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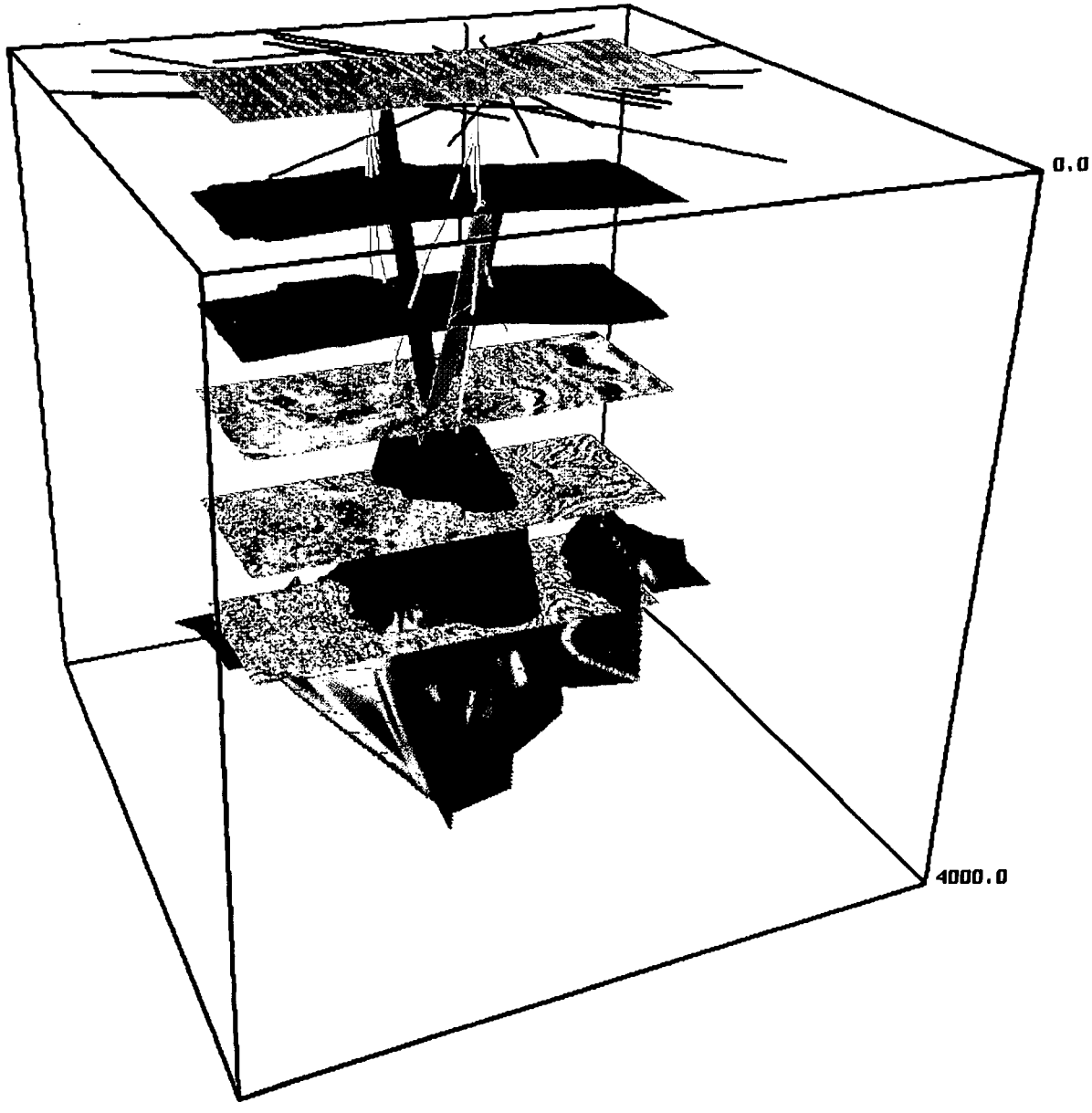
ANNUAL ENERGY OUTLOOK 1993

With Projections to 2010



EIA Energy Information Administration

January 1993

For Further Information . . .

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A brief description of the *Annual Energy Outlook 1993* Forecasting System and a list of key contacts for each subject area are contained in Appendix H of this report.

The report includes analyses for major fuels previously published in EIA's *Annual Outlook for Oil and Gas*, *Annual Outlook for U.S. Coal*, *Annual Prospects for World Coal Trade*, *Annual Outlook for U.S. Electric Power*, and *Commercial Nuclear Power: Prospects for the United States and the World*. Selected regional tables previously published in these reports are included in the *Supplement to the Annual Energy Outlook 1993*, the companion document to this report that will be available in February 1993. Quantitative assumptions underlying the *AEO* forecasts will be provided in *Assumptions for the Annual Energy Outlook 1993*, to be published during January 1993. Questions regarding these reports may be addressed to the following EIA analysts:

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Annual Energy Outlook 1993

With Projections to 2010

January 1993

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U.S. Department of Energy
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Preface

Since 1974, the Energy Information Administration (EIA) or a predecessor agency has produced an outlook for energy prices, supply, demand, and imports. Under Section 205(c) of the Department of Energy Organization Act of 1977 (Public Law 95-91), the Administrator of EIA is required to prepare an annual report that contains trends and projections of energy consumption and energy supply. These projections are widely used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors.

Cover image was created with GeoViz™, a three-dimensional geovisualization application used by geoscientists in their search for oil and gas. The red lines and blue grid at the top of the image show the location of the 2D and 3D seismic data used to analyze this Gulf of Mexico field. The green surface rising upward from the bottom is a salt dome that caused faulting through the geologic formations (shown by the red and blue horizontal layers). The fault planes are represented by the vertical purple and brown surfaces. The three multi-colored surfaces are horizontal slices of the 3D seismic data used for the interpretation. The vertical yellow lines indicate drilled well paths deviating from the two offshore platforms. This image was provided courtesy of GeoQuest Systems, Inc., of Houston, Texas.

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In the history of U.S. energy policy, the year 1992 will be noteworthy because of the passage of the Energy Policy Act of 1992. Fortunately, the major provisions of the Act were anticipated when this year's *Annual Energy Outlook* (*AEO93*) was under preparation, and they are included in the projections contained in this report. Over the timespan covered by *AEO93* (1992 to 2010), three major issues will continue to dominate energy discussions despite the passage of the Act:

- The rising dependency of this Nation on imported oil
- Concerns about global climate changes and other environmental issues
- The potential of energy conservation and energy efficiency as alternatives to energy production.

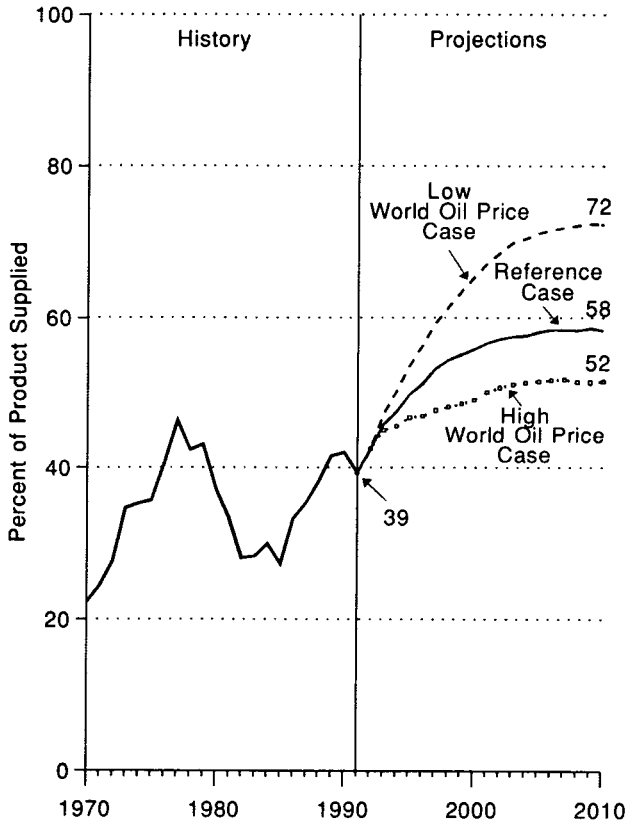
Using the projections of *AEO93* as a basis, this message provides a framework for understanding those issues and the options for action that they present.

Rising U.S. Oil Import Dependency

Real domestic oil prices reached their apex in March 1981 and have consistently declined since then, except for a brief spike during the August 1990-March 1991 Iraqi occupation of Kuwait. In spite of the rising real oil prices assumed in the *AEO93* Reference Case,[1] oil production will continue to decline in the United States (see Figure 11, p. 29). Even though domestic production does recover slightly toward the end of the forecast period, the deficit between production and consumption is projected to grow, and import dependency will continue to rise (see Figure 13, p. 37).

Under all three of the *AEO93* Oil Price scenarios, oil imports rise dramatically over the period 1992 to 2010 (see Figure, "Percentage of U.S. Oil Consumption Supplied by Net Imports, 1970-2010"). In the Reference Case, net oil imports are expected to rise from a level of 6.6 million barrels per day in 1991 to approximately 12.2 million barrels per day by 2010. Higher oil prices would discourage consumption and spur efficiency, reducing imports, but net imports are still projected to rise to 10.3 million barrels per day by 2010 in the High World Oil Price Case. Low oil prices would have exactly the opposite effect, and net oil imports are projected to soar to 17 million barrels per day in the Low World Oil Price Case. Under these scenarios, net imports as a percent of U.S. oil consumption rise from almost 40 percent in 1991 to between 52 and 72 percent in the High and Low World Oil Price Cases, respectively.

Percentage of U.S. Oil Consumption Supplied by Net Imports, 1970-2010

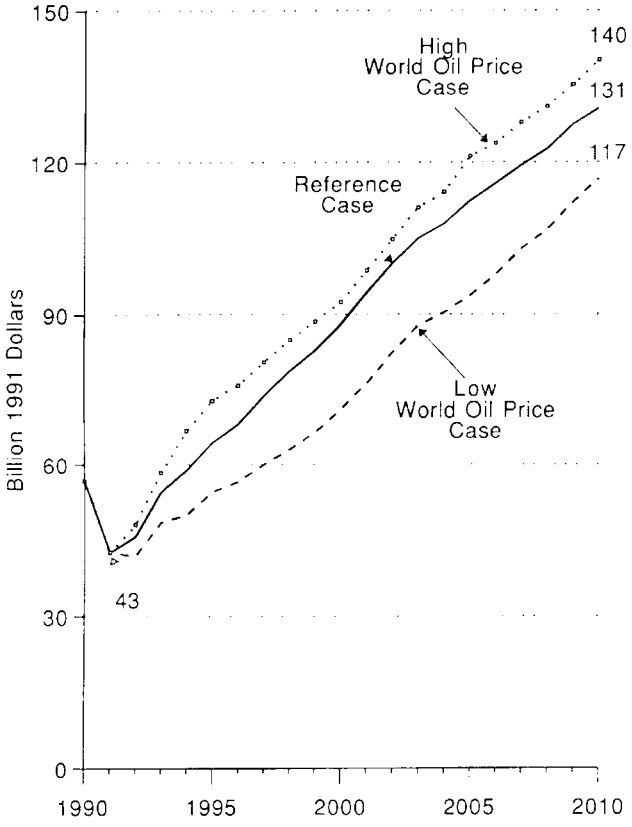


Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A8, D8, and E8.

[1]For a description of the *AEO93* projection scenarios, see Chapter 1, pp. 5-7.

Under any of these scenarios, the cost to the economy of oil imports rises dramatically by 2010 (see Figure, "Cost of Imported Oil and Petroleum Products, 1990-2010"). The oil import cost virtually triples from about $43 billion spent in 1991 to $131 billion in constant 1991 dollars in the Reference Case. In the High World Oil Price Case, the figure is $140 billion, and, even in the Low World Oil Price Case, the money outflow totals $117 billion.

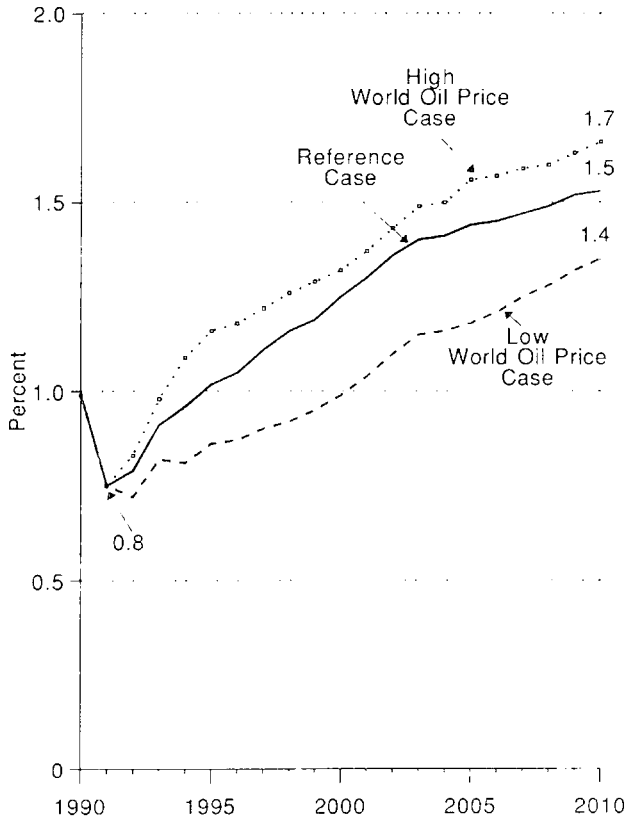
Cost of Imported Oil and Petroleum Products, 1990-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A3, A8, D3, D8, E3, and E8.

This outlook presents formidable challenges to the U.S. economy as it attempts to remain competitive in world markets. Petroleum import costs per dollar of gross domestic product (GDP) rise from 0.8 percent in 1991 to between 1.4 and 1.7 percent in the alternative price cases by 2010 (see Figure, "Cost of Petroleum Imports as a Percent of Gross Domestic Product, 1990-2010"). A

Cost of Petroleum Imports as a Percent of Gross Domestic Product, 1990-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A3, A7, A8, D3, D7, D8, E3, E7, and E8.

persuasive case can be made that, if oil prices are low, this Nation should buy what it needs from the cheapest market, recognizing that low fuel costs can lead to low energy costs, which ultimately benefit the American economy.[2] This outflow of dollars tends, however, to push up domestic interest rates, slow domestic growth, and restrict the ability of the U.S. Government to use fiscal policy to encourage economic growth.

