaneous commercial uses.
[2]Includes cooking and other miscellaneous commercial uses.
[3]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[4]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1990 and 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993).
Projections: Energy Information Administration, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

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

Key Indicators and Consumption	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2536	2552	3076	3450	3828	2.1%	2.3%
Nonmanufacturing	883	875	1001	1077	1132	1.2%	1.4%
Total	**3419**	**3427**	**4077**	**4527**	**4959**	**1.9%**	**2.1%**
Energy Prices (1992 dollars per million Btu)							
Electricity	15.22	14.87	14.69	14.79	15.37	0.0%	0.2%
Natural Gas	3.46	3.07	3.74	4.09	4.53	1.3%	2.2%
Steam Coal	1.64	1.56	1.71	1.80	1.89	0.7%	1.1%
Residual Oil	3.30	2.54	3.40	4.12	4.63	1.7%	3.4%
Distillate Oil	6.02	4.88	5.07	5.83	6.39	0.3%	1.5%
Liquefied Petroleum Gas	5.84	4.95	6.14	7.49	8.40	1.8%	3.0%
Motor Gasoline	10.01	9.07	10.18	11.02	11.62	0.8%	1.4%
Metallurgical Coal	1.87	1.80	2.09	2.26	2.24	0.9%	1.2%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.23	3.29	3.72	4.01	4.24	1.4%	1.4%
Natural Gas[2]	8.50	8.96	9.38	9.94	10.31	1.0%	0.8%
Steam Coal	1.71	1.65	1.84	2.01	2.12	1.1%	1.4%
Metallurgical Coal and Coke[3]	1.05	0.90	0.75	0.66	0.58	-2.9%	-2.4%
Residual Fuel	0.42	0.34	0.48	0.45	0.43	0.1%	1.3%
Distillate	1.18	1.19	1.31	1.39	1.45	1.0%	1.1%
Liquefied Petroleum Gas	1.61	1.83	1.94	2.12	2.28	1.8%	1.2%
Petrochemical Feedstocks	1.10	1.23	1.29	1.41	1.51	1.6%	1.2%
Other Petroleum[4]	4.00	4.03	4.55	4.56	4.59	0.7%	0.7%
Renewables	1.96	1.99	2.32	2.51	2.68	1.6%	1.7%
Total	**24.78**	**25.42**	**27.58**	**29.05**	**30.19**	**1.0%**	**1.0%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.94	0.96	0.91	0.89	0.86	-0.5%	-0.6%
Natural Gas[2]	2.49	2.61	2.30	2.20	2.08	-0.9%	-1.3%
Steam Coal	0.50	0.48	0.45	0.44	0.43	-0.8%	-0.7%
Metallurgical Coal and Coke[3]	0.31	0.26	0.18	0.15	0.12	-4.7%	-4.4%
Residual Fuel	0.12	0.10	0.12	0.10	0.09	-1.7%	-0.8%
Distillate	0.35	0.35	0.32	0.31	0.29	-0.8%	-0.9%
Liquefied Petroleum Gas	0.47	0.53	0.48	0.47	0.46	-0.1%	-0.8%
Petrochemical Feedstocks	0.32	0.36	0.32	0.31	0.30	-0.3%	-0.9%
Other Petroleum[4]	1.17	1.18	1.12	1.01	0.93	-1.2%	-1.3%
Renewables	0.57	0.58	0.57	0.55	0.54	-0.3%	-0.4%
Total	**7.25**	**7.41**	**6.76**	**6.42**	**6.09**	**-0.9%**	**-1.1%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net imports of coal coke.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington,D.C., May 1993). 1990 and 1992 natural gas values: *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

LOW ECONOMIC GROWTH CASE PROJECTIONS

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

Key Indicators and Consumption	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Level of Travel Index (1990 = 1.0)							
Light-Duty Vehicles	1.00	1.01	1.17	1.28	1.37	1.6%	1.7%
Freight Trucks	1.00	1.09	1.28	1.40	1.50	2.0%	1.8%
Air	1.00	1.07	1.41	1.62	1.80	3.0%	3.0%
Rail	1.00	1.04	1.13	1.20	1.26	1.2%	1.1%
Marine	1.00	0.99	1.04	1.09	1.14	0.6%	0.8%
Energy Efficiency Indicators							
New Car MPG[1]	28.20	28.05	29.35	30.40	31.19	0.5%	0.6%
New Light Truck MPG[1]	20.91	20.98	22.32	23.28	24.04	0.7%	0.8%
Light-Duty Fleet MPG[2]	18.90	19.26	20.16	20.82	21.53	0.7%	0.6%
Aircraft Efficiency Index	1.00	1.01	1.07	1.11	1.14	0.7%	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.09	1.13	1.17	0.8%	0.8%
Rail Efficiency Index	1.00	1.00	1.04	1.06	1.07	0.3%	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.01	1.01	1.02	0.1%	0.1%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles[3]	12.74	12.79	14.17	14.84	15.33	0.9%	1.0%
Freight Trucks[3]	5.22	5.31	6.36	6.76	7.11	1.6%	1.6%
Air	3.17	3.04	3.68	4.01	4.29	1.5%	1.9%
Rail	0.51	0.49	0.55	0.58	0.60	0.8%	1.1%
Marine	1.53	1.59	1.85	2.02	2.17	1.7%	1.8%
Pipeline Fuel	0.68	0.61	0.66	0.69	0.69	0.0%	0.6%
Other[4]	0.15	0.15	0.16	0.17	0.18	1.0%	1.1%
Total[5]	**22.50**	**22.38**	**25.69**	**27.25**	**28.49**	**1.2%**	**1.3%**

[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.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990: Federal Highway Administration, *Highway Statistics 1991*; Oak Ridge National Laboratory, *Transportation Energy Data Book: 12 and 13*, (March 1993); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, February 1993; Energy Information Administration (EIA), *Residential Transportation Energy Consumption Survey 1991*; Argonne National Laboratory, FRATE Model 1990. 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

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

Supply, Disposition, and Prices	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Generation by Fuel Type							
Coal	1560	1576	1654	1724	1794	0.7%	0.7%
Petroleum	117	89	76	79	81	-1.8%	-0.5%
Natural Gas	264	264	335	371	345	1.3%	1.5%
Nuclear Power	577	619	671	680	612	0.3%	-0.1%
Pumped Storage/Other[1]	-2	-4	-11	-11	-11	9.1%	5.8%
Renewable Sources[2]	293	254	306	311	332	0.6%	1.5%
Total	**2809**	**2798**	**3032**	**3154**	**3153**	**0.6%**	**0.7%**
Nonutilities (excluding cogenerators)[3]							
Generation by Fuel Type							
Coal	1	2	9	10	40	23.1%	19.9%
Petroleum/Other[4]	1	1	1	1	0	-3.8%	-4.0%
Natural Gas	9	16	53	57	113	13.5%	11.5%
Renewable Sources[2]	29	40	67	92	130	7.8%	6.8%
Total	**39**	**60**	**130**	**160**	**283**	**10.4%**	**9.0%**
Cogeneration[5]	**178**	**192**	**205**	**216**	**224**	**1.2%**	**0.9%**
Net Imports	**2**	**28**	**26**	**28**	**30**	**14.5%**	**0.4%**
Electricity Sales by Sector							
Residential	924	936	976	992	1019	0.5%	0.5%
Commercial	839	850	955	985	990	0.8%	0.9%
Industrial	946	973	1090	1175	1243	1.4%	1.4%
Transportation	4	4	25	39	55	14.0%	15.7%
Total	**2713**	**2763**	**3046**	**3191**	**3307**	**1.0%**	**1.0%**
End-Use Prices (1992 cents per kilowatthour)[6]							
Residential	8.5	8.1	8.5	8.7	9.2	0.4%	0.7%
Commercial	7.7	7.5	7.5	7.5	7.7	0.0%	0.2%
Industrial	5.2	5.1	5.0	5.0	5.2	0.0%	0.2%
Transportation	5.1	5.1	5.1	5.1	5.2	0.1%	0.1%
All Sectors Average	**7.1**	**6.8**	**6.9**	**6.9**	**7.2**	**0.1%**	**0.3%**
***Price* Components (1992 cents per kilowatthour)[6]**							
Capital Component	3.0	2.9	2.6	2.5	2.4	-1.0%	-0.9%
Fuel Component	1.4	1.3	1.4	1.5	1.6	0.8%	1.5%
O&M Component	2.6	2.6	2.6	2.6	2.6	0.1%	0.2%
Net Wholesale Power Component	0.1	0.1	0.2	0.3	0.5	6.2%	6.9%
Total	**7.1**	**6.8**	**6.9**	**6.9**	**7.2**	**0.1%**	**0.3%**

[1]Other includes methane and propane and blast furnace gas.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[3]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for delivery to the grid.
[4]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[5]Includes cogeneration at industrial, commercial, and other facilities whose primary function is not electricity production. Includes both sales to utilities and generation for own use.
[6]Prices represent average revenue per kilowatthour.
O&M = Operation and maintenance.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). 1990 Nonutility generation: Form EIA-861, "Annual Electric Utility Report" and the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is filed by nonutilities reporting the electricity delivered, while the EIA-861 is filed by electric utilities reporting the electricity received. Because the Form EIA-861 collects data from the universe of utilities, these data are used for electricity sold to utilities. Own use data is from Form EIA-867. **Prices, 1992 cogeneration, 1992 prices, and all projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Capability							
Coal Steam	299.5	298.7	297.2	299.2	305.1	0.1%	0.1%
Other Fossil Steam[2]	143.9	142.5	129.7	123.5	120.4	-0.9%	-0.9%
Combined Cycle	7.2	7.8	19.3	27.5	30.6	7.5%	7.8%
Combustion Turbine/Diesel	45.6	47.9	64.3	68.0	68.8	2.1%	2.0%
Nuclear Power	99.6	99.0	102.6	103.8	90.7	-0.5%	-0.5%
Pumped Storage/Other[3]	17.6	19.1	20.2	20.2	20.2	0.7%	0.3%
Renewable Sources[4]	76.0	76.2	77.5	78.6	85.2	0.6%	0.6%
Total	**689.4**	**691.2**	**710.9**	**720.7**	**720.9**	**0.2%**	**0.2%**
Cumulative Planned Additions[5]							
Coal Steam	0.00	1.29	8.30	13.35	16.25	N/A	N/A
Other Fossil Steam[2]	0.00	0.95	1.54	1.64	1.64	N/A	N/A
Combined Cycle	0.00	0.67	9.14	14.30	14.99	N/A	N/A
Combustion Turbine/Diesel	0.00	2.50	18.84	24.18	24.55	N/A	N/A
Nuclear Power	0.00	0.00	4.70	5.91	5.91	N/A	N/A
Pumped Storage/Other[3]	0.00	1.41	2.56	2.56	2.56	N/A	N/A
Renewable Sources[4]	0.00	0.28	1.13	1.14	1.14	N/A	N/A
Total	**0.00**	**7.10**	**46.20**	**63.08**	**67.03**	**N/A**	**N/A**
Cumulative Unplanned Additions[5]						**N/A**	**N/A**
Coal Steam	0.00	0.00	0.00	0.00	5.81	N/A	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Combined Cycle	0.00	0.00	3.15	6.13	8.52	N/A	N/A
Combustion Turbine/Diesel	0.00	0.00	0.37	0.37	0.87	N/A	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[3]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	0.00	0.00	0.42	1.38	7.95	N/A	N/A
Total	**0.00**	**0.00**	**3.94**	**7.88**	**23.14**	**N/A**	**N/A**
Cumulative Total Utility Additions[5]	**0.00**	**7.10**	**50.14**	**70.96**	**90.18**	**N/A**	**N/A**
Cumulative Utility Retirements	**1.20**	**6.46**	**30.34**	**41.38**	**60.43**	**N/A**	**N/A**
Nonutilities (excludes cogenerators)[6]							
Installed Capability[7]							
Coal Steam	0.09	0.35	1.51	1.66	6.24	23.6%	17.4%
Other Fossil Steam[2]	0.23	0.40	0.83	0.83	0.83	6.6%	4.1%
Combined Cycle	1.27	2.88	6.81	7.31	16.48	13.7%	10.2%
Combustion Turbine/Diesel	0.90	1.48	4.20	7.64	12.38	14.0%	12.5%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[8]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	6.64	7.42	13.32	17.06	23.96	6.6%	6.7%
Total	**9.13**	**12.53**	**26.66**	**34.50**	**59.89**	**9.9%**	**9.1%**
Cogenerators[7,9]	**33.74**	**37.78**	**43.46**	**44.07**	**44.57**	**1.4%**	**0.9%**
Cumulative Nonutility Additions[5,7]	**0.00**	**7.44**	**27.25**	**35.70**	**61.59**	**N/A**	**12.5%**

[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]Other includes methane and propane and blast furnace gas.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[5]Cumulative additions after December 31, 1990.
[6]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for sales to the grid.
[7]Nameplate capacity is reported for nonutilities. Nameplate capacity is designated by the manufacturer.
[8]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[9]Includes cogenerators at industrial, commercial, and other facilities whose primary function is not electricity productionN/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992: EIA, *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	146.3	146.3	118.4	115.4	115.4	-1.2%	-1.3%
Gross Domestic Economy Sales	89.0	89.6	83.7	87.1	87.9	-0.1%	-0.1%
Gross Domestic Trade	**235.4**	**235.9**	**202.0**	**202.5**	**203.3**	**-0.7%**	**-0.8%**
Gross Domestic Firm Power Sales (million 1992 dollars)	6188.8	6407.3	5954.1	6332.2	6906.0	0.5%	0.4%
Gross Domestic Economy Sales (million 1992 dollars)	1720.7	1645.6	2028.2	2537.4	2694.8	2.3%	2.8%
Gross Domestic Sales (million 1992 dollars)	**7909.4**	**8052.8**	**7982.2**	**8869.6**	**9600.8**	**1.0%**	**1.0%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	5.6	14.2	14.4	14.4	14.4	4.8%	0.1%
Economy Imports From Canada and Mexico	16.9	23.8	27.2	29.5	31.9	3.2%	1.6%
Gross Imports From Canada and Mexico	**22.5**	**38.0**	**41.6**	**43.9**	**46.4**	**3.7%**	**1.1%**
Firm Power Exports To Canada and Mexico	1.7	4.7	8.8	8.8	8.8	8.5%	3.6%
Economy Exports To Canada and Mexico	18.8	5.6	6.4	7.0	7.7	-4.4%	1.7%
Gross Exports To Canada and Mexico	**20.5**	**10.3**	**15.2**	**15.7**	**16.4**	**-1.1%**	**2.6%**

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. Electricity trade among utilities in the same region is excluded from these data.

Sources: 1990 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1990 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1990 firm/interruptible share: National Energy Board, *Annual Report 1990.* Planned interregional and international firm power sales (1993 through 2001): DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1992. **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C11. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil[1]	7.36	7.17	5.15	4.79	5.04	-1.9%	-1.9%
Alaska	1.77	1.71	0.87	0.59	0.74	-4.3%	-4.6%
Lower 48 States	5.58	5.46	4.29	4.20	4.30	-1.3%	-1.3%
Natural Gas Plant Liquids	1.56	1.70	1.77	1.84	1.85	0.9%	0.5%
Total	**8.91**	**8.87**	**6.92**	**6.63**	**6.88**	**-1.3%**	**-1.4%**
Net Imports							
Crude Oil (including SPR)[2]	5.78	5.99	8.49	8.94	8.74	2.1%	2.1%
Refined Products[3]	0.90	0.45	2.20	2.94	3.53	7.1%	12.1%
Total	**6.68**	**6.44**	**10.69**	**11.88**	**12.27**	**3.1%**	**3.6%**
Other Inputs[4]	**0.49**	**0.58**	**0.68**	**0.66**	**0.67**	**1.6%**	**0.8%**
Refinery Processing Gain[5]	**0.68**	**0.77**	**0.78**	**0.80**	**0.84**	**1.1%**	**0.5%**
SPR Fill Rate Additions(-)[2]	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**0.0%**	**0.0%**
Total Primary Supply[6]	**16.75**	**16.64**	**19.05**	**19.95**	**20.65**	**1.1%**	**1.2%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.23	7.27	7.93	8.14	8.22	0.6%	0.7%
Jet Fuel[8]	1.52	1.45	1.76	1.92	2.05	1.5%	1.9%
Distillate Fuel	3.02	2.98	3.51	3.74	3.94	1.3%	1.6%
Residual Fuel	1.23	1.09	1.24	1.29	1.34	0.4%	1.2%
Other[9]	3.98	4.24	4.53	4.75	4.98	1.1%	0.9%
Total	**16.99**	**17.03**	**18.98**	**19.85**	**20.54**	**1.0%**	**1.0%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.15	1.16	1.17	1.14	1.11	-0.1%	-0.3%
Industrial[10]	4.32	4.33	4.96	5.18	5.39	1.1%	1.2%
Transportation	10.98	11.01	12.45	13.11	13.61	1.1%	1.2%
Electric Utilities[11]	0.55	0.52	0.40	0.42	0.44	-1.1%	-1.0%
Total	**16.99**	**17.03**	**18.98**	**19.85**	**20.54**	**1.0%**	**1.0%**
Discrepancy[12]	**-0.24**	**-0.39**	**0.08**	**0.10**	**0.11**	**N/A**	**N/A**
World Oil Price (1992 dollars per barrel)[13]	**23.22**	**18.20**	**20.20**	**24.31**	**27.31**	**0.8%**	**2.3%**
Domestic Refinery Distillation Capacity	**15.6**	**15.5**	**15.3**	**15.3**	**15.4**	**-0.1%**	**0.0%**
Capacity Utilization Rate (percent)	**87.1**	**87.9**	**88.9**	**89.4**	**89.2**	**0.1%**	**0.1%**

[1]Includes lease condensate.
[2]SPR is the Strategic Petroleum Reserve.
[3]Net imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[4]Includes alcohols, ethers, and imports of unfinished oils.
[5]Represents volumetric gain in refinery distillation and cracking processes.
[6]Total production plus net imports plus other inputs plus refinery processing gain minus SPR additions.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[10]Includes consumption by cogenerators.
[11]Includes consumption by independent power producers.
[12]Balancing item. Includes unaccounted for supply, losses and gains.
[13]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: 1990: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, D.C., May 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C12. Petroleum Product Prices

(1992 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (dollars per barrel)	**23.22**	**18.20**	**20.20**	**24.31**	**27.31**	**0.8%**	**2.3%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	118.5	92.7	102.4	112.6	120.1	0.1%	1.5%
Liquefied Petroleum Gas	106.6	86.7	93.8	105.9	114.2	0.3%	1.5%
Commercial							
Distillate Fuel	90.3	66.0	70.7	80.8	88.4	-0.1%	1.6%
Residual Fuel	54.8	39.3	50.9	61.4	68.3	1.1%	3.1%
Residual Fuel (dollars per barrel)	23.02	16.50	21.39	25.78	28.70	1.1%	3.1%
Industrial							
Distillate Fuel	84.1	67.6	70.3	80.8	88.7	0.3%	1.5%
Liquefied Petroleum Gas	52.6	42.7	53.0	64.7	72.5	1.6%	3.0%
Petrochemical Feedstocks	83.7	64.1	49.3	58.2	66.1	-1.2%	0.2%
Residual Fuel	49.5	38.0	50.9	61.6	69.3	1.7%	3.4%
Residual Fuel (dollars per barrel)	20.80	15.95	21.36	25.89	29.11	1.7%	3.4%
Transportation							
Distillate Fuel[1]	125.2	111.2	126.4	137.2	145.1	0.7%	1.5%
Jet Fuel[2]	81.8	61.0	70.9	81.5	89.9	0.5%	2.2%
Motor Gasoline[3]	121.7	113.7	127.4	137.8	145.3	0.9%	1.4%
Residual Fuel	47.6	32.1	46.3	56.5	65.1	1.6%	4.0%
Residual Fuel (dollars per barrel)	19.99	13.47	19.44	23.72	27.34	1.6%	4.0%
Electric Utilities							
Distillate Fuel	83.2	62.6	65.2	75.7	84.2	0.1%	1.7%
Residual Fuel	52.7	37.5	50.0	61.4	68.3	1.3%	3.4%
Residual Fuel (dollars per barrel)	22.14	15.77	20.99	25.77	28.68	1.3%	3.4%
Refined Petroleum Product Prices[4]							
Distillate Fuel	113.9	97.6	109.4	120.3	128.7	0.6%	1.5%
Jet Fuel	81.8	61.0	70.9	81.5	89.9	0.5%	2.2%
Liquefied Petroleum Gas	58.9	51.9	61.4	73.3	81.7	1.6%	2.6%
Motor Gasoline	121.7	113.7	127.4	137.8	145.3	0.9%	1.4%
Petrochemical Feedstocks	83.7	64.1	49.3	58.2	66.1	-1.2%	0.2%
Residual Fuel	50.6	35.5	48.5	59.0	66.8	1.4%	3.6%
Residual Fuel (dollars per barrel)	21.26	14.90	20.38	24.79	28.06	1.4%	3.6%
Average	**102.2**	**90.8**	**101.9**	**112.0**	**119.2**	**0.8%**	**1.5%**

[1]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[2]Kerosene-type jet fuel.
[3]Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[4]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1990 prices: Energy Information Administration (EIA), *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1992 prices for gasoline, distillate, and jet fuel are based on prices in the EIA, *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, D.C., July 1993). 1992 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). **Projections**: EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

LOW ECONOMIC GROWTH CASE PROJECTIONS

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

Supply, Disposition, and Prices	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Dry Gas Production[1]	17.81	17.84	18.39	19.04	19.16	0.4%	0.4%
Supplemental Natural Gas[2]	0.12	0.12	0.11	0.11	0.07	-2.8%	-3.1%
Net Imports	**1.45**	**1.92**	**2.93**	**3.31**	**3.85**	**5.0%**	**3.9%**
Canada	1.43	2.03	2.67	2.76	2.93	3.6%	2.1%
Mexico	-0.02	-0.10	-0.05	0.00	0.17	N/A	N/A
LNG	0.03	-0.01	0.31	0.55	0.75	17.2%	N/A
Total Supply	**19.38**	**19.88**	**21.43**	**22.47**	**23.08**	**0.9%**	**0.8%**
Consumption by Sector							
Residential	4.39	4.69	4.79	4.73	4.70	0.3%	0.0%
Commercial	2.62	2.80	2.78	2.83	2.89	0.5%	0.2%
Industrial[3]	7.02	7.53	7.82	8.33	8.69	1.1%	0.8%
Electric Utilities[4]	2.79	2.77	4.01	4.37	4.48	2.4%	2.7%
Lease and Plant Fuel[5]	1.24	1.17	1.29	1.32	1.32	0.3%	0.7%
Pipeline Fuel	0.66	0.59	0.64	0.67	0.66	0.0%	0.7%
Transportation[6]	0.00	0.00	0.13	0.24	0.36	N/A	N/A
Total	**18.72**	**19.54**	**21.46**	**22.49**	**23.11**	**1.1%**	**0.9%**
Discrepancy[7]	**0.66**	**0.33**	**-0.03**	**-0.02**	**-0.03**	**N/A**	**N/A**
Average Wellhead Price[8] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.31**	**2.51**	**2.93**	**2.4%**	**2.9%**
Delivered Prices (1992 dollars per thousand cubic feet)							
Residential	6.19	5.89	7.15	7.44	7.92	1.2%	1.7%
Commercial	5.15	4.88	6.11	6.39	6.86	1.4%	1.9%
Industrial[9]	3.57	3.17	3.85	4.22	4.66	1.3%	2.2%
Electric Utilities	2.54	2.36	2.94	3.30	3.68	1.9%	2.5%
Transportation	3.62	4.05	9.78	10.58	11.18	5.8%	5.8%
Average[10]	**4.33**	**4.03**	**4.84**	**5.14**	**5.59**	**1.3%**	**1.8%**

[1]Dry marketed production minus nonhydrocarbon gases removed.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributes with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Reflects natural gas lost, the net 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.
[8]Represents Lower-48 onshore and offshore supplies.
[9]Excludes uses for lease and plant fuel.
[10]Weighted average price. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 industrial and transportation delivered prices: Energy Information Administration (EIA), AEO 1994 National Energy Modeling System run LMAC94.D1221932. Other 1990 and 1992: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C14. Oil and Gas Supply

Production and Supply	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Crude Oil							
Lower 48 Average Wellhead Price[1] (1992 dollars per barrel)	23.02	17.38	19.71	23.45	26.21	0.7%	2.3%
Production (million barrels per day)[2]							
U.S. Total	7.36	7.17	5.14	4.79	5.04	-1.9%	-1.9%
Lower 48 Onshore	4.63	4.38	3.60	3.56	3.59	-1.3%	-1.1%
Conventional	3.97	3.68	3.03	2.85	2.76	-1.8%	-1.6%
Enhanced Oil Recovery	0.66	0.71	0.57	0.71	0.84	1.2%	1.0%
Lower 48 Offshore	0.95	1.07	0.67	0.64	0.70	-1.5%	-2.3%
Alaska	1.77	1.71	0.87	0.59	0.74	-4.3%	-4.6%
U.S. End of Year Reserves (billion barrels)	27.56	24.97	18.77	17.35	18.17	-2.1%	-1.8%
Natural Gas							
Lower 48 Average Wellhead Price[1] (1992 dollars per thousand cubic feet)	1.83	1.75	2.31	2.50	2.93	2.4%	2.9%
Production (trillion cubic feet)[3]							
U.S. Total	17.81	17.84	18.39	19.04	19.16	0.4%	0.4%
Lower 48 Onshore	12.15	12.50	14.67	14.20	13.73	0.6%	0.5%
Associated-Dissolved[4]	2.07	2.11	1.64	1.62	1.65	-1.1%	-1.3%
Non-Associated	10.08	10.39	13.04	12.57	12.08	0.9%	0.8%
Conventional	8.63	8.53	9.81	9.34	8.89	0.1%	0.2%
Unconventional	1.45	1.86	3.23	3.24	3.19	4.0%	3.0%
Tight Sands	1.13	1.19	1.97	2.00	2.01	2.9%	3.0%
Coal Bed Methane	0.19	0.51	0.91	0.89	0.86	7.9%	2.9%
Devonian Shale	0.12	0.16	0.35	0.34	0.32	4.8%	3.9%
Lower 48 Offshore	5.28	4.93	3.22	4.36	4.95	-0.3%	0.0%
Associated-Dissolved[4]	0.63	0.68	0.58	0.57	0.59	-0.4%	-0.8%
Non-Associated	4.65	4.25	2.64	3.79	4.37	-0.3%	0.2%
Alaska	0.38	0.41	0.50	0.49	0.47	1.1%	0.8%
U.S. End of Year Reserves (trillion cubic feet)	169.35	165.02	165.09	155.63	146.98	-0.7%	-0.6%
Supplemental Gas Supplies[5]	0.12	0.12	0.11	0.11	0.07	-2.8%	-3.1%
Total Wells Completed	31.17	23.01	36.25	50.00	69.13	4.1%	6.3%