Global Climate Change

One of the more visible issues linking energy and the environment is concern about the possibility of global warming induced by human activity. For several years, some general circulation models have predicted aggregate increases in the temperature of the planet on the order of 1 to 5 degrees Celsius by the middle of the

[2]Kent, C.A., "National Energy Strategy: Perspectives and Problems," *Journal of Private Enterprise* (Spring 1991), pp. 1-9.

next century.[3] This increase is attributed to an amplification of the Earth's natural greenhouse effect attributable to a doubling in the concentration of certain gases in the atmosphere. Approximately two-thirds of these greenhouse gas emissions caused by human activity come from carbon dioxide, principally from energy combustion. According to some studies, the impact of the temperature increase may border on the catastrophic, causing a rise in sea levels, flooding of coastal plains, disruption of agriculture patterns and ecosystems, and increased severity of storms.

The United States is currently the largest single producer of greenhouse gases. In 1990, total carbon emissions from the combustion of fuels in the United States were 1.3 billion metric tons. Under any of the scenarios contained in *AEO93*, U.S. carbon emissions will continue to increase throughout the forecast period (see Figure 23, page 69), rising to between 1.6 billion and 1.7 billion metric tons per year by the end of the forecast period. This rise is primarily attributable to the increase in the use of coal in the generation of electricity and to increased petroleum demand for transportation. It is likely, however, that the fastest growth in greenhouse gas emissions will come from the developing nations (particularly the Peoples Republic of China), which have abundant fossil fuel resources, mainly coal, and few environmental constraints on their use.

Great uncertainty surrounds these dire forecasts, however, and no agreement exists in the scientific community about human-caused global warming because variations in global temperatures have been as much as 7 degrees Celsius in the past without human intervention.[4] The causal relationship between the noted increase in temperatures and the greenhouse effect has been questioned, and the climate models would appear to overestimate the temperature increase that has already occurred. In addition, it is acknowledged that many factors affect climate or provide potential offsets to global warming that are neither understood nor accurately represented in the models. It should also be noted that with global warming, some regions of the world might suffer but other more arid and desolate zones might benefit.[5] Despite these uncertainties, environmental quality and the link between the use of energy and environmental problems will remain key issues for policymakers in the foreseeable future.

Energy Conservation and Efficiency

In light of the discussion concerning imported oil and global warming, there has been renewed focus on conserving energy through improved efficiency in energy end use. Considerable improvements in energy intensity and conservation in the developed world are going to be achieved without any changes in existing policy.[6] As *AEO93* points out, this outcome is true for the United States. The historical relationship between energy consumption and economic growth has been reversed in the United States (see Figure, "Indexes of U.S. Energy Consumption and Economic Growth, 1950-2010"). Instead of energy consumption growing faster than the economy, as was the case in the 1950s, 1960s, and early 1970s, the use of energy will grow at a rate less than half the growth rate of the economy. Because of the projected slow growth in real prices for electricity, more than 50 percent of the increase in energy use is expected to be for electricity. Because of the efficiency provisions of the Energy Policy Act of 1992, however, the projections show lower growth in electricity than in the projections of previous years.

Despite a slowing in the rate of improvement in energy intensity in the latter part of the 1980s, *AEO93* projects that the trend of the past two decades toward improved U.S. energy intensity will continue (see Figure 4, p. 12). Total energy consumption per dollar of real gross domestic product will continue to decline for two reasons: first, the continuing shift in the economy toward more services and less energy-intensive manufacturing as a percentage of total output; and, second, the improvements in energy efficiency in the end-use sectors. Rising prices for all fuels, as forecast in *AEO93*, will also add a strong incentive for conservation.

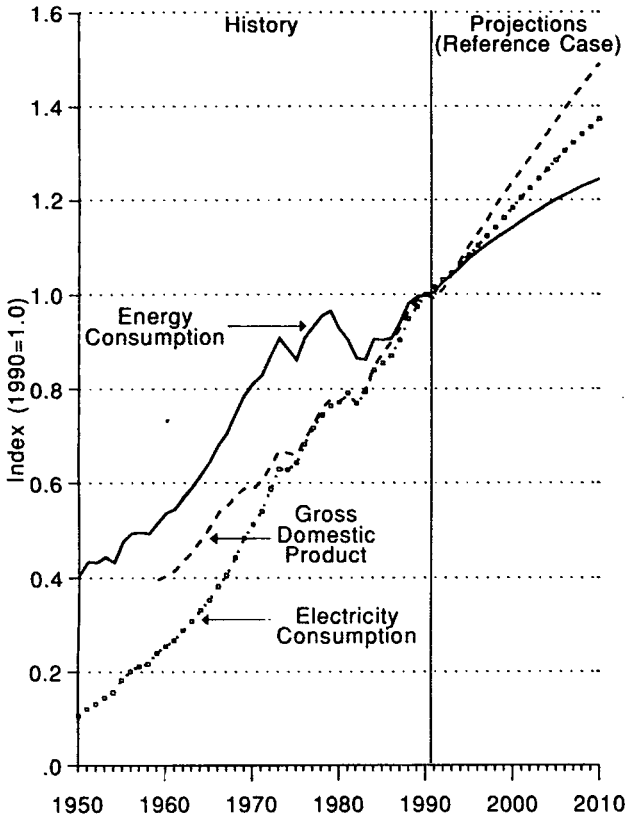
[3]Brethern, F.P., Bryan, J., and Woods, J.A., "Time Dependent Greenhouse Gas Induced Climate Change," in *Climate Change: The IPCC Scientific Assessment* (New York, NY, Cambridge University Press, 1990), pp. 177-192. U.S. Congress, Office of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases*, OTA-0-482 (Washington, DC, U.S. Government Printing Office, Feb. 1991). Intergovernmental Panel on Climate Change, *1992 IPCC Supplement* (New York, NY, United Nations, 1992). National Academy of Sciences *Policy Implications of Greenhouse Warming* (Washington, DC, National Academy Press, 1991).

[4]U.S. Congress, Office of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases*, OTA-0-482 (Washington, DC, U.S. Government Printing Office, Feb. 1991). Michaels, P.J., *Sound and Fury: The Science and Politics of Global Warming* (Washington, DC, Cato Institute, 1992). Stone, P., "Forecast Cloudy: The Limits of Global Warming Models," *Technology Review* (1992), p. 32.

[5]Michaels, P.J. (1992), pp. 93-94.

[6]Howarth, R.D., Schipper, L., Duerr, P., and Strom, S., "Manufacturing Energy Use in Eight OECD Countries," *Energy Economics* (1991), pp. 135-141.

Indexes of U.S. Energy Consumption and Economic Growth, 1950-2010



Note: Total energy consumption excludes renewable sources of energy except for hydropower and geothermal sources used for electricity generation.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A1, A2, and A7.

The state of industrial energy intensity in the United States has become an issue because of its direct relationship to global competitiveness and the emission of greenhouse gases.[7] In the industrialized countries, manufacturing value added has been increasing at an approximate rate of 2.3 percent per year, while energy use has been falling at an average of about 1.2 percent per year. While aggregate manufacturing intensity in the eight most developed countries of the world fell by 3.7 percent per year, or 40 percent overall, the decline was greater in the United States (43 percent) and Japan (45 percent) than in Europe.[8]

The projections in *AEO93* include increased efficiency for virtually each sector of the economy. In the buildings sector, substantial improvements are possible in building shells and windows as well as in appliances.[9] Purchases, particularly for residences and consumer appliances, are more heavily influenced by initial prices than by any other factor. To the extent that more efficient buildings and technologies are initially more expensive, full market penetration becomes less likely.[10] Recent studies by the Energy Information Administration (EIA) indicate significant conservation potential in commercial buildings.[11] As older buildings are replaced, more efficient shells will replace them; large gains for existing buildings are also feasible through the use of energy management and control systems and better insulation. Another EIA study found that converting all lamps and fixtures to their most efficient equivalents and installing lighting control could save 57 to 72 percent of energy used.[12] Demand-side management (DSM) programs by utilities are projected in *AEO93* to reduce demand for electricity by almost 10 percent by the turn of the century. A forthcoming EIA report notes that only a small fraction (7.1 percent) of those households that could have participated in DSM programs did so in 1990.[13] Thus, great potential exists for expansion of DSM programs.

In manufacturing, significant improvements can be made in the most energy-intensive industries (primary metals; stone, clay, and glass; paper products; chemicals; and rubber) through the use of more efficient motors and DSM programs.[14] For transportation—where the dominant fuel will remain petroleum, according to these forecasts—increases in vehicle efficiency will continue to materialize as the large stock of older vehicles is replaced by more efficient ones. Under all three Oil Price cases, new car efficiency rises: from 28 miles per gallon (mpg) currently to 31 to 37 mpg in the Low and High World Oil Price scenarios, respectively, and to 35 mpg in the Reference Case (see Figure 10, p. 24). The alternate fuels provisions of the

[7]Weisskopf, M., "Rust-Belt Emissions Cloud Earth Summit," *The Washington Post* (June 2, 1992), p. A1.

[8]Schipper, L., and Meyers, S., *Energy Efficiency in Human Activity: Past Trends, Future Prospects* (New York, NY, Cambridge University Press, forthcoming), pp. 7-14.

[9]Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, SR/NES/90-02 (Washington, DC, Dec. 1990), pp. 27-72.

[10]U.S. Congress, Office of Technology Assessment, *Building Energy Efficiency*, (Washington, DC, 1992), pp. 73-88.

[11]Energy Information Administration, *Commercial Buildings: Energy Consumption and Expenditures 1989* (Washington, DC, Apr. 1992).

[12]Energy Information Administration, *Lighting in Commercial Buildings* (Washington, DC, Mar. 1992).

[13]Energy Information Administration, *Household Energy Consumption and Expenditures 1990* (Washington, DC, forthcoming, 1993).

[14]Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, p. 142.

Energy Policy Act of 1992 may further accelerate the trend toward less use of petroleum for transportation.

The trends toward conservation will be complemented by expanding use of renewable energy in the form of alcohol fuels, biomass (wood and municipal solid waste), solar, geothermal, and wind. Direct use of these fuels is projected to grow at about 2.7 percent per year in the *AEO93* projections. Use of renewables in generating electricity will also grow because of the provisions of the Energy Policy Act that provide incentives for expanded use of renewables and, to a lesser extent, because of the Clean Air Act Amendments of 1990 (CAAA90). The CAAA90 will also lead to increased use of natural gas because of its environmental qualities and competitive prices.

The Future and EIA

As *AEO93* makes clear, the need for energy in the United States will increase in the foreseeable future. While recognizing that there are no facts about the future, government policymakers may seek to change the outcomes forecast in *AEO93*. If so, they have a rich policy menu from which to choose. EIA will continue to supply to policymakers not only its best forecasts for the future, but also analyses of the consequences of the various policy options they will have to consider.

Beginning with next year's *AEO*, EIA will have a powerful new tool to assist in the process. The National Energy Modeling System (NEMS) will be used for the 1994 forecasts to provide improved analysis of emerging technologies, environmental issues, conservation, and renewables. NEMS will provide comprehensive, integrated forecasts for supply of all fuels with the energy demand for all end-use sectors, and will be capable of evaluating the effects of policy options as well as energy market developments. EIA's goal is to make NEMS and its methods accessible to users for greater understanding of the model projections and for possible use for their own analyses. Through NEMS, EIA will have the capability to continue to provide quality data, analyses, and forecasts for the U.S. Department of Energy, Congress, industry, and consumers.

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Highlights

The Energy Information Administration's (EIA's) *Annual Energy Outlook 1993* (*AEO93*) presents forecasts for energy prices, supply, demand, and imports over the period 1990 to 2010. These projections take into account existing legislation, including the Energy Policy Act of 1992.

Even though the world oil market remains relatively tight, the long-term outlook for oil prices has been revised downward since the *Annual Energy Outlook 1992* as expectations for both the Organization of Petroleum Exporting Countries (OPEC) and non-OPEC production potential have been revised upward. Domestic natural gas prices are also expected to be lower than projected last year, in part because of a more optimistic outlook for drilling technology. Finally, lower growth in the demand for electricity is expected because of the Energy Policy Act of 1992, which mandates efficiency standards for new energy-using equipment. These are the most striking differences between last year's EIA evaluation of long-term energy market trends and this year's evaluation. Highlights of *AEO93* follow:

The Nation's total energy use varies with the overall outlook for economic growth

Total energy consumption is expected to grow to between 102 quadrillion British thermal units (Btu) and 112 quadrillion Btu (including renewable fuels) by 2010. This growth reflects the moderating effects of energy conservation. In all cases, energy demand is expected to grow at a far lower rate than overall economic growth. Energy demand per unit of gross domestic product is expected to fall by between 0.7 and 1.0 percent per year. The introduction, adoption, and use of more efficient energy-using technologies in all sectors, because of the Energy Policy Act of 1992, and general improvements in technology should continue these trends. On an aggregate basis, however, the additional output of goods and services associated with higher economic growth increases energy consumption.

Electricity continues to garner a growing share of the total energy market

Over the next 20 years, electricity will capture an increasing share of the total energy market. After growing from 24 percent in 1970 to 36 percent in 1990, the share of total primary energy consumed to produce electricity is expected to approach 39 percent by 2010. Stable electricity prices, effects of the Energy Policy Act of 1992, and continuing consumer preference for electricity cause growth in the demand for electricity to increase only slightly slower than economic growth. To meet this demand growth, between 149 and 245 gigawatts of new generating capacity will be needed by 2010. As in recent years, nonutility generators are expected to provide a large share of the new capacity. Between 1990 and 2005, the majority of the new plants will be natural-gas-fired combined-cycle and turbine plants added to serve intermediate and peak load requirements. After 2005, new coal-fired plants will be built to serve growing baseload needs.

The level of the Nation's oil imports is highly dependent on world oil market conditions

Higher oil prices are associated with higher domestic production, lower consumption, and lower oil imports. Based on worldwide projections for supply and demand, world oil prices, which averaged $18.70 per barrel in 1991, are projected to average between about $14 and $29 per barrel in 2000 (in 1991 dollars) and between about $18 and $38 per barrel in 2010. These uncertainties lead to a projection of oil imports of between 9.2 million and 13.6 million barrels per day in 2000 and between 10 million and 17 million barrels per day in 2010. This wide range in oil prices is attributable to possible differences in OPEC production (which increasingly is becoming

the world's marginal oil producer), non-OPEC production, especially in regions outside the United States, and the demand for oil from the developing countries. It is important to note that these developments affect the U.S. oil market outlook, which creates substantial uncertainty.

The outlook for the natural gas market depends on factors affecting the size and development of the domestic resource base, including production from Alaska

Natural gas wellhead prices are expected to increase from a 1991 level of approximately $1.60 per thousand cubic feet (mcf), in 1991 dollars, to between $2.40 and $2.80 per mcf in 2000 and to between $3.20 and $4.40 per mcf in 2010. These projections are sensitive to assumptions about the rate of technology improvement in exploration and development and to uncertainty with respect to the size of the U.S. resource base. Also, imports (mainly from Canada) will become a more important feature of the domestic gas market over the next 20 years. Domestic events will dominate the U.S. natural gas outlook, however, as the cost of transportation and storage precludes the internationalization of this market to the same extent as the oil market.

Coal production grows at the highest rate among domestic fossil fuels

Growth in coal-fired electricity generation, and a more than doubling of coal exports, are expected to stimulate strong growth in coal production over the next two decades. From just over 1 billion short tons in 1990, coal production will reach between 1.3 billion and 1.5 billion short tons by 2010, an annual increase of between 1.0 and 1.9 percent. Although consumption for non-electric uses is relatively stagnant over the forecast period, coal should continue to be the mainstay of baseload electricity generation in the United States, responsible for just about half of total generation in 2010. The United States is also expected to regain its position as the world's leading coal exporter by 2010, with increased coal demand in Western Europe being met by U.S. coal producers, thus helping to reduce the domestic trade deficit. Real minemouth coal prices should rise moderately over the next two decades; while the Clean Air Act Amendments of 1990 and increased exports will increase demand for higher cost coal from central Appalachia, increased production of Western subbituminous coal will mitigate the rise in prices.

Clean Air Act Amendments change petroleum product formulations and fuel use patterns for electricity generation

The Clean Air Act Amendments of 1990 mainly affect the electricity generation and petroleum refining sectors. To comply with the Act, electric utilities will increase their use of low-sulfur coal, low-sulfur residual fuel oil, and natural gas, purchase sulfur dioxide allowances from other utilities, and add scrubbers to older units. Refiners will need to produce new formulations of petroleum products, particularly for gasoline and diesel fuel in the transportation sector.

Absent any new legislative or other initiatives, carbon emissions will grow by between 0.8 and 1.3 percent per year over the next 20 years

Estimates of carbon emissions from fossil fuel combustion totaled more than 1.3 billion metric tons in 1990. Accumulation of such emissions may contribute to global climate change by increasing the greenhouse gas effect. The electric utility and transportation sectors emitted the largest amounts of carbon in 1990, 480 million metric tons and 435 million metric tons, respectively. The industrial and buildings sectors' direct carbon emissions are substantially lower because electricity is a large share of their energy consumption and electricity emissions are included in the electric utility sector. Combustion of oil products in 1990 emitted more carbon into the atmosphere (about 40 percent of the total) than combustion of any other type of fossil fuel because of their dominant market share. Coal is the second largest source (about 35 percent of the total), followed by natural gas.

1. Framing the 1993 Energy Outlook

As a result of the Persian Gulf crisis in 1990-91, world attention remained focused on the pivotal role of the Middle East in determining the world's future oil supplies and prices. Even under those dramatic circumstances, however, the *Annual Energy Outlook 1992* reminded readers that "economic and environmental issues—domestically and internationally—remain in the forefront of most serious discussions about energy." Those issues are, if anything, even more pronounced in this successor volume, the *Annual Energy Outlook 1993* (*AEO93*).

This chapter briefly reviews the significant events in 1992 in the international energy field, describes the central factors in current domestic economic growth in the United States, and reports on the effects of recent Federal energy legislation on energy markets, especially on reducing energy demand.

Against that background, this chapter then summarizes the forecasts of the Energy Information Administration (EIA) for energy demand, supply, imports, and prices over the next two decades (out to 2010). A Reference Case, or baseline scenario, is described along with three pairs of other forecasts that are based on various assumptions. These scenarios are compared with the recent past, major assumptions and rationale for the scenarios are described, and assumptions about world oil supplies and demands are discussed.

More efficient use of energy in the United States is a goal of the Energy Policy Act of 1992, which is discussed in this chapter. The Act promotes use of alternative fuels, revises efficiency standards for buildings, simplifies the licensing process for nuclear power plants, promotes advanced coal-use technologies, allows utilities to operate independent wholesale generating plants outside their service territories, authorizes research to reduce consumption of imported oil, supports development of renewable energy technologies, and grants U.S. oil and natural gas producers more favorable tax treatment for percentage depletion and intangible drilling costs.

Chapter 2 focuses on forecasts for energy consumption in the United States during the next two decades. Succeeding chapters analyze four key energy subjects: Chapter 3 addresses the outlook for U.S. oil and gas markets, Chapter 4 explores the outlook for electricity in the U.S. energy markets, Chapter 5 examines the outlook for coal in U.S. energy production, and Chapter 6 discusses carbon emissions. The report concludes, in Chapter 7, with a comparison of the EIA scenarios with other forecasts.

1992 in Review

A modest economic recovery led to an increase in total U.S. demand for energy during 1992. "Energy intensity" (the amount of energy consumed per unit of gross domestic product (GDP)) held steady after adjusting for weather-related effects. After rising in 1991, U.S. oil production fell during 1992 in response to lower oil prices resulting from the end of the Middle East conflict and the worldwide recession. U.S. petroleum net imports increased during 1992, as recovering Middle East production of crude oil and refined products expanded world supplies and domestic production declined. Growth in natural gas consumption outpaced growth in consumption of any other fuel because natural gas prices remained low in the first half of the year. Mild temperatures in early 1992 led to a slight decline in electricity demand; however, coal consumption increased because a larger share of electricity generation was from coal-fired plants.

Despite the continued loss of Iraqi oil production and political instability in the former Soviet Union, the world oil market remains remarkably stable. Key countries such as Saudi Arabia continue to expand production. Former Soviet Union (FSU) oil exports to the West have declined moderately. The last well fire in Kuwait was extinguished in November 1991, and repairs to the Kuwaiti oil production infrastructure continue. By the end of 1992, Kuwait neared 75 percent of its prewar oil production. The Organization of Petroleum Exporting Countries (OPEC) sought to achieve a reference price of $21 per barrel and did not expect additional Kuwaiti production to thwart that goal. By the end of 1992, Kuwaiti production helped to increase OPEC's share of the world oil market by almost 2 percent.

Nonetheless, uncertainties remain in world oil markets, the greatest of which results from the events unfolding in the FSU and Eastern Europe. Economic activity in the FSU is contracting. If FSU oil consumption falls faster than its oil production, FSU oil exports to Eastern Europe and the world could actually increase, particularly in the near term. Otherwise, loss or reduction of this important energy source could increase demands for oil from other sources, including OPEC. Over the longer term, with the increased use of Western technology and capital, expanded exploration could uncover and develop new oil reserves in the FSU and increase recovery from existing reserves.

Another uncertainty in world oil markets arises from OPEC's decisions concerning expansion of production capacity. These decisions will, in turn, be influenced by market-share and oil-revenue objectives as well as by other political and security considerations. Saudi Arabia demonstrated its ability to influence world oil markets when it decided to increase market share, resulting in the price collapse of 1986. Political uncertainty in the Middle East was manifest in the Persian Gulf war and, more recently, in the dispute between Iran and the United Arab Emirates over Abu Musa, a strategically located island near the Strait of Hormuz. OPEC dominates world markets: OPEC controls a huge share of the world's high-quality low-cost oil reserves, especially the Persian Gulf members. About two-thirds of the world's known petroleum reserves are located in the Middle East alone. Currently, OPEC produces more than one-third of all oil consumed in the world and could easily produce half of all oil consumed by 2010.

Domestic Economic Growth

Potential economic output in the mid-term period, through 2010, is defined as the ability to produce a supply of goods and services, if all resources are fully used. The rate of growth of this potential output depends on the rate of expansion of the resource base (primarily labor and capital) and changes in the productivity of that resource base. This is to be contrasted to a short-term forecast, which is focused more on aggregate demand, assuming that the resource and technology base is relatively constant, although not necessarily fully utilized.

Trends and Current Conditions

Although it is convenient to categorize the short term as demand driven and the long term as supply driven, the two are obviously linked. In the long term, some factors are considered outside of the forecast by way of assuming a particular growth path. Population and labor-force growth fall into this category. However, much of the long-term potential of the economy responds to decisions and directions taken now, in the short term. Consider the following trends and recent developments that have implications for long-term growth.

Population. The rate of population growth for the United States has steadily declined for 30 years. During the 1960s, the U.S. population grew at 1.3 percent. The growth rate declined to 1.0 percent in the 1970s and to 0.9 percent in the 1980s. The population trend was partly offset by increases in the labor force participation rate, largely through the creation of two-earner families in the workforce during the 1970s and 1980s. As a result, the labor force for the economy grew by 2.6 percent between 1970 and 1980, almost a full percentage point above the 1960's rate of 1.7 percent. From 1980 to 1990, however, labor force growth dropped to 1.6 percent. The long-run implication of declining population growth, combined with smaller increases in labor force participation rates than in the past, is that future economic growth will mirror the path of population growth if no offsetting improvements in productivity occur.

Trade. Trade accounts for a growing portion of the U.S. economy. From 1980 to 1990, the total volume of merchandise trade (exports plus imports) has doubled. The U.S. trade position is becoming more important in explaining U.S. economic growth. Increased global competition has led to a significant increase in the U.S. trade balance deficit with the rest of the world—especially during the mid-1980s. In response to this growth in the importance of trade to the U.S. economy, American businesses have restructured and streamlined production processes to compete in international markets. In the short run, this restructuring has led to employment losses for both white- and blue-collar jobs. In the long run, however, the increased global competition and trade will lead to increased U.S. economic growth as both productivity improves and costs decrease.

Consumption, Savings, and Investment. During the 1970s and 1980s, the economy experienced dramatic shifts in the pattern of consumption, savings, and investment. Consumption as a share of GDP rose steadily, while savings as a share of GDP fell. Much of the decline in aggregate savings came about because of the rapid growth in the Federal deficit. Domestic investment as a share of GDP also fell, but not by as much as savings. The difference was essentially made up through an increase in foreign funds flowing into the United States, which further exacerbated the foreign

trade deficit as payments on this debt left this country. The decline in investment share of output has adverse consequences on capital stock formation. With a lower level of capital stock formation, labor force productivity is diminished and the potential output of the economy is lowered.

Recession. Events in the past 2 years underscore the uncertain nature of short-term economic growth. During the early 1990s, the U.S. economy experienced slow economic and job growth, accompanied by similar developments in Western Europe and Japan. Moreover, the economy has been slow to rebound from the recession. After an economic downturn, growth over the first year in the recovery period typically exceeds 5 percent. In this current recovery phase, growth is expected to be less than 3 percent per year.

Federal Deficit. Concerns about the stability of the economy in the near term are being weighed against long-run considerations, such as the reduction of the Federal deficit. Cutbacks in defense spending may decrease the deficit, but may slow near-term growth. Conversely, expansion of programs to stabilize the economy may affect the ability to deal with the deficit. State and local governments, in an attempt to balance their books, have been raising taxes and cutting spending to balance falling revenues.

Financial Industry Shocks. Shocks to the financial industry have resulted in increased government spending to insure large losses of the savings and loans and commercial banks attributable to problems in the real estate sector and loans to developing countries. Even the insurance industry is experiencing financial difficulties, in part because of their investments in commercial real estate. The financial industry, a source of new jobs in past recoveries, is unlikely to experience much employment growth in the near term.

Real Estate. The commercial and residential real estate markets do not offer short-run reasons for optimism. Vacancy rates in commercial real estate are still high, given the amount of overbuilding that took place before 1986, when tax reform eliminated many tax incentives for commercial building. Although growth is expected in the housing market, the extent of the expansion is smaller than might be expected in past recoveries. Lower interest rates are beginning to bring buyers to the market, but demographics, low consumer confidence, and overbuilding of rental properties all temper the rebound.

Although the effects of some of these trends are more pronounced in the near term, all of them set the stage for economic growth prospects in the mid-term, out to 2010. Differences of opinion about the path or significance of trends in various key economic factors lead to differing views about the long-term average growth

Revisions to the National Income and Product Accounts

The Department of Commerce recently made major revisions to the National Income and Product Accounts (NIPA). These revisions accomplished two primary objectives: they placed primary emphasis on gross domestic product (GDP), and changed the base year from 1982 to 1987 dollars. These changes are incorporated in the *AEO93* reporting of macroeconomic results.

The switch to GDP puts the United States on a comparable accounting basis with the rest of the world. GDP emphasizes the production of goods and services located in the United States, rather than measuring activity of U.S.-owned factors of production. GDP focuses on the location rather than the ownership of assets.

From a forecasting perspective, however, the rebasing of the NIPA data to 1987 has an unanticipated result that needs to be flagged. Changing the NIPA base to 1987 raises the level of GDP, *but lowers the growth rate for history and for the forecast.* In the composition of GDP, the weights attached to any commodity are essentially the prices for that good or service. Any commodity that has had a relatively large rise in prices therefore has a higher weight in the rebased series. Because consumers tend to substitute away from commodities that have had large price increases, consumption of those goods and services rises less rapidly over time. This affects the calculated growth rates.

What does this mean for the interpretation of *AEO93*? For the *AEO93* Reference Case, economic growth between 1990 and 2010 is 2.02 percent in 1987 dollars. Expressed in 1982 dollars, the growth rate is 2.28 percent. These two figures describe exactly the same economy; it just matters in what dollars the data base is expressed. For those who use the *AEO93* forecast of economic growth to drive their own forecasts, or just to interpret the *AEO93* forecast, this distinction is important. The underlying economic data are available in 1982 dollars for those who wish to have that information.

rate in the economy. Some factors, such as the decline in labor force growth, are common to most long-term forecasts and are expected to continue over the next 20 years and reinforce a slower rate of GDP growth. There is more divergence of opinion about other elements, such as the rate of savings and investment for the economy or productivity changes. An increase in the rate of savings and investment, leading to increased productivity, may partially offset the effects of declining labor force growth on GDP growth. The differences in these trends explain many of the reasons for alternative GDP growth present in other long-term forecasts.

Energy Policy Act of 1992

The Energy Policy Act of 1992 will substantially affect energy markets, primarily through reductions in expected energy demand. (See box.) Most of the reduction is reflected in lower electric utility demand. The major provisions affecting these forecasts are revised efficiency standards, nuclear licensing reform, and revision of the Public Utility Holding Company Act of 1935 (PUHCA). Other provisions of the Energy Policy Act may become more significant over time. For example, increased funding of research and develop-

New Energy Legislation Brings Many Changes

All projections in *AEO93* are based on the provisions of the Energy Policy Act of 1992 and on assumptions discussed in this report and its accompanying volume, *Assumptions for the Annual Energy Outlook 1993*. The Act affects almost every sector of the energy industry. It streamlines licensing for nuclear power plants, mandates various energy-efficiency programs and the phase-in of cars that run on alternative fuels, and restructures the wholesale electric power market. The Act also authorizes scores of energy-related research and development (R&D) projects, for which funds have not been appropriated.