[1]Represents Lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Dry marketed production minus nonhydrocarbon gases removed.
[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: 1990: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - Energy Information Administration (EIA), *Petroleum Supply Annual 1990*, DOE/EIA-340(90)/1 (Washington, D.C., May 1991); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90) (Washington, D.C., September 1991). 1992: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - EIA, *Petroleum Supply Annual 1992*, DOE/EIA-340(92)/1 (Washington, D.C., May 1993); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, D.C., October 1993). 1990 and 1992: Crude Oil Lower 48 Average Wellhead Prices - EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993); Natural Gas Lower 48 Average Wellhead Prices, Alaska and Total Natural Gas Production, Supplemental Gas Supplies - EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, D.C., November 1993); Total Wells Completed - *Monthly Energy Review*, DOE/EIA-0035(93/11) (Washington, D.C., November 1993). Other 1990 and 1992 values - EIA, Office of Integrated Analysis and Forecasting. Figures for 1990 and 1992 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections**: EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

LOW ECONOMIC GROWTH CASE PROJECTIONS

Table C15. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production[1]							
East of the Mississippi	630	589	615	617	624	0.0%	0.3%
West of the Mississippi	399	409	450	491	541	1.5%	1.6%
Total	**1029**	**998**	**1065**	**1108**	**1165**	**0.6%**	**0.9%**
Net Imports							
Imports	3	4	10	10	11	7.1%	5.9%
Exports	106	103	133	144	153	1.8%	2.2%
Total	**-103**	**-99**	**-123**	**-134**	**-142**	**1.6%**	**2.0%**
Total Supply[2]	**926**	**899**	**942**	**974**	**1023**	**0.5%**	**0.7%**
Consumption by Sector							
Residential and Commercial	7	6	6	6	5	-1.0%	-0.8%
Industrial[3]	76	74	84	91	96	1.2%	1.4%
Coke Plants	39	32	28	24	21	-3.0%	-2.3%
Electricity[4]	774	780	822	855	901	0.8%	0.8%
Total	**895**	**892**	**939**	**976**	**1023**	**0.7%**	**0.8%**
Discrepancy and Stock Change[5]	**31**	**-6**	**3**	**-2**	**0**	**-21.0%**	**N/A**
Average Minemouth Price[6] (1992 dollars per short ton)	**23.22**	**21.03**	**25.13**	**27.01**	**29.97**	**1.3%**	**2.0%**
Delivered Prices (1992 dollars per short ton)							
Industrial	35.85	32.78	37.62	39.78	41.77	0.8%	1.4%
Coke Plants	50.93	47.92	55.95	60.66	60.15	0.8%	1.3%
Electricity	32.49	29.36	33.72	35.48	38.91	0.9%	1.6%
Average[7]	**33.59**	**30.32**	**34.73**	**36.51**	**39.62**	**0.8%**	**1.5%**
Average Price to All Users (1992 dollars per million Btu)	**1.58**	**1.42**	**1.63**	**1.71**	**1.86**	**0.8%**	**1.5%**
Exports[8]	45.49	41.34	51.11	55.10	56.58	1.1%	1.8%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Balancing item: the sum of production and net imports, minus total consumption.
[6]Free-on-board price.
[7]Weighted average prices. Weights used are consumption values by sector. Average of Industrial, Coke Plant, and Electricity Sectors.
[8]Free alongside ship price at U.S. port-of-exit.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121 (90/4Q) (Washington, D.C., May 1991); and EIA, *Coal Production 1990*, DOE/EIA-0118(90) (Washington, D.C., September 1991). 1992: EIA, *Quarterly Coal Report*, DOE/EIA-0121(93/2Q) (Washington, D.C., November 1993); and EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, D.C., October 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C16. Renewable Energy

(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Nonelectric	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electricity							
Capability (gigawatts)							
Conventional Hydropower	75.30	75.54	78.26	78.39	78.48	0.2%	0.2%
Geothermal[1]	2.91	2.89	5.46	6.56	8.54	5.5%	6.2%
Municipal Solid Waste	2.13	2.66	3.58	4.28	4.98	4.3%	3.5%
Biomass/Other Waste[2]	6.86	7.29	8.98	11.84	14.64	3.9%	4.0%
Solar[3]	0.36	0.36	0.73	0.98	1.33	6.7%	7.5%
Wind[4]	1.55	1.65	1.76	2.19	10.38	10.0%	10.8%
Total	**89.11**	**90.40**	**98.77**	**104.23**	**118.33**	**1.4%**	**1.5%**
Generation (billion kilowatthours)							
Conventional Hydropower	288.04	247.88	304.92	305.67	306.24	0.4%	1.3%
Geothermal[1]	15.86	16.68	35.41	43.18	57.12	6.6%	7.1%
Municipal Solid Waste	12.32	17.24	19.71	24.93	30.17	5.2%	3.6%
Biomass/Other Waste[2]	34.14	41.73	47.18	64.17	80.94	13.4%	13.6%
Solar[3]	0.70	1.75	2.34	3.36	4.81	10.1%	5.8%
Wind[4]	2.38	2.91	2.91	4.25	28.36	13.2%	13.5%
Total	**353.44**	**328.19**	**412.47**	**445.56**	**507.64**	**1.8%**	**2.5%**
Consumption Equivalent							
Conventional Hydropower	2.98	2.57	3.16	3.17	3.17	0.4%	1.3%
Geothermal[1]	0.16	0.17	0.37	0.45	0.59	6.6%	7.2%
Municipal Solid Waste	0.13	0.18	0.20	0.26	0.31	5.2%	3.8%
Biomass/Other Waste[2]	0.35	0.43	0.49	0.66	0.84	13.4%	17.0%
Solar[3]	0.01	0.01	0.02	0.03	0.05	10.1%	9.3%
Wind[4]	0.02	0.03	0.03	0.04	0.29	13.2%	13.8%
Total	**3.66**	**3.40**	**4.27**	**4.61**	**5.26**	**1.8%**	**2.5%**
Nonelectric Renewable Energy							
Residential, Commercial, and Industrial							
Geothermal	0.01	0.01	0.01	0.02	0.02	7.0%	6.4%
Biofuels	2.53	2.57	2.91	3.10	3.26	1.3%	1.3%
Solar Thermal	0.02	0.02	0.04	0.04	0.04	3.8%	4.0%
Transportation							
Ethanol	0.06	0.09	0.11	0.12	0.12	3.6%	1.7%
Total	**2.62**	**2.69**	**3.07**	**3.27**	**3.45**	**1.5%**	**1.6%**
Total Renewable Energy	**6.28**	**6.07**	**7.33**	**7.88**	**8.70**	**1.7%**	**1.7%**

[1]Includes hydrothermal resources only (hot water and steam).
[2]Does not include projections for energy crops.
[3]Utility-grid connected generation only.
[4]Includes horizontal-axis wind turbines only.
Btu = British thermal unit.
Note: Includes renewables used in industrial power generation and cogeneration.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 ethanol: Energy Information Administration (EIA), *Weekly Petroleum Status Report*, DOE/EIA-0208(93-01) (Washington, D.C., January 1993). Other 1990 and 1992: EIA, sum of EIA-860 "Annual Electric Generator Report" and EIA-867 "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C17. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Petroleum	24.0	25.7	24.9	24.3	23.7	-0.1%	-0.5%
Natural Gas	65.0	69.3	71.0	70.2	69.7	0.3%	0.0%
Coal	1.6	1.4	1.3	1.3	1.2	-1.2%	-0.7%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**90.6**	**96.4**	**97.2**	**95.7**	**94.5**	**0.2%**	**-0.1%**
Commercial							
Petroleum	18.1	18.1	18.4	18.1	17.6	-0.1%	-0.1%
Natural Gas	38.7	39.9	41.1	41.9	42.8	0.5%	0.4%
Coal	2.3	2.3	2.2	2.2	2.2	-0.4%	-0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	2.6%	0.2%
Total	**59.2**	**60.3**	**61.7**	**62.1**	**62.6**	**0.3%**	**0.2%**
Industrial[1]							
Petroleum	91.9	85.1	105.0	106.6	108.4	0.8%	1.4%
Natural Gas[2]	119.6	123.0	132.7	140.7	145.8	1.0%	0.9%
Coal	67.8	62.2	63.7	65.7	66.3	-0.1%	0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**279.3**	**270.4**	**301.4**	**312.9**	**320.5**	**0.7%**	**0.9%**
Transportation							
Petroleum	422.3	428.8	469.7	491.6	506.9	0.9%	0.9%
Natural Gas[3]	9.9	9.8	11.8	14.2	16.2	2.5%	2.8%
Renewable/Other[4]	0.0	0.0	0.3	0.8	1.6	35.3%	31.0%
Total	**432.2**	**438.6**	**481.7**	**506.5**	**524.5**	**1.0%**	**1.0%**
Electric Utilities[5]							
Petroleum	26.8	17.2	16.6	17.2	17.7	-2.0%	0.2%
Natural Gas	41.2	42.8	59.1	64.4	66.0	2.4%	2.4%
Steam Coal	408.8	414.8	435.9	454.4	479.7	0.8%	0.8%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	4.7%
Total	**476.7**	**474.8**	**511.5**	**536.0**	**563.4**	**0.8%**	**1.0%**
Total Energy Consumption							
Petroleum	583.2	574.9	634.6	657.7	674.4	0.7%	0.9%
Natural Gas	274.4	284.8	315.7	331.3	340.5	1.1%	1.0%
Coal	480.4	480.7	503.1	523.5	549.3	0.7%	0.7%
Renewable Energy	0.0	0.0	0.2	0.5	0.9	33.2%	25.0%
Other[4]	0.0	0.0	0.1	0.4	0.7	38.7%	29.2%
Total	**1338.0**	**1340.5**	**1453.6**	**1513.3**	**1565.8**	**0.8%**	**0.9%**

[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 consumption of energy by electric utilities, independent power producers, and small power producers that sell electricity to utilities.
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, 1985 - 1990*, DOE/EIA-0573 (Washington, D.C., September 1993), Table 11, p. 15. 1990 consumption estimates: EIA, *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). **Consumption projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

Table C18. Macroeconomic Indicators

(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
GDP Implicit Price Deflator (Index 1987=1.000)	1.132	1.208	1.674	2.134	2.756	4.5%	4.7%
Real Gross Domestic Product	4877	4920	5847	6436	6941	1.8%	1.9%
Real Consumption	3260	3312	3832	4139	4479	1.6%	1.7%
Real Investment	739	712	1048	1168	1238	2.6%	3.1%
Real Government Spending	930	938	969	1021	1057	0.6%	0.7%
Real Exports	510	571	885	1153	1387	5.1%	5.1%
Real Imports	562	614	887	1045	1220	4.0%	3.9%
Real Disposable Personal Income	3517	3584	4168	4520	4888	1.7%	1.7%
Index of Manufacturing Gross Output (Index 1987=1.000)	1.087	1.094	1.318	1.479	1.641	2.1%	2.3%
AA Utility Bond Rate (percent)	9.66	8.55	10.51	10.49	10.61	0.5%	1.2%
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	3.43	6.28	6.33	6.52	-0.7%	3.6%
Real Yield on Government 10 Year Bonds (percent)	4.91	3.61	4.75	4.30	4.24	-0.7%	0.9%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	16.06	15.25	14.59	-0.8%	-1.0%
Consumer Price Index (1982=1.00)	1.31	1.40	2.05	2.67	3.48	5.0%	5.2%
Employment Cost Index (1987=1.00)	1.05	1.12	1.66	2.19	2.90	5.2%	5.4%
Unemployment Rate (percent)	5.52	7.40	5.85	5.68	5.91	0.3%	-1.2%
Million Units							
Truck Deliveries, Light-Duty	4.39	4.50	5.49	5.95	5.94	1.5%	1.6%
Unit Sales of Automobiles	9.51	8.35	9.41	9.56	9.49	0.0%	0.7%
U.S. Trade-Weighted Exchange Rate	0.87	0.84	0.81	0.76	0.72	-0.9%	-0.9%
Millions of People							
Population with Armed Forces Overseas	250.3	255.8	271.5	279.8	288.2	0.7%	0.7%
Population (aged 16 and over)	192.7	196.3	209.6	218.2	227.5	0.8%	0.8%
Employment, Non-Agriculture	109.8	108.4	122.0	129.6	134.8	1.0%	1.2%

GDP = Gross domestic product.

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

Sources: 1990 and 1992: Data Resources Incorporated (DRI), DRI Trend0293. **Projections:** Energy Information Administration, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

LOW ECONOMIC GROWTH CASE PROJECTIONS

Table C19. International Petroleum Supply and Disposition Summary

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Economic Growth Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (1992 dollars per barrel)[1]	**23.22**	**18.20**	**20.20**	**24.31**	**27.31**	**0.8%**	**2.3%**
Production[2]							
U.S. (50 states)	9.59	9.77	7.92	7.67	7.97	-0.9%	-1.1%
Canada	2.03	2.12	2.21	2.50	2.44	0.9%	0.8%
OECD Europe[3]	4.58	5.08	6.41	5.27	4.73	0.2%	-0.4%
OPEC	25.04	26.38	35.54	40.92	43.97	2.9%	2.9%
Rest of the World[4]	11.06	11.00	12.92	12.23	12.02	0.4%	0.5%
Total Production	**52.30**	**54.35**	**64.99**	**68.60**	**71.13**	**1.5%**	**1.5%**
Net Eurasian Exports	**1.88**	**1.58**	**1.24**	**1.42**	**1.60**	**-0.8%**	**0.1%**
Total Supply	**53.60**	**55.93**	**66.23**	**70.02**	**72.73**	**1.5%**	**1.5%**
Consumption							
U.S. (50 states)	16.99	17.03	18.97	19.85	20.54	1.0%	1.0%
U.S. Territories	0.21	0.21	0.26	0.27	0.28	1.5%	1.5%
Canada	1.69	1.64	1.89	1.91	1.92	0.6%	0.9%
Japan	5.14	5.45	6.84	7.23	7.36	1.8%	1.7%
Australia & New Zealand	0.82	0.82	0.95	1.01	1.07	1.3%	1.5%
OECD Europe	12.90	13.61	15.58	16.01	16.11	1.1%	0.9%
Rest of the World[4]	15.78	17.56	22.06	24.04	25.75	2.5%	2.1%
Total Consumption	**53.53**	**56.33**	**66.53**	**70.32**	**73.03**	**1.6%**	**1.5%**
Discrepancy	**-0.07**	**0.40**	**0.30**	**0.30**	**0.30**	**N/A**	**-1.6%**
Consumption Aggregations							
OECD	37.75	38.77	44.48	46.29	47.28	1.1%	1.1%
OPEC	4.61	4.95	5.89	6.51	7.18	2.2%	2.1%
Rest of the World[4]	11.18	12.61	16.16	17.53	18.57	2.6%	2.2%
Non-OPEC Production[4]	**27.26**	**27.97**	**29.45**	**27.68**	**27.16**	**0.0%**	**-0.2%**
OPEC Summary							
Market Share	0.47	0.47	0.53	0.58	0.60	1.3%	1.4%
Production Capacity[5]	29.80	28.90	38.40	44.10	47.75	2.4%	2.8%
Capacity Utilization	0.84	0.91	0.93	0.93	0.92	0.5%	0.1%

[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: 1990: Energy Information Administration (EIA), *International Energy Annual 1991*, DOE/EIA-0219(93); and EIA, International Petroleum Statistics Report, DOE/EIA-0520(93/07). 1992: EIA, *International Energy Annual 1992*, DOE/EIA-0219(94); and EIA, *Monthly Energy Review*, DOE/EIA-0035(93/12). **Projections:** EIA, AEO 1994 National Energy Modeling System run LMAC94.D1221932.

HIGH OIL PRICE CASE PROJECTIONS

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil and Lease Condensate	15.57	15.22	11.57	11.28	12.54	-1.1%	-1.1%
Natural Gas Plant Liquids	2.17	2.36	2.54	2.69	2.70	1.1%	0.7%
Dry Natural Gas[1]	18.49	18.51	19.64	20.83	20.85	0.6%	0.7%
Coal	22.46	21.62	23.46	24.51	26.61	0.9%	1.2%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[2]	6.20	6.28	7.29	7.88	8.97	1.9%	2.0%
Total	**71.08**	**70.64**	**71.71**	**74.50**	**78.24**	**0.5%**	**0.6%**
Imports							
Crude Oil[3]	12.80	13.24	18.00	18.43	17.53	1.6%	1.6%
Petroleum Products[4]	3.40	2.71	6.58	7.84	8.75	4.8%	6.7%
Natural Gas	1.54	2.15	3.19	3.59	4.16	5.1%	3.7%
Other Imports[5]	0.73	0.96	1.29	1.35	1.46	3.5%	2.3%
Total	**18.46**	**19.07**	**29.05**	**31.21**	**31.90**	**2.8%**	**2.9%**
Exports							
Petroleum	1.82	2.02	2.12	2.12	2.12	0.7%	0.2%
Natural Gas	0.09	0.22	0.24	0.27	0.30	6.4%	1.7%
Coal	2.70	2.68	3.31	3.54	3.75	1.7%	1.9%
Total	**4.61**	**4.92**	**5.68**	**5.92**	**6.17**	**1.5%**	**1.3%**
Discrepancy[6]	**-0.65**	**1.01**	**0.11**	**0.21**	**0.37**	**N/A**	**-5.5%**
Consumption							
Petroleum Products[7]	33.55	33.65	37.60	39.23	40.65	1.0%	1.1%
Natural Gas	19.30	20.15	22.68	24.27	24.85	1.3%	1.2%
Coal	19.01	18.99	20.36	21.17	23.03	1.0%	1.1%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[8]	6.23	6.37	7.36	8.03	9.24	2.0%	2.1%
Total	**84.28**	**85.80**	**95.20**	**100.00**	**104.34**	**1.1%**	**1.1%**
Net Imports - Petroleum	**14.37**	**13.93**	**22.46**	**24.16**	**24.16**	**2.6%**	**3.1%**
Prices (1992 dollars per unit)							
World Oil Price (dollars per barrel)[9]	23.22	18.20	24.16	29.90	34.11	1.9%	3.6%
Gas Wellhead Price (dollars per Mcf)[10]	1.83	1.75	2.49	2.97	3.54	3.4%	4.0%
Coal Minemouth Price (dollars per ton)	23.22	21.03	25.78	27.54	31.49	1.5%	2.3%

[1]Includes synthetic gas.

[2]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, liquid hydrogen, and methanol.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Imports of finished petroleum products. Does not include imports of unfinished oils or blending components.

[5]Includes coal, coal coke (net), and electricity (net), methanol, methyl tertiary butyl ether (MTBE), and imports of unfinished oils.

[6]Balancing item. Includes unaccounted for supply, losses, and gains.

[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and non-petroleum based liquids for blending, such as ethanol.

[8]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, plus 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.

Mcf = Thousand cubic feet.

N/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D2. Energy Consumption by End-Use Sector and Source
(Quadrillion Btu per Year)

Sector and Source	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Distillate Fuel	0.84	0.85	0.90	0.87	0.85	0.1%	0.0%
Kerosene	0.06	0.06	0.06	0.06	0.06	-0.6%	-0.3%
Liquefied Petroleum Gas	0.36	0.41	0.36	0.34	0.32	-0.6%	-1.3%
Natural Gas	4.52	4.83	4.99	4.96	4.99	0.5%	0.2%
Coal	0.06	0.06	0.05	0.05	0.05	-1.3%	-1.3%
Renewable Energy[1]	0.61	0.63	0.65	0.65	0.65	0.3%	0.2%
Electricity	3.15	3.19	3.39	3.49	3.63	0.7%	0.7%
Total	**9.61**	**10.04**	**10.40**	**10.42**	**10.55**	**0.5%**	**0.3%**
Commercial							
Distillate Fuel	0.49	0.49	0.50	0.47	0.45	-0.4%	-0.5%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.5%	-0.5%
Motor Gasoline[2]	0.11	0.09	0.11	0.11	0.11	0.2%	1.3%
Residual Fuel	0.23	0.23	0.22	0.22	0.22	-0.4%	-0.4%
Natural Gas	2.70	2.89	2.89	2.96	3.05	0.6%	0.3%
Other[3]	0.16	0.16	0.15	0.15	0.15	-0.2%	-0.2%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Electricity	2.86	2.91	3.30	3.44	3.51	1.0%	1.0%
Total	**6.57**	**6.78**	**7.20**	**7.39**	**7.52**	**0.7%**	**0.6%**
Industrial[5]							
Distillate Fuel	1.18	1.19	1.36	1.46	1.56	1.4%	1.5%
Liquefied Petroleum Gas	1.61	1.83	1.98	2.18	2.39	2.0%	1.5%
Motor Gasoline[2]	0.18	0.20	0.23	0.25	0.26	1.8%	1.5%
Petrochemical Feedstocks	1.10	1.23	1.31	1.45	1.59	1.8%	1.4%
Residual Fuel	0.42	0.34	0.43	0.41	0.40	-0.2%	0.9%
Other Petroleum[6]	3.82	3.83	4.27	4.24	4.36	0.7%	0.7%
Natural Gas[7]	8.50	8.96	9.62	10.28	10.82	1.2%	1.1%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	1.71	1.65	2.00	2.23	2.40	1.7%	2.1%
Net Coal Coke Imports	0.00	0.03	0.01	0.02	0.02	N/A	-2.6%
Renewable Energy	1.96	1.99	2.38	2.60	2.82	1.8%	2.0%
Electricity	3.23	3.29	3.81	4.14	4.47	1.6%	1.7%
Total	**24.78**	**25.42**	**28.15**	**29.90**	**31.66**	**1.2%**	**1.2%**
Transportation							
Distillate Fuel	3.83	3.76	4.81	5.25	5.74	2.0%	2.4%
Jet Fuel[8]	3.13	3.00	3.67	4.02	4.35	1.7%	2.1%
Motor Gasoline[2]	13.58	13.69	14.75	14.98	14.99	0.5%	0.5%
Residual Fuel	1.03	1.09	1.32	1.48	1.63	2.3%	2.3%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.13	0.21	12.4%	13.9%
Other Petroleum[9]	0.22	0.20	0.21	0.22	0.23	0.3%	0.9%
Pipeline Fuel Natural Gas	0.68	0.61	0.68	0.73	0.73	0.3%	1.0%
Compressed Natural Gas	0.00	0.00	0.14	0.26	0.46	N/A	N/A
Renewables (ethanol)[10]	0.00	0.00	0.02	0.07	0.13	39.4%	40.0%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	105.7%	85.2%
Methanol[11]	0.00	0.00	0.01	0.05	0.10	42.2%	32.8%
Electricity	0.01	0.01	0.08	0.13	0.20	16.0%	17.9%
Total	**22.50**	**22.38**	**25.78**	**27.33**	**28.77**	**1.2%**	**1.4%**
Electric Utilities[12]							
Distillate Fuel	0.02	0.03	0.07	0.13	0.10	7.0%	7.5%
Residual Fuel	1.23	0.90	0.88	0.88	0.76	-2.4%	-1.0%
Natural Gas	2.88	2.86	4.37	5.08	4.81	2.6%	2.9%
Steam Coal	16.10	16.30	17.47	18.15	19.93	1.1%	1.1%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[13]	3.64	3.20	4.24	4.61	5.48	2.1%	3.0%
Total	**30.07**	**29.69**	**34.25**	**36.15**	**37.64**	**1.1%**	**1.3%**

Table D2. Energy Consumption by End-Use Sector and Source (Continued)
(Quadrillion Btu per Year)

Sector and Source	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Primary Energy Consumption							
Distillate Fuel	6.36	6.31	7.64	8.18	8.69	1.6%	1.8%
Kerosene	0.08	0.07	0.07	0.07	0.07	-0.6%	-0.3%
Jet Fuel[8]	3.13	3.00	3.67	4.02	4.35	1.7%	2.1%
Liquefied Petroleum Gas	2.06	2.32	2.48	2.72	2.99	1.9%	1.4%
Motor Gasoline[2]	13.87	13.98	15.09	15.34	15.37	0.5%	0.5%
Petrochemical Feedstocks	1.10	1.23	1.31	1.45	1.59	1.8%	1.4%
Residual Fuel	2.91	2.56	2.85	2.99	3.00	0.2%	0.9%
Other Petroleum[14]	4.04	4.03	4.48	4.46	4.59	0.6%	0.7%
Natural Gas	19.30	20.15	22.68	24.27	24.85	1.3%	1.2%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	17.96	18.05	19.61	20.52	22.46	1.1%	1.2%
Net Coal Coke Imports	0.00	0.03	0.01	0.02	0.02	N/A	-2.6%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[15]	6.22	5.83	7.34	8.02	9.22	2.0%	2.6%
Total	**84.29**	**84.86**	**95.20**	**100.00**	**104.34**	**1.1%**	**1.2%**
Electricity Consumption (all sectors)	**9.25**	**9.45**	**10.58**	**11.20**	**11.80**	**1.2%**	**1.2%**

[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, ground-water 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 co-generated 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 electric utilities, independent power producers, and small power producers that sell power to the grid.

[13]Includes electricity sold to utilities by nonutilities, including cogenerators, from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports. Does not include own use.

[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.

N/A = Not applicable.

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

Sources: 1990 coal consumption: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0118(90) (Washington, D.C. May 1991) and *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas consumption: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). 1990 and 1992 consumption other than coal and natural gas: EIA, *Monthly Energy Review*, DOE/EIA-0035(93/07) (Washington, D.C., July 1993) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. The 1990 values are not final and may be updated in EIA publications. **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D3. Energy Prices by End-Use Sector and Source

(1992 Dollars per Million Btu)

Sector and Source	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential	**13.12**	**12.11**	**13.83**	**14.91**	**16.35**	**1.1%**	**1.7%**
Primary Energy	6.72	6.12	7.53	8.24	8.95	1.4%	2.1%
Petroleum Products	9.49	7.78	9.25	10.50	11.49	1.0%	2.2%
Distillate Fuel	8.55	6.68	8.18	9.27	10.09	0.8%	2.3%
Liquefied Petroleum Gas	11.67	10.05	12.08	13.87	15.40	1.4%	2.4%
Natural Gas	6.00	5.72	7.13	7.71	8.38	1.7%	2.1%
Electricity	24.98	23.76	25.64	26.90	29.12	0.8%	1.1%
Commercial	**12.78**	**12.08**	**13.69**	**14.49**	**15.29**	**0.9%**	**1.3%**
Primary Energy	5.27	4.72	6.10	6.79	7.47	1.8%	2.6%
Petroleum Products	6.35	4.94	6.47	7.60	8.43	1.4%	3.0%
Distillate Fuel	6.51	4.76	5.90	6.99	7.79	0.9%	2.8%
Residual Fuel	3.66	2.62	4.16	5.07	5.66	2.2%	4.4%
Natural Gas	5.00	4.74	6.11	6.68	7.34	1.9%	2.5%
Electricity	22.49	21.85	22.63	23.28	24.17	0.4%	0.6%
Industrial	**5.75**	**5.19**	**6.23**	**7.06**	**7.81**	**1.5%**	**2.3%**
Primary Energy	4.09	3.49	4.58	5.45	6.20	2.1%	3.2%
Petroleum Products	5.71	4.42	5.82	7.17	8.20	1.8%	3.5%
Distillate Fuel	6.06	4.87	5.86	6.98	7.80	1.3%	2.6%
Liquefied Petroleum Gas	5.76	4.95	7.39	9.14	10.65	3.1%	4.4%
Residual Fuel	3.31	2.54	4.15	5.17	5.83	2.9%	4.7%
Natural Gas[1]	3.46	3.07	4.05	4.66	5.28	2.1%	3.0%
Metallurgical Coal	1.87	1.79	2.11	2.27	2.17	0.8%	1.1%
Steam Coal	1.64	1.47	1.74	1.82	1.93	0.8%	1.5%
Electricity	15.22	14.87	15.15	15.50	16.08	0.3%	0.4%
Transportation	**8.72**	**7.88**	**9.71**	**10.82**	**11.57**	**1.4%**	**2.2%**
Primary Energy	8.72	7.88	9.69	10.80	11.54	1.4%	2.1%
Petroleum Products	8.81	7.88	9.69	10.79	11.53	1.4%	2.1%
Distillate Fuel[2]	9.03	8.02	10.12	11.35	12.17	1.5%	2.3%
Jet Fuel[3]	6.06	4.52	6.08	7.19	8.11	1.5%	3.3%
Motor Gasoline[4]	9.73	9.09	11.03	12.20	12.94	1.4%	2.0%
Residual Fuel	3.18	2.14	3.78	4.75	5.58	2.8%	5.5%
Natural Gas[5]	3.51	3.93	10.27	11.37	12.12	6.4%	6.5%
Electricity	18.15	17.94	15.40	15.58	15.90	-0.7%	-0.7%
Total End-Use Energy	**8.80**	**8.03**	**9.48**	**10.43**	**11.29**	**1.3%**	**1.9%**
Primary Energy	8.45	7.72	9.17	10.10	10.89	1.3%	1.9%
Electricity	20.79	20.05	20.85	21.44	22.49	0.4%	0.6%
Electric Utilities							
Fossil Fuel Average	1.81	1.59	2.03	2.28	2.51	1.7%	2.6%
Petroleum Products	3.55	2.56	4.19	5.31	5.96	2.6%	4.8%
Distillate Fuel	6.00	4.51	5.50	6.64	7.44	1.1%	2.8%
Residual Fuel	3.52	2.51	4.08	5.11	5.78	2.5%	4.7%
Natural Gas	2.46	2.28	3.07	3.68	4.20	2.7%	3.5%
Steam Coal	1.56	1.41	1.65	1.72	1.96	1.2%	1.8%

Table D3. Energy Prices by End-Use Sector and Source (Continued)

(1992 Dollars per Million Btu)

Sector and Source	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Average Price to All Users[6]							
Petroleum Products	7.94	6.84	8.55	9.72	10.56	1.4%	2.4%
Distillate Fuel[2]	8.18	6.98	8.81	10.02	10.91	1.4%	2.5%
Jet Fuel	6.06	4.52	6.08	7.19	8.11	1.5%	3.3%
Liquefied Petroleum Gas	6.45	5.98	8.34	10.10	11.65	3.0%	3.8%
Motor Gasoline[4]	9.73	9.09	11.03	12.20	12.94	1.4%	2.0%
Residual Fuel	3.38	2.37	3.96	4.94	5.67	2.6%	5.0%
Natural Gas	4.20	3.91	4.92	5.47	6.15	1.9%	2.5%
Coal	1.57	1.42	1.66	1.73	1.96	1.1%	1.8%
Electricity	20.79	20.05	20.85	21.44	22.49	0.4%	0.6%

[1]Excludes uses for lease and plant fuel.

[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]Compressed natural gas used as a vehicle fuel.

[6]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption. For each sector, electricity and natural gas prices are derived by dividing total revenues by sales.

Btu = British thermal unit.

Sources: 1990 petroleum prices: *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington,D.C., September 1993). 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, D.C., July 1993). 1992 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 coal prices: EIA, *Quarterly Coal Report*, DOE/EIA-0121(90/4Q) (Washington, D.C., May 1991); EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993), Table A6; and EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 industrial and transportation natural gas delivered prices: EIA, AEO National Energy Modeling System run HWOP94.D1221932. Other 1990 and 1992 natural gas prices: EIA, *Natural Gas Annual*, DOE/EIA-0131 (92)/1 (Washington, DC, November 1993). 1990 electricity prices: EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932. **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D4. Residential Sector Key Indicators and End-Use Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Household Characteristics							
Households (millions)							
Single-Family	64.36	65.60	71.65	75.10	78.73	1.0%	1.0%
Multifamily	24.42	24.27	24.72	25.43	26.38	0.4%	0.5%
Mobile Homes	5.21	5.19	5.31	5.39	5.40	0.2%	0.2%
Total	**93.99**	**95.06**	**101.67**	**105.92**	**110.51**	**0.8%**	**0.8%**
Housing Starts (millions)							
Single-Family	0.90	1.04	1.06	1.08	1.05	0.7%	0.0%
Multifamily	0.30	0.17	0.38	0.39	0.46	2.1%	5.6%
Mobile Homes	0.19	0.21	0.22	0.22	0.21	0.5%	0.0%
Total	**1.39**	**1.42**	**1.66**	**1.70**	**1.71**	**1.0%**	**1.1%**
Energy Intensity (million Btu per year per household)							
Heating	54.59	58.45	56.43	53.46	50.74	-0.4%	-0.8%
Total	**102.23**	**105.60**	**102.27**	**98.35**	**95.43**	**-0.3%**	**-0.6%**
Fuel Consumption							
Distillate							
Space Heating	0.75	0.77	0.82	0.80	0.78	0.2%	0.1%
Water Heating	0.08	0.08	0.07	0.07	0.07	-0.7%	-0.6%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	1.0%	1.0%
Total	**0.84**	**0.85**	**0.90**	**0.87**	**0.85**	**0.1%**	**0.0%**
Liquefied Petroleum Gas							
Space Heating	0.23	0.27	0.24	0.22	0.21	-0.5%	-1.4%
Water Heating	0.08	0.09	0.07	0.07	0.07	-1.0%	-1.6%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-1.0%	-0.4%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.9%	0.9%
Total	**0.36**	**0.41**	**0.36**	**0.34**	**0.32**	**-0.6%**	**-1.3%**
Natural Gas							
Space Heating	3.12	3.42	3.55	3.50	3.48	0.5%	0.1%
Space Cooling	0.00	0.00	0.00	0.00	0.01	N/A	N/A
Water Heating	1.09	1.10	1.11	1.12	1.16	0.3%	0.3%
Cooking[2]	0.18	0.18	0.19	0.20	0.21	0.8%	0.9%
Clothes Dryers	0.08	0.08	0.07	0.06	0.06	-1.3%	-1.4%
Other Uses[3]	0.06	0.06	0.06	0.07	0.07	1.0%	1.0%
Total	**4.52**	**4.83**	**4.99**	**4.96**	**4.99**	**0.5%**	**0.2%**
Electricity							
Space Heating	0.30	0.33	0.38	0.39	0.41	1.5%	1.1%
Space Cooling	0.52	0.51	0.52	0.52	0.54	0.2%	0.3%
Water Heating	0.34	0.34	0.35	0.35	0.35	0.2%	0.1%
Refrigeration	0.53	0.52	0.45	0.39	0.33	-2.3%	-2.5%
Cooking	0.15	0.15	0.16	0.17	0.18	1.0%	1.0%
Clothes Dryers	0.17	0.18	0.18	0.18	0.18	0.3%	0.2%
Freezers	0.15	0.14	0.11	0.09	0.07	-3.6%	-3.7%
Lighting	0.30	0.30	0.32	0.33	0.34	0.5%	0.7%
Other Uses[4]	0.69	0.72	0.92	1.07	1.23	2.9%	3.0%
Total	**3.15**	**3.19**	**3.39**	**3.49**	**3.63**	**0.7%**	**0.7%**

Table D4. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Renewables							
Wood[5]	0.59	0.61	0.62	0.62	0.62	0.2%	0.0%
Geothermal[6]	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Solar[7]	0.01	0.01	0.01	0.01	0.01	1.1%	1.1%
Total	**0.61**	**0.63**	**0.65**	**0.65**	**0.65**	**0.3%**	**0.2%**
Other Fuels[8]	**0.13**	**0.12**	**0.11**	**0.11**	**0.10**	**-0.9%**	**-0.9%**
Total Fuels							
Space Heating	5.13	5.53	5.74	5.66	5.61	0.4%	0.1%
Space Cooling	0.52	0.51	0.53	0.54	0.55	0.3%	0.4%
Water Heating	1.60	1.67	1.62	1.62	1.67	0.2%	0.0%
Cooking	0.37	0.37	0.39	0.41	0.42	0.7%	0.7%
Clothes Dryers	0.25	0.26	0.25	0.24	0.24	-0.2%	-0.4%
Other Uses	1.73	1.75	1.87	1.95	2.05	0.8%	0.9%
Total	**9.61**	**10.04**	**10.40**	**10.42**	**10.55**	**0.5%**	**0.3%**

[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: 1990: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price Case					Annual Growth 1990- 2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Total Employment (millions)	109.8	108.4	124.3	132.6	139.5	1.2%	1.4%
Total Floorspace (billion square feet)							
Surviving	62.7	64.7	71.0	74.0	77.0	1.0%	1.0%
New Additions	1.5	1.4	1.4	1.5	1.6	0.3%	0.9%
Total	64.3	66.1	72.4	75.4	78.6	1.0%	1.0%
Energy Consumption Intensity (Thousand Btu per square feet)	102.3	102.6	99.5	98.0	95.7	-0.3%	-0.4%
End-Use Consumption							
Electricity							
Space Heating	0.06	0.06	0.05	0.04	0.04	-2.0%	-2.0%
Space Cooling	0.26	0.26	0.26	0.25	0.26	0.0%	-0.1%
Lighting	1.20	1.20	1.21	1.19	1.19	0.0%	-0.1%
Water Heating	0.03	0.03	0.04	0.05	0.06	4.1%	4.4%
Office Equipment	0.39	0.41	0.78	0.94	1.01	4.8%	5.1%
Other Uses[1]	0.93	0.95	0.96	0.96	0.96	0.2%	0.1%
Total Electricity	2.86	2.91	3.30	3.44	3.51	1.0%	1.0%
Natural Gas							
Space Heating	1.36	1.38	1.34	1.33	1.31	-0.2%	-0.3%
Space Cooling	0.01	0.01	0.02	0.02	0.02	3.3%	2.5%
Water Heating	0.37	0.39	0.38	0.37	0.37	0.0%	-0.3%
Other Uses[2]	0.96	1.11	1.14	1.24	1.34	1.7%	1.1%
Total Natural Gas	2.70	2.89	2.89	2.96	3.05	0.6%	0.3%
Distillate							
Space Heating	0.31	0.31	0.32	0.30	0.27	-0.6%	-0.7%
Water Heating	0.03	0.03	0.03	0.03	0.02	-1.1%	-1.3%
Other Uses[2]	0.15	0.15	0.15	0.15	0.15	0.0%	0.0%
Total Distillate	0.49	0.49	0.50	0.47	0.45	-0.4%	-0.5%
Other Fuels[3]	0.51	0.49	0.50	0.49	0.49	-0.2%	0.0%
Renewables[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Total Consumption	6.57	6.78	7.20	7.39	7.52	0.7%	0.6%

[1]Includes ventilation, cooking, refrigeration, and other miscellaneous commercial uses.
[2]Includes cooking and other miscellaneous commercial uses.
[3]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[4]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1990 and 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993).
Projections: Energy Information Administration, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2536	2552	3175	3603	4066	2.4%	2.6%
Nonmanufacturing	883	875	1060	1157	1247	1.7%	2.0%
Total	**3419**	**3427**	**4235**	**4760**	**5313**	**2.2%**	**2.5%**
Energy Prices (1992 dollars per million Btu)							
Electricity	15.22	14.87	15.15	15.50	16.08	0.3%	0.4%
Natural Gas	3.46	3.07	4.05	4.66	5.28	2.1%	3.0%
Steam Coal	1.64	1.56	1.74	1.82	1.93	0.8%	1.2%
Residual Oil	3.30	2.54	4.15	5.17	5.83	2.9%	4.7%
Distillate Oil	6.02	4.88	5.86	6.98	7.80	1.3%	2.6%
Liquefied Petroleum Gas	5.84	4.95	7.39	9.14	10.65	3.1%	4.3%
Motor Gasoline	10.01	9.07	11.03	12.20	12.95	1.3%	2.0%
Metallurgical Coal	1.87	1.80	2.11	2.27	2.17	0.8%	1.0%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.23	3.29	3.81	4.14	4.47	1.6%	1.7%
Natural Gas[2]	8.50	8.96	9.62	10.28	10.82	1.2%	1.1%
Steam Coal	1.71	1.65	2.00	2.23	2.40	1.7%	2.1%
Metallurgical Coal and Coke[3]	1.05	0.90	0.76	0.67	0.59	-2.8%	-2.3%
Residual Fuel	0.42	0.34	0.43	0.41	0.40	-0.2%	0.9%
Distillate	1.18	1.19	1.36	1.46	1.56	1.4%	1.5%
Liquefied Petroleum Gas	1.61	1.83	1.98	2.18	2.39	2.0%	1.5%
Petrochemical Feedstocks	1.10	1.23	1.31	1.45	1.59	1.8%	1.4%
Other Petroleum[4]	4.00	4.03	4.50	4.48	4.62	0.7%	0.8%
Renewables	1.96	1.99	2.38	2.60	2.82	1.8%	2.0%
Total	**24.78**	**25.42**	**28.15**	**29.90**	**31.66**	**1.2%**	**1.2%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.94	0.96	0.90	0.87	0.84	-0.6%	-0.7%
Natural Gas[2]	2.49	2.61	2.27	2.16	2.04	-1.0%	-1.4%
Steam Coal	0.50	0.48	0.47	0.47	0.45	-0.5%	-0.3%
Metallurgical Coal and Coke[3]	0.31	0.26	0.18	0.14	0.11	-4.9%	-4.6%
Residual Fuel	0.12	0.10	0.10	0.09	0.08	-2.4%	-1.6%
Distillate	0.35	0.35	0.32	0.31	0.29	-0.8%	-0.9%
Liquefied Petroleum Gas	0.47	0.53	0.47	0.46	0.45	-0.2%	-0.9%
Petrochemical Feedstocks	0.32	0.36	0.31	0.30	0.30	-0.4%	-1.0%
Other Petroleum[4]	1.17	1.18	1.06	0.94	0.87	-1.5%	-1.7%
Renewables	0.57	0.58	0.56	0.55	0.53	-0.4%	-0.5%
Total	**7.25**	**7.41**	**6.65**	**6.28**	**5.96**	**-1.0%**	**-1.2%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net imports of coal coke.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington,D.C., May 1993). 1990 and 1992 natural gas values: *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

HIGH OIL PRICE CASE PROJECTIONS

Table D7. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Level of Travel Index (1990 = 1.0)							
Light-Duty Vehicles	1.00	1.01	1.17	1.28	1.38	1.6%	1.7%
Freight Trucks	1.00	1.09	1.33	1.47	1.60	2.4%	2.1%
Air	1.00	1.07	1.42	1.63	1.85	3.1%	3.1%
Rail	1.00	1.04	1.16	1.25	1.34	1.5%	1.4%
Marine	1.00	0.99	1.07	1.14	1.21	1.0%	1.1%
Energy Efficiency Indicators							
New Car MPG[1]	28.20	28.05	30.37	31.77	32.70	0.7%	0.9%
New Light Truck MPG[1]	20.91	20.98	23.05	24.26	25.17	0.9%	1.0%
Light-Duty Fleet MPG[2]	18.90	19.26	20.45	21.37	22.29	0.8%	0.8%
Aircraft Efficiency Index	1.00	1.01	1.07	1.11	1.15	0.7%	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.10	1.15	1.20	0.9%	0.9%
Rail Efficiency Index	1.00	1.00	1.04	1.06	1.07	0.3%	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.01	1.01	1.02	0.1%	0.1%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles[3]	12.74	12.79	14.06	14.63	15.12	0.9%	0.9%
Freight Trucks[3]	5.22	5.31	6.49	6.94	7.42	1.8%	1.9%
Air	3.17	3.04	3.71	4.06	4.39	1.6%	2.1%
Rail	0.51	0.49	0.57	0.60	0.63	1.0%	1.4%
Marine	1.53	1.59	1.88	2.07	2.26	1.9%	2.0%
Pipeline Fuel	0.68	0.61	0.68	0.73	0.73	0.3%	1.0%
Other[4]	0.15	0.15	0.17	0.18	0.19	1.3%	1.4%
Total[5]	**22.50**	**22.38**	**25.78**	**27.33**	**28.77**	**1.2%**	**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.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990: Federal Highway Administration, *Highway Statistics 1991*; Oak Ridge National Laboratory, *Transportation Energy Data Book: 12 and 13*, (March 1993); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, February 1993; Energy Information Administration (EIA), *Residential Transportation Energy Consumption Survey 1991*; Argonne National Laboratory, FRATE Model 1990. 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Generation by Fuel Type							
Coal	1560	1576	1686	1745	1884	0.9%	1.0%
Petroleum	117	89	80	82	68	-2.7%	-1.5%
Natural Gas	264	264	360	403	374	1.7%	1.9%
Nuclear Power	577	619	671	680	612	0.3%	-0.1%
Pumped Storage/Other[1]	-2	-4	-11	-11	-11	9.1%	5.8%
Renewable Sources[2]	293	254	308	315	335	0.7%	1.6%
Total	**2809**	**2798**	**3094**	**3215**	**3261**	**0.8%**	**0.9%**
Nonutilities (excluding cogenerators)[3]							
Generation by Fuel Type							
Coal	1	2	9	14	56	25.2%	22.3%
Petroleum/Other[4]	1	1	1	1	0	-4.5%	-4.8%
Natural Gas	9	16	48	87	111	13.4%	11.4%
Renewable Sources[2]	29	40	68	94	155	8.8%	7.8%
Total	**39**	**60**	**126**	**196**	**323**	**11.1%**	**9.8%**
Cogeneration[5]	**178**	**192**	**210**	**223**	**235**	**1.4%**	**1.2%**
Net Imports	**2**	**28**	**26**	**28**	**30**	**14.5%**	**0.4%**
Electricity Sales by Sector							
Residential	924	936	994	1023	1063	0.7%	0.7%
Commercial	839	850	966	1008	1028	1.0%	1.1%
Industrial	946	973	1116	1214	1309	1.6%	1.7%
Transportation	4	4	25	39	57	14.2%	15.9%
Total	**2713**	**2763**	**3101**	**3283**	**3457**	**1.2%**	**1.3%**
End-Use Prices (1992 cents per kilowatthour)[6]							
Residential	8.5	8.1	8.7	9.2	9.9	0.8%	1.1%
Commercial	7.7	7.5	7.7	7.9	8.2	0.4%	0.6%
Industrial	5.2	5.1	5.2	5.3	5.5	0.3%	0.4%
Transportation	5.1	5.1	5.3	5.3	5.4	0.3%	0.4%
All Sectors Average	**7.1**	**6.8**	**7.1**	**7.3**	**7.7**	**0.4%**	**0.6%**
Price Components (1992 cents per kilowatthour)[6]							
Capital Component	3.0	2.9	2.8	2.7	2.7	-0.5%	-0.4%
Fuel Component	1.4	1.3	1.5	1.7	1.8	1.1%	1.9%
O&M Component	2.6	2.6	2.6	2.6	2.6	0.1%	0.1%
Net Wholesale Power Component	0.1	0.1	0.2	0.4	0.6	7.2%	8.1%
Total	**7.1**	**6.8**	**7.1**	**7.3**	**7.7**	**0.4%**	**0.6%**

[1]Other includes methane and propane and blast furnace gas.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[3]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for delivery to the grid.
[4]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[5]Includes cogeneration at industrial, commercial, and other facilities whose primary function is not electricity production. Includes both sales to utilities and generation for own use.
[6]Prices represent average revenue per kilowatthour.
O&M = Operation and maintenance.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). 1990 Nonutility generation: Form EIA-861, "Annual Electric Utility Report" and the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is filed by nonutilities reporting the electricity delivered, while the EIA-861 is filed by electric utilities reporting the electricity received. Because the Form EIA-861 collects data from the universe of utilities, these data are used for electricity sold to utilities. Own use data is from Form EIA-867. **Prices, 1992 cogeneration, 1992 prices, and all projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D9. Electricity Generating Capability
(Thousand Megawatts)

Net Summary Capability[1]	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Capability							
Coal Steam	299.5	298.7	297.2	299.2	316.5	0.3%	0.3%
Other Fossil Steam[2]	143.9	142.5	129.7	123.5	120.4	-0.9%	-0.9%
Combined Cycle	7.2	7.8	21.6	29.9	37.9	8.7%	9.1%
Combustion Turbine/Diesel	45.6	47.9	64.5	70.2	73.4	2.4%	2.4%
Nuclear Power	99.6	99.0	102.6	103.8	90.7	-0.5%	-0.5%
Pumped Storage/Other[3]	17.6	19.1	20.2	20.2	20.2	0.7%	0.3%
Renewable Sources[4]	76.0	76.2	78.1	79.7	86.1	0.6%	0.7%
Total	**689.4**	**691.2**	**713.9**	**726.5**	**745.2**	**0.4%**	**0.4%**
Cumulative Planned Additions[5]							
Coal Steam	0.00	1.29	8.30	13.35	16.25	N/A	N/A
Other Fossil Steam[2]	0.00	0.95	1.54	1.64	1.64	N/A	N/A
Combined Cycle	0.00	0.67	9.14	14.30	14.99	N/A	N/A
Combustion Turbine/Diesel	0.00	2.50	18.84	24.18	24.55	N/A	N/A
Nuclear Power	0.00	0.00	4.70	5.91	5.91	N/A	N/A
Pumped Storage/Other[3]	0.00	1.41	2.56	2.56	2.56	N/A	N/A
Renewable Sources[4]	0.00	0.28	1.13	1.14	1.14	N/A	N/A
Total	**0.00**	**7.10**	**46.20**	**63.08**	**67.03**	**N/A**	**N/A**
Cumulative Unplanned Additions[5]						**N/A**	**N/A**
Coal Steam	0.00	0.00	0.00	0.04	17.22	N/A	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Combined Cycle	0.00	0.00	5.45	8.58	15.88	N/A	N/A
Combustion Turbine/Diesel	0.00	0.00	0.56	2.52	5.46	N/A	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[3]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	0.00	0.00	1.01	2.56	8.90	N/A	N/A
Total	**0.00**	**0.00**	**7.02**	**13.69**	**47.46**	**N/A**	**N/A**
Cumulative Total Utility Additions[5]	**0.00**	**7.10**	**53.23**	**76.77**	**114.50**	**N/A**	**N/A**
Cumulative Utility Retirements	**1.20**	**6.46**	**30.34**	**41.38**	**60.43**	**N/A**	**N/A**
Nonutilities (excludes cogenerators)[6]							
Installed Capability[7]							
Coal Steam	0.09	0.35	1.51	2.29	8.84	25.7%	19.7%
Other Fossil Steam[2]	0.23	0.40	0.83	0.83	0.83	6.6%	4.1%
Combined Cycle	1.27	2.88	6.67	11.68	17.78	14.1%	10.6%
Combustion Turbine/Diesel	0.90	1.48	5.13	8.71	12.55	14.1%	12.6%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[8]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	6.64	7.42	13.61	17.83	33.57	8.4%	8.8%
Total	**9.13**	**12.53**	**27.74**	**41.33**	**73.57**	**11.0%**	**10.3%**
Cogenerators[7,9]	**33.74**	**37.78**	**43.59**	**44.32**	**45.07**	**1.5%**	**1.0%**
Cumulative Nonutility Additions[5,7]	**0.00**	**7.44**	**28.46**	**42.78**	**75.77**	**N/A**	**13.8%**

[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]Other includes methane and propane and blast furnace gas.

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

[5]Cumulative additions after December 31, 1990.

[6]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for sales to the grid.

[7]Nameplate capacity is reported for nonutilities. Nameplate capacity is designated by the manufacturer.