Major provisions of the Act are described below.

Alternative Fuels and Fleets. The Act mandates that governments and private businesses with fleets of automobiles or trucks phase in vehicles that do not rely on petroleum products. Methanol, ethanol, natural gas, electricity, and coal-derived liquid fuels are some of the eligible alternative fuels.

Energy Efficiency. The Secretary of Energy is required to set minimum building-efficiency standards that apply to all new Federal buildings and new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and commercial and industrial equipment are required. The Act authorizes the Federal Government to help industry to develop a voluntary efficiency-labeling program for windows and fluorescent light fixtures.

Nuclear Power Plant Licensing. The Act adopts the Nuclear Regulatory Commission's proposed rule to issue a combined construction and operating license for nuclear power plants, instead of maintaining the current process of granting two separate licenses.

Coal. The Act authorizes Federal R&D projects designed to promote advanced coal technologies, including efforts to burn coal with fewer acid emissions. The Act also creates a technology transfer program to export "clean coal" and renewable energy technologies to other nations.

PUHCA. The Act exempts certain wholesale electric generators from the Public Utility Holding Company Act of 1935 (PUHCA), thus allowing utilities to operate independent wholesale plants outside their service territories. In addition, the Act improves efficiency in the transmission system by authorizing the Federal Energy Regulatory Commission to order wholesale, but not retail, transmission access on a case-by-case basis.

Research and Development. The Act authorizes an array of R&D programs to reduce consumption of imported oil. Research includes the examination of high-efficiency heat engines, development of oil shale, exploration of high-temperature superconducting electric power systems, and development of advanced oil-recovery techniques.

Renewable Energy. The Act establishes a program, similar in structure to the Clean Coal Program, to support development of renewable energy technologies. It provides a production incentive to public power utilities for electricity produced from renewable energy resources, comparable to the tax credit provided to investor-owned utilities.

Oil and Natural Gas Production. The Act repeals the minimum tax preferences for percentage depletion and intangible drilling costs for independent oil and natural gas producers. Independent oil and natural gas producers are permitted to take greater deductions against the alternative minimum tax for percentage depletion and intangible drilling costs.

ment programs may eventually have large impacts on energy markets.

Renewable energy incentives increase the future role of renewable energy sources. These incentives include a permanent 10-percent investment tax credit for solar and geothermal projects, a production credit for wind and biomass electric generating plants, and an extension of the Federal excise tax exemption for 10-percent ethanol-gasoline blends.

Revised and more comprehensive mandated energy standards and labeling are aimed at reducing energy consumption. The programs include window labeling and rating standards, building codes for new construction, efficiency standards for certain types of equipment (including electric motors), and Federal mortgage-funding based on household energy efficiency.

Seven Cases Offer a Range of Forecasts

This report follows the tradition of its predecessor volumes in presenting the EIA's forecasts for energy prices, supply, demand, and imports over the next two decades (the forecast period for *AEO93* extends to 2010). In *AEO93*, EIA offers a baseline case, called the Reference Case, and three pairs of other cases (also called scenarios) that give high and low projections based on various assumptions. Details on all seven scenarios are provided in Appendices A through G.

The seven cases are based on existing legislation and regulations, without incorporating any proposed legislation or regulations. For the most part, the divergence among cases results from the uncertainties associated with the major sensitivity factors: world oil prices, macroeconomic growth, and the Nation's oil and gas resource base (Table 1).

The purpose of the Reference Case is to facilitate comparisons among the other six cases and with forecasts developed by other organizations. It should not be viewed as the most likely scenario.

This year, EIA adopts a new approach to assist readers of *AEO93*: This report traces one pair of cases through the remaining chapters as a theme. This pair of cases, the High Oil and Gas Recovery Case and the Low Oil and Gas Recovery Case, is based on estimates of the amount of oil and natural gas that is undiscovered and potentially economically recoverable within U.S. territory. The magnitude of effect of the High and Low Oil and Gas Recovery Cases varies, of course, from fuel to fuel.

Following are brief descriptions of the Reference Case and the six other cases analyzed in *AEO93*.

Reference Case

The Reference Case combines the assumption of an annual economic growth rate of 2.0 percent with a mid-level path for the world oil price. The latter assumes that the average price to U.S. refiners for imported oil will drop from $23 per barrel in 1990, hover in the $19-to-$23 range (in constant 1991 dollars) through the 1990s, then rise to $29 (in 1991 dollars) by 2010. The Reference Case also assumes that economically recoverable oil and natural gas resources are 94 billion barrels and 892 trillion cubic feet, respectively. The economic growth assumption represents a mainstream projection (see Chapter 7). Total demand for energy grows at an annual rate of 1.2 percent per year under these assumptions, increasing by 2010 to 22 quadrillion British thermal units (Btu) above the 1990 level of 85 quadrillion Btu.

High Economic Growth Case

This case assumes the same mid-level world oil prices as those in the Reference Case, but combines them with an assumption of higher macroeconomic growth (2.4 percent per year). With this combination, energy demand increases at 1.4 percent per year, the highest rate among the cases considered. High macroeconomic growth is associated with strong industrial growth and also with high levels of travel in all transportation modes. By 2010, total U.S. demand for energy is projected to be 27 quadrillion Btu higher than in 1990.

Low Economic Growth Case

This case also assumes the mid-level world oil price path, but combines it with lower macroeconomic growth (1.6 percent per year), a combination that produces the lowest energy demand of any of the seven cases. Low macroeconomic growth is associated with sluggish industrial activity, low employment, and relatively low levels of travel in all transportation modes. By 2010, total U.S. demand for energy is projected to be 17 quadrillion Btu higher than in 1990, an increase of 0.9 percent per year.

Table 1. A Range of Projections for 2010—Summary

Sensitivity Factors	1990	2010						
		Reference	High Economic Growth	Low Economic Growth	High World Oil Price	Low World Oil Price	High Oil and Gas Recovery	Low Oil and Gas Recovery
Primary Production (quadrillion Btu)								
Petroleum	17.9	15.3	15.3	15.0	17.1	10.7	17.8	12.9
Natural Gas	18.5	20.8	21.5	20.0	21.8	19.4	22.4	19.0
Coal	22.2	28.8	31.5	26.4	28.2	28.9	28.3	29.7
Nuclear Power	6.2	6.9	7.1	6.9	6.9	6.9	6.9	6.9
Renewable Energy/Other	6.5	10.1	10.4	9.7	10.4	9.9	10.1	10.1
Total Primary Production	**71.3**	**82.0**	**85.7**	**78.1**	**84.5**	**75.8**	**85.5**	**78.6**
Net Imports (quadrillion Btu)								
Petroleum (including SPR)	15.3	25.8	28.1	23.6	21.7	35.7	22.9	28.5
Natural Gas	1.5	4.3	4.4	4.0	3.6	4.4	3.9	4.5
Coal/Other (- indicates export)	-2.5	-4.9	-6.3	-3.6	-4.8	-4.9	-4.8	-4.9
Total Net Imports	**14.2**	**25.1**	**26.2**	**23.9**	**20.5**	**35.2**	**22.0**	**28.1**
Net Stock Withdrawals	-1.4	-0.2	-0.2	-0.1	-0.1	-0.2	-0.2	-0.2
Discrepancy	0.4	-0.3	-0.3	-0.3	-0.1	-0.5	-0.1	-0.4
Consumption (quadrillion Btu)								
Petroleum Products	33.5	41.2	43.5	38.6	39.1	46.3	40.9	41.3
Natural Gas	19.3	25.0	25.8	23.9	25.3	23.7	26.2	23.5
Coal	19.1	22.9	24.1	21.9	22.4	23.0	22.4	23.8
Nuclear Power	6.2	6.9	7.1	6.9	6.9	6.9	6.9	6.9
Renewable Energy/Other	6.5	10.7	11.0	10.4	11.1	10.5	10.8	10.7
Total Consumption	**84.6**	**106.7**	**111.5**	**101.7**	**104.8**	**110.4**	**107.2**	**106.2**
Prices (1991 dollars)								
World Oil Price (dollars per barrel)	22.54	29.30	29.30	29.30	38.10	18.10	29.30	29.30
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.77	3.68	4.07	3.30	3.89	3.52	3.19	4.44
Domestic Coal at Minemouth (dollars per short ton)	22.52	30.97	33.12	29.03	30.14	31.02	30.67	31.25
Average Electricity Price (cents per kilowatthour)	6.80	6.89	7.04	6.74	7.00	6.69	6.80	7.04
Economic Indicators								
Real Gross Domestic Product (billion 1987 dollars)	4,885	7,287	7,854	6,691	7,217	7,382	7,297	7,275
(annual change, 1990-2010)	--	2.0%	2.4%	1.6%	2.0%	2.1%	2.0%	2.0%
GDP Implicit Price Deflator (index, 1987=1.00)	1.129	2.432	2.160	3.155	2.442	2.421	2.430	2.435
(annual change, 1990-2010)	--	3.9%	3.3%	5.3%	3.9%	3.9%	3.9%	3.9%
Real Disposable Personal Income (billion 1987 dollars)	3,538	5,041	5,373	4,757	5,021	5,065	5,044	5,036
(annual change, 1990-2010)	--	1.8%	2.1%	1.5%	1.8%	1.8%	1.8%	1.8%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.030	1.694	1.848	1.534	1.662	1.738	1.699	1.689
(annual change, 1990-2010)	--	2.5%	3.0%	2.0%	2.4%	2.6%	2.5%	2.5%
Energy Intensity (thousand Btu per 1987 dollar of GDP)								
Oil and Gas Use	10.81	9.08	8.82	9.34	8.92	9.48	9.19	8.90
Electricity End-Use	1.90	1.75	1.71	1.80	1.75	1.74	1.74	1.75
Total Energy Use	17.33	14.64	14.20	15.20	14.53	14.95	14.69	14.60
Total Energy Use Less Dispersed Renewables	16.72	13.96	13.55	14.49	13.80	14.29	13.99	13.91

Note: Quantities are derived from historical volumes and assumed thermal conversion factors.

Sources: **History (1990):** Energy Information Administration, *Monthly Energy Review* (July 1991), and Office of Coal, Nuclear, Electric and Alternate Fuels estimates. **Projections:** Tables A1, A2, A4, A7, B1, B2, B4, B7, C1, C2, C4, C7, D1, D2, D4, D7, E1, E2, E4, E7, F1, F2, F4, F7, G1, G2, G4, and G7.

High World Oil Price Case

World oil prices are defined as the average refiner acquisition cost of imported crude oil in the United States. This case combines the Reference Case economic growth trend (2.0 percent per year) with a higher world oil price path (starting at $19 per barrel in 1991 and rising gradually to $38 in 2010, both in real terms). A higher world oil price path such as this could result from such factors as increased instability (resulting in lower-than-expected capacity additions) in the Middle East or unanticipated increases in demand. Because the world oil price is higher than that assumed for the Reference Case, the effective rate of economic growth and the level of GDP in 2010 are slightly lower than in the Reference Case. Lower demand for energy results in a rise of only 20 quadrillion Btu (1.1 percent per year) above the total 1990 consumption of primary energy.

Low World Oil Price Case

This case combines the Reference Case economic growth (2.0 percent per year) with an assumption that world oil prices will fall to $14 per barrel by 1999 and then rise to about $18 per barrel by 2010. Such relatively low prices could result from improved oil production capacity outside the United States, new discoveries, or the breakdown of discipline within OPEC. With oil prices lower than in the Reference Case, the economic growth path and the level of GDP in 2010 are somewhat higher than in the Reference Case. The combined effects of lower oil prices and macroeconomic feedback result in energy demand increasing by 1.3 percent per year through 2010, with demand in 2010 reaching 26 quadrillion Btu above the 1990 level.

High Oil and Gas Recovery Case

The High and Low Oil and Gas Recovery Cases are designed to demonstrate the effects of the uncertainties that are inherent in recoverable oil and natural gas resource estimates. The recoverable resource estimates are derived from the U.S. Geological Survey's (USGS) probability distributions of technically recoverable oil and gas resources in the United States. These probability distributions give a range of recoverable resources, based on current technology, and the probability associated with each level. The Reference Case uses the median of the probability distribution (50th percentile) to estimate economically recoverable resources. The High Oil and Gas Recovery Case uses the USGS 5th percentile and the Low Oil and Gas Recovery Case uses its 95th percentile. Proportional changes in other recovery categories (e.g., inferred reserves, enhanced oil recovery) between the Reference Case and the High and Low Recovery Cases were made to match the proportional shifts in the conventional economically recoverable resource estimates.

The High Recovery Case entails an estimate of 126 billion barrels (731 quadrillion Btu) of economically recoverable crude oil and 1,125 trillion cubic feet (1,160 quadrillion Btu) of economically recoverable natural gas. Crude oil production in 2010 is 15.2 quadrillion Btu compared with 13.0 quadrillion Btu for the Reference Case. Similarly, natural gas production in 2010 reaches 22.4 quadrillion Btu in 2010, compared with 20.8 quadrillion Btu for the Reference Case.

Low Oil and Gas Recovery Case

The Low Oil and Gas Recovery Case results in economically recoverable resources at 75 billion barrels (435 quadrillion Btu) of crude oil and 721 trillion cubic feet (743 quadrillion Btu) of natural gas. Crude oil production falls to 10.7 quadrillion Btu in 2010, compared with the Reference Case level of 13.0 quadrillion Btu in 2010. Natural gas production does not fall as steeply as crude oil production. Natural gas production in 2010 declines from 20.8 quadrillion Btu in the Reference Case to 19.0 quadrillion Btu in the Low Oil and Gas Recovery Case.

The six complementary scenarios were constructed to examine the individual effects of these contrasting assumptions. For example, in contrasting world oil prices, feedback effects on the economy are considered, but they do not alter the economic growth paths significantly in comparison with the shifts in economic growth assumed for the High and Low Economic Growth Cases.

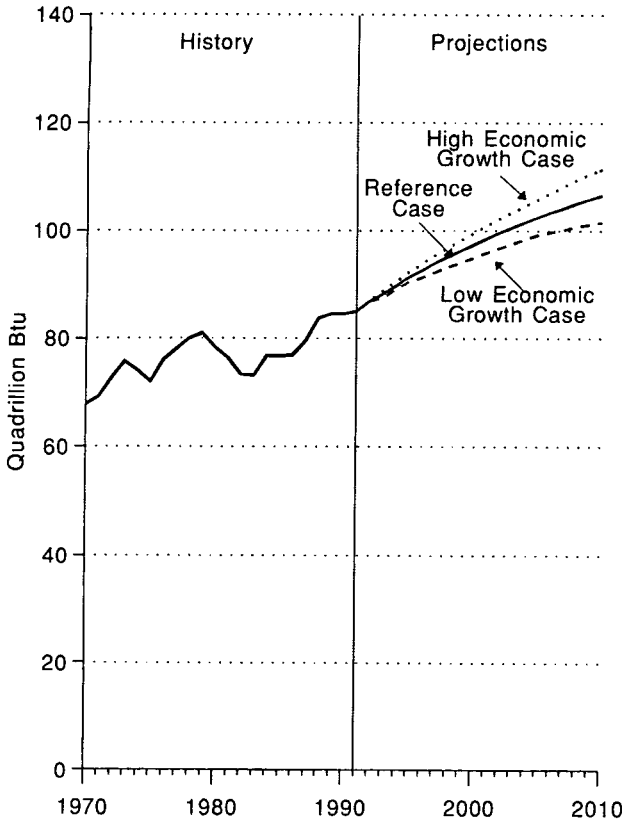
Comparison with the Recent Past

Over the forecast period, the average annual growth in total U.S. energy consumption ranges across the scenarios from 0.9 percent in the Low Economic Growth Case to 1.4 percent in the High Economic Growth Case. Demand for electricity grows much less than in past forecasts because of the Energy Policy Act of 1992, but it continues to grow strongly compared with both petroleum and natural gas. As electricity demand rises and as low natural gas prices lead to construction of more gas-fueled combined-cycle units, the use of natural gas for electric generation increases more than twice as much as electricity demand. The use of coal, the leading fuel for electric power generation,

continues to increase, but at a lower rate than the use of natural gas for this purpose. Consumption of renewable energy as a primary input to electric power generation also shows large growth, primarily by nonutility power producers.

In comparison with these projections, actual total U.S. energy consumption increased at an average annual rate of 1.1 percent per year between 1970 and 1990—reaching 85.0 quadrillion Btu, the highest level in history (Figure 1). The decreases in energy use that followed two earlier increases in the price of oil (and coincidental periods of recession) show clearly in this figure. In all sectors other than transportation (which remained almost exclusively dependent on petroleum), there was a continued shift from 1970 to 1990 in the composition of end-use demand away from other fuels to electricity. Strong growth also occurred in the consumption of coal and nuclear energy for use in generating electricity.

Figure 1. U.S. Energy Consumption, 1970-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A1, B1, and C1.

Actual total U.S. energy consumption reached its highest level in history in 1990, and continues upward in the High and Low Economic Growth Cases and the Reference Case.

Major Assumptions and Rationale

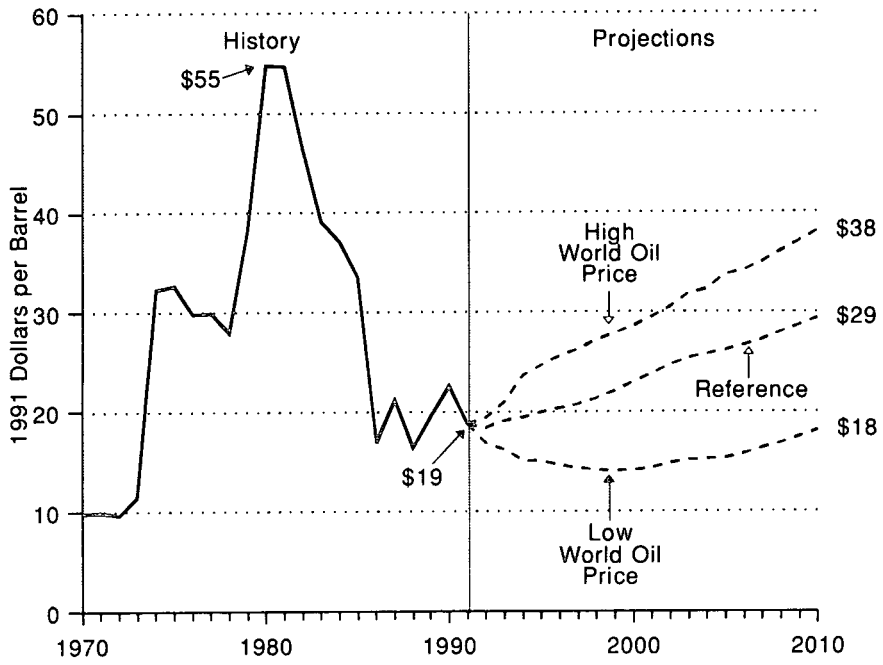
World Oil Price Trends

World oil prices are expected to rise slowly throughout the forecast period but to remain well below the post-oil-shock highs of 1980 and 1981 (Figure 2). For example, the Reference Case price of $23 per barrel for 2000, in constant 1991 dollars, is about the same as in 1990, the year world markets worried about hostilities in the Persian Gulf. The real price ranges between $14 and $29 per barrel in 2000 and between $18 and $38 per barrel in 2010, reflecting uncertainties about future market prospects. Potential impacts from a politically caused supply disruption are excluded.

Market forces will determine if prices track closer to the high or low end of this range. Supply and demand actions that would encourage lower prices include renewed efforts at energy conservation and fuel substitution, successful expansion of production capability among countries outside of OPEC, and a favorable capacity expansion policy by OPEC itself. Actions that would tend to raise prices include an extended period of high economic growth and associated high oil demand growth, less energy conservation and greater reliance on oil relative to other energy sources, less success at expanding production in non-OPEC regions, and the desire and ability by OPEC to implement aggressive policies with respect to higher prices.

In the Reference Case, where world oil prices rise slowly in real terms, it is assumed that demands for oil continue to grow along with economic growth, particularly in the developing and newly industrialized countries of the world. The fastest growth in economic activity is expected to occur in developing countries taken as a group, with particularly high rates of growth occurring in the Pacific Rim region. Low-cost, labor-intensive production has spurred growth in this region and in other rapidly developing countries. Relatively rapid economic growth in the developing countries group should continue, particularly in those countries making the transition to a higher value-added production base.

Figure 2. U.S. Refiners' Acquisition Cost of Imported Crude Oil, 1970-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A1, D1, and E1.

Absent a major oil supply disruption, world oil prices, in real terms, remain well below the record highs reached in 1980 and 1981.

On the supply side, world reliance on OPEC oil continues to grow through 2010 in the Reference Case. In contrast, non-OPEC production reaches a peak in about 5 years, as production gains from new fields lag production losses from mature fields. Oil exports from the FSU to markets beyond Eastern Europe are projected to decline steadily. U.S. oil production declines while its oil consumption and net oil imports rise. World oil prices rise to balance Reference Case supply-and-demand conditions. Uncertainties concerning world supply and demand interactions are represented by the range of oil prices shown in Figure 2.

World Oil Price Comparison

Recent and anticipated developments in world oil markets have resulted in assumed price paths for world oil that are considerably lower in *AEO93* than those published in *AEO92*. Defined as the cost of imported crude oil to U.S. refiners, Reference Case prices in constant 1991 dollars are about $4 per barrel lower in 2000 and about $5 per barrel lower in 2010 than those assumed last year. The gradual increasing trend in oil prices remains, with the greater part of the increase occurring after 1995 (Figure 2).

Many assumptions concerning world oil supplies and demands underlie the price paths presented in *AEO93*, but the main reason for lower prices compared with last year's projections involves raised expectations about the expansion of oil production capacity among OPEC members, particularly over the next several years. Major increases in production capacity are expected from Saudi Arabia, which may become the world's largest producer in the future, as production from the FSU (the world's largest producer in 1991) declines. Production capacity will accelerate, as Kuwait and Iraq restore prewar capabilities and other Persian Gulf producers continue more moderate expansion programs. Currently, production from Iraq is limited by United Nations sanctions arising from the Persian Gulf war, but increases in Iraq are expected eventually.

Even with lower prices, prospects for oil production from non-OPEC sources have been raised again this year, after already rising considerably in *AEO92* compared with previous years. Higher production levels in *AEO93*, primarily after 2000 when prices begin to rise at a faster rate, result from more optimistic assumptions concerning additions to reserves in several non-OPEC developing countries and areas (including the North Sea, Yemen, and Syria, among others), increased production from existing fields attributable to improved methods of extraction, and the rate at which certain countries are willing to produce from given reserves. In no instance, however, are revised depletion rates as high as those observed for the United States.

Altered expectations about world oil demands have also contributed to lower oil prices in *AEO93*, compared with those in *AEO92*. These changes deal primarily with expected oil consumption behavior among the developing countries. The developing countries group excludes the industrialized countries of the Organization for Economic Development (OECD)—the United States, Canada, Western Europe, Japan, Australia, and New Zealand—and excludes current and former centrally planned economies, such as the FSU, Eastern Europe, and the Peoples Republic of China. As was the case for *AEO92*, the fastest growth in economic activity is assumed to occur in the developing countries taken as a group. The technology used to produce high-value-added products should also reduce the overall energy intensity of economic activity in these countries, as it has among the industrialized OECD countries. To account for this changing economic base in many developing countries, the oil intensity (the ratio of oil consumption per unit of GDP) of prospective economic activity for the developing countries group was reduced slightly. The world oil prices presented in *AEO93* reflect that adjustment.

Assumptions concerning the change in oil consumption, given a change in oil price, were also adjusted slightly for the developing countries group in deriving world oil prices for *AEO93*. Again, because of technological advances, and given more optimistic prospects for other energy supplies, it was assumed that the developing countries group would in the future be somewhat more responsive to oil price changes than in the past. The relationship between the change in oil consumption and a change in oil price was altered for the developing countries group in the direction of that assumed for the OECD countries. These changes in assumptions concerning oil intensity and price responsiveness were marginal, but result in the developing countries group consuming less oil at a given price in *AEO93* than would have been the case using *AEO92* assumptions. At that, the developing countries will account for half of all the growth in oil consumption in the world by 2010.

Mid-Term Economic Growth

Labor is the most fundamental resource of the U.S. economy. The supply of labor is, therefore, the single most important determinant of long-term growth. A consistently held assumption across forecasters, however, is that labor force growth over the next 20 years will be smaller than that experienced over the past 20 years. While the U.S. labor force grew by an average annual rate of 2.1 percent between 1970 and 1990, yearly growth rates over the forecast period are expected to average only about 1 percent.

The labor force participation rate, the percent of people over 16 seeking employment, has risen dramatically in the past three decades, from 57 percent in 1960 to around 65 percent in 1990. This trend is expected to level off in the forecast period, however, dampening the growth in the labor supply. To the extent that labor-force projections differ across macroeconomic scenarios, they generally reflect differing views on the potential for immigration, rather than varied expectations about the extent to which members of the population will participate in the active labor force. The current forecast relies on the middle case forecast of net immigration prepared by the U.S. Bureau of the Census. Using the high case immigration assumption would result in the growth rate in the labor force between 1990 and 2010 rising by no more than 0.1 percent, from 1.0 to 1.1.

Even with common assumptions about labor force growth, projections about economic growth can differ. Alternative views of the growth potential in the economy also spring from differing judgments about the prospects for new capital formation and improvements in technology. Forecasts of higher rates of growth in potential GDP are generally based on more optimistic assumptions about capital formation and technology change. As capital (and/or more productive technology) is substituted for labor, slower growth in the labor force can be partially offset by improvements in labor productivity. Lower rates of growth are less optimistic about capital formation, technology change and continued high Federal deficits and weak trade growth.

The Reference Case projects that total savings as a share of GDP will increase over the forecast period, as personal and business savings shares remain relatively constant and the Federal deficit declines. By 2010, the Federal deficit is forecast to represent less than 1

percent of GDP, down from the current value of more than 5 percent. This increase in the pool of savings funds available for investment is a key ingredient in providing a boost to the long-term growth potential of the economy. Increasing investment and higher capital accumulation will allow for increased productivity and long-run growth.

As a result of these supply elements—labor force growth, capital expansion, and productivity change—the Reference Case real GDP is expected to grow by 2 percent annually between 1990 and 2010 (Table 2). Labor force and productivity growth will contribute roughly equally towards overall growth—with both of them increasing annually by 1 percent. Growth is slightly higher for the first 10 years of the forecast period, reaching an average annual growth rate of 2.2 percent, and then growth for the next 10 years diminishes to 1.9 percent per year (Figure 3). During the first decade of the forecast, labor force growth is 1.2 percent, while productivity (measured as real GDP per member of the labor force) is 1.0 percent. Consistent with trends for population, however, labor force growth trails off to 0.7 percent in the second decade. This decline is only partially offset by an increase in total productivity, which rises to 1.2 percent.

Inflation (as measured by the implicit GDP deflator) averages 3.9 percent over the next 20 years. Inflation is expected to rise more in the final 10 years of the forecast as wages increase, reflecting lower population and labor force growth. Consumer prices rise an

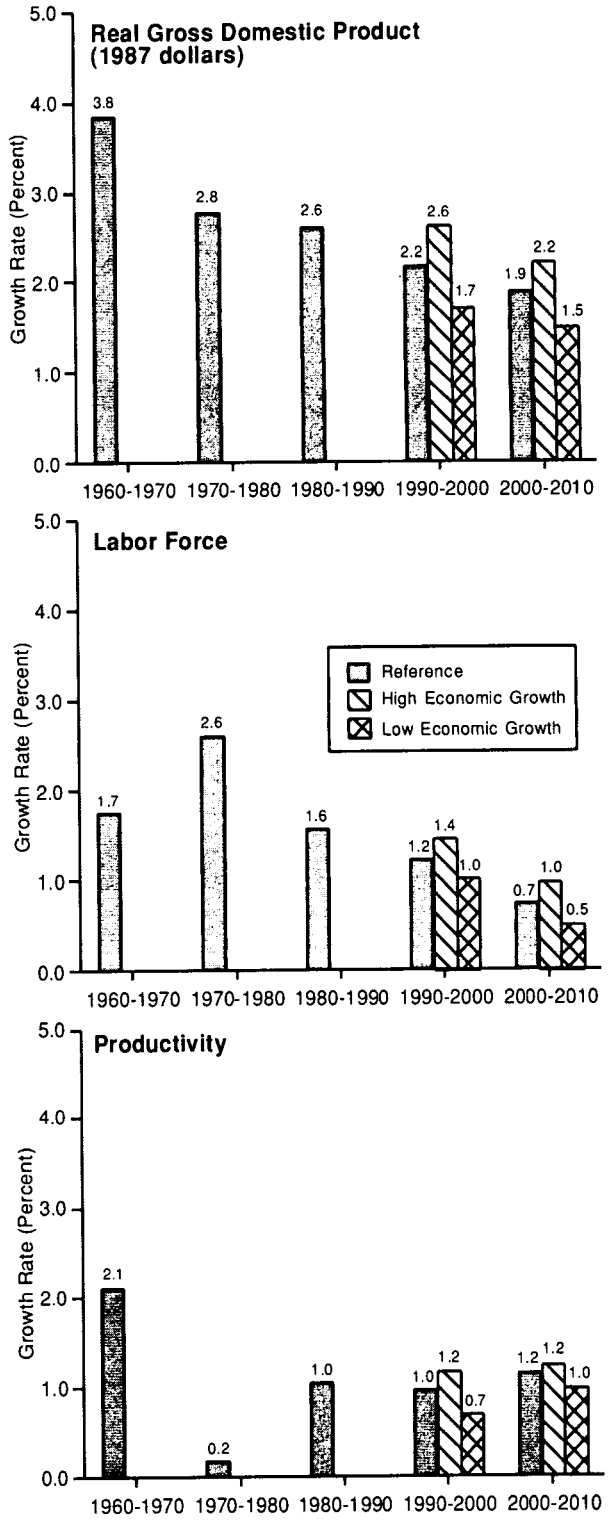
Table 2. Growth Rate of Real Gross Domestic Product (GDP), 1990 to 2010
(1987 Dollars)

Supply Elements	Reference	High Economic Growth	Low Economic Growth
Labor Force	1.0	1.2	0.8
Productivity	1.0	1.2	0.8
Real GDP	2.0	2.4	1.6

Source: Energy Information Administration projections based on simulations of the Data Resources, Inc., Quarterly Model of the U.S. Economy.