[8]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[9]Includes cogenerators at industrial, commercial, and other facilities whose primary function is not electricity productionN/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992: EIA, *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	146.3	146.3	118.4	115.4	115.4	-1.2%	-1.3%
Gross Domestic Economy Sales	89.0	89.6	86.7	89.0	96.6	0.4%	0.4%
Gross Domestic Trade	**235.4**	**235.9**	**205.0**	**204.4**	**212.1**	**-0.5%**	**-0.6%**
Gross Domestic Firm Power Sales (million 1992 dollars)	6188.8	6407.3	5954.1	6332.2	6906.0	0.5%	0.4%
Gross Domestic Economy Sales (million 1992 dollars)	1720.7	1645.6	2163.4	2816.4	3323.3	3.3%	4.0%
Gross Domestic Sales (million 1992 dollars)	**7909.4**	**8052.8**	**8117.5**	**9148.7**	**10229.3**	**1.3%**	**1.3%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	5.6	14.2	14.4	14.4	14.4	4.8%	0.1%
Economy Imports From Canada and Mexico	16.9	23.8	27.2	29.5	31.9	3.2%	1.6%
Gross Imports From Canada and Mexico	**22.5**	**38.0**	**41.6**	**43.9**	**46.4**	**3.7%**	**1.1%**
Firm Power Exports To Canada and Mexico	1.7	4.7	8.8	8.8	8.8	8.5%	3.6%
Economy Exports To Canada and Mexico	18.8	5.6	6.4	7.0	7.7	-4.4%	1.7%
Gross Exports To Canada and Mexico	**20.5**	**10.3**	**15.2**	**15.7**	**16.4**	**-1.1%**	**2.6%**

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. Electricity trade among utilities in the same region is excluded from these data.

Sources: 1990 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1990 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1990 firm/interruptible share: National Energy Board, *Annual Report 1990.* Planned interregional and international firm power sales (1993 through 2001): DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1992. **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D11. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil[1]	7.36	7.17	5.45	5.33	5.92	-1.1%	-1.1%
Alaska	1.77	1.71	0.91	0.64	0.92	-3.2%	-3.4%
Lower 48 States	5.58	5.46	4.54	4.69	5.01	-0.5%	-0.5%
Natural Gas Plant Liquids	1.56	1.70	1.83	1.94	1.94	1.1%	0.8%
Total	**8.91**	**8.87**	**7.27**	**7.27**	**7.87**	**-0.6%**	**-0.7%**
Net Imports							
Crude Oil (including SPR)[2]	5.78	5.99	8.15	8.37	7.96	1.6%	1.6%
Refined Products[3]	0.90	0.45	2.30	2.92	3.36	6.8%	11.8%
Total	**6.68**	**6.44**	**10.45**	**11.30**	**11.32**	**2.7%**	**3.2%**
Other Inputs[4]	**0.49**	**0.58**	**0.62**	**0.66**	**0.72**	**1.9%**	**1.2%**
Refinery Processing Gain[5]	**0.68**	**0.77**	**0.78**	**0.81**	**0.88**	**1.3%**	**0.7%**
SPR Fill Rate Additions(-)[2]	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**0.0%**	**0.0%**
Total Primary Supply[6]	**16.75**	**16.64**	**19.11**	**20.01**	**20.76**	**1.1%**	**1.2%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.23	7.27	7.87	8.00	8.02	0.5%	0.5%
Jet Fuel[8]	1.52	1.45	1.77	1.94	2.10	1.6%	2.1%
Distillate Fuel	3.02	2.98	3.59	3.85	4.09	1.5%	1.8%
Residual Fuel	1.23	1.09	1.24	1.30	1.31	0.3%	1.0%
Other[9]	3.98	4.24	4.55	4.78	5.11	1.3%	1.0%
Total	**16.99**	**17.03**	**19.03**	**19.88**	**20.62**	**1.0%**	**1.1%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.15	1.16	1.16	1.12	1.09	-0.3%	-0.4%
Industrial[10]	4.32	4.33	4.98	5.23	5.56	1.3%	1.4%
Transportation	10.98	11.01	12.46	13.07	13.60	1.1%	1.2%
Electric Utilities[11]	0.55	0.52	0.42	0.45	0.37	-1.9%	-1.9%
Total	**16.99**	**17.03**	**19.03**	**19.88**	**20.62**	**1.0%**	**1.1%**
Discrepancy[12]	**-0.24**	**-0.39**	**0.08**	**0.14**	**0.14**	**N/A**	**N/A**
World Oil Price (1992 dollars per barrel)[13]	**23.22**	**18.20**	**24.16**	**29.90**	**34.11**	**1.9%**	**3.6%**
Domestic Refinery Distillation Capacity	**15.6**	**15.5**	**15.3**	**15.3**	**15.5**	**0.0%**	**0.0%**
Capacity Utilization Rate (percent)	**87.1**	**87.9**	**88.8**	**89.5**	**89.6**	**0.1%**	**0.1%**

[1]Includes lease condensate.
[2]SPR is the Strategic Petroleum Reserve.
[3]Net imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[4]Includes alcohols, ethers, and imports of unfinished oils.
[5]Represents volumetric gain in refinery distillation and cracking processes.
[6]Total production plus net imports plus other inputs plus refinery processing gain minus SPR additions.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[10]Includes consumption by cogenerators.
[11]Includes consumption by independent power producers.
[12]Balancing item. Includes unaccounted for supply, losses and gains.
[13]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: 1990: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, D.C., May 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D12. Petroleum Product Prices
(1992 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (dollars per barrel)	**23.22**	**18.20**	**24.16**	**29.90**	**34.11**	**1.9%**	**3.6%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	118.5	92.7	113.4	128.5	139.9	0.8%	2.3%
Liquefied Petroleum Gas	106.6	86.7	104.3	119.7	133.0	1.1%	2.4%
Commercial							
Distillate Fuel	90.3	66.0	81.8	96.9	108.1	0.9%	2.8%
Residual Fuel	54.8	39.3	62.2	75.9	84.7	2.2%	4.4%
Residual Fuel (dollars per barrel)	23.02	16.50	26.14	31.87	35.57	2.2%	4.4%
Industrial							
Distillate Fuel	84.1	67.6	81.3	96.8	108.2	1.3%	2.6%
Liquefied Petroleum Gas	52.6	42.7	63.8	78.9	91.9	2.8%	4.3%
Petrochemical Feedstocks	83.7	64.1	58.6	72.1	83.8	0.0%	1.5%
Residual Fuel	49.5	38.0	62.1	77.4	87.3	2.9%	4.7%
Residual Fuel (dollars per barrel)	20.80	15.95	26.07	32.50	36.65	2.9%	4.7%
Transportation							
Distillate Fuel[1]	125.2	111.2	140.3	157.5	168.8	1.5%	2.3%
Jet Fuel[2]	81.8	61.0	82.0	97.1	109.5	1.5%	3.3%
Motor Gasoline[3]	121.7	113.7	138.0	152.6	161.9	1.4%	2.0%
Residual Fuel	47.6	32.1	56.6	71.1	83.6	2.9%	5.5%
Residual Fuel (dollars per barrel)	19.99	13.47	23.75	29.86	35.10	2.9%	5.5%
Electric Utilities							
Distillate Fuel	83.2	62.6	76.2	92.1	103.1	1.1%	2.8%
Residual Fuel	52.7	37.5	61.1	76.5	86.4	2.5%	4.7%
Residual Fuel (dollars per barrel)	22.14	15.77	25.67	32.13	36.31	2.5%	4.7%
Refined Petroleum Product Prices[4]							
Distillate Fuel	113.9	97.6	122.2	139.0	151.3	1.4%	2.5%
Jet Fuel	81.8	61.0	82.0	97.1	109.5	1.5%	3.3%
Liquefied Petroleum Gas	58.9	51.9	72.0	87.2	100.6	2.7%	3.7%
Motor Gasoline	121.7	113.7	138.0	152.6	161.9	1.4%	2.0%
Petrochemical Feedstocks	83.7	64.1	58.6	72.1	83.8	0.0%	1.5%
Residual Fuel	50.6	35.5	59.2	73.9	84.9	2.6%	5.0%
Residual Fuel (dollars per barrel)	21.26	14.90	24.88	31.04	35.65	2.6%	5.0%
Average	**102.2**	**90.8**	**112.8**	**127.2**	**137.4**	**1.5%**	**2.3%**

[1]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[2]Kerosene-type jet fuel.
[3]Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[4]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1990 prices: Energy Information Administration (EIA), *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1992 prices for gasoline, distillate, and jet fuel are based on prices in the EIA, *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, D.C., July 1993). 1992 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). **Projections**: EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D13. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Dry Gas Production[1]	17.81	17.84	18.94	20.09	20.15	0.6%	0.7%
Supplemental Natural Gas[2]	0.12	0.12	0.11	0.12	0.08	-2.3%	-2.6%
Net Imports	**1.45**	**1.92**	**2.93**	**3.31**	**3.85**	**5.0%**	**3.9%**
Canada	1.43	2.03	2.67	2.76	2.92	3.6%	2.0%
Mexico	-0.02	-0.10	-0.05	0.00	0.17	N/A	N/A
LNG	0.03	-0.01	0.31	0.55	0.75	17.2%	N/A
Total Supply	**19.38**	**19.88**	**21.98**	**23.51**	**24.07**	**1.1%**	**1.1%**
Consumption by Sector							
Residential	4.39	4.69	4.84	4.81	4.84	0.5%	0.2%
Commercial	2.62	2.80	2.80	2.87	2.96	0.6%	0.3%
Industrial[3]	7.02	7.53	8.02	8.60	9.13	1.3%	1.1%
Electric Utilities[4]	2.79	2.77	4.22	4.91	4.65	2.6%	2.9%
Lease and Plant Fuel[5]	1.24	1.17	1.32	1.38	1.38	0.5%	0.9%
Pipeline Fuel	0.66	0.59	0.66	0.71	0.70	0.3%	1.0%
Transportation[6]	0.00	0.00	0.13	0.26	0.45	N/A	N/A
Total	**18.72**	**19.54**	**22.00**	**23.54**	**24.11**	**1.3%**	**1.2%**
Discrepancy[7]	**0.66**	**0.33**	**-0.03**	**-0.02**	**-0.03**	**N/A**	**N/A**
Average Wellhead Price[8] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.49**	**2.97**	**3.54**	**3.4%**	**4.0%**
Delivered Prices (1992 dollars per thousand cubic feet)							
Residential	6.19	5.89	7.34	7.94	8.64	1.7%	2.1%
Commercial	5.15	4.88	6.29	6.88	7.56	1.9%	2.5%
Industrial[9]	3.57	3.17	4.18	4.80	5.44	2.1%	3.0%
Electric Utilities	2.54	2.36	3.17	3.80	4.34	2.7%	3.4%
Transportation	3.62	4.05	10.58	11.71	12.48	6.4%	6.5%
Average[10]	**4.33**	**4.03**	**5.07**	**5.64**	**6.34**	**1.9%**	**2.5%**

[1]Dry marketed production minus nonhydrocarbon gases removed.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributes with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Reflects natural gas lost, the net 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.
[8]Represents Lower-48 onshore and offshore supplies.
[9]Excludes uses for lease and plant fuel.
[10]Weighted average price. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 industrial and transportation delivered prices: Energy Information Administration (EIA), AEO 1994 National Energy Modeling System run HWOP94.D1221932. Other 1990 and 1992: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D14. Oil and Gas Supply

Production and Supply	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Crude Oil							
Lower 48 Average Wellhead Price[1] (1992 dollars per barrel)	**23.02**	**17.38**	**23.34**	**28.53**	**32.31**	**1.7%**	**3.5%**
Production (million barrels per day)[2]							
U.S. Total	**7.36**	**7.17**	**5.43**	**5.33**	**5.92**	**-1.1%**	**-1.1%**
Lower 48 Onshore	4.63	4.38	3.81	3.91	4.09	-0.6%	-0.4%
Conventional	3.97	3.68	3.18	3.12	3.09	-1.3%	-1.0%
Enhanced Oil Recovery	0.66	0.71	0.63	0.79	1.00	2.1%	2.0%
Lower 48 Offshore	0.95	1.07	0.71	0.78	0.92	-0.2%	-0.8%
Alaska	1.77	1.71	0.91	0.64	0.92	-3.2%	-3.4%
U.S. End of Year Reserves (billion barrels)	**27.56**	**24.97**	**19.58**	**18.77**	**20.53**	**-1.5%**	**-1.1%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.49**	**2.97**	**3.54**	**3.4%**	**4.0%**
Production (trillion cubic feet)[3]							
U.S. Total	**17.81**	**17.84**	**18.94**	**20.09**	**20.15**	**0.6%**	**0.7%**
Lower 48 Onshore	12.15	12.50	14.62	14.69	14.50	0.9%	0.8%
Associated-Dissolved[4]	2.07	2.11	1.72	1.76	1.85	-0.6%	-0.7%
Non-Associated	10.08	10.39	12.90	12.92	12.66	1.1%	1.1%
Conventional	8.63	8.53	9.70	9.58	9.33	0.4%	0.5%
Unconventional	1.45	1.86	3.20	3.35	3.33	4.3%	3.3%
Tight Sands	1.13	1.19	1.95	2.07	2.11	3.2%	3.2%
Coal Bed Methane	0.19	0.51	0.91	0.92	0.88	8.0%	3.1%
Devonian Shale	0.12	0.16	0.35	0.36	0.33	5.0%	4.2%
Lower 48 Offshore	5.28	4.93	3.82	4.91	5.17	-0.1%	0.3%
Associated-Dissolved[4]	0.63	0.68	0.59	0.61	0.64	0.1%	-0.3%
Non-Associated	4.65	4.25	3.23	4.31	4.53	-0.1%	0.4%
Alaska	0.38	0.41	0.50	0.49	0.47	1.1%	0.8%
U.S. End of Year Reserves (trillion cubic feet)	**169.35**	**165.02**	**164.75**	**157.62**	**154.20**	**-0.5%**	**-0.4%**
Supplemental Gas Supplies[5]	**0.12**	**0.12**	**0.11**	**0.12**	**0.08**	**-2.3%**	**-2.6%**
Total Wells Completed	**31.17**	**23.01**	**40.54**	**59.36**	**83.06**	**5.0%**	**7.4%**

[1]Represents Lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Dry marketed production minus nonhydrocarbon gases removed.
[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: 1990: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - Energy Information Administration (EIA), *Petroleum Supply Annual 1990*, DOE/EIA-340(90)/1 (Washington, D.C., May 1991); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90) (Washington, D.C., September 1991). 1992: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - EIA, *Petroleum Supply Annual 1992*, DOE/EIA-340(92)/1 (Washington, D.C., May 1993); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, D.C., October 1993). 1990 and 1992: Crude Oil Lower 48 Average Wellhead Prices - EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993); Natural Gas Lower 48 Average Wellhead Prices, Alaska and Total Natural Gas Production, Supplemental Gas Supplies - EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, D.C., November 1993); Total Wells Completed - *Monthly Energy Review*, DOE/EIA-0035(93/11) (Washington, D.C., November 1993). Other 1990 and 1992 values - EIA, Office of Integrated Analysis and Forecasting. Figures for 1990 and 1992 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production[1]							
East of the Mississippi	630	589	630	635	659	0.2%	0.6%
West of the Mississippi	399	409	453	496	568	1.8%	1.8%
Total	**1029**	**998**	**1083**	**1130**	**1227**	**0.9%**	**1.2%**
Net Imports							
Imports	3	4	10	10	11	7.1%	5.9%
Exports	106	103	133	144	153	1.8%	2.2%
Total	**-103**	**-99**	**-124**	**-134**	**-142**	**1.6%**	**2.0%**
Total Supply[2]	**926**	**899**	**960**	**996**	**1085**	**0.8%**	**1.1%**
Consumption by Sector							
Residential and Commercial	7	6	6	6	5	-1.1%	-0.9%
Industrial[3]	76	74	91	100	108	1.8%	2.1%
Coke Plants	39	32	28	24	21	-2.9%	-2.2%
Electricity[4]	774	780	835	865	948	1.0%	1.1%
Total	**895**	**892**	**960**	**995**	**1083**	**1.0%**	**1.1%**
Discrepancy and Stock Change[5]	**31**	**-6**	**0**	**1**	**2**	**-11.9%**	**N/A**
Average Minemouth Price[6] **(1992 dollars per short ton)**	**23.22**	**21.03**	**25.78**	**27.54**	**31.49**	**1.5%**	**2.3%**
Delivered Prices (1992 dollars per short ton)							
Industrial	35.85	32.78	38.24	40.62	42.89	0.9%	1.5%
Coke Plants	50.93	47.92	56.56	60.76	58.22	0.7%	1.1%
Electricity	32.49	29.36	34.52	36.02	41.15	1.2%	1.9%
Average[7]	**33.59**	**30.32**	**35.52**	**37.09**	**41.66**	**1.1%**	**1.8%**
Average Price to All Users (1992 dollars per million Btu)	**1.58**	**1.42**	**1.66**	**1.73**	**1.96**	**1.1%**	**1.8%**
Exports[8]	45.49	41.34	51.46	56.09	55.31	1.0%	1.6%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Balancing item: the sum of production and net imports, minus total consumption.
[6]Free-on-board price.
[7]Weighted average prices. Weights used are consumption values by sector. Average of Industrial, Coke Plant, and Electricity Sectors.
[8]Free alongside ship price at U.S. port-of-exit.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121 (90/4Q) (Washington, D.C., May 1991); and EIA, *Coal Production 1990*, DOE/EIA-0118(90) (Washington, D.C., September 1991). 1992: EIA, *Quarterly Coal Report*, DOE/EIA-0121(93/2Q) (Washington, D.C., November 1993); and EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, D.C., October 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D16. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Nonelectric	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electricity							
Capability (gigawatts)							
Conventional Hydropower	75.30	75.54	78.28	78.42	78.53	0.2%	0.2%
Geothermal[1]	2.91	2.89	5.37	6.56	8.54	5.5%	6.2%
Municipal Solid Waste	2.13	2.66	3.63	4.41	5.22	4.6%	3.8%
Biomass/Other Waste[2]	6.86	7.29	9.17	12.13	15.12	4.0%	4.1%
Solar[3]	0.36	0.36	0.73	0.98	1.33	6.7%	7.5%
Wind[4]	1.55	1.65	2.67	4.01	20.73	13.9%	15.1%
Total	**89.11**	**90.40**	**99.87**	**106.50**	**129.46**	**1.9%**	**2.0%**
Generation (billion kilowatthours)							
Conventional Hydropower	288.04	247.88	305.03	305.85	306.55	0.4%	1.3%
Geothermal[1]	15.86	16.68	34.80	43.19	57.15	6.6%	7.1%
Municipal Solid Waste	12.32	17.24	20.12	25.90	31.89	5.5%	3.9%
Biomass/Other Waste[2]	34.14	41.73	48.15	65.59	83.34	13.6%	13.8%
Solar[3]	0.70	1.75	2.35	3.36	4.81	10.1%	5.8%
Wind[4]	2.38	2.91	5.68	9.48	54.94	17.0%	17.7%
Total	**353.44**	**328.19**	**416.14**	**453.37**	**538.68**	**2.1%**	**2.8%**
Consumption Equivalent							
Conventional Hydropower	2.98	2.57	3.16	3.17	3.17	0.4%	1.3%
Geothermal[1]	0.16	0.17	0.36	0.45	0.59	6.6%	7.2%
Municipal Solid Waste	0.13	0.18	0.21	0.27	0.33	5.5%	4.1%
Biomass/Other Waste[2]	0.35	0.43	0.50	0.68	0.86	13.6%	17.1%
Solar[3]	0.01	0.01	0.02	0.03	0.05	10.1%	9.3%
Wind[4]	0.02	0.03	0.06	0.10	0.57	17.0%	18.0%
Total	**3.66**	**3.40**	**4.31**	**4.69**	**5.58**	**2.1%**	**2.8%**
Nonelectric Renewable Energy							
Residential, Commercial, and Industrial							
Geothermal	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Biofuels	2.53	2.57	2.98	3.19	3.41	1.5%	1.6%
Solar Thermal	0.02	0.02	0.04	0.04	0.04	3.8%	4.0%
Transportation							
Ethanol	0.06	0.09	0.12	0.14	0.16	5.2%	3.4%
Total	**2.62**	**2.69**	**3.15**	**3.39**	**3.64**	**1.8%**	**1.9%**
Total Renewable Energy	**6.28**	**6.07**	**7.45**	**8.07**	**9.21**	**2.0%**	**2.0%**

[1]Includes hydrothermal resources only (hot water and steam).
[2]Does not include projections for energy crops.
[3]Utility-grid connected generation only.
[4]Includes horizontal-axis wind turbines only.
Btu = British thermal unit.
Note: Includes renewables used in industrial power generation and cogeneration.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 ethanol: Energy Information Administration (EIA), *Weekly Petroleum Status Report*, DOE/EIA-0208(93-01) (Washington, D.C., January 1993). Other 1990 and 1992: EIA, sum of EIA-860 "Annual Electric Generator Report" and EIA-867 "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D17. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Petroleum	24.0	25.7	25.0	24.2	23.5	-0.1%	-0.5%
Natural Gas	65.0	69.3	71.8	71.3	71.8	0.5%	0.2%
Coal	1.6	1.4	1.3	1.2	1.2	-1.3%	-0.8%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**90.6**	**96.4**	**98.1**	**96.7**	**96.4**	**0.3%**	**0.0%**
Commercial							
Petroleum	18.1	18.1	18.1	17.5	17.0	-0.3%	-0.4%
Natural Gas	38.7	39.9	41.5	42.5	43.8	0.6%	0.5%
Coal	2.3	2.3	2.2	2.2	2.2	-0.4%	-0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	2.6%	0.2%
Total	**59.2**	**60.3**	**61.8**	**62.2**	**62.9**	**0.3%**	**0.2%**
Industrial[1]							
Petroleum	91.9	85.1	103.8	105.6	110.2	0.9%	1.4%
Natural Gas[2]	119.6	123.0	136.2	145.6	153.1	1.2%	1.2%
Coal	67.8	62.2	67.8	71.4	73.6	0.4%	0.9%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**279.3**	**270.4**	**307.9**	**322.6**	**336.8**	**0.9%**	**1.2%**
Transportation							
Petroleum	422.3	428.8	469.0	488.4	503.2	0.9%	0.9%
Natural Gas[3]	9.9	9.8	12.1	15.0	18.3	3.1%	3.6%
Renewable/Other[4]	0.0	0.0	0.5	1.7	3.2	40.3%	36.4%
Total	**432.2**	**438.6**	**481.6**	**505.0**	**524.5**	**1.0%**	**1.0%**
Electric Utilities[5]							
Petroleum	26.8	17.2	17.5	18.2	14.8	-2.9%	-0.8%
Natural Gas	41.2	42.8	62.3	72.5	68.6	2.6%	2.7%
Steam Coal	408.8	414.8	444.2	461.3	506.7	1.1%	1.1%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	5.0%
Total	**476.7**	**474.8**	**524.0**	**552.1**	**590.0**	**1.1%**	**1.2%**
Total Energy Consumption							
Petroleum	583.2	574.9	633.4	653.9	668.5	0.7%	0.8%
Natural Gas	274.4	284.8	323.9	346.9	355.5	1.3%	1.2%
Coal	480.4	480.7	515.6	536.2	583.6	1.0%	1.1%
Renewable Energy	0.0	0.0	0.4	1.1	2.0	39.2%	31.2%
Other[4]	0.0	0.0	0.2	0.6	1.2	42.2%	32.8%
Total	**1338.0**	**1340.5**	**1473.4**	**1538.7**	**1610.9**	**0.9%**	**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 consumption of energy by electric utilities, independent power producers, and small power producers that sell electricity to utilities.
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, 1985 - 1990*, DOE/EIA-0573 (Washington, D.C., September 1993), Table 11, p. 15. 1990 consumption estimates: EIA, *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). **Consumption projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D18. Macroeconomic Indicators

(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
GDP Implicit Price Deflator (index 1987=1.000)	1.132	1.208	1.493	1.757	2.080	3.1%	3.1%
Real Gross Domestic Product	4877	4920	6018	6705	7368	2.1%	2.3%
Real Consumption	3260	3312	3880	4201	4581	1.7%	1.8%
Real Investment	739	712	1130	1299	1441	3.4%	4.0%
Real Government Spending	930	938	994	1063	1124	1.0%	1.0%
Real Exports	510	571	918	1225	1520	5.6%	5.6%
Real Imports	562	614	904	1083	1297	4.3%	4.2%
Real Disposable Personal Income	3517	3584	4184	4540	4948	1.7%	1.8%
Index of Manufacturing Gross Output (index 1987=1.000)	1.087	1.094	1.361	1.544	1.743	2.4%	2.6%
AA Utility Bond Rate (percent)	9.66	8.55	8.65	8.57	8.33	-0.7%	-0.1%
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	3.43	4.70	4.66	4.41	-2.6%	1.4%
Real Yield on Government 10 Year Bonds (percent)	4.91	3.61	4.45	4.16	3.88	-1.2%	0.4%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	15.82	14.91	14.16	-1.0%	-1.1%
Consumer Price Index (1982=1.00)	1.31	1.40	1.84	2.22	2.67	3.6%	3.6%
Employment Cost Index (1987=1.00)	1.05	1.12	1.46	1.78	2.17	3.7%	3.7%
Unemployment Rate (percent)	5.52	7.40	5.76	5.78	5.96	0.4%	-1.2%
Million Units							
Truck Deliveries, Light-Duty	4.39	4.50	5.53	6.11	6.37	1.9%	2.0%
Unit Sales of Automobiles	9.51	8.35	9.70	10.02	10.30	0.4%	1.2%
U.S. Trade-Weighted Exchange Rate	0.87	0.84	0.84	0.80	0.77	-0.6%	-0.5%
Millions of People							
Population with Armed Forces Overseas	250.3	255.8	275.6	287.1	298.9	0.9%	0.9%
Population (aged 16 and over)	192.7	196.3	212.8	223.8	235.4	1.0%	1.0%
Employment, Non-Agriculture	109.8	108.4	124.3	132.6	139.5	1.2%	1.4%

GDP = Gross domestic product.