Labor force and productivity growth are reflected in the growth of real gross domestic product, which is expected to grow 2.2 percent annually between 1990 and 2000 and 1.9 percent annually for the following 10 years in the Reference Case.

Figure 3. Growth Rates for U.S. Real Gross Domestic Product, Labor Force, and Labor Productivity, 1960-2010



Sources: **History:** Bureau of Economic Analysis, U.S. Department of Commerce, and Bureau of Labor Statistics, U.S. Department of Labor. **Forecast:** *AEO93* Forecasting System run AEO93B.D0918921.

average of 4.1 percent over the entire period. Interest rates, low in the initial years of the forecast as a result of slow short-run growth, recover in the mid-1990s and then settle to a relatively stable path after 1997.

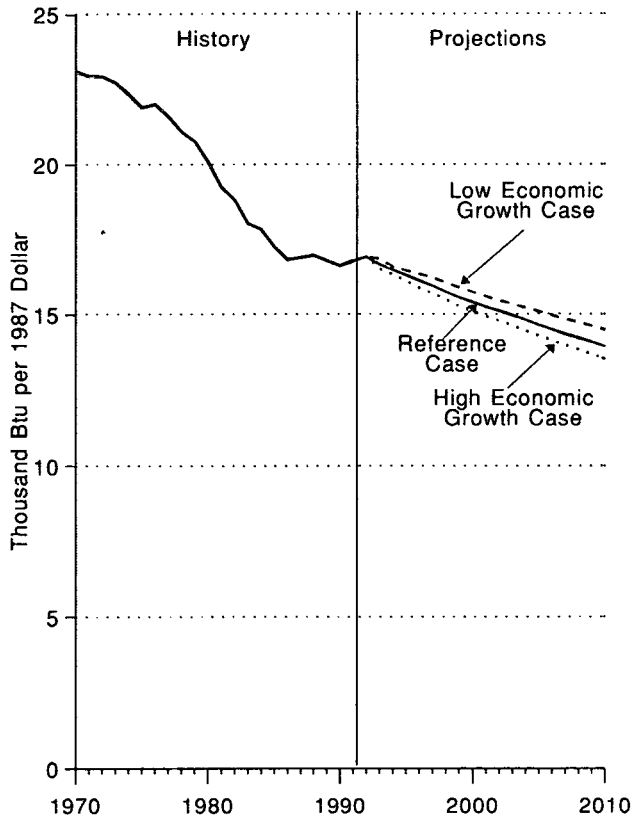
In the Reference Case, total industrial output is expected to grow by 2.3 percent annually, while manufacturing output grows at a slightly higher rate of 2.5 percent. Industrial output growth varies across industries. Production of machinery (Standard Industrial Classifications 34-38) registers the highest expected growth, attaining 3.3 percent, as foreign demand stimulates exports of these products. Growth in the paper, chemical, and plastic sectors surpasses GDP growth for the forecast period. For other industrial sectors, growth is below the aggregate growth in real GDP.

AEO93 presents different macroeconomic growth cases, a real GDP growth of 2.4 percent in the High Economic Growth Case and 1.6 percent in the Low Economic Growth Case. This spread of 0.8 percentage points reflects the extent to which successive 20-year growth rates varied from the trend from 1970 to 1990.

The High Economic Growth Case incorporates higher labor force and productivity growth (both growing at 1.2 percent annually over the forecast period) compared with the Reference Case. The combination of higher labor and productivity growth means that real GDP grows by 2.4 percent per year between 1990 and 2010. Because of higher productivity gains, inflation and interest rates are lower than in the Reference Case. Consumer prices increase by 3.5 percent per year, and the GDP implicit price deflator increases by 3.3 percent. Lower interest rates combined with higher disposable income growth boost the housing and automotive sectors. Increased income growth, stronger demand for exports, and higher productivity boost industrial output. Manufacturing output increases by 3.0 percent through 2010, with machinery, chemicals, and plastics showing the highest growth.

The Low Economic Growth Case assumes lower labor force (0.8 percent) and productivity (0.8 percent) growth compared with the Reference Case, to yield a real GDP growth of 1.6 percent from 1990 to 2010. Because factors of production are more scarce, both inflation and interest rates are higher. The GDP implicit price deflator increases by 5.3 percent and consumer prices show 5.4-percent growth until 2010. The higher inflation and interest rates slow interest-rate-sensitive sectors of the economy, and investment slows. Both potential output (output that can be produced if all factors of production are at full employment) and actual output grow at slower rates compared with the Reference Case. Industrial output also grows more slowly. Output of manufacturing industries increases by 2.0 percent as both domestic and foreign demand for goods and services increase at slower rates compared with the Reference Case. Similar to the other macroeconomic growth cases, machinery, chemicals and plastics, and paper sectors cause manufacturing output to increase at a rate higher than that of real GDP.

Figure 4. U.S. Energy Intensity: Total Energy Consumption per Dollar of Real Gross Domestic Product, 1970-2010



Note: Due to lack of historical data on dispersed renewables, the total energy consumption amounts included in the calculations depicted above do not include dispersed renewables.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1991* (June 1992). **Projections:** Tables A2, A7, B2, B7, C2, and C7.

The ratio of total energy use per dollar of real gross domestic product (GDP) is one measure of the efficient use of energy. In 1970, the Nation used 23.1 thousand Btu for every dollar of GDP output. A 20-year decline brought that figure down to 16.6 thousand Btu per dollar of output. This downward trend is forecast to continue, with the ratio falling to 14.0 thousand Btu per dollar in 2010 in the Reference Case.

The Efficiency of Energy Use

One measure of the efficient use of energy in the economy is the ratio of total energy use per dollar of real GDP. Figure 4 shows this ratio historically from 1970 to 1992 and in the forecast period through 2010. In 1970, the Nation used 23.1 thousand Btu for every dollar of output in the economy. With the volatile energy prices of the 1970s and 1980s, however, there was a steady decline in this ratio, falling to 20.1 thousand Btu by 1980 and to 16.6 thousand Btu per dollar in 1990. This downward trend is forecast to continue, although at a slower rate. By 2000, the Reference Case shows this ratio declining to 15.5 thousand Btu and by 2010 to 14.0 thousand Btu per dollar. Moreover, if the economy experiences higher growth in real output, the actual efficiency of energy use may improve at an accelerated rate. Conversely, if the economy grows at a slower rate, the energy efficiency of the economy may be different from the Reference Case path.

Summary

Very large questions confront those who wish to forecast energy production, demand, and prices in the United States in coming years. The seven scenarios described in this report offer at least a framework for analyzing possible paths of these factors. A key influence is, of course, how much and what kinds of energy Americans want to use in their homes and their commercial and governmental activities. End use is the subject of Chapter 2.

2. U.S. Energy End Use

Based on the assumptions of the *AEO93* Reference Case, the United States is projected to consume about 107 quadrillion British thermal units (Btu) of primary energy resources (in all forms combined) during the year 2010 (Table 3). This would be 26 percent above the 1990 level of energy use. By 2010, the total U.S. population should have increased by nearly 14 percent and gross domestic product (GDP) (in the Reference Case) by some 49 percent. Economic expansion and continued gains in the standard of living will thus take place against a backdrop of reduced energy intensity.

Depending on which scenario is considered, estimates of total energy consumption for 2010 vary by nearly 10 percent (by about 9.8 quadrillion Btu). In both the Low Oil and Gas Recovery and the Low Economic Growth scenarios, energy demand is lower than in the Reference Case. High energy prices in the Low Oil and Gas Recovery Case tend to induce more conservation because they offer greater incentives to improve efficiency in energy use. Low economic growth reduces the demand for energy-related services, particularly in the industrial and transportation sectors.

Table 3. Summary of Energy Consumption by Sector and Source, with Projections for 2010
(Quadrillion Btu)

Energy Consumption	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil and Gas Recovery	Low Oil and Gas Recovery
Consumption by Sector						
Residential	9.8	11.6	11.8	11.3	11.6	11.4
Commercial	6.7	8.3	8.4	8.2	8.3	8.2
Industrial	24.8	30.9	32.4	29.2	31.4	30.5
Transportation	22.5	28.9	31.0	26.9	28.9	28.9
Total End-Use Consumption	**63.8**	**79.7**	**83.6**	**76.0**	**80.2**	**79.0**
Electrical Generation and Distribution Losses	20.8	27.0	27.9	25.7	27.0	27.2
Total Consumption of Primary Energy	**84.6**	**106.7**	**111.5**	**101.7**	**107.2**	**106.2**
Consumption by Source						
Petroleum	33.5	41.2	43.5	38.6	40.9	41.3
Natural Gas	19.3	25.0	25.8	23.9	26.2	23.5
Coal	19.1	22.9	24.1	21.9	22.4	23.8
Other[a]	12.7	17.7	18.1	17.3	17.8	17.6
Total Consumption of Primary Energy	**84.6**	**106.7**	**111.5**	**101.7**	**107.2**	**106.2**
Electricity (End Use)	9.3	12.7	13.4	12.0	12.7	12.7

[a]Includes primary energy inputs from nuclear power, hydroelectric systems, and a variety of other renewables.

Sources: **History (1990):** Energy Information Administration, *Monthly Energy Review* (July 1991). **Projections:** Tables A1, A2, B1, B2, C1, C2, F1, F2, G1, and G2.

Basically, however, energy conservation will continue to play an important role in every case. As a benchmark, the Reference Case shows each dollar of the Nation's total production of goods and services as requiring over 15 percent less energy input per dollar of GDP by the end of the 20-year forecast period. The lower energy intensity results from both improved energy efficiency and structural changes in the U.S. economy that are associated with a shift toward a service economy.

The mix of energy sources that will be required depends on the types of services they will be called upon to provide (for example, space heating, manufacturing, or personal transportation). In every end-use sector except transportation, a pronounced trend toward heavier reliance on electricity is expected to continue. Over the forecast period, total use of electricity goes up by 37 percent—taking market share away from both oil and natural gas as end-use products. The fact that natural gas and—to a lesser extent—oil also serve as primary fuels to generate electricity complicates the overall energy demand picture somewhat—a consideration reflected in other segments of *AEO93*.

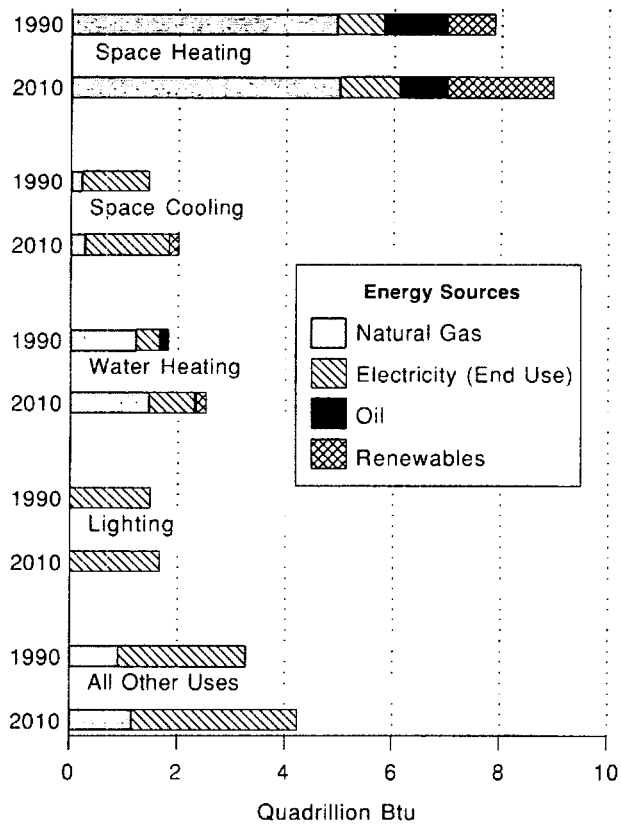
Shifts in the levels and pattern of energy use across fuels will reflect shifts in energy prices, technology change, efficiency standards, government and utility sector programs, and regional growth. This chapter outlines the major trends within each end-use sector and describes how consumption patterns are projected to change over the forecast period.

Buildings Sector

The buildings sector comprises both the residential and commercial sectors. As such, it includes individual houses and apartments, commercial business establishments, and public institutions, as well as all the associated energy-using equipment and appliances. Energy use in this combined buildings sector mainly involves space heating and cooling, water heating, and lighting. Appliances within the buildings range from cooking stoves, refrigerators, and television sets in homes to computers and communications equipment in offices. Energy sources for the buildings sector thus include electricity, natural gas, distillate oil, and various minor fuels. Total consumption of end-use energy in the buildings sector in 1990 was estimated at 16.5 quadrillion Btu, approximately 26 percent of total U.S. end-use energy. If the losses involved in generating and delivering electricity are included, the total consumption of primary energy amounted to 30.0 quadrillion Btu.

In the buildings sector, energy is used for many different applications. Figure 5 represents an estimate of the scope and magnitude of major fuel use within the sector for 1990 and 2010. The comparison indicates where the growth and change is expected to take place. Natural gas is an important source, with its use concentrated in space heating and water heating. Electricity is the predominant source of energy for lighting, cooling, and appliances in general. The use of oil as a fuel in this sector is generally limited to space

Figure 5. Energy End Use in U.S. Residential and Commercial Buildings, 1990 and 2010 (Reference Case)



Sources: Tables A11 and A12.

Natural gas and electricity continue as the primary sources of energy in the buildings sector over the forecast period. Natural gas use is concentrated in space and water heating, while electricity is spread across all end uses and is a major energy source for space cooling, lighting, and other uses.

heating applications, with its use concentrated in the Northeast Census Region, where natural gas use has previously been somewhat restricted by pipeline capacity.

Total energy consumption in buildings will tend to grow in response to the net increase in the stock of buildings, appliances, and equipment for space heating, water heating, and air conditioning. More specifically, the growth in energy consumption is related to the increase in the number of households and in total occupied floor space in commercial buildings, as well as to increased market penetration of energy-using equipment into the buildings sector. The growth in buildings stock depends directly upon the level of macroeconomic activity assumed, while increased market penetration of energy-using equipment depends upon technological development and consumer behavior. The extent to which energy demand per building changes will depend on improvements in the thermal integrity of building shells and equipment efficiency, regional factors, and changes in the level of utilization.

These factors cannot be predicted with certainty, and the range of energy consumption forecasts depends on the pace of building growth assumed and on the choice of more efficient technologies or the use of mandated efficiency standards to achieve certain conservation goals. Certain mandated efficiency standards are included in the Energy Policy Act of 1992. The legislation considers various programs aimed at reducing energy demand in the buildings sector. These programs include window labeling and rating standards, building codes for all new construction, efficiency standards for certain types of equipment, and Federal mortgage funding based on household energy efficiency.[1] All of these programs would cut energy use, but the impact of the Federal legislation would depend on many factors, such as building construction and replacement rates, the success of voluntary standards, the extent to which State and local officials adopt more stringent building codes, and growth in utility-sponsored demand-side management programs. Because many provisions of the legislation affecting the buildings sector are aimed at improving the thermal integrity of building shells, it would follow that the effects of the legislation would be most pronounced on space heating and cooling. In the residential sector projections, for example, the relative importance of the major fuels used for space heating declines over the forecast period as tighter standards and use of dispersed renewables become more widespread.

Space Conditioning in Buildings

The choice of home heating fuel in new construction is a major factor in determining future patterns of energy consumption in the residential sector. In every year since 1985, the share of newly constructed single-family homes using natural gas as the main heating fuel has risen, while electricity's share for space heating has declined, with the distillate share remaining fairly constant. Based on the most recent data (1991), the fuel shares for main heating fuel in new privately owned single-family construction are 60 percent for natural gas, 32 percent for electricity, and 4 percent for distillate.[2] If this pattern continues, the increased use of natural gas over electricity will increase overall end-use (or onsite) energy consumption (although primary energy consumption in the residential sector would decrease). This trend is present in the near term, as natural gas consumption for space heating increases while consumption of electricity remains relatively constant. In the long run, improved energy efficiency (the result of improved thermal integrity and equipment standards) and projected increases in the price of natural gas relative to electricity will check the growth of natural gas consumption for space heating. The projected rise in the consumption of dispersed renewable energy (including wood) in the residential sector also acts to displace consumption of natural gas in space heating.

The type of house or building constructed, as well as the region in which it is built, influences the amount and type of fuel used. For example, if the recent trend of building more single-family houses relative to multi-family dwellings (i.e., apartments) continues, it will increase the amount of energy demanded in the sector. New construction is occurring at a higher rate in the more temperate regions of the country, however, thus reducing the amount of energy required for a given housing type. Over the forecast period, this phenomenon will limit the demand for natural gas because of smaller demand for space heating and increase the demand for electricity attributable to the larger space-cooling requirement. This regional effect is especially true of commercial buildings in which a high percentage of floor space is air conditioned.

[1]For the assumptions made regarding the Energy Policy Act of 1992, see *Assumptions for the Annual Energy Outlook 1993*, forthcoming.
[2]U.S. Bureau of the Census, *Current Construction Reports, Series C25 Characteristics of New Housing: 1991* (U.S. Department of Commerce, Washington, DC, June 1991), p. 20.

Energy Efficiency Improvements

Over the forecast period (to 2010), energy efficiency and operational improvements are expected in home heating and cooling technology. Heat-pump water heaters and condensing furnaces will become mature technologies and realize an increasing market share. With Federal efficiency standards for heating, cooling, water heating, and refrigeration equipment and appliances now issued, all new and replacement purchases of appliances should help to raise the average efficiency level. The Department of Energy is responsible for revisiting these standards within 3 to 10 years. Thus, efficiency levels can be expected to rise in the future; however, the exact level of efficiency that will be specified in any revised standards is uncertain.

Additional improvements in the integrity of building shells will reduce the requirements for both heating and cooling services. Nevertheless, future improvements in energy efficiency may not be as dramatic as improvements of the recent past. A relative lull in energy-price increases during the forecast period (with all fuel prices showing more moderate increases than in 1973 to 1984) reduces the incentive for adopting measures that improve the efficiency of the buildings stock. The levels of improvement that have already been achieved in existing buildings also imply that the rate of penetration of some technologies will decline as market saturation limits are approached. The Energy Policy Act of 1992 should act to cut overall energy demand for space conditioning by requiring tighter building shells, to the extent that its requirements are more strict than State and local building codes.

Historically, fuel consumption in commercial buildings has outpaced that of residential buildings. However, the share of electricity has increased relative to other fuels since 1960 in both residential and commercial buildings. This change is attributable partly to regional shifts in economic activity (with most growth taking place in the South, where air conditioning is now used almost universally) and also to restrictions on the supply of natural gas during the 1970s.

In the various *AEO93* projections, the use of electricity by the buildings sector increases at an annual rate of 1.2 to 1.5 percent—faster than either natural gas or oil use. Electric appliance technology (particularly in computers and communication equipment) continues to penetrate the buildings sector, increasing the overall demand for electricity. Electricity's market share decreases slightly for space heating in the residential sector, as the combination of efficiency gains in building shells, upgraded building codes, utility-sponsored demand-side management programs, and the use of renewable energy sources reduces the demand for space heating in general. In the commercial sector, natural gas cooling technologies have made inroads into a service that electricity has historically dominated. Furthermore, floor space grows most rapidly in regions that already have a high intensity of electricity use.

In contrast, the level of natural gas use changes little over the forecast period because the higher number of gas appliances is offset by their increased efficiency and by continued improvements in thermal shell integrity. Oil use in both residential and commercial buildings continues to decline as natural gas service becomes more available to customers in the Northeast.

Over time, space conditioning comes to represent a more significant share of electricity use in buildings, as commercial floor space continues its use of electric heating systems (especially in the South and West). Lighting increases in terms of absolute usage, but drops from 40 percent of all electricity consumption in the commercial sector to 33 percent by 2010 as various types of electrical and electronic equipment (such as electronic ballasts, occupancy sensors, and automatic dimming controls) are employed more extensively. Cooling, which relies primarily on electricity in new units, continues to penetrate the household market and is found in up to 95 percent of all residential units in the South Census Region by the end of the forecast period. Existing utility-sponsored demand-side management programs are expected to continue to promote conservation in the buildings sector. Natural gas cooling technologies are expected to have a negligible impact in the residential sector, but are expected to continue to penetrate the commercial sector. At the national level, more natural gas will be consumed for heating than is now the case, as that fuel gains compared with oil. Natural gas is seen as losing part of its share in the overall space-heating market, however, as renewable energy sources become more significant in the long run and as natural gas prices rise relative to electricity prices.

The High (Low) Economic Growth Case shows the combined effects of higher (lower) personal incomes, and a higher (lower) rate of new construction. Relative to the Low Economic Growth Case, the High Economic Growth Case contains 7.9 percent more households in 2010 and 5.3 percent more commercial square footage, leading to an increase in end-use consumption of 0.7 quadrillion Btu.

Industrial Sector Consumption

The U.S. industrial sector consists of both manufacturing and nonmanufacturing industries. The 1987 Standard Industrial Classification (SIC) system, developed by the Office of Management and Budget, underlies all establishment-based Federal statistics classified by industry. The SIC system is a hierarchical classification, each level of which contains increasingly homogeneous categories of industrial activity. The manufacturing sector includes all industries classified under SIC codes 20 through 39, and the nonmanufacturing sector includes agriculture, mining, and construction. In 1990, the industrial sector consumed 24.8 quadrillion Btu, 38 percent of total U.S. end-use energy consumption. More than 80 percent of total industrial energy is consumed in the manufacturing sector, with chemicals (SIC 28), petroleum (SIC 29), paper (SIC 26), primary metals (SIC 33), stone, clay, glass (SIC 32), and food (SIC 20) being the largest energy-consuming manufacturing industries.

Industrial energy use comprises three elements: energy for industrial processes, for buildings, and for boilers and electricity generation. Consumption of energy for industrial processes includes, for example, electricity for motor drives and electrolytic processes, steam for drying, natural gas for furnaces, diesel fuel for farm vehicles, and liquefied petroleum gases for feedstocks use. Electricity and natural gas are consumed in plants and building facilities for lighting and for space heating, ventilation, and air conditioning. Steam is produced from boilers and cogeneration facilities. The major fuels used for steam and electricity generation are coal, natural gas, fuel oil, and biomass (including byproducts).

Energy Sources

Natural gas and petroleum are the dominant energy sources in the industrial sector. In 1990, natural gas and petroleum consumption were 8.5 quadrillion and 8.3 quadrillion Btu, respectively. After peaking at 10.5 quadrillion Btu in 1973, consumption of natural gas began a downward trend that did not begin to reverse itself until 1987. The decline in consumption resulted from rising prices and uncertainty about supply along with a recessionary period in the early 1980s and a general decline in much manufacturing that used natural gas more intensely. Petroleum consumption peaked in 1979 at 10.6 quadrillion Btu, generally declined until 1985, and has remained fairly level since then. Petroleum consumption responds to changes in petroleum product prices when substitutes are available and to changing uses of petroleum products. Most petroleum consumption in industry is in byproducts (still gas and petroleum coke, for example) and in feedstocks, however, which are less responsive to overall price changes and more related to activity in specific industries. Electricity consumption in 1990 was 3.2 quadrillion Btu. Electricity use by the industrial sector has steadily increased from the 1960s to the present, following U.S. industrial production. Coal consumption (2.8 quadrillion Btu in 1990) has, however, been decreasing since the mid-1960s. In 1990, renewables consumption was 2.1 quadrillion Btu. Renewable fuels consumed in the industrial sector consist mainly of wood, spent liquor (a major byproduct of the chemical pulping process in the paper industry), and municipal solid waste. Consumption of renewables has been increasing since the 1960s, largely as a result of greater use of chemical pulping in the paper industry.

From 1960 to 1990, industrial energy consumption generally increased at a slower rate than the value of output in industry. This decrease in energy intensity was reversed temporarily in two strong growth periods, for a couple of years around 1970 and between 1985 and 1990. This long-term movement toward higher energy efficiency can be attributed to several factors. The structural change toward less energy-intensive industries (e.g., electronics and pharmaceuticals) and the decreasing role of high energy-intensive industries (e.g., iron and steel and basic chemicals) in U.S. industrial production have resulted in significant reduction in overall energy intensity. The rise in imports of energy-intensive products has also contributed to the rise of overall energy efficiency in the industrial sector. Technological breakthroughs in various industrial processes (e.g., continuous casting in the steel industry) have also resulted in considerable energy conservation. The increasing use of recyclable materials has been and will continue to be an important factor in the decline of energy intensity for some industries. The manufacture of recycled products such as paper, aluminum, steel, glass, and plastic requires significantly less energy than the manufacture of products from the original raw materials.

Cogeneration in the industrial sector, or the production of both electricity and steam in the same process (from a single energy source), has been increasing in the past few years. According to the Energy Information Administration's (EIA's) 1988 Manufacturing Energy Consumption Survey (MECS), total onsite electricity generation was about 115 billion kilowatthours. Net electricity demand by manufacturers exceeded 819 billion kilowatthours in 1988. Cogenerating systems are an effective means of increasing the efficiency of fuel use. Cogeneration is a significant activity in some

industries, particularly the paper, chemical, and primary metals industries. Electricity generated onsite by industrial establishments is usually consumed in the plant itself, although a small amount of generated electricity is also sold to utilities.

Energy Legislation

The Energy Policy Act of 1992 includes several provisions that affect energy consumption in the U.S. industrial sector, the most important of which are the minimum efficiency standards established for several specific types of industrial equipment such as lighting, boilers, and motors. Approximately 80 percent of motors and 70 percent of lighting are affected by the legislation. Several research and development programs to increase energy efficiency for energy-intensive industries are also identified, but funds have not yet been appropriated.

Energy-Intensive Industries

The chemical, paper, primary metals, and petroleum refinery industries account for 70 percent of total U.S. industrial sector energy consumption. These industries have distinct energy consumption patterns.

The chemical industry consists of diverse products with varied energy consumption (and production) activities. This industry consumes substantial amounts of energy for heat and power, and for feedstocks. This industry cogenerates a large amount of steam and electricity, and is also capable of capturing waste heat from chemical reactions that can then be used for heat and power. Recycling, which is a major activity in this sector, generally involves regenerating various chemicals and processing post-consumer plastic products.

The paper industry is one of the larger consumers of energy for heat and power, but its use of energy feedstocks is minimal. Aside from being a major consumer of energy, this industry consumes the most renewables (in the form of wood and spent liquor), cogenerates the most electricity, and is a major product recycler. The consumption of renewables and cogeneration of electricity in this industry are related to the amount of spent liquor and wood wastes that are recovered in the pulping processes.

The primary metals industry includes iron and steel, aluminum, and other metals manufacturing and processing. The majority of energy consumption in this industry is consumed in blast furnaces and steel mills and in aluminum smelters. The major fuel used for steel production is metallurgical coal, which is used as a feedstock to produce coke. Electricity is also an important energy source and is used primarily in aluminum smelters and electric arc furnaces. Increased recycling activity in this industry has resulted in significant energy savings.