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

Sources: 1990 and 1992: Data Resources Incorporated (DRI), DRI Trend0293. **Projections:** Energy Information Administration, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

Table D19. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (1992 dollars per barrel)[1]	**23.22**	**18.20**	**24.16**	**29.90**	**34.11**	**1.9%**	**3.6%**
Production[2]							
U.S. (50 states)	9.59	9.77	8.29	8.33	9.07	-0.3%	-0.4%
Canada	2.03	2.12	2.29	2.64	2.59	1.2%	1.1%
OECD Europe[3]	4.58	5.08	6.47	5.36	4.83	0.3%	-0.3%
OPEC	25.04	26.38	33.93	38.21	40.41	2.4%	2.4%
Rest of the World[4]	11.06	11.00	13.10	12.51	12.40	0.6%	0.7%
Total Production	**52.30**	**54.35**	**64.08**	**67.05**	**69.29**	**1.4%**	**1.4%**
Net Eurasian Exports	**1.88**	**1.58**	**0.64**	**0.32**	**0.00**	**-100.0%**	**-100.0%**
Total Supply	**53.60**	**55.93**	**64.72**	**67.37**	**69.29**	**1.3%**	**1.2%**
Consumption							
U.S. (50 states)	16.99	17.03	19.02	19.87	20.62	1.0%	1.1%
U.S. Territories	0.21	0.21	0.24	0.25	0.24	0.8%	0.7%
Canada	1.69	1.64	1.79	1.75	1.71	0.0%	0.2%
Japan	5.14	5.45	6.47	6.56	6.44	1.1%	0.9%
Australia & New Zealand	0.82	0.82	0.93	0.98	1.03	1.1%	1.3%
OECD Europe	12.90	13.61	14.97	15.05	14.94	0.7%	0.5%
Rest of the World[4]	15.78	17.56	21.59	23.21	24.62	2.2%	1.9%
Total Consumption	**53.53**	**56.33**	**65.02**	**67.67**	**69.59**	**1.3%**	**1.2%**
Discrepancy	**-0.07**	**0.40**	**0.30**	**0.30**	**0.30**	**N/A**	**-1.6%**
Consumption Aggregations							
OECD	37.75	38.77	43.43	44.46	44.97	0.9%	0.8%
OPEC	4.61	4.95	5.89	6.51	7.18	2.2%	2.1%
Rest of the World[4]	11.18	12.61	15.70	16.71	17.44	2.2%	1.8%
Non-OPEC Production[4]	**27.26**	**27.97**	**30.15**	**28.84**	**28.89**	**0.3%**	**0.2%**
OPEC Summary							
Market Share	0.47	0.47	0.52	0.56	0.58	1.1%	1.2%
Production Capacity[5]	29.80	28.90	38.40	44.10	47.75	2.4%	2.8%
Capacity Utilization	0.84	0.91	0.88	0.87	0.85	0.0%	-0.4%

[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: 1990: Energy Information Administration (EIA), *International Energy Annual 1991*, DOE/EIA-0219(93); and EIA, International Petroleum Statistics Report, DOE/EIA-0520(93/07). 1992: EIA, *International Energy Annual 1992*, DOE/EIA-0219(94); and EIA, *Monthly Energy Review*, DOE/EIA-0035(93/12). **Projections:** EIA, AEO 1994 National Energy Modeling System run HWOP94.D1221932.

LOW OIL PRICE CASE PROJECTIONS

Table E1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil and Lease Condensate	15.57	15.22	10.20	8.40	7.77	-3.4%	-3.7%
Natural Gas Plant Liquids	2.17	2.36	2.49	2.62	2.65	1.0%	0.6%
Dry Natural Gas[1]	18.49	18.51	19.25	20.29	20.49	0.5%	0.6%
Coal	22.46	21.62	23.34	24.07	25.98	0.7%	1.0%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[2]	6.20	6.28	7.30	7.87	8.56	1.6%	1.7%
Total	**71.08**	**70.64**	**69.78**	**70.55**	**72.02**	**0.1%**	**0.1%**
Imports							
Crude Oil[3]	12.80	13.24	20.99	22.75	23.40	3.1%	3.2%
Petroleum Products[4]	3.40	2.71	7.39	9.58	11.47	6.3%	8.3%
Natural Gas	1.54	2.15	3.19	3.59	4.16	5.1%	3.7%
Other Imports[5]	0.73	0.96	1.84	1.88	1.96	5.1%	4.0%
Total	**18.46**	**19.07**	**33.41**	**37.80**	**40.98**	**4.1%**	**4.3%**
Exports							
Petroleum	1.82	2.02	2.51	2.12	2.12	0.7%	0.2%
Natural Gas	0.09	0.22	0.24	0.27	0.30	6.4%	1.7%
Coal	2.70	2.68	3.31	3.54	3.75	1.7%	1.9%
Total	**4.61**	**4.92**	**6.06**	**5.92**	**6.17**	**1.5%**	**1.3%**
Discrepancy[6]	**-0.65**	**1.01**	**-0.50**	**-0.44**	**-0.36**	**-3.0%**	**N/A**
Consumption							
Petroleum Products[7]	33.55	33.65	39.50	42.17	44.30	1.4%	1.5%
Natural Gas	19.30	20.15	22.29	23.72	24.48	1.2%	1.1%
Coal	19.01	18.99	20.27	20.85	22.44	0.8%	0.9%
Nuclear Power	6.20	6.64	7.21	7.30	6.57	0.3%	-0.1%
Renewable Energy/Other[8]	6.23	6.37	7.36	7.95	8.69	1.7%	1.7%
Total	**84.28**	**85.80**	**96.62**	**101.98**	**106.48**	**1.2%**	**1.2%**
Net Imports - Petroleum	**14.37**	**13.93**	**25.87**	**30.21**	**32.75**	**4.2%**	**4.9%**
Prices (1992 dollars per unit)							
World Oil Price (dollars per barrel)[9]	23.22	18.20	15.44	17.49	20.15	-0.7%	0.6%
Gas Wellhead Price (dollars per Mcf)[10]	1.83	1.75	2.28	2.67	3.25	2.9%	3.5%
Coal Minemouth Price (dollars per ton)	23.22	21.03	24.96	25.21	29.07	1.1%	1.8%

[1]Includes synthetic gas.

[2]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, liquid hydrogen, and methanol.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Imports of finished petroleum products. Does not include imports of unfinished oils or blending components.

[5]Includes coal, coal coke (net), and electricity (net), methanol, methyl tertiary butyl ether (MTBE), and imports of unfinished oils.

[6]Balancing item. Includes unaccounted for supply, losses, and gains.

[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and non-petroleum based liquids for blending, such as ethanol.

[8]Includes utility and non-utility 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, ground-water heat pumps, and wood; alcohol fuels from renewable sources; and, in addition to renewables, electricity from waste heat, plus 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.

Mcf = Thousand cubic feet.

N/A = Not applicable.

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

Sources: 1990: Energy Information Administration (EIA), *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E2. Energy Consumption by End-Use Sector and Source
(Quadrillion Btu per Year)

Sector and Source	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Distillate Fuel	0.84	0.85	0.90	0.89	0.89	0.3%	0.2%
Kerosene	0.06	0.06	0.06	0.06	0.06	-0.5%	-0.3%
Liquefied Petroleum Gas	0.36	0.41	0.36	0.34	0.33	-0.4%	-1.1%
Natural Gas	4.52	4.83	5.02	4.99	5.01	0.5%	0.2%
Coal	0.06	0.06	0.05	0.05	0.05	-1.2%	-1.1%
Renewable Energy[1]	0.61	0.63	0.65	0.66	0.67	0.5%	0.3%
Electricity	3.15	3.19	3.40	3.49	3.64	0.7%	0.7%
Total	**9.61**	**10.04**	**10.44**	**10.49**	**10.64**	**0.5%**	**0.3%**
Commercial							
Distillate Fuel	0.49	0.49	0.54	0.56	0.58	0.9%	0.9%
Kerosene	0.01	0.01	0.01	0.01	0.01	-0.5%	-0.5%
Motor Gasoline[2]	0.11	0.09	0.11	0.11	0.11	0.2%	1.3%
Residual Fuel	0.23	0.23	0.22	0.22	0.22	-0.4%	-0.4%
Natural Gas	2.70	2.89	2.87	2.91	2.96	0.5%	0.1%
Other[3]	0.16	0.16	0.15	0.15	0.15	-0.2%	-0.2%
Renewable Energy[4]	0.01	0.01	0.03	0.03	0.03	5.2%	4.9%
Electricity	2.86	2.91	3.30	3.45	3.52	1.0%	1.1%
Total	**6.57**	**6.78**	**7.24**	**7.45**	**7.59**	**0.7%**	**0.6%**
Industrial[5]							
Distillate Fuel	1.18	1.19	1.38	1.49	1.58	1.5%	1.6%
Liquefied Petroleum Gas	1.61	1.83	2.01	2.22	2.43	2.1%	1.6%
Motor Gasoline[2]	0.18	0.20	0.23	0.25	0.27	1.8%	1.6%
Petrochemical Feedstocks	1.10	1.23	1.33	1.47	1.61	1.9%	1.5%
Residual Fuel	0.42	0.34	0.76	0.84	0.90	3.9%	5.5%
Other Petroleum[6]	3.82	3.83	4.56	4.69	4.81	1.2%	1.3%
Natural Gas[7]	8.50	8.96	9.18	9.68	9.99	0.8%	0.6%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	1.71	1.65	1.77	1.88	2.06	0.9%	1.2%
Net Coal Coke Imports	0.00	0.03	0.02	0.02	0.02	N/A	-2.5%
Renewable Energy	1.96	1.99	2.42	2.65	2.87	1.9%	2.1%
Electricity	3.23	3.29	3.89	4.25	4.55	1.7%	1.8%
Total	**24.78**	**25.42**	**28.31**	**30.09**	**31.65**	**1.2%**	**1.2%**
Transportation							
Distillate Fuel	3.83	3.76	4.96	5.45	5.95	2.2%	2.6%
Jet Fuel[8]	3.13	3.00	3.78	4.18	4.53	1.9%	2.3%
Motor Gasoline[2]	13.58	13.69	15.47	16.23	16.70	1.0%	1.1%
Residual Fuel	1.03	1.09	1.33	1.50	1.65	2.4%	2.3%
Liquefied Petroleum Gas	0.02	0.02	0.08	0.14	0.21	12.4%	13.9%
Other Petroleum[9]	0.22	0.20	0.22	0.22	0.24	0.4%	1.0%
Pipeline Fuel Natural Gas	0.68	0.61	0.68	0.71	0.74	0.4%	1.1%
Compressed Natural Gas	0.00	0.00	0.14	0.25	0.38	N/A	N/A
Renewables (ethanol)[10]	0.00	0.00	0.00	0.01	0.01	24.5%	23.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	67.2%	47.1%
Methanol[11]	0.00	0.00	0.00	0.02	0.04	34.8%	25.2%
Electricity	0.01	0.01	0.09	0.13	0.19	16.0%	17.9%
Total	**22.50**	**22.38**	**26.76**	**28.85**	**30.63**	**1.6%**	**1.8%**
Electric Utilities[12]							
Distillate Fuel	0.02	0.03	0.09	0.14	0.13	8.6%	9.4%
Residual Fuel	1.23	0.90	1.02	1.07	1.05	-0.8%	0.8%
Natural Gas	2.88	2.86	4.40	5.17	5.39	3.2%	3.6%
Steam Coal	16.10	16.30	17.62	18.18	19.67	1.0%	1.0%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[13]	3.64	3.20	4.23	4.57	5.06	1.7%	2.6%
Total	**30.07**	**29.69**	**34.55**	**36.43**	**37.87**	**1.2%**	**1.4%**

Table E2. Energy Consumption by End-Use Sector and Source (Continued)

(Quadrillion Btu per Year)

Sector and Source	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Primary Energy Consumption							
Distillate Fuel	6.36	6.31	7.87	8.54	9.12	1.8%	2.1%
Kerosene	0.08	0.07	0.07	0.07	0.07	-0.5%	-0.3%
Jet Fuel[8]	3.13	3.00	3.78	4.18	4.53	1.9%	2.3%
Liquefied Petroleum Gas	2.06	2.32	2.51	2.77	3.03	2.0%	1.5%
Motor Gasoline[2]	13.87	13.98	15.81	16.59	17.07	1.0%	1.1%
Petrochemical Feedstocks	1.10	1.23	1.33	1.47	1.61	1.9%	1.5%
Residual Fuel	2.91	2.56	3.33	3.63	3.81	1.4%	2.2%
Other Petroleum[14]	4.04	4.03	4.78	4.92	5.05	1.1%	1.3%
Natural Gas	19.30	20.15	22.29	23.72	24.48	1.2%	1.1%
Metallurgical Coal	1.04	0.87	0.74	0.65	0.57	-2.9%	-2.3%
Steam Coal	17.96	18.05	19.52	20.19	21.86	1.0%	1.1%
Net Coal Coke Imports	0.00	0.03	0.02	0.02	0.02	N/A	-2.5%
Nuclear Power	6.20	6.40	7.21	7.30	6.57	0.3%	0.1%
Renewable Energy/Other[15]	6.22	5.83	7.34	7.93	8.67	1.7%	2.2%
Total	**84.29**	**84.86**	**96.62**	**101.98**	**106.48**	**1.2%**	**1.3%**
Electricity Consumption (all sectors)	**9.25**	**9.45**	**10.67**	**11.33**	**11.90**	**1.3%**	**1.3%**

[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, ground-water 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 co-generated 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 electric utilities, independent power producers, and small power producers that sell power to the grid.

[13]Includes electricity sold to utilities by nonutilities, including cogenerators, from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources, plus waste heat and net electricity imports. Does not include own use.

[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.

N/A = Not applicable.

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

Sources: 1990 coal consumption: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0118(90) (Washington, D.C. May 1991) and *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas consumption: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). 1990 and 1992 consumption other than coal and natural gas: EIA, *Monthly Energy Review*, DOE/EIA-0035(93/07) (Washington, D.C., July 1993) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. The 1990 values are not final and may be updated in EIA publications. **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E3. Energy Prices by End-Use Sector and Source

(1992 Dollars per Million Btu)

Sector and Source	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential	**13.12**	**12.11**	**13.25**	**14.03**	**15.38**	**0.8%**	**1.3%**
Primary Energy	6.72	6.12	6.97	7.44	8.09	0.9%	1.6%
Petroleum Products	9.49	7.78	7.40	7.78	8.35	-0.6%	0.4%
Distillate Fuel	8.55	6.68	6.56	6.86	7.38	-0.7%	0.6%
Liquefied Petroleum Gas	11.67	10.05	9.59	10.26	11.06	-0.3%	0.5%
Natural Gas	6.00	5.72	6.91	7.40	8.07	1.5%	1.9%
Electricity	24.98	23.76	25.06	25.99	28.09	0.6%	0.9%
Commercial	**12.78**	**12.08**	**13.09**	**13.64**	**14.34**	**0.6%**	**1.0%**
Primary Energy	5.27	4.72	5.53	5.98	6.58	1.1%	1.9%
Petroleum Products	6.35	4.94	4.76	5.07	5.57	-0.7%	0.7%
Distillate Fuel	6.51	4.76	4.27	4.53	5.03	-1.3%	0.3%
Residual Fuel	3.66	2.62	2.67	2.88	3.30	-0.5%	1.3%
Natural Gas	5.00	4.74	5.89	6.39	7.04	1.7%	2.2%
Electricity	22.49	21.85	22.03	22.46	23.23	0.2%	0.3%
Industrial	**5.75**	**5.19**	**5.31**	**5.71**	**6.33**	**0.5%**	**1.1%**
Primary Energy	4.09	3.49	3.52	3.89	4.43	0.4%	1.3%
Petroleum Products	5.71	4.42	3.86	4.29	4.86	-0.8%	0.5%
Distillate Fuel	6.06	4.87	4.25	4.54	5.06	-0.9%	0.2%
Liquefied Petroleum Gas	5.76	4.95	4.78	5.49	6.24	0.4%	1.3%
Residual Fuel	3.31	2.54	2.60	2.71	3.11	-0.3%	1.1%
Natural Gas[1]	3.46	3.07	3.63	4.01	4.62	1.5%	2.3%
Metallurgical Coal	1.87	1.79	2.06	2.06	2.06	0.5%	0.8%
Steam Coal	1.64	1.47	1.66	1.69	1.83	0.6%	1.2%
Electricity	15.22	14.87	14.85	15.06	15.84	0.2%	0.4%
Transportation	**8.72**	**7.88**	**7.92**	**8.35**	**8.82**	**0.1%**	**0.6%**
Primary Energy	8.72	7.88	7.89	8.31	8.78	0.0%	0.6%
Petroleum Products	8.81	7.88	7.89	8.31	8.77	0.0%	0.6%
Distillate Fuel[2]	9.03	8.02	8.21	8.58	9.03	0.0%	0.7%
Jet Fuel[3]	6.06	4.52	4.46	4.82	5.36	-0.6%	1.0%
Motor Gasoline[4]	9.73	9.09	9.16	9.68	10.18	0.2%	0.6%
Residual Fuel	3.18	2.14	2.33	2.65	3.18	0.0%	2.2%
Natural Gas[5]	3.51	3.93	8.56	9.08	9.60	5.2%	5.1%
Electricity	18.15	17.94	15.27	15.41	15.57	-0.8%	-0.8%
Total End-Use Energy	**8.80**	**8.03**	**8.31**	**8.76**	**9.45**	**0.4%**	**0.9%**
Primary Energy	8.45	7.72	7.93	8.34	8.93	0.3%	0.8%
Electricity	20.79	20.05	20.32	20.69	21.76	0.2%	0.5%
Electric Utilities							
Fossil Fuel Average	1.81	1.59	1.86	2.03	2.34	1.3%	2.2%
Petroleum Products	3.55	2.56	2.70	2.95	3.38	-0.2%	1.5%
Distillate Fuel	6.00	4.51	3.87	4.20	4.73	-1.2%	0.3%
Residual Fuel	3.52	2.51	2.60	2.78	3.21	-0.5%	1.4%
Natural Gas	2.46	2.28	2.73	3.25	3.91	2.3%	3.0%
Steam Coal	1.56	1.41	1.60	1.62	1.84	0.8%	1.5%

Table E3. Energy Prices by End-Use Sector and Source (Continued)
(1992 Dollars per Million Btu)

Sector and Source	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Average Price to All Users[6]							
Petroleum Products	7.94	6.84	6.70	7.11	7.62	-0.2%	0.6%
Distillate Fuel[2]	8.18	6.98	7.00	7.36	7.87	-0.2%	0.7%
Jet Fuel	6.06	4.52	4.46	4.82	5.36	-0.6%	1.0%
Liquefied Petroleum Gas	6.45	5.98	5.75	6.46	7.26	0.6%	1.1%
Motor Gasoline[4]	9.73	9.09	9.16	9.68	10.18	0.2%	0.6%
Residual Fuel	3.38	2.37	2.50	2.72	3.18	-0.3%	1.7%
Natural Gas	4.20	3.91	4.60	4.99	5.63	1.5%	2.0%
Coal	1.57	1.42	1.61	1.63	1.84	0.8%	1.5%
Electricity	20.79	20.05	20.32	20.69	21.76	0.2%	0.5%

[1]Excludes uses for lease and plant fuel.
[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]Compressed natural gas used as a vehicle fuel.
[6]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption. For each sector, electricity and natural gas prices are derived by dividing total revenues by sales.
Btu = British thermal unit.

Sources: 1990 petroleum prices: *State Energy Price and Expenditure Report 1991*, DOE/EIA-0376(91) (Washington,D.C., September 1993). 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, D.C., July 1993). 1992 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 coal prices: EIA, *Quarterly Coal Report*, DOE/EIA-0121(90/4Q) (Washington, D.C., May 1991); EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993), Table A6; and EIA, *State Energy Price and Expenditures Report 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1990 industrial and transportation natural gas delivered prices: EIA, AEO National Energy Modeling System run LWOP94.D1221932. Other 1990 and 1992 natural gas prices: EIA, *Natural Gas Annual*, DOE/EIA-0131 (92)/1 (Washington, DC, November 1993). 1990 electricity prices: EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932. **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E4. Residential Sector Key Indicators and End-Use Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Household Characteristics							
Households (millions)							
Single-Family	64.36	65.60	71.63	75.06	78.66	1.0%	1.0%
Multifamily	24.42	24.27	24.72	25.43	26.37	0.4%	0.5%
Mobile Homes	5.21	5.19	5.31	5.38	5.38	0.2%	0.2%
Total	**93.99**	**95.06**	**101.66**	**105.87**	**110.41**	**0.8%**	**0.8%**
Housing Starts (millions)							
Single-Family	0.90	1.04	1.05	1.07	1.04	0.7%	0.0%
Multifamily	0.30	0.17	0.38	0.39	0.45	2.0%	5.6%
Mobile Homes	0.19	0.21	0.22	0.22	0.20	0.4%	-0.1%
Total	**1.39**	**1.42**	**1.65**	**1.69**	**1.70**	**1.0%**	**1.0%**
Energy Intensity (million Btu per year per household)							
Heating	54.59	58.45	56.84	54.16	51.65	-0.3%	-0.7%
Total	**102.23**	**105.60**	**102.70**	**99.09**	**96.41**	**-0.3%**	**-0.5%**
Fuel Consumption							
Distillate							
Space Heating	0.75	0.77	0.82	0.82	0.81	0.4%	0.3%
Water Heating	0.08	0.08	0.07	0.07	0.07	-0.7%	-0.6%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	1.0%	1.0%
Total	**0.84**	**0.85**	**0.90**	**0.89**	**0.89**	**0.3%**	**0.2%**
Liquefied Petroleum Gas							
Space Heating	0.23	0.27	0.24	0.23	0.22	-0.2%	-1.1%
Water Heating	0.08	0.09	0.07	0.07	0.07	-1.0%	-1.6%
Cooking[2]	0.05	0.04	0.04	0.04	0.04	-1.0%	-0.4%
Other Uses[1]	0.01	0.01	0.01	0.01	0.01	0.9%	0.9%
Total	**0.36**	**0.41**	**0.36**	**0.34**	**0.33**	**-0.4%**	**-1.1%**
Natural Gas							
Space Heating	3.12	3.42	3.58	3.54	3.51	0.6%	0.1%
Space Cooling	0.00	0.00	0.00	0.00	0.01	N/A	N/A
Water Heating	1.09	1.10	1.11	1.12	1.16	0.3%	0.3%
Cooking[2]	0.18	0.18	0.19	0.20	0.21	0.8%	0.9%
Clothes Dryers	0.08	0.08	0.07	0.06	0.06	-1.3%	-1.4%
Other Uses[3]	0.06	0.06	0.06	0.07	0.07	1.0%	1.0%
Total	**4.52**	**4.83**	**5.02**	**4.99**	**5.01**	**0.5%**	**0.2%**
Electricity							
Space Heating	0.30	0.33	0.38	0.40	0.41	1.5%	1.1%
Space Cooling	0.52	0.51	0.52	0.53	0.54	0.3%	0.4%
Water Heating	0.34	0.34	0.35	0.35	0.35	0.2%	0.1%
Refrigeration	0.53	0.52	0.45	0.39	0.33	-2.3%	-2.5%
Cooking	0.15	0.15	0.16	0.17	0.18	1.0%	1.0%
Clothes Dryers	0.17	0.18	0.18	0.18	0.18	0.3%	0.2%
Freezers	0.15	0.14	0.11	0.09	0.07	-3.6%	-3.7%
Lighting	0.30	0.30	0.32	0.33	0.34	0.5%	0.7%
Other Uses[4]	0.69	0.72	0.92	1.07	1.23	2.9%	3.0%
Total	**3.15**	**3.19**	**3.40**	**3.49**	**3.64**	**0.7%**	**0.7%**

Table E4. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Renewables							
Wood[5]	0.59	0.61	0.63	0.63	0.63	0.3%	0.2%
Geothermal[6]	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Solar[7]	0.01	0.01	0.01	0.01	0.01	1.1%	1.1%
Total	**0.61**	**0.63**	**0.65**	**0.66**	**0.67**	**0.5%**	**0.3%**
Other Fuels[8]	**0.13**	**0.12**	**0.12**	**0.11**	**0.11**	**-0.8%**	**-0.8%**
Total Fuels							
Space Heating	5.13	5.53	5.78	5.73	5.70	0.5%	0.2%
Space Cooling	0.52	0.51	0.53	0.54	0.56	0.4%	0.5%
Water Heating	1.60	1.67	1.62	1.62	1.67	0.2%	0.0%
Cooking	0.37	0.37	0.39	0.41	0.42	0.7%	0.7%
Clothes Dryers	0.25	0.26	0.25	0.24	0.24	-0.2%	-0.4%
Other Uses	1.73	1.75	1.87	1.95	2.05	0.8%	0.9%
Total	**9.61**	**10.04**	**10.44**	**10.49**	**10.64**	**0.5%**	**0.3%**

[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: 1990: Energy Information Administration (EIA), *State Energy Data Report*, DOE/EIA-0214(91) (Washington, D.C., May 1993). 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E5. Commercial Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price Case					Annual Growth 1990- 2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Total Employment (millions)	**109.8**	**108.4**	**124.8**	**133.1**	**139.7**	**1.2%**	**1.4%**
Total Floorspace (billion square feet)							
Surviving	62.7	64.7	71.0	74.0	77.0	1.0%	1.0%
New Additions	1.5	1.4	1.4	1.5	1.6	0.3%	0.9%
Total	**64.3**	**66.1**	**72.4**	**75.4**	**78.6**	**1.0%**	**1.0%**
Energy Consumption Intensity (Thousand Btu per square feet)	**102.3**	**102.6**	**100.0**	**98.7**	**96.5**	**-0.3%**	**-0.3%**
End-Use Consumption							
Electricity							
Space Heating	0.06	0.06	0.05	0.04	0.04	-1.9%	-1.9%
Space Cooling	0.26	0.26	0.26	0.26	0.26	0.0%	0.0%
Lighting	1.20	1.20	1.21	1.20	1.20	0.0%	0.0%
Water Heating	0.03	0.03	0.04	0.05	0.06	4.2%	4.5%
Office Equipment	0.39	0.41	0.78	0.94	1.01	4.8%	5.1%
Other Uses[1]	0.93	0.95	0.96	0.96	0.96	0.2%	0.1%
Total Electricity	**2.86**	**2.91**	**3.30**	**3.45**	**3.52**	**1.0%**	**1.1%**
Natural Gas							
Space Heating	1.36	1.38	1.32	1.27	1.23	-0.5%	-0.7%
Space Cooling	0.01	0.01	0.02	0.02	0.02	3.4%	2.7%
Water Heating	0.37	0.39	0.39	0.38	0.37	0.0%	-0.2%
Other Uses[2]	0.96	1.11	1.14	1.24	1.34	1.7%	1.1%
Total Natural Gas	**2.70**	**2.89**	**2.87**	**2.91**	**2.96**	**0.5%**	**0.1%**
Distillate							
Space Heating	0.31	0.31	0.36	0.39	0.41	1.4%	1.5%
Water Heating	0.03	0.03	0.03	0.03	0.03	-0.9%	-1.1%
Other Uses[2]	0.15	0.15	0.15	0.15	0.15	0.0%	0.0%
Total Distillate	**0.49**	**0.49**	**0.54**	**0.56**	**0.58**	**0.9%**	**0.9%**
Other Fuels[3]	**0.51**	**0.49**	**0.50**	**0.49**	**0.49**	**-0.2%**	**0.0%**
Renewables[4]	**0.01**	**0.01**	**0.03**	**0.03**	**0.03**	**5.2%**	**4.9%**
Total Consumption	**6.57**	**6.78**	**7.24**	**7.45**	**7.59**	**0.7%**	**0.6%**

[1]Includes ventilation, cooking, refrigeration, and other miscellaneous commercial uses.
[2]Includes cooking and other miscellaneous commercial uses.
[3]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[4]Includes solar, geothermal, and biomass energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1990 and 1992 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993).
Projections: Energy Information Administration, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2536	2552	3203	3637	4092	2.4%	2.7%
Nonmanufacturing	883	875	1063	1160	1244	1.7%	2.0%
Total	**3419**	**3427**	**4266**	**4797**	**5337**	**2.3%**	**2.5%**
Energy Prices (1992 dollars per million Btu)							
Electricity	15.22	14.87	14.85	15.06	15.84	0.2%	0.3%
Natural Gas	3.46	3.07	3.63	4.01	4.62	1.5%	2.3%
Steam Coal	1.64	1.56	1.66	1.69	1.83	0.6%	0.9%
Residual Oil	3.30	2.54	2.60	2.71	3.11	-0.3%	1.1%
Distillate Oil	6.02	4.88	4.25	4.54	5.06	-0.9%	0.2%
Liquefied Petroleum Gas	5.84	4.95	4.78	5.49	6.24	0.3%	1.3%
Motor Gasoline	10.01	9.07	9.16	9.68	10.18	0.1%	0.6%
Metallurgical Coal	1.87	1.80	2.06	2.06	2.06	0.5%	0.7%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.23	3.29	3.89	4.25	4.55	1.7%	1.8%
Natural Gas[2]	8.50	8.96	9.18	9.68	9.99	0.8%	0.6%
Steam Coal	1.71	1.65	1.77	1.88	2.06	0.9%	1.2%
Metallurgical Coal and Coke[3]	1.05	0.90	0.76	0.67	0.59	-2.8%	-2.3%
Residual Fuel	0.42	0.34	0.76	0.84	0.90	3.9%	5.5%
Distillate	1.18	1.19	1.38	1.49	1.58	1.5%	1.6%
Liquefied Petroleum Gas	1.61	1.83	2.01	2.22	2.43	2.1%	1.6%
Petrochemical Feedstocks	1.10	1.23	1.33	1.47	1.61	1.9%	1.5%
Other Petroleum[4]	4.00	4.03	4.79	4.94	5.07	1.2%	1.3%
Renewables	1.96	1.99	2.42	2.65	2.87	1.9%	2.1%
Total	**24.78**	**25.42**	**28.31**	**30.09**	**31.65**	**1.2%**	**1.2%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.94	0.96	0.91	0.89	0.85	-0.5%	-0.7%
Natural Gas[2]	2.49	2.61	2.15	2.02	1.87	-1.4%	-1.8%
Steam Coal	0.50	0.48	0.41	0.39	0.39	-1.3%	-1.2%
Metallurgical Coal and Coke[3]	0.31	0.26	0.18	0.14	0.11	-4.9%	-4.6%
Residual Fuel	0.12	0.10	0.18	0.18	0.17	1.6%	2.9%
Distillate	0.35	0.35	0.32	0.31	0.30	-0.8%	-0.9%
Liquefied Petroleum Gas	0.47	0.53	0.47	0.46	0.45	-0.2%	-0.8%
Petrochemical Feedstocks	0.32	0.36	0.31	0.31	0.30	-0.3%	-1.0%
Other Petroleum[4]	1.17	1.18	1.12	1.03	0.95	-1.0%	-1.2%
Renewables	0.57	0.58	0.57	0.55	0.54	-0.3%	-0.4%
Total	**7.25**	**7.41**	**6.64**	**6.27**	**5.93**	**-1.0%**	**-1.2%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net imports of coal coke.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington,D.C., May 1993). 1990 and 1992 natural gas values: *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E7. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Key Indicators							
Level of Travel Index (1990 = 1.0)							
Light-Duty Vehicles	1.00	1.01	1.18	1.29	1.39	1.7%	1.8%
Freight Trucks	1.00	1.09	1.35	1.48	1.61	2.4%	2.2%
Air	1.00	1.07	1.48	1.71	1.93	3.4%	3.4%
Rail	1.00	1.04	1.16	1.24	1.32	1.4%	1.3%
Marine	1.00	0.99	1.07	1.13	1.19	0.9%	1.0%
Energy Efficiency Indicators							
New Car MPG[1]	28.20	28.05	28.04	28.76	29.46	0.2%	0.3%
New Light Truck MPG[1]	20.91	20.98	21.36	22.03	22.70	0.4%	0.4%
Light-Duty Fleet MPG[2]	18.90	19.26	19.80	20.16	20.64	0.4%	0.4%
Aircraft Efficiency Index	1.00	1.01	1.07	1.11	1.14	0.7%	0.7%
Freight Truck Efficiency Index	1.00	1.01	1.07	1.10	1.14	0.7%	0.7%
Rail Efficiency Index	1.00	1.00	1.04	1.06	1.07	0.3%	0.4%
Domestic Shipping Efficiency Index	1.00	1.00	1.01	1.01	1.02	0.1%	0.1%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles[3]	12.74	12.79	14.71	15.72	16.50	1.3%	1.4%
Freight Trucks[3]	5.22	5.31	6.77	7.31	7.81	2.0%	2.2%
Air	3.17	3.04	3.83	4.22	4.58	1.8%	2.3%
Rail	0.51	0.49	0.57	0.60	0.62	1.0%	1.3%
Marine	1.53	1.59	1.89	2.09	2.27	2.0%	2.0%
Pipeline Fuel	0.68	0.61	0.68	0.71	0.74	0.4%	1.1%
Other[4]	0.15	0.15	0.17	0.18	0.20	1.4%	1.6%
Total[5]	**22.50**	**22.38**	**26.76**	**28.85**	**30.63**	**1.6%**	**1.8%**

[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.
[5]Total will not equal sum of components due to light-duty freight trucks included in both light-duty vehicle and freight truck consumption.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990: Federal Highway Administration, *Highway Statistics 1991*; Oak Ridge National Laboratory, *Transportation Energy Data Book: 12 and 13*, (March 1993); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, February 1993; Energy Information Administration (EIA), *Residential Transportation Energy Consumption Survey 1991*; Argonne National Laboratory, FRATE Model 1990. 1990 and 1992 natural gas values: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Generation by Fuel Type							
Coal	1560	1576	1698	1754	1852	0.9%	0.9%
Petroleum	117	89	93	101	97	-0.9%	0.5%
Natural Gas	264	264	331	368	354	1.5%	1.6%
Nuclear Power	577	619	671	680	612	0.3%	-0.1%
Pumped Storage/Other[1]	-2	-4	-11	-11	-11	9.1%	5.8%
Renewable Sources[2]	293	254	305	308	316	0.4%	1.2%
Total	**2809**	**2798**	**3088**	**3199**	**3220**	**0.7%**	**0.8%**
Nonutilities (excluding cogenerators)[3]							
Generation by Fuel Type							
Coal	1	2	9	9	63	25.9%	23.0%
Petroleum/Other[4]	1	1	1	1	1	-1.3%	-1.2%
Natural Gas	9	16	81	139	201	16.9%	15.1%
Renewable Sources[2]	29	40	69	96	133	7.9%	6.9%
Total	**39**	**60**	**160**	**245**	**398**	**12.3%**	**11.1%**
Cogeneration[5]	**178**	**192**	**212**	**225**	**236**	**1.4%**	**1.2%**
Net Imports	**2**	**28**	**26**	**28**	**30**	**14.5%**	**0.4%**
Electricity Sales by Sector							
Residential	924	936	995	1024	1066	0.7%	0.7%
Commercial	839	850	968	1011	1032	1.0%	1.1%
Industrial	946	973	1140	1245	1334	1.7%	1.8%
Transportation	4	4	25	39	57	14.2%	15.9%
Total	**2713**	**2763**	**3128**	**3319**	**3488**	**1.3%**	**1.3%**
End-Use Prices (1992 cents per kilowatthour)[6]							
Residential	8.5	8.1	8.5	8.9	9.6	0.6%	0.9%
Commercial	7.7	7.5	7.5	7.7	7.9	0.2%	0.3%
Industrial	5.2	5.1	5.1	5.1	5.4	0.2%	0.3%
Transportation	5.1	5.1	5.2	5.3	5.3	0.2%	0.3%
All Sectors Average	**7.1**	**6.8**	**6.9**	**7.1**	**7.4**	**0.2%**	**0.5%**
Price Components (1992 cents per kilowatthour)[6]							
Capital Component	3.0	2.9	2.7	2.6	2.6	-0.7%	-0.6%
Fuel Component	1.4	1.3	1.4	1.4	1.6	0.6%	1.3%
O&M Component	2.6	2.6	2.6	2.6	2.6	0.1%	0.1%
Net Wholesale Power Component	0.1	0.1	0.3	0.4	0.6	7.8%	8.7%
Total	**7.1**	**6.8**	**6.9**	**7.1**	**7.4**	**0.2%**	**0.5%**

[1]Other includes methane and propane and blast furnace gas.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[3]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for delivery to the grid.
[4]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[5]Includes cogeneration at industrial, commercial, and other facilities whose primary function is not electricity production. Includes both sales to utilities and generation for own use.
[6]Prices represent average revenue per kilowatthour.
O&M = Operation and maintenance.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1990 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992 (except for nonutility generation and prices): Energy Information Administration (EIA), *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). 1990 Nonutility generation: Form EIA-861, "Annual Electric Utility Report" and the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is filed by nonutilities reporting the electricity delivered, while the EIA-861 is filed by electric utilities reporting the electricity received. Because the Form EIA-861 collects data from the universe of utilities, these data are used for electricity sold to utilities. Own use data is from Form EIA-867. **Prices, 1992 cogeneration, 1992 prices, and all projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electric Utilities							
Capability							
Coal Steam	299.5	298.7	297.2	299.2	313.6	0.2%	0.3%
Other Fossil Steam[2]	143.9	142.5	129.7	123.5	120.4	-0.9%	-0.9%
Combined Cycle	7.2	7.8	16.8	26.4	33.8	8.1%	8.5%
Combustion Turbine/Diesel	45.6	47.9	65.1	70.6	71.8	2.3%	2.3%
Nuclear Power	99.6	99.0	102.6	103.8	90.7	-0.5%	-0.5%
Pumped Storage/Other[3]	17.6	19.1	20.2	20.2	20.2	0.7%	0.3%
Renewable Sources[4]	76.0	76.2	77.5	78.1	80.3	0.3%	0.3%
Total	**689.4**	**691.2**	**709.2**	**721.8**	**730.8**	**0.3%**	**0.3%**
Cumulative Planned Additions[5]							
Coal Steam	0.00	1.29	8.30	13.35	16.25	N/A	N/A
Other Fossil Steam[2]	0.00	0.95	1.54	1.64	1.64	N/A	N/A
Combined Cycle	0.00	0.67	9.14	14.30	14.99	N/A	N/A
Combustion Turbine/Diesel	0.00	2.50	18.84	24.18	24.55	N/A	N/A
Nuclear Power	0.00	0.00	4.70	5.91	5.91	N/A	N/A
Pumped Storage/Other[3]	0.00	1.41	2.56	2.56	2.56	N/A	N/A
Renewable Sources[4]	0.00	0.28	1.13	1.14	1.14	N/A	N/A
Total	**0.00**	**7.10**	**46.20**	**63.08**	**67.03**	**N/A**	**N/A**
Cumulative Unplanned Additions[5]						**N/A**	**N/A**
Coal Steam	0.00	0.00	0.00	0.00	14.28	N/A	N/A
Other Fossil Steam[2]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Combined Cycle	0.00	0.00	0.67	5.04	11.79	N/A	N/A
Combustion Turbine/Diesel	0.00	0.00	1.22	2.96	3.85	N/A	N/A
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[3]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	0.00	0.00	0.37	0.91	3.06	N/A	N/A
Total	**0.00**	**0.00**	**2.26**	**8.92**	**32.99**	**N/A**	**N/A**
Cumulative Total Utility Additions[5]	**0.00**	**7.10**	**48.46**	**71.99**	**100.02**	**N/A**	**N/A**
Cumulative Utility Retirements	**1.20**	**6.46**	**30.34**	**41.38**	**60.43**	**N/A**	**N/A**
Nonutilities (excludes cogenerators)[6]							
Installed Capability[7]							
Coal Steam	0.09	0.35	1.51	1.51	10.00	26.5%	20.5%
Other Fossil Steam[2]	0.23	0.40	0.83	0.83	0.83	6.6%	4.1%
Combined Cycle	1.27	2.88	10.11	18.22	27.90	16.7%	13.4%
Combustion Turbine/Diesel	0.90	1.48	6.23	11.07	16.33	15.6%	14.3%
Nuclear Power	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Pumped Storage/Other[8]	0.00	0.00	0.00	0.00	0.00	N/A	N/A
Renewable Sources[4]	6.64	7.42	13.53	17.81	23.86	6.6%	6.7%
Total	**9.13**	**12.53**	**32.20**	**49.44**	**78.92**	**11.4%**	**10.8%**
Cogenerators[7,9]	**33.74**	**37.78**	**43.52**	**43.71**	**43.99**	**1.3%**	**0.8%**
Cumulative Nonutility Additions[5,7]	**0.00**	**7.44**	**32.85**	**50.28**	**80.05**	**N/A**	**14.1%**

[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]Other includes methane and propane and blast furnace gas.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[5]Cumulative additions after December 31, 1990.
[6]Includes small power producers, independent power producers, and exempt wholesale generators, which produce electricity for sales to the grid.
[7]Nameplate capacity is reported for nonutilities. Nameplate capacity is designated by the manufacturer.
[8]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[9]Includes cogenerators at industrial, commercial, and other facilities whose primary function is not electricity productionN/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, D.C., February 1993). 1992: EIA, *Electric Power Annual 1992*, DOE/EIA-0348(92) (Washington, D.C., February 1994). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	146.3	146.3	118.4	115.4	115.4	-1.2%	-1.3%
Gross Domestic Economy Sales	89.0	89.6	84.9	83.6	84.8	-0.2%	-0.3%
Gross Domestic Trade	**235.4**	**235.9**	**203.3**	**199.0**	**200.2**	**-0.8%**	**-0.9%**
Gross Domestic Firm Power Sales (million 1992 dollars)	6188.8	6407.3	5954.1	6332.2	6906.0	0.5%	0.4%
Gross Domestic Economy Sales (million 1992 dollars)	1720.7	1645.6	2092.4	2344.1	2582.9	2.1%	2.5%
Gross Domestic Sales (million 1992 dollars)	**7909.4**	**8052.8**	**8046.5**	**8676.3**	**9488.8**	**0.9%**	**0.9%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	5.6	14.2	14.4	14.4	14.4	4.8%	0.1%
Economy Imports From Canada and Mexico	16.9	23.8	27.2	29.5	31.9	3.2%	1.6%
Gross Imports From Canada and Mexico	**22.5**	**38.0**	**41.6**	**43.9**	**46.4**	**3.7%**	**1.1%**
Firm Power Exports To Canada and Mexico	1.7	4.7	8.8	8.8	8.8	8.5%	3.6%
Economy Exports To Canada and Mexico	18.8	5.6	6.4	7.0	7.7	-4.4%	1.7%
Gross Exports To Canada and Mexico	**20.5**	**10.3**	**15.2**	**15.7**	**16.4**	**-1.1%**	**2.6%**

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. Electricity trade among utilities in the same region is excluded from these data.

Sources: 1990 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1990 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1990 firm/interruptible share: National Energy Board, *Annual Report 1990.* Planned interregional and international firm power sales (1993 through 2001): DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1992. **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

LOW OIL PRICE CASE PROJECTIONS

Table E11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Crude Oil[1]	7.36	7.17	4.80	3.97	3.67	-3.4%	-3.7%
Alaska	1.77	1.71	0.80	0.51	0.33	-8.1%	-8.8%
Lower 48 States	5.58	5.46	4.00	3.46	3.34	-2.5%	-2.7%
Natural Gas Plant Liquids	1.56	1.70	1.79	1.89	1.91	1.0%	0.7%
Total	**8.91**	**8.87**	**6.59**	**5.86**	**5.58**	**-2.3%**	**-2.5%**
Net Imports							
Crude Oil (including SPR)[2]	5.78	5.99	9.53	10.36	10.66	3.1%	3.3%
Refined Products[3]	0.90	0.45	2.51	3.77	4.68	8.6%	13.9%
Total	**6.68**	**6.44**	**12.04**	**14.13**	**15.34**	**4.2%**	**4.9%**
Other Inputs[4]	**0.49**	**0.58**	**0.86**	**0.88**	**0.90**	**3.1%**	**2.5%**
Refinery Processing Gain[5]	**0.68**	**0.77**	**0.78**	**0.75**	**0.77**	**0.6%**	**0.0%**
SPR Fill Rate Additions(-)[2]	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**0.0%**	**0.0%**
Total Primary Supply[6]	**16.75**	**16.64**	**20.25**	**21.59**	**22.57**	**1.5%**	**1.7%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.23	7.27	8.25	8.66	8.91	1.0%	1.1%
Jet Fuel[8]	1.52	1.45	1.83	2.02	2.19	1.8%	2.3%
Distillate Fuel	3.02	2.98	3.70	4.01	4.29	1.8%	2.0%
Residual Fuel	1.23	1.09	1.45	1.58	1.66	1.5%	2.3%
Other[9]	3.98	4.24	4.72	5.04	5.36	1.5%	1.3%
Total	**16.99**	**17.03**	**19.95**	**21.31**	**22.41**	**1.4%**	**1.5%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.15	1.16	1.19	1.18	1.18	0.1%	0.1%
Industrial[10]	4.32	4.33	5.31	5.68	6.03	1.7%	1.9%
Transportation	10.98	11.01	12.97	13.91	14.68	1.5%	1.6%
Electric Utilities[11]	0.55	0.52	0.48	0.53	0.52	-0.3%	-0.1%
Total	**16.99**	**17.03**	**19.95**	**21.31**	**22.41**	**1.4%**	**1.5%**
Discrepancy[12]	**-0.24**	**-0.39**	**0.30**	**0.28**	**0.16**	**N/A**	**N/A**
World Oil Price (1992 dollars per barrel)[13]	**23.22**	**18.20**	**15.44**	**17.49**	**20.15**	**-0.7%**	**0.6%**
Domestic Refinery Distillation Capacity	**15.6**	**15.5**	**15.9**	**15.9**	**15.9**	**0.1%**	**0.2%**
Capacity Utilization Rate (percent)	**87.1**	**87.9**	**90.0**	**90.0**	**90.0**	**0.2%**	**0.1%**

[1]Includes lease condensate.
[2]SPR is the Strategic Petroleum Reserve.
[3]Net imports of finished petroleum products. Does not include imports of unfinished oils or blending components.
[4]Includes alcohols, ethers, and imports of unfinished oils.
[5]Represents volumetric gain in refinery distillation and cracking processes.
[6]Total production plus net imports plus other inputs plus refinery processing gain minus SPR additions.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[10]Includes consumption by cogenerators.
[11]Includes consumption by independent power producers.
[12]Balancing item. Includes unaccounted for supply, losses and gains.
[13]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: 1990: Energy Information Administration (EIA), *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) (Washington, D.C., May 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E12. Petroleum Product Prices
(1992 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (dollars per barrel)	**23.22**	**18.20**	**15.44**	**17.49**	**20.15**	**-0.7%**	**0.6%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	118.5	92.7	90.9	95.1	102.3	-0.7%	0.6%
Liquefied Petroleum Gas	106.6	86.7	82.8	88.6	95.4	-0.6%	0.5%
Commercial							
Distillate Fuel	90.3	66.0	59.2	62.9	69.8	-1.3%	0.3%
Residual Fuel	54.8	39.3	40.0	43.0	49.3	-0.5%	1.3%
Residual Fuel (dollars per barrel)	23.02	16.50	16.80	18.08	20.72	-0.5%	1.3%
Industrial							
Distillate Fuel	84.1	67.6	58.9	63.0	70.2	-0.9%	0.2%
Liquefied Petroleum Gas	52.6	42.7	41.3	47.4	53.8	0.1%	1.3%
Petrochemical Feedstocks	83.7	64.1	38.7	42.9	49.5	-2.6%	-1.4%
Residual Fuel	49.5	38.0	39.0	40.6	46.6	-0.3%	1.1%
Residual Fuel (dollars per barrel)	20.80	15.95	16.37	17.04	19.55	-0.3%	1.1%
Transportation							
Distillate Fuel[1]	125.2	111.2	113.8	119.0	125.3	0.0%	0.7%
Jet Fuel[2]	81.8	61.0	60.2	65.0	72.4	-0.6%	1.0%
Motor Gasoline[3]	121.7	113.7	114.5	121.0	127.4	0.2%	0.6%
Residual Fuel	47.6	32.1	34.8	39.6	47.6	0.0%	2.2%
Residual Fuel (dollars per barrel)	19.99	13.47	14.63	16.64	19.99	0.0%	2.2%
Electric Utilities							
Distillate Fuel	83.2	62.6	53.7	58.3	65.6	-1.2%	0.3%
Residual Fuel	52.7	37.5	38.9	41.7	48.1	-0.5%	1.4%
Residual Fuel (dollars per barrel)	22.14	15.77	16.32	17.50	20.18	-0.5%	1.4%
Refined Petroleum Product Prices[4]							
Distillate Fuel	113.9	97.6	97.1	102.1	109.1	-0.2%	0.6%
Jet Fuel	81.8	61.0	60.2	65.0	72.4	-0.6%	1.0%
Liquefied Petroleum Gas	58.9	51.9	49.6	55.8	62.7	0.3%	1.1%
Motor Gasoline	121.7	113.7	114.5	121.0	127.4	0.2%	0.6%
Petrochemical Feedstocks	83.7	64.1	38.7	42.9	49.5	-2.6%	-1.4%
Residual Fuel	50.6	35.5	37.4	40.6	47.6	-0.3%	1.6%
Residual Fuel (dollars per barrel)	21.26	14.90	15.69	17.07	19.98	-0.3%	1.6%
Average	**102.2**	**90.8**	**89.3**	**94.4**	**100.5**	**-0.1%**	**0.6%**

[1]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[2]Kerosene-type jet fuel.
[3]Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[4]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1990 prices: Energy Information Administration (EIA), *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). 1992 prices for gasoline, distillate, and jet fuel are based on prices in the EIA, *Petroleum Marketing Annual 1992*, DOE/EIA-0487(92) (Washington, D.C., July 1993). 1992 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1991*, DOE/EIA-0376(91) (Washington, D.C., September 1993). **Projections**: EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E13. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production							
Dry Gas Production[1]	17.81	17.84	18.56	19.56	19.80	0.5%	0.6%
Supplemental Natural Gas[2]	0.12	0.12	0.11	0.11	0.07	-2.6%	-2.9%
Net Imports	**1.45**	**1.92**	**2.93**	**3.31**	**3.85**	**5.0%**	**3.9%**
Canada	1.43	2.03	2.67	2.76	2.92	3.6%	2.0%
Mexico	-0.02	-0.10	-0.05	0.00	0.17	N/A	N/A
LNG	0.03	-0.01	0.31	0.55	0.75	17.2%	N/A
Total Supply	**19.38**	**19.88**	**21.60**	**22.99**	**23.72**	**1.0%**	**1.0%**
Consumption by Sector							
Residential	4.39	4.69	4.87	4.85	4.87	0.5%	0.2%
Commercial	2.62	2.80	2.79	2.83	2.88	0.5%	0.2%
Industrial[3]	7.02	7.53	7.62	8.05	8.35	0.9%	0.6%
Electric Utilities[4]	2.79	2.77	4.25	5.00	5.22	3.2%	3.6%
Lease and Plant Fuel[5]	1.24	1.17	1.29	1.35	1.35	0.5%	0.8%
Pipeline Fuel	0.66	0.59	0.66	0.69	0.71	0.4%	1.1%
Transportation[6]	0.00	0.00	0.13	0.25	0.37	N/A	N/A
Total	**18.72**	**19.54**	**21.62**	**23.01**	**23.74**	**1.2%**	**1.1%**
Discrepancy[7]	**0.66**	**0.33**	**-0.02**	**-0.02**	**-0.02**	**N/A**	**N/A**
Average Wellhead Price[8] (1992 dollars per thousand cubic feet)	**1.83**	**1.75**	**2.28**	**2.67**	**3.25**	**2.9%**	**3.5%**
Delivered Prices (1992 dollars per thousand cubic feet)							
Residential	6.19	5.89	7.12	7.63	8.32	1.5%	1.9%
Commercial	5.15	4.88	6.07	6.58	7.26	1.7%	2.2%
Industrial[9]	3.57	3.17	3.74	4.13	4.76	1.5%	2.3%
Electric Utilities	2.54	2.36	2.82	3.36	4.04	2.4%	3.0%
Transportation	3.62	4.05	8.82	9.36	9.89	5.2%	5.1%
Average[10]	**4.33**	**4.03**	**4.74**	**5.15**	**5.81**	**1.5%**	**2.0%**

[1]Dry marketed production minus nonhydrocarbon gases removed.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributes with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Reflects natural gas lost, the net 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.
[8]Represents Lower-48 onshore and offshore supplies.
[9]Excludes uses for lease and plant fuel.
[10]Weighted average price. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 industrial and transportation delivered prices: Energy Information Administration (EIA), AEO 1994 National Energy Modeling System run LWOP94.D1221932. Other 1990 and 1992: EIA, *Natural Gas Annual 1992 Volume 1*, DOE/EIA-0131(92)/1 (Washington, D.C., November 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E14. Oil and Gas Supply

Production and Supply	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Crude Oil							
Lower 48 Average Wellhead Price[1] (1992 dollars per barrel)	23.02	17.38	15.26	17.16	19.64	-0.8%	0.7%
Production (million barrels per day)[2]							
U.S. Total	7.36	7.17	4.79	3.97	3.67	-3.4%	-3.7%
Lower 48 Onshore	4.63	4.38	3.37	2.90	2.80	-2.5%	-2.5%
Conventional	3.97	3.68	2.84	2.49	2.32	-2.7%	-2.5%
Enhanced Oil Recovery	0.66	0.71	0.53	0.41	0.48	-1.5%	-2.1%
Lower 48 Offshore	0.95	1.07	0.62	0.56	0.54	-2.8%	-3.7%
Alaska	1.77	1.71	0.80	0.51	0.33	-8.1%	-8.8%
U.S. End of Year Reserves (billion barrels)	27.56	24.97	17.95	14.97	13.75	-3.4%	-3.3%
Natural Gas							
Lower 48 Average Wellhead Price[1] (1992 dollars per thousand cubic feet)	1.83	1.75	2.28	2.67	3.25	2.9%	3.5%
Production (trillion cubic feet)[3]							
U.S. Total	17.81	17.84	18.56	19.56	19.80	0.5%	0.6%
Lower 48 Onshore	12.15	12.50	14.99	14.53	14.20	0.8%	0.7%
Associated-Dissolved[4]	2.07	2.11	1.54	1.39	1.36	-2.1%	-2.4%
Non-Associated	10.08	10.39	13.45	13.15	12.84	1.2%	1.2%
Conventional	8.63	8.53	10.14	9.75	9.47	0.5%	0.6%
Unconventional	1.45	1.86	3.31	3.39	3.37	4.3%	3.4%
Tight Sands	1.13	1.19	2.03	2.10	2.14	3.2%	3.3%
Coal Bed Methane	0.19	0.51	0.91	0.93	0.88	8.0%	3.1%
Devonian Shale	0.12	0.16	0.36	0.36	0.34	5.1%	4.3%
Lower 48 Offshore	5.28	4.93	3.08	4.54	5.12	-0.2%	0.2%
Associated-Dissolved[4]	0.63	0.68	0.56	0.54	0.54	-0.8%	-1.3%
Non-Associated	4.65	4.25	2.51	4.00	4.59	-0.1%	0.4%
Alaska	0.38	0.41	0.49	0.49	0.47	1.1%	0.8%
U.S. End of Year Reserves (trillion cubic feet)	169.35	165.02	164.93	154.84	147.79	-0.7%	-0.6%
Supplemental Gas Supplies[5]	0.12	0.12	0.11	0.11	0.07	-2.6%	-2.9%
Total Wells Completed	31.17	23.01	32.39	45.64	65.81	3.8%	6.0%

[1]Represents Lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Dry marketed production minus nonhydrocarbon gases removed.
[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: 1990: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - Energy Information Administration (EIA), *Petroleum Supply Annual 1990*, DOE/EIA-340(90)/1 (Washington, D.C., May 1991); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90) (Washington, D.C., September 1991). 1992: Lower 48 Onshore, Lower 48 Offshore, Alaska Crude Oil Production - EIA, *Petroleum Supply Annual 1992*, DOE/EIA-340(92)/1 (Washington, D.C., May 1993); U.S. Crude Oil Reserves, U.S. Natural Gas Reserves, Lower 48 Offshore Natural Gas Production - EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(92) (Washington, D.C., October 1993). 1990 and 1992: Crude Oil Lower 48 Average Wellhead Prices - EIA, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, D.C., June 1993); Natural Gas Lower 48 Average Wellhead Prices, Alaska and Total Natural Gas Production, Supplemental Gas Supplies - EIA, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, D.C., November 1993); Total Wells Completed - *Monthly Energy Review*, DOE/EIA-0035(93/11) (Washington, D.C., November 1993). Other 1990 and 1992 values - EIA, Office of Integrated Analysis and Forecasting. Figures for 1990 and 1992 may differ from published data due to internal conversion factors within the AEO 1994 National Energy Modeling System. **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Production[1]							
East of the Mississippi	630	589	627	618	624	-0.1%	0.3%
West of the Mississippi	399	409	451	493	576	1.9%	1.9%
Total	**1029**	**998**	**1078**	**1110**	**1200**	**0.8%**	**1.0%**
Net Imports							
Imports	3	4	10	10	11	7.1%	5.9%
Exports	106	103	133	144	152	1.8%	2.2%
Total	**-103**	**-99**	**-123**	**-134**	**-142**	**1.6%**	**2.0%**
Total Supply[2]	**926**	**899**	**954**	**977**	**1059**	**0.7%**	**0.9%**
Consumption by Sector							
Residential and Commercial	7	6	6	6	5	-1.0%	-0.8%
Industrial[3]	76	74	81	84	94	1.0%	1.3%
Coke Plants	39	32	28	24	21	-2.9%	-2.2%
Electricity[4]	774	780	841	867	937	1.0%	1.0%
Total	**895**	**892**	**956**	**981**	**1058**	**0.8%**	**1.0%**
Discrepancy and Stock Change[5]	**31**	**-6**	**-2**	**-5**	**1**	**-17.1%**	**N/A**
Average Minemouth Price[6] (1992 dollars per short ton)	**23.22**	**21.03**	**24.96**	**25.21**	**29.07**	**1.1%**	**1.8%**
Delivered Prices (1992 dollars per short ton)							
Industrial	35.85	32.78	36.31	37.86	40.38	0.6%	1.2%
Coke Plants	50.93	47.92	55.30	55.33	55.11	0.4%	0.8%
Electricity	32.49	29.36	33.44	34.01	38.65	0.9%	1.5%
Average[7]	**33.59**	**30.32**	**34.32**	**34.87**	**39.13**	**0.8%**	**1.4%**
Average Price to All Users (1992 dollars per million Btu)	**1.58**	**1.42**	**1.61**	**1.63**	**1.84**	**0.8%**	**1.5%**
Exports[8]	45.49	41.34	50.38	50.66	52.25	0.7%	1.3%

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports.
[3]Includes consumption by cogenerators.
[4]Includes consumption by independent power producers.
[5]Balancing item: the sum of production and net imports, minus total consumption.
[6]Free-on-board price.
[7]Weighted average prices. Weights used are consumption values by sector. Average of Industrial, Coke Plant, and Electricity Sectors.
[8]Free alongside ship price at U.S. port-of-exit.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121 (90/4Q) (Washington, D.C., May 1991); and EIA, *Coal Production 1990*, DOE/EIA-0118(90) (Washington, D.C., September 1991). 1992: EIA, *Quarterly Coal Report*, DOE/EIA-0121(93/2Q) (Washington, D.C., November 1993); and EIA, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, D.C., October 1993). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E16. Renewable Energy

(Quadrillion Btu per Year, Unless Otherwise Noted)

Electric and Nonelectric	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Electricity							
Capability (gigawatts)							
Conventional Hydropower	75.30	75.54	78.30	78.44	78.54	0.2%	0.2%
Geothermal[1]	2.91	2.89	5.54	6.56	8.54	5.5%	6.2%
Municipal Solid Waste	2.13	2.66	3.66	4.45	5.26	4.6%	3.9%
Biomass/Other Waste[2]	6.86	7.29	9.31	12.30	15.26	4.1%	4.2%
Solar[3]	0.36	0.36	0.73	0.98	1.33	6.7%	7.5%
Wind[4]	1.55	1.65	1.76	2.31	5.14	6.2%	6.5%
Total	**89.11**	**90.40**	**99.31**	**105.03**	**114.07**	**1.2%**	**1.3%**
Generation (billion kilowatthours)							
Conventional Hydropower	288.04	247.88	305.13	305.97	306.63	0.4%	1.3%
Geothermal[1]	15.86	16.68	36.01	43.20	57.15	6.6%	7.1%
Municipal Solid Waste	12.32	17.24	20.27	26.23	32.27	5.5%	4.0%
Biomass/Other Waste[2]	34.14	41.73	48.85	66.47	84.04	13.7%	13.9%
Solar[3]	0.70	1.75	2.35	3.37	4.81	10.1%	5.8%
Wind[4]	2.38	2.91	2.91	4.61	13.63	9.1%	9.0%
Total	**353.44**	**328.19**	**415.51**	**449.84**	**498.54**	**1.7%**	**2.4%**
Consumption Equivalent							
Conventional Hydropower	2.98	2.57	3.16	3.17	3.18	0.4%	1.3%
Geothermal[1]	0.16	0.17	0.37	0.45	0.59	6.6%	7.2%
Municipal Solid Waste	0.13	0.18	0.21	0.27	0.33	5.6%	4.2%
Biomass/Other Waste[2]	0.35	0.43	0.51	0.69	0.87	13.7%	17.2%
Solar[3]	0.01	0.01	0.02	0.03	0.05	10.1%	9.3%
Wind[4]	0.02	0.03	0.03	0.05	0.14	9.1%	9.2%
Total	**3.66**	**3.40**	**4.30**	**4.66**	**5.16**	**1.7%**	**2.4%**
Nonelectric Renewable Energy							
Residential, Commercial, and Industrial							
Geothermal	0.01	0.01	0.01	0.02	0.02	7.9%	7.3%
Biofuels	2.53	2.57	3.02	3.25	3.47	1.6%	1.7%
Solar Thermal	0.02	0.02	0.04	0.04	0.04	3.8%	4.0%
Transportation							
Ethanol	0.06	0.09	0.10	0.12	0.12	3.6%	1.7%
Total	**2.62**	**2.69**	**3.17**	**3.42**	**3.66**	**1.8%**	**1.9%**
Total Renewable Energy	**6.28**	**6.07**	**7.46**	**8.07**	**8.81**	**1.8%**	**1.8%**

[1]Includes hydrothermal resources only (hot water and steam).
[2]Does not include projections for energy crops.
[3]Utility-grid connected generation only.
[4]Includes horizontal-axis wind turbines only.
Btu = British thermal unit.
Note: Includes renewables used in industrial power generation and cogeneration.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992 ethanol: Energy Information Administration (EIA), *Weekly Petroleum Status Report*, DOE/EIA-0208(93-01) (Washington, D.C., January 1993). Other 1990 and 1992: EIA, sum of EIA-860 "Annual Electric Generator Report" and EIA-867 "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E17. Carbon Emissions by End-Use Sector and Source
(Million Metric Tons per Year)

Sector and Source	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
Residential							
Petroleum	24.0	25.7	25.1	24.6	24.3	0.1%	-0.3%
Natural Gas	65.0	69.3	72.2	71.8	72.2	0.5%	0.2%
Coal	1.6	1.4	1.3	1.3	1.2	-1.2%	-0.6%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**90.6**	**96.4**	**98.7**	**97.8**	**97.7**	**0.4%**	**0.1%**
Commercial							
Petroleum	18.1	18.1	18.9	19.3	19.6	0.4%	0.4%
Natural Gas	38.7	39.9	41.3	41.8	42.6	0.5%	0.4%
Coal	2.3	2.3	2.2	2.2	2.2	-0.4%	-0.4%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	2.6%	0.2%
Total	**59.2**	**60.3**	**62.4**	**63.3**	**64.3**	**0.4%**	**0.4%**
Industrial[1]							
Petroleum	91.9	85.1	116.5	123.3	129.0	1.7%	2.3%
Natural Gas[2]	119.6	123.0	129.9	137.0	141.1	0.8%	0.8%
Coal	67.8	62.2	62.1	62.6	65.2	-0.2%	0.3%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Total	**279.3**	**270.4**	**308.4**	**322.9**	**335.3**	**0.9%**	**1.2%**
Transportation							
Petroleum	422.3	428.8	487.6	520.0	545.1	1.3%	1.3%
Natural Gas[3]	9.9	9.8	12.1	14.6	17.1	2.8%	3.2%
Renewable/Other[4]	0.0	0.0	0.1	0.3	0.6	29.3%	24.6%
Total	**432.2**	**438.6**	**499.8**	**534.8**	**562.7**	**1.3%**	**1.4%**
Electric Utilities[5]							
Petroleum	26.8	17.2	20.4	22.5	21.5	-1.1%	1.3%
Natural Gas	41.2	42.8	62.6	73.7	76.9	3.2%	3.3%
Steam Coal	408.8	414.8	447.8	462.2	500.2	1.0%	1.0%
Renewable Energy	0.0	0.0	0.0	0.0	0.0	N/A	5.1%
Total	**476.7**	**474.8**	**530.8**	**558.4**	**598.7**	**1.1%**	**1.3%**
Total Energy Consumption							
Petroleum	583.2	574.9	668.5	709.7	739.6	1.2%	1.4%
Natural Gas	274.4	284.8	318.1	339.0	349.9	1.2%	1.1%
Coal	480.4	480.7	513.5	528.3	568.8	0.8%	0.9%
Renewable Energy	0.0	0.0	0.1	0.2	0.2	25.0%	16.4%
Other[4]	0.0	0.0	0.0	0.2	0.4	34.8%	25.2%
Total	**1338.0**	**1340.5**	**1500.2**	**1577.3**	**1658.9**	**1.1%**	**1.2%**

[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 consumption of energy by electric utilities, independent power producers, and small power producers that sell electricity to utilities.
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, 1985 - 1990*, DOE/EIA-0573 (Washington, D.C., September 1993), Table 11, p. 15. 1990 consumption estimates: EIA, *State Energy Data Report 1991*, DOE/EIA-0214(91) (Washington, D.C., May 1993). **Consumption projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E18. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicators	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
GDP Implicit Price Deflator (index 1987=1.000)	1.132	1.208	1.479	1.738	2.067	3.1%	3.0%
Real Gross Domestic Product	4877	4920	6075	6783	7437	2.1%	2.3%
Real Consumption	3260	3312	3926	4262	4640	1.8%	1.9%
Real Investment	739	712	1149	1323	1462	3.5%	4.1%
Real Government Spending	930	938	1003	1075	1136	1.0%	1.1%
Real Exports	510	571	929	1246	1544	5.7%	5.7%
Real Imports	562	614	930	1124	1346	4.5%	4.5%
Real Disposable Personal Income	3517	3584	4230	4597	4998	1.8%	1.9%
Index of Manufacturing Gross Output (index 1987=1.000)	1.087	1.094	1.373	1.559	1.754	2.4%	2.7%
AA Utility Bond Rate (percent)	9.66	8.55	8.51	8.32	8.13	-0.9%	-0.3%
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	3.43	4.68	4.66	4.55	-2.5%	1.6%
Real Yield on Government 10 Year Bonds (percent)	4.91	3.61	4.38	3.77	3.39	-1.8%	-0.4%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	15.90	15.04	14.32	-0.9%	-1.1%
Consumer Price Index (1982=1.00)	1.31	1.40	1.81	2.18	2.63	3.5%	3.5%
Employment Cost Index (1987=1.00)	1.05	1.12	1.46	1.78	2.19	3.7%	3.8%
Unemployment Rate (percent)	5.52	7.40	5.51	5.56	5.86	0.3%	-1.3%
Million Units							
Truck Deliveries, Light-Duty	4.39	4.50	5.85	6.50	6.71	2.1%	2.3%
Unit Sales of Automobiles	9.51	8.35	9.90	10.28	10.51	0.5%	1.3%
U.S. Trade-Weighted Exchange Rate	0.87	0.84	0.84	0.80	0.77	-0.6%	-0.5%
Millions of People							
Population with Armed Forces Overseas	250.3	255.8	275.6	287.1	298.9	0.9%	0.9%
Population (aged 16 and over)	192.7	196.3	212.8	223.8	235.4	1.0%	1.0%
Employment, Non-Agriculture	109.8	108.4	124.8	133.1	139.7	1.2%	1.4%

GDP = Gross domestic product.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 and 1992: Data Resources Incorporated (DRI), DRI Trend0293. **Projections:** Energy Information Administration, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

Table E19. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Oil Price Case					Annual Growth 1990-2010 (percent)	Annual Growth 1992-2010 (percent)
	1990	1992	2000	2005	2010		
World Oil Price (1992 dollars per barrel)[1]	**23.22**	**18.20**	**15.44**	**17.49**	**20.15**	**-0.7%**	**0.6%**
Production[2]							
U.S. (50 states)	9.59	9.77	7.58	6.84	6.58	-1.9%	-2.2%
Canada	2.03	2.12	2.10	2.30	2.24	0.5%	0.3%
OECD Europe[3]	4.58	5.08	6.33	5.15	4.61	0.0%	-0.5%
OPEC	25.04	26.38	39.07	45.53	48.74	3.4%	3.5%
Rest of the World[4]	11.06	11.00	12.67	12.11	11.93	0.4%	0.5%
Total Production	**52.30**	**54.35**	**67.75**	**71.94**	**74.10**	**1.8%**	**1.7%**
Net Eurasian Exports	**1.88**	**1.58**	**1.84**	**2.52**	**3.20**	**2.7%**	**4.0%**
Total Supply	**53.60**	**55.93**	**69.59**	**74.46**	**77.30**	**1.8%**	**1.8%**
Consumption							
U.S. (50 states)	16.99	17.03	19.95	21.32	22.42	1.4%	1.5%
U.S. Territories	0.21	0.21	0.28	0.32	0.34	2.5%	2.6%
Canada	1.69	1.64	2.04	2.12	2.09	1.1%	1.4%
Japan	5.14	5.45	7.39	7.92	7.95	2.2%	2.1%
Australia & New Zealand	0.82	0.82	0.97	1.06	1.14	1.6%	1.8%
OECD Europe	12.90	13.61	16.50	17.24	17.25	1.5%	1.3%
Rest of the World[4]	15.78	17.56	22.74	24.77	26.43	2.6%	2.3%
Total Consumption	**53.53**	**56.33**	**69.89**	**74.76**	**77.60**	**1.9%**	**1.8%**
Discrepancy	**-0.07**	**0.40**	**0.30**	**0.30**	**0.30**	**N/A**	**-1.6%**
Consumption Aggregations							
OECD	37.75	38.77	47.15	49.99	51.18	1.5%	1.6%
OPEC	4.61	4.95	5.89	6.51	7.18	2.2%	2.1%
Rest of the World[4]	11.18	12.61	16.85	18.26	19.24	2.8%	2.4%
Non-OPEC Production[4]	**27.26**	**27.97**	**28.68**	**26.41**	**25.36**	**-0.4%**	**-0.5%**
OPEC Summary							
Market Share	0.47	0.47	0.56	0.61	0.63	1.5%	1.6%
Production Capacity[5]	29.80	28.90	40.16	45.80	49.60	2.6%	3.0%
Capacity Utilization	0.84	0.91	0.97	0.99	0.98	0.8%	0.4%

[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: 1990: Energy Information Administration (EIA), *International Energy Annual 1991*, DOE/EIA-0219(93); and EIA, International Petroleum Statistics Report, DOE/EIA-0520(93/07). 1992: EIA, *International Energy Annual 1992*, DOE/EIA-0219(94); and EIA, *Monthly Energy Review*, DOE/EIA-0035(93/12). **Projections:** EIA, AEO 1994 National Energy Modeling System run LWOP94.D1221932.

DETAILED COMPARATIVE FORECASTS

Table F1. Comparison of Electricity Forecasts

(Billion Kilowatthours, Except Where Noted)

Projection	EIA *AEO94*			Other Forecasts					
	Reference	High Economic Growth	Low Economic Growth	WEFA	GRI	DRI	NERC	EEI	NERA
2000									
Average End-Use Price									
(1992 cents per kilowatthour)	**7.00**	**7.10**	**6.90**	**7.33**	**6.35**	**6.50**	**NA**	**7.10**	**NA**
Residential	8.70	8.80	8.50	8.80	7.48	7.60	NA	8.38	NA
Commercial	7.60	7.80	7.50	7.98	6.73	7.00	NA	7.73	NA
Industrial	5.10	5.20	5.00	5.20	4.81	5.00	NA	5.32	NA
Net Energy for Load	**3,335**	**3,411**	**3,273**	**3,485**	**3,472**	**3,537**	**3,479**	**3,693**	**3,810**
Coal	1,687	1,714	1,654	1,727	1,795	1,720	1,764	1,859	1,760
Petroleum	85	94	76	128	114	116	61	121	180
Natural Gas	335	354	335	403	342	349	354	671	500
Nuclear	671	671	671	601	664	696	678	677	640
Hydroelectric/Other[a]	294	295	295	354	287	336	277	301	380
Nonutility Sales to Grid	237	258	215	214	233	286	280	NA	270
Net Imports	26	26	26	59	37	34	65	64	80
Electricity Sales	**3,112**	**3,178**	**3,046**	**3,227**	**3,153**	**3,228**	**NA**	**3,427**	**3,570**
Residential	995	1,012	976	1,113	1,063	1,129	NA	1,121	1,130
Commercial/Other[b]	992	1,004	980	1,004	1,000	1,011	NA	1,066	1,150
Industrial	1,126	1,162	1,090	1,110	1,090	1,088	NA	1,240	1,290
Capability (gigawatts)[c,d,e]	**740.0**	**745.2**	**737.6**	**747.0**	**787.7**	**791.5**	**718.5**	**813.4**	**789.0**
Coal Steam	298.7	298.7	298.7	306.5	339.2	335.8	294.6	318.6	335.0
Oil and Gas	227.5	232.3	225.1	235.0	243.2	247.2	229.8	296.1	242.0
Nuclear	102.6	102.6	102.6	101.4	109.9	113.0	103.1	101.8	112.0
Hydroelectric/Other[a]	111.2	111.6	111.0	104.1	95.4	95.6	91.0	96.9	100.0
2010									
Average End-Use Price									
(1992 cents per kilowatthour)	**7.60**	**7.90**	**7.20**	**8.01**	**6.18**	**6.50**	**NA**	**7.18**	**NA**
Residential	9.80	10.30	9.20	9.74	7.37	7.40	NA	8.48	NA
Commercial	8.10	8.40	7.70	8.64	6.56	7.00	NA	7.82	NA
Industrial	5.50	5.70	5.20	5.65	4.72	5.30	NA	5.38	NA
Net Energy for Load	**3,720**	**3,894**	**3,556**	**4,121**	**4,118**	**4,390**	**NA**	**4,672**	**NA**
Coal	1,886	1,990	1,794	2,136	2,183	2,048	NA	2,355	NA
Petroleum	74	68	81	204	124	138	NA	150	NA
Natural Gas	373	371	345	498	374	405	NA	1,017	NA
Nuclear	612	612	612	566	648	713	NA	689	NA
Hydroelectric/Other[a]	315	313	321	362	292	336	NA	393	NA
Nonutility Sales to Grid	430	510	373	285	446	702	NA	NA	NA
Net Imports	30	30	30	71	53	48	NA	67	NA
Electricity Sales	**3,469**	**3,631**	**3,307**	**3,816**	**3,707**	**3,982**	**NA**	**4,343**	**NA**
Residential	1,065	1,108	1,019	1,308	1,201	1,402	NA	1,319	NA
Commercial/Other[b]	1,086	1,128	1,045	1,210	1,153	1,208	NA	1,394	NA
Industrial	1,318	1,396	1,243	1,298	1,353	1,372	NA	1,630	NA
Capability (gigawatts)[c,d,e]	**812.3**	**850.1**	**780.8**	**877.8**	**860.5**	**879.2**	**NA**	**924.8**	**NA**
Coal Steam	325.7	347.2	311.3	365.4	391.1	384.7	NA	340.6	NA
Oil and Gas	266.2	276.6	249.5	304.4	266.1	285.9	NA	360.8	NA
Nuclear	90.7	90.7	90.7	101.0	107.8	113.0	NA	103.8	NA
Hydroelectric/Other[a]	129.8	135.8	129.4	107.0	95.5	95.6	NA	119.7	NA

[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 GRI, capability represents nameplate capacity; for the others, capability represents net summer capability.

[d]WEFA's, DRI's, and EEI's capability projections include cogeneration.

[e]GRI, DRI, and NERC do not provide nonutility capacity by plant type. The total nonutility capacity in 2000 is 27.1, 86.8, and 41.2 gigawatts for GRI, DRI, and NERC, respectively. In 2010, the projections are 65.3 and 164.8 gigawatts for GRI and DRI, respectively.

NA = not available.

Sources: **EIA:** AEO94 Forecasting System, runs AEO94B.D1221934 (Reference Case), HMAC94.D1221932 (High Economic Growth Case), and LMAC94.D1221932 (Low Economic Growth Case). **WEFA:** The WEFA Group, *Coal and Electricity Report* (Summer 1993). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1994 Edition (Aug. 1993). **DRI:** DRI/McGraw-Hill, *Energy Review* (Third Quarter 1993). **NERC:** North American Electric Reliability Council, *Electricity Supply and Demand 1993-2000* (June 1993). **EEI:** Edison Electric Institute, *Electricity Futures Project* (draft report). **NERA:** National Economic Research Association, *NERA Energy Outlook* (Dec. 1992).

Table F2. Comparison of Petroleum Forecasts

(Million Barrels per Day, Except Where Noted)

Projection	EIA *AEO94*			Other Forecasts				
	Reference	High World Oil Price	Low World Oil Price	WEFA	GRI	DRI	AGA	IPAA
2000								
World Oil Price (1992 dollars per barrel)	**20.72**	**24.16**	**15.44**	**[a]20.62**	**[a]21.21**	**[a]22.74**	**[a]21.54**	**NA**
Crude Oil and NGL Production	**7.0**	**7.3**	**6.6**	**7.9**	**7.9**	**8.1**	**NA**	**7.7**
Crude Oil	5.2	5.5	4.8	6.2	6.1	6.4	NA	6.0
Natural Gas Liquids	1.8	1.8	1.8	1.8	1.8	1.8	NA	1.7
Total Net Imports	**10.9**	**10.5**	**12.0**	**8.7**	**9.2**	**9.7**	**NA**	**9.2**
Petroleum Demand	**19.3**	**19.0**	**20.0**	**18.3**	**15.2**	**18.7**	**NA**	**18.5**
Motor Gasoline	8.0	7.9	8.3	7.6	7.1	7.7	NA	7.6
Jet Fuel	1.8	1.8	1.8	1.6	1.7	1.7	NA	1.8
Distillate Fuel	3.6	3.6	3.7	3.2	3.5	3.4	NA	3.4
Residual Fuel	1.3	1.2	1.5	1.3	1.3	1.2	NA	1.2
Other	4.6	4.6	4.7	4.6	4.9	4.6	NA	4.5
2010								
World Oil Price (1992 dollars per barrel)	**28.16**	**34.11**	**20.15**	**[a]26.84**	**[a]27.27**	**[a]30.03**	**[a]24.47**	**NA**
Crude Oil and NGL Production	**7.1**	**7.9**	**5.6**	**6.8**	**8.5**	**7.0**	**NA**	**NA**
Crude Oil	5.1	5.9	3.7	4.8	6.8	5.2	NA	NA
Natural Gas Liquids	2.0	1.9	1.9	2.0	1.8	1.7	NA	NA
Total Net Imports	**12.8**	**11.3**	**15.3**	**10.4**	**9.9**	**13.1**	**NA**	**NA**
Petroleum Demand	**21.3**	**20.6**	**22.4**	**18.9**	**19.4**	**20.9**	**NA**	**NA**
Motor Gasoline	8.4	8.0	8.9	7.7	6.9	8.2	NA	NA
Jet Fuel	2.1	2.1	2.2	1.6	1.9	2.0	NA	NA
Distillate Fuel	4.2	4.1	4.3	3.3	4.0	4.2	NA	NA
Residual Fuel	1.4	1.3	1.7	1.7	1.3	1.3	NA	NA
Other	5.2	5.1	5.4	4.5	5.5	5.2	NA	NA

[a]Refiner's acquisition cost.

NA = not available.

Sources: **EIA:** AEO94 Forecasting System, runs AEO94B.D1221934 (Reference Case), HWOP94.D1221932 (High World Oil Price Case), and LWOP94.D1221932 (Low World Oil Price Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Winter 1993). **GRI:** Gas Research Institute, *Draft of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1994 Edition (Aug. 1993). **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Summer 1993). **AGA:** American Gas Association, An Overview of The *1993 AGA-TERA Base Case* (June 1993). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Forecast 1993-2000* (Mar. 1993).

Table F3. Comparison of Natural Gas Forecasts
(Trillion Cubic Feet, Except Where Noted)

Projection	EIA *AEO94*			Other Forecasts				
	Reference	High Economic Growth	Low Economic Growth	WEFA	GRI	DRI	AGA	NPC
2000								
Wellhead Price (1992 dollars per thousand cubic feet)	**2.42**	**2.56**	**2.31**	**2.39**	**[a]2.58**	**2.56**	**[a]2.26**	**3.23**
Dry Gas Production	**18.9**	**19.6**	**18.4**	**19.2**	**19.3**	**19.9**	**19.8**	**18.3**
Net Imports	**2.9**	**2.9**	**2.9**	**2.6**	**2.7**	**2.7**	**NA**	**NA**
Consumption	**22.0**	**22.7**	**21.5**	**21.8**	**22.4**	**22.3**	**22.9**	**20.8**
Residential	4.9	4.9	4.8	4.7	4.8	4.8	5.0	4.7
Commercial	2.8	2.8	2.8	3.0	3.0	3.0	3.4	2.9
Industrial	8.0	8.2	7.8	8.0	9.8	9.0	10.1	7.6
Electric Utility	4.2	4.6	4.0	3.9	3.8	3.5	3.6	3.7
Other	2.1	2.2	2.1	2.2	1.1	1.9	0.8	1.8
2010								
Wellhead Price (1992 dollars per thousand cubic feet)	**3.47**	**3.88**	**2.93**	**3.13**	**[a]3.22**	**3.88**	**[a]2.89**	**3.77**
Dry Gas Production	**20.2**	**21.3**	**19.2**	**20.3**	**21.6**	**21.8**	**21.9**	**20.5**
Net Imports	**3.9**	**3.9**	**3.9**	**3.1**	**3.3**	**3.4**	**NA**	**NA**
Consumption	**24.1**	**25.3**	**23.1**	**23.3**	**25.3**	**24.8**	**25.4**	**24.0**
Residential	4.9	5.0	4.7	4.8	4.9	4.7	5.1	4.8
Commercial	2.9	3.0	2.9	3.3	3.5	3.1	4.0	3.4
Industrial	9.0	9.4	8.7	7.8	11.3	10.9	10.7	8.6
Electric Utility	4.9	5.2	4.5	4.8	4.2	3.9	4.1	5.2
Other	2.4	2.7	2.3	2.7	1.4	2.1	1.6	2.0

[a]Average acquisition price.
NA = not available.

Sources: **EIA:** AEO94 Forecasting System, runs AEO94B.D1221934 (Reference Case), HMAC94.D1221932 (High Economic Growth Case), and LMAC94.D1221932 (Low Economic Growth Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Winter 1993). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1994 Edition (Aug. 1993). **DRI:** DRI/McGraw-Hill, *Energy Review* (Spring-Summer 1993). **AGA:** American Gas Association, *1993 AGA-TERA Base Case* (Mar. 1993). **NPC:** National Petroleum Council, *The Potential for Natural Gas in the United States, Vol. VI* (Dec. 1992).

Table F4. Comparison of Coal Forecasts
(Million Short Tons, Except Where Noted)

Projection	EIA *AEO94*			Other Forecasts		
	Reference	High Economic Growth	Low Economic Growth	DRI	GRI	WEFA
2000						
Production	**1,081**	**1,094**	**1,065**	**1,090**	**1,091**	**1,060**
Consumption by Sector						
Electricity	837	847	822	844	863	847
Coking Plants	28	28	28	32	26	32
Industrial/Other	93	95	90	105	78	79
Total	**958**	**971**	**939**	**981**	**973**	**958**
Net Coal Exports	**123**	**123**	**123**	**109**	**117**	**102**
Minemouth Price (1992 dollars per short ton)	**25.29**	**26.86**	**25.13**	**NA**	**NA**	**24.99**
Average Delivered Price: Electricity (1992 dollars per short ton)	**34.11**	**35.60**	**33.72**	**29.66**	**26.66**	**34.28**
2010						
Production	**1,223**	**1,287**	**1,165**	**1,379**	**1,333**	**1,278**
Consumption by Sector						
Electricity	950	1,006	901	1,004	1,077	1,053
Coking Plants	21	22	21	29	22	28
Industrial/Other	107	114	101	204	82	84
Total	**1,079**	**1,142**	**1,023**	**1,237**	**1,182**	**1,165**
Net Coal Exports	**142**	**142**	**142**	**136**	**146**	**112**
Minemouth Price (1992 dollars per short ton)	**30.87**	**32.95**	**29.97**	**NA**	**NA**	**27.08**
Average Delivered Price: Electricity (1992 dollars per short ton)	**40.32**	**43.17**	**38.91**	**33.03**	**24.98**	**41.13**

NA = not available.

Sources: **EIA:** AEO94 Forecasting System, runs AEO94B.D1221934 (Reference Case), HMAC94.D1221932 (High Economic Growth Case), and LMAC94.D1221932 (Low Economic Growth Case). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1993). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1994 Edition (Aug. 1993). **WEFA:** The WEFA Group, *Coal and Electricity Report* (Summer 1993).

MAJOR ASSUMPTIONS FOR THE FORECASTS

The National Energy Modeling System

The *Annual Energy Outlook 1994 (AEO94)* presents the first projections and analysis developed with the National Energy Modeling System (NEMS). Developed in the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA), NEMS is the third in a series of computer-based, midterm energy modeling systems used since 1974 by EIA and its predecessor, the Federal Energy Administration, to analyze domestic energy-economy markets and develop projections. From 1982 through 1993, the *AEO* presented projections from the Intermediate Future Forecasting System, the system which preceded NEMS. In addition to developing the *AEO* projections, EIA also uses the models in analytical studies for the U.S. Congress and other offices within the Department of Energy. Projections from these models are also used by analysts and planners in other government agencies and outside organizations.

NEMS was developed to enhance and update EIA's modeling and analysis capability by internally incorporating models of energy markets previously analyzed off line. In addition, the greater structural detail of NEMS permits the analysis of a broader range of energy issues. 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.

The projections in NEMS are developed using a market-based approach to energy analysis, as did the earlier models. 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. 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 environmental regulations that affect that sector and reports key emissions. NEMS represents current environmental regulations, such as the Clean Air Act Amendments of 1990, and the costs of compliance with other regulations.

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, disposal 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.

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 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 the Clean Air Act Amendments 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 Clean Air Act 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 wood, municipal solid waste, wind energy, solar energy, hydroelectric power, 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.

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 firm and interruptible 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 the Clean Air Act Amendments of 1990 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 off line to NEMS 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 1994*

Assumptions on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in the *AEO94*. 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 1994*, 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) and the Energy Policy Act of 1992 (EPACT) 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—a 8.6 energy efficiency ratio in 1990, with an assumed increase to 10.6 in 1998
- 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, assumed to increase to 0.93 in 1998.

Only the standards for 1994 and earlier have been specified in the NAECA rulemaking by the Department of Energy. Projections for 1998 are EIA assumptions with respect to future rulemakings and are subject to change.

Other programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs are cooperative efforts between the EPA and energy appliance manufacturers and 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.

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, projected to increase to 10.0 in 1998
- 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, projected to rise to 80.0 in 1998.

As in the residential sector, the projections for 1998 standards are EIA assumptions with respect to future rulemakings and are subject to change.

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 Model 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.

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, local, and fuel providers) purchase a minimum fraction of alternative-fueled 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-fueled vehicle sales; consumers are allowed to purchase more of these vehicles should cost and performance characteristics make them desirable. In fact, the projections indicate that more than the minimum will be purchased as shown in Table 7.

Projections for both the 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 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.

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 1994*.

The projections include 67 gigawatts of generating capacity currently under construction as reported by utilities to EIA. Retirements announced by utilities are also assumed to account for nearly 14 gigawatts by 2010. In addition, it is assumed that 43 gigawatts of capacity not reported by utilities will also retire after 45 years of operation. Conversely, investments to either maintain existing fossil-fueled plants or repower them will affect 343 gigawatts of capacity.

Regulation of electricity markets. It is assumed that electricity producers comply with the Clean Air Act Amendments of 1990, which mandate 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 $170 per kilowatt, in 1991 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 orders. It is assumed that 4 nuclear generating units currently under construction will be operational by 2010: Watts Bar 1 in 1994, Watts Bar 2 in 1997, Bellefonte 1 in 1999 and Bellefonte 2 in 2002. It is also 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 about power plant performance
- Uncertainty in the licensing and regulatory processes.

With regard to the waste disposal issue, either a high-level waste repository, or, temporarily, a monitored retrievable storage facility is required; however, a permanent repository is not scheduled to be operational until at least 2010. A number of states have already expressed their intent, through either legislation (e.g., California), referendum (e.g., Oregon and Maine) or regulation (e.g., New York and Colorado) to not site new nuclear plants until the Federal government has a license to operate a high-level waste repository. According to the Nuclear Waste Policy Act of 1982, DOE is to take title to nuclear waste beginning in 1998, but this provision will likely be adjudicated in the courts since a storage facility will not be available. Although DOE might finance the on-site storage of the waste pending a repository, this is only a temporary measure, and some plants are reaching the limits of their spent fuel storage facilities. Furthermore, with a number of nuclear units scheduled for retirement beginning around 2005, the lack of a high-level waste repository becomes critical for decommissioning purposes as well. According to the Nuclear Waste Policy Amendments Act of 1987, construction of a monitored retrievable storage (MRS) facility cannot begin until the Nuclear Regulatory Commission issues a construction permit for the high-level waste repository. Under the current schedule, construction of an MRS could begin in 2004 at the earliest, and the facility would open in 2007, assuming a site is found and licensed to operate by the Nuclear Regulatory Commission. Given the history of schedule slippages in the waste repository program and the first-of-a-kind nature of the project, it is assumed that utilities, investors, and state regulatory commissions would not commit to a new order until an MRS was completed and available to receive waste. Assuming this occurs in 2007 and given the four to five year construction leadtime for a new plant, an order placed in 2007 would result in an operational plant post-2010.

Public concerns about nuclear power plant operational safety and waste disposal must also be addressed. The safety concerns stem from the public's association of the technology with its weapons origin and the well-publicized accidents at operating plants, particularly Three Mile Island and Chernobyl.

Utilities currently have an aversion to capital-intensive, long leadtime technologies. With the increased competition in electricity generation markets, especially from short leadtime, low capital cost options, this aversion is likely to increase in the future. In addition, there are substantial uncertainties associated with the costs and risks of nuclear power. Research has shown that there is a 3.5 to 4.0

percentage point risk premium associated to the common stock of utilities with nuclear power plants. More importantly, this risk premium is not related to construction and licensing related issues, but rather to concerns about safety, operational factors, and decommissioning. There is growing investor concern about the escalation in decommissioning cost, early retirements, and the "stranded plant" problem [8].

Additionally, even though vendors estimate competitive economics and four-to-five year construction leadtimes, these estimates are targets or best-case estimates. No nuclear plant to date has been built at initial estimated cost and schedule. Also, major parts of new midsize plants will be prefabricated and constructed modularly. This new construction approach, while likely to decrease leadtimes in follow-on units, is less flexible than the conventional approach if design changes are required and therefore adds uncertainty when building a first-of-a-kind unit. Also, a new plant will incorporate a large percentage of untested new technology, thereby greatly increasing the uncertainty associated with plant performance.

Given the history of *ex post facto* nuclear prudence reviews and cost disallowances, coupled with the high capital intensity of nuclear investments and historically long construction leadtimes, investments in nuclear technology would likely require some form of financial protection.

Finally, the passage of EPACT allows the issuance of a combined construction and operating license; however, it also allows for a post-construction hearing and judicial review. The uncertainty associated with these waste, regulatory, and financial issues is sufficiently large to require their resolution or some manner of financial protection for investors before investments in nuclear power would take place. Unresolved, these conditions would lead to investments in alternative capacity additions or a delay in capital investment.

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 [9]. 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 [10]. This credit is included as a 10-percent reduction to the capital costs in the Renewable Fuels Module.

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 remains nearly stable. The total resources for most other renewables are theoretically large, for example, the amount of sunlight. However, total resources are not always the relevant constraint as they tend to require regional characterization in order to properly represent the constraint. Thus, 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 significantly only in those regions where its economics are most favorable. Wind energy resource potential, while large, is constrained by environmental and land-use 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 [11]. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Capacity in 1990 totaled 2.9 gigawatts [12]. 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.

Dispersed renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [13] (RECS) and data from the *Characteristics of New Housing: 1992*, published by the Bureau of the Census [14]. 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 air source heat pump. 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 [*15*]. 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

Crude oil and natural gas resource base. 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 [*16*]. 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. Estimates were developed on a regional basis. Total unproved oil resources are assumed to be 83 billion barrels with 1990 technology and 123 billion barrels with 2010 technology. Total unproved gas resources are assumed to be 852 trillion cubic feet with 1990 technology and 1,266 trillion cubic feet with 2010 technology.

Productivity improvements for drilling and extraction. 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 by about 2 percent annually, in response to technological innovation. The increase is due to both the development of new technologies, for example, three-dimensional reflection seismology, and their increasing deployment, such as the increased use of horizontal drilling and completion techniques, which is motivated in part by associated cost reductions. Productivity improvements are thus simulated by assuming that the effective cost of supply activities will be reduced and the recoverable resource target will be expanded.

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 coast of southern California. In Alaska, drilling is prohibited in the Arctic National Wildlife Refuge. The projections also assume that coastal leasing and drilling activities will be reduced in response to the restrictions of the Clean Air Act Amendments of 1990, which require that offshore drilling sites within 25 miles of the coast, with the exception of areas off the coasts of Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

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 $3.55, in 1992 dollars per thousand cubic feet. The level of pipeline imports from Canada is constrained by the pipeline design capacity which is assumed to increase from 1,778 billion cubic feet in 1990 to 3,556 billion cubic feet in 2010. The current liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana, are operating at an initial capacity of 301 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen in 1996 and 1998 respectively, expanding total liquefied natural gas capacity to 794 billion cubic feet.

Natural gas transmission and distribution assumptions

Order 636. The projections reflect the assumption that the provisions of Order 636 are fully implemented by January 1, 1994. Implementation of Order 636 alters interstate transportation tariffs because of changes in rate design and recovery of transition costs. All interstate pipeline companies

are assumed to have completed the switch from modified fixed variable (MFV) to straight fixed variable (SFV) rate design by January 1994. Pipeline transportation tariffs derived using the SFV rate design reflect recovery of all fixed costs in the reservation fee and recovery of variable costs in the usage fee. The primary difference between the SFV and the MFV rate design, that was widely adopted by the industry in the 1980's, is that the return on equity and associated income taxes are collected through the reservation fee rather than as a part of the usage fee. Full implementation of the new rate design is expected during 1993 in time for the 1994 winter heating season. In addition, it is assumed that transition costs totaling $3.8 billion will be recovered beginning in 1994. Approximately 90 percent of the $3,214 million of gas supply realignment costs is recovered over a 5-year period via a surcharge on firm transportation rates and 10 percent is recovered via a surcharge on interruptible transportation rates. Furthermore, a total of $543 million of Account 191 costs are recovered from firm customers over a 2-year period beginning in 1994 [*17*].

The *AEO94* methodology employed in solving for the natural gas supply and demand equilibrium assumes that marginal costs are the basis for determining market-clearing prices throughout the forecast period. Although marginal cost pricing is currently inconsistent with past and most current practices which use average cost pricing, a number of recent events point to a trend toward marginal pricing in the gas industry. In addition to various aspects of Order 636, State Public Service Commissions are reviewing and advocating unbundling in the local distribution company (LDC) markets. To meet competition, cross-subsidization among customer classes is being eliminated, the market is being segmented for marketing purposes, LDC gas services are being unbundled and gas service prices are being determined through competition. These factors lead to prices that reflect marginal pricing by customer class. How broadly and how rapidly marginal cost pricing is adopted throughout the natural gas industry is largely a function of implementation of recent FERC rulemaking, the level of activity in capacity release markets, and changes in State-level regulations.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large environmental costs to comply with the Clean Air Act Amendments of 1990 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*18*] 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 1994*. The expected oxygenated gasoline market shares assume wintertime participation of 39 carbon monoxide nonattainment areas and year-round participation of Minnesota beginning in 1995. For reformulated gasoline, it is assumed that the nine required ozone nonattainment areas plus additional areas that have announced intentions to opt-in will consume reformulated gasoline in 1995 [*19*]. All other nonattainment areas are assumed to opt-in by 1997. Product specifications reflect the State requirement for severely reformulated gasoline in California beginning in 1996.

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.

Recoverable coal reserves in the United States are estimated at nearly 265 billion short tons [*20*]. Low-sulfur recoverable coal reserves are estimated to total 100 billion short tons, 87 percent of which is concentrated in the West.

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 day. 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. The following general pattern applies for the rate of improvement: from 1990 to 1995, declining from 6 to 4 percent per year; from 1996 to 2000, declining from 3.5 to 2 percent; from 2000 to 2010, declining from 2.0 to 1.0 percent.

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. The stranded plant problem refers to capital-intensive plants that cannot recover all their capital costs because of competitive pressure from plants that use lower cost fuels.
9. National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1914.
10. National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.
11. 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).
12. Energy Information Administration, EIA-861, "Annual Electric Utility Report," and EIA-867, "Annual Nonutility Power Producer Report."
13. Energy Information Administration, *Household Energy Consumption and Expenditures 1990*, (DOE/EIA-0321(90)) (Washington, DC, 1993).
14. U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1992*, (Washington, DC, 1993).
15. 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).
16. 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, D.C., 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.
17. *Natural Gas: Cost, Benefits, and Concerns Related to FERC Order 636*, Final Report of the General Accounting Office, GAO/RCED-94-11 (Washington, DC, November 1993).
18. Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993).
19. Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, and San Diego. 1995 opt-ins: Texas, District of Columbia, New Jersey, Maryland, Delaware, New York, Connecticut, Virginia, New Hampshire, Massachusetts, Pennsylvania, Maine, and Rhode Island.
20. Energy Information Administration, *U.S. Coal Reserves: An Update by Heat and Sulfur Content*, DOE/EIA-0529(92), (Washington, DC, February 1992).

SUMMARY OF RESULTS

Sensitivity Factors	1990	1992	2010				
			Reference	High Economic Growth	Low Economic Growth	High World Oil Price	Low World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	17.74	17.58	13.50	13.77	13.23	15.24	10.42
Natural Gas	18.49	18.51	20.39	22.06	19.83	20.85	20.49
Coal	22.46	21.62	26.47	27.83	25.22	26.61	25.98
Nuclear Power	6.20	6.64	6.57	6.57	6.57	6.57	6.57
Renewable Energy/Other	6.20	6.28	8.69	9.10	8.48	8.97	8.56
Total Primary Production	**71.08**	**70.64**	**76.12**	**79.32**	**73.33**	**78.24**	**72.02**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	14.38	13.93	27.31	28.13	26.20	24.16	32.75
Natural Gas	1.45	1.93	3.86	3.86	3.86	3.86	3.86
Coal/Other (- indicates export)	-1.97	-1.72	-2.14	-1.88	-2.27	-2.29	-1.79
Total Net Imports	**13.85**	**14.15**	**29.04**	**30.11**	**27.79**	**25.73**	**34.81**
Discrepancy	-0.65	1.01	0.07	0.07	0.13	0.37	-0.36
Consumption (quadrillion Btu)							
Petroleum Products	33.55	33.65	42.00	43.39	40.51	40.65	44.30
Natural Gas	19.30	20.15	24.89	26.05	23.82	24.85	24.48
Coal	19.01	18.99	22.88	24.23	21.69	23.03	22.44
Nuclear Power	6.20	6.64	6.57	6.57	6.57	6.57	6.57
Renewable Energy/Other	6.23	6.37	8.89	9.26	8.67	9.24	8.69
Total Consumption	**84.28**	**85.80**	**105.23**	**109.50**	**101.26**	**104.34**	**106.48**
Prices (1992 dollars)							
World Oil Price (dollars per barrel)	23.22	18.20	28.16	28.81	27.31	34.11	20.15
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.83	1.75	3.47	3.88	2.93	3.54	3.25
Domestic Coal at Minemouth (dollars per short ton)	23.22	21.03	30.87	32.95	29.97	31.49	29.07
Average Electricity Price (cents per kilowatthour)	7.1	6.8	7.6	7.9	7.2	7.7	7.4
Economic Indicators							
Real Gross Domestic Product (billion 1987 dollars)	4,877	4,920	7,397	7,864	6,941	7,368	7,437
(annual change, 1990-2010)	--	--	2.1%	2.4%	1.8%	2.1%	2.1%
GDP Implicit Price Deflator (index, 1987=1.00)	1.132	1.208	2.075	1.813	2.756	2.080	2.067
(annual change, 1990-2010)	--	--	3.1%	2.4%	4.5%	3.1%	3.1%
Real Disposable Personal Income (billion 1987 dollars)	3,517	3,584	4,970	5,089	4,888	4,948	4,998
(annual change, 1990-2010)	--	--	1.7%	1.9%	1.7%	1.7%	1.8%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.087	1.094	1.747	1.868	1.641	1.743	1.754
(annual change, 1990-2010)	--	--	2.4%	2.7%	2.1%	2.4%	2.4%
Energy Intensity (thousand Btu per 1987 dollar of GDP)	17.28	17.41	14.23	13.92	14.59	14.16	14.32
(annual change, 1990-2010)	--	--	-1.0%	-1.1%	-0.8%	-1.0%	-0.9%

Note: Quantities are derived from historical volumes and assumed thermal conversion factors.
Source: Tables A1, A8, A18, B1, B8, B18, C1, C8, C18, D1, D8, D18, E1, E8, and E18.

Appendix I

CONVERSION FACTORS

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.822
Consumption	million Btu per short ton	21.331
Coke Plants	million Btu per short ton	26.799
Industrial	million Btu per short ton	22.457
Residential and Commercial	million Btu per short ton	23.137
Electric Utilities	million Btu per short ton	20.929
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.202
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	3.625
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	5.823
Natural Gas Plant Liquids		
Production	million Btu per barrel	3.805
Natural Gas		
Production, Dry	Btu per cubic foot	1,031
Consumption	Btu per cubic foot	1,031
Non-electric Utilities	Btu per cubic foot	1,030
Electric Utilities	Btu per cubic foot	1,034
Imports	Btu per cubic foot	1,004
Exports	Btu per cubic foot	1,004
Electricity Consumption	Btu per kilowatthour	3,412
Electricity Component		
Plant Generation Efficiency (heat rate)		
Fossil Fuel Steam	Btu per kilowatthour	10,335
Nuclear Energy	Btu per kilowatthour	10,700
Geothermal[2]	Btu per kilowatthour	21,096

[1]Coal conversion factors vary from year to year, 1990 values are reported.
[2]*Annual Energy Outlook* tables use the fossil fuel heat rate.
Source: Energy Information Administration, AEO94 National Energy Modeling System.

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Annual Energy Outlook Conference

April 18 and 19, 1994

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The focus of this conference will be:

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