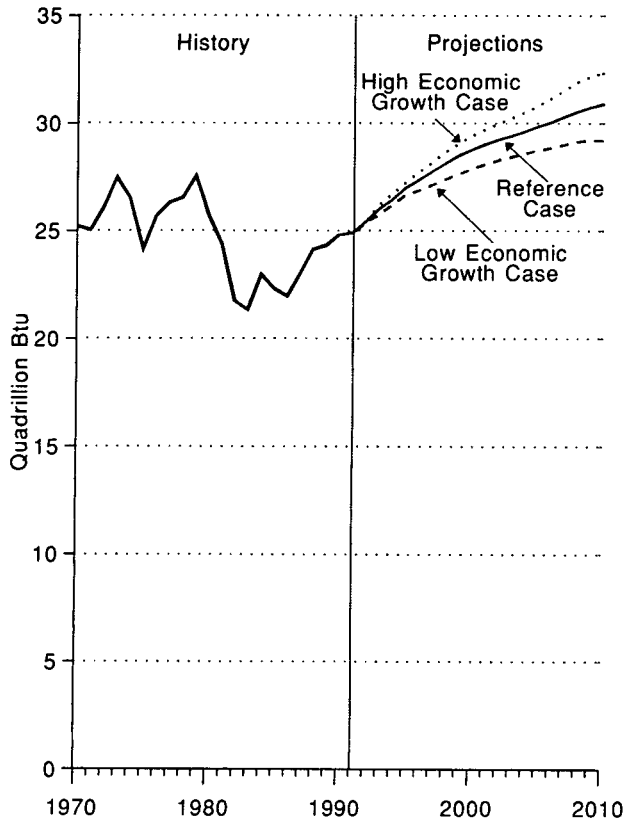
The major fuels used in petroleum refineries are still gas and petroleum coke, which are byproducts of refining processes. Natural gas is the largest source of purchased fuel, and is used for process heating and steam generation. Substantial growth in electricity consumption in this industry is attributable to the growing importance of downstream processes to meet the demand for light products.

Energy Use Patterns

Total energy consumption in the industrial sector in 2010 is projected to range between 29 quadrillion and 32 quadrillion Btu, depending on the various assumptions in different cases (Figures 6 and 7). The average annual growth rates of industrial energy use range from 0.8 to 1.3 percent in the Low and High Economic Growth Cases, respectively; these are considerably lower than the gross domestic product growth rates (1.6 to 2.4 percent). Thus, overall energy intensity in the industrial sector will continue to decline. The trend is motivated by various factors including the continued change in the composition of industrial production (energy-intensive industries will continue to grow at a slower pace than the less intensive ones), better capacity utilization patterns, and the use of more efficient equipment attributable to rising prices and established mandatory and voluntary efficiency standards.

Electricity purchased from utilities accounted for 13 percent of total energy in the industrial sector in 1990 (Figure 8). The common applications of electricity are motor drives, lighting, and electrolytic processes. Many electrotechnologies are preferred for producing higher quality products, lower air pollutant emissions, more precise controllability, and higher temperature requirements. For *AEO93*, electricity consumption in the industrial sector is projected to grow at a rate of 1.5 (Low Economic Growth Case) to 2.5 (High Economic Growth Case) percent to 2010. The expanding role of the high value industries contributes to this growth, as these industries are generally more electricity intensive. The continued penetration of electrotechnologies also supports this growth. The steel industry, for example, has experienced significant growth in the use of electric arc furnaces. Other new technologies that have and will

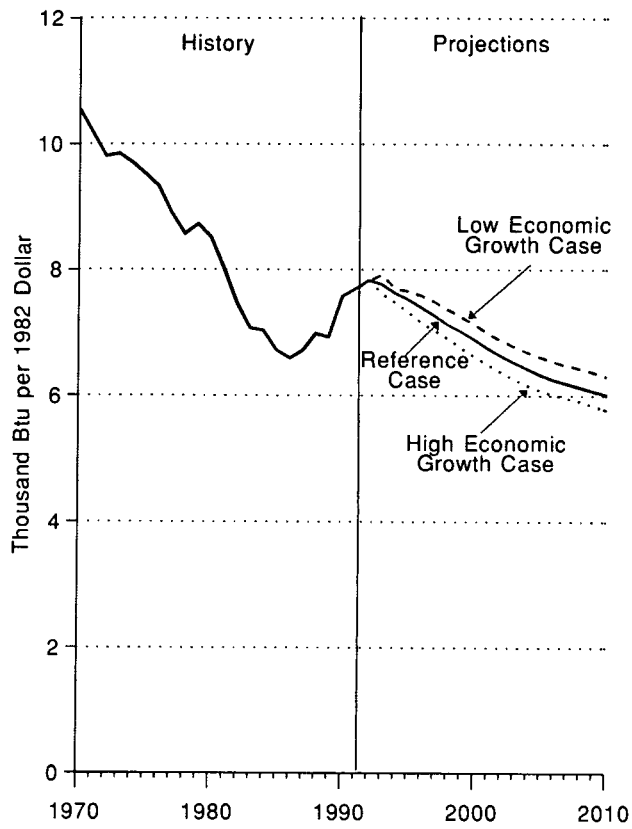
Figure 6. U.S. Industrial Energy Consumption, 1970-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1990* (May 1992). **Projections:** Tables A2, B2, and C2.

U.S. industrial energy consumption ranges from 29 quadrillion Btu to 32 quadrillion Btu, from the Low Economic Growth Case across the Reference Case to the High Economic Growth Case, in 2010.

Figure 7. U.S. Industrial Energy Intensity, 1970-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1990* (May 1992). **Projections:** Tables A13, B13, and C13.

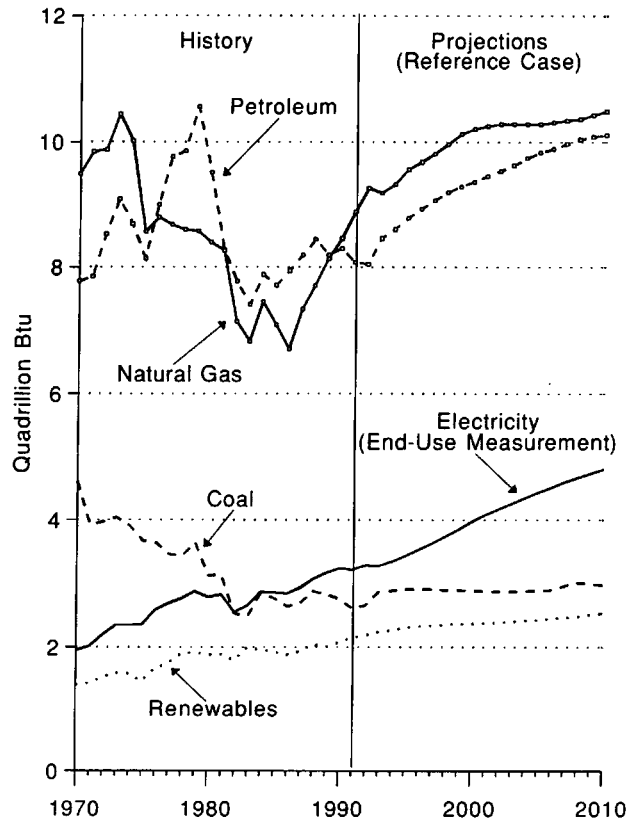
U.S. industrial energy intensity shows a sharp decline from 1970 through the mid-1980s, and, after a brief rise, a continued decline in all scenarios from the early 1990s to 2010.

continue to spur electricity consumption include infrared heating, lasers, microwaves, and computer applications.

The forecast for natural gas consumption is for modest growth (0.9- to 1.3-percent growth rates in the Low and High Economic Growth Cases, respectively), reacting mainly to industrial output growth but at a lesser rate because of higher natural gas prices. Natural gas is used for a variety of industrial operations. It is widely used for boilers, furnaces, process heating, space heating, cogeneration, and as feedstocks. Natural gas has maintained its place as the major energy source for the industrial sector. Gas is commonly associated with dual-fired technology such as boilers and furnaces, so that a relative change in prices or efficiency between natural gas and the other competing fuel (usually oil and coal) can easily increase or decrease its level of consumption. The demand for natural gas for feedstocks use depends on the demand for petrochemicals in the industrial sector and fertilizers in the agriculture sector.

A wide variety of petroleum products find many applications in the industrial sector, and overall petroleum consumption represents about one-third of total U.S. industrial energy consumption. Most industrial petroleum consumption consists of feedstocks and byproducts (still gas and petroleum coke). Consumption based on these end-uses is sensitive to the economic activity of industries involved. Still gas and petroleum coke are usually used for heat and

Figure 8. U.S. Industrial Energy Consumption by Energy Source, 1970-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1990* (May 1992). **Projections:** Table A2.

Significant fluctuations occur in U.S. industrial consumption, by energy source, from 1970 to 1990. After 1990, electricity, natural gas, and petroleum show steady increases.

power at refineries, although a small amount of petroleum coke is also used as a raw material to manufacture electric anodes used in the primary metals industry. Residual fuel oil is commonly used in boilers, but small amounts of liquefied petroleum gas and distillate oil are also consumed. Consumption of residual oil is relatively sensitive to oil and natural gas prices because some boilers can switch between oil and gas. Diesel fuel is the standard fuel used in farm vehicles. The construction industry uses road oil and asphalt for paving and roofing.

Petroleum consumption in the industrial sector is projected to increase at an annual rate of 0.9 percent (in the Reference Case) from 1990 to 2010. Consumption of petroleum is sensitive not only to overall economic output and to oil prices but also to the strength of the chemical industry, which consumes most of the petroleum feedstocks.

Industrial coal consumption is forecasted to grow slowly at an annual rate of 0.4 percent (Reference Case). Coal has two major uses: as boiler fuel (steam coal) and as feedstock to produce coke (metallurgical coal). Coal use for direct process heating is minimal (about 12 percent of total coal consumption) except for the cement industry, which uses it as a major kiln fuel. The demand for steam coal in the future depends on coal prices and also on new technologies that are able to reduce air pollutants from coal combustion. The consumption of metallurgical coal will continue to fall because of the increasing use of recycled scrap and the retirement of coking plants in response to environmental regulations.

Uncertainties

This energy consumption outlook for the U.S. industrial sector is premised on assumptions about factors that are themselves highly uncertain. Some of these factors include:

- The enactment of the Energy Policy Act of 1992 and its impact upon energy efficiency through funding for research and development, voluntary industry-wide efficiency standards, and efficiency standards on specific equipment.
- The impact of utility sponsored demand-side management or integrated resource planning programs.
- Possible environmental or regulatory changes pursuant to the Clean Air Act Amendments of 1990 (currently not mandatory) that could significantly change the mix of fuel uses.
- The future growth rates and growth paths of industry, which are complex matters sensitive to such macroeconomic considerations as sectoral growth, the savings rate, the role of international competition, and structural or compositional change in industrial demand and in industrial production.
- The future growth rates and growth paths of energy prices and their effects on energy consumption through overall reductions and demand changes and through the future availability of substitutes.
- The impact of technological change on industrial production processes.

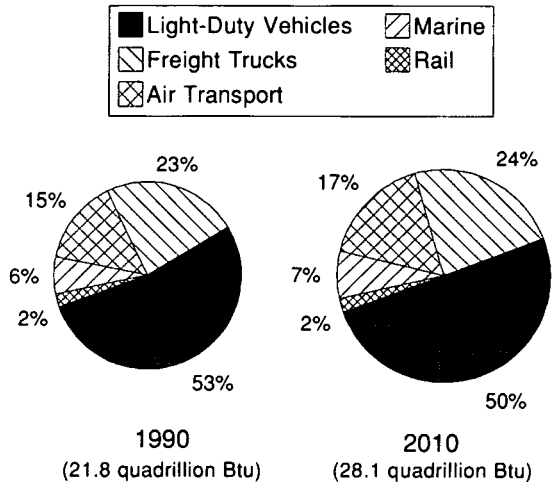
Transportation Sector

The transportation sector depends almost completely on petroleum as an energy source. This sector's share of total petroleum consumption has increased sharply over the past decade as other end-use sectors have switched from petroleum to natural gas and electricity. In the Reference Case, the transportation sector accounts for about two-thirds of total domestic oil consumption throughout the forecast period. Oil consumption in this sector increases by 27 percent above 1992 levels, reaching 13.9 million barrels per day in 2010. The transportation sector already consumes more oil than the United States produces domestically. By 2010, depending upon which oil price case is considered, the United States could be consuming between 39 and 137 percent more petroleum for transportation than is expected to be produced domestically. About one-third of carbon emissions (in the form of carbon dioxide and carbon monoxide) stems from energy consumption in the transportation sector in the Reference Case. Implications of the growth in emissions of such greenhouse gases are a major long-range policy concern.

The major sources of transportation energy are motor gasoline for light-duty vehicles (automobiles and light trucks), diesel and motor gasoline for freight trucks, jet fuel and aviation gasoline in aircraft, the diesel and electricity used by trains, and the diesel and residual oil that fuels domestic and international ships. Natural gas is commonly used to operate pipeline pumps and is included as transportation energy use in EIA statistical reports. More than half of all transportation energy in 1990 was consumed by light-duty vehicles. Freight trucks used about one-fourth and air transport accounted for most of the rest (Figure 9). Over the forecast, highway and air transportation are expected to account for most of the increase in transportation energy use; the level of oil consumption varies significantly, however, with energy price and economic growth assumptions. Alternative energy price assumptions employed in the Low and High World Oil Price Cases and alternative economic growth assumptions considered in the Low and High Economic Growth Cases help to quantify the range of uncertainty in the forecast.

Recently enacted legislation, including the Clean Air Act Amendments of 1990 (CAAA90) and the Energy Policy Act of 1992, may significantly alter future trends in the level and mix of fuels used in the transportation sector. Both environmental and energy legislation have focused on reducing oil use in the transportation sector.

Figure 9. Energy Use in U.S. Transportation, 1990 and 2010



Note: This excludes natural gas used to operate pipeline pumps.

Source: Table A14.

Light-duty vehicles consumed more than half (53 percent) of all transportation energy in 1990, a percentage that drops only slightly (to 50 percent) in 2010 in the Reference Case.

These efforts have included regulations that require reduced emissions from conventional vehicles and programs to hasten the market introduction of alternative-fuel vehicles.

Variables in Transportation Energy Consumption

Prior to the sharp increase in world oil prices during the 1970s, little attention had been paid to the availability or price of energy. Vehicle performance and comfort improved while transportation fuel efficiency declined (by nearly 10 percent between 1950 and 1970). In sharp contrast, between 1970 and 1990, on-the-road passenger car fuel efficiency increased by 55 percent. Total passenger car fuel consumption in 1990 was only 7 percent higher than the level in 1970, in spite of a 65-percent increase in travel. Greater fuel efficiency in automobiles was accomplished by putting lighter (often smaller), more technically advanced vehicles on the road. Multi-port fuel injection and four-speed automatic transmissions, once considered advanced technologies, are now commonplace, and the use of plastics and lighter weight metal alloys have improved the fuel efficiency of virtually all automobiles sold today.

Energy Prices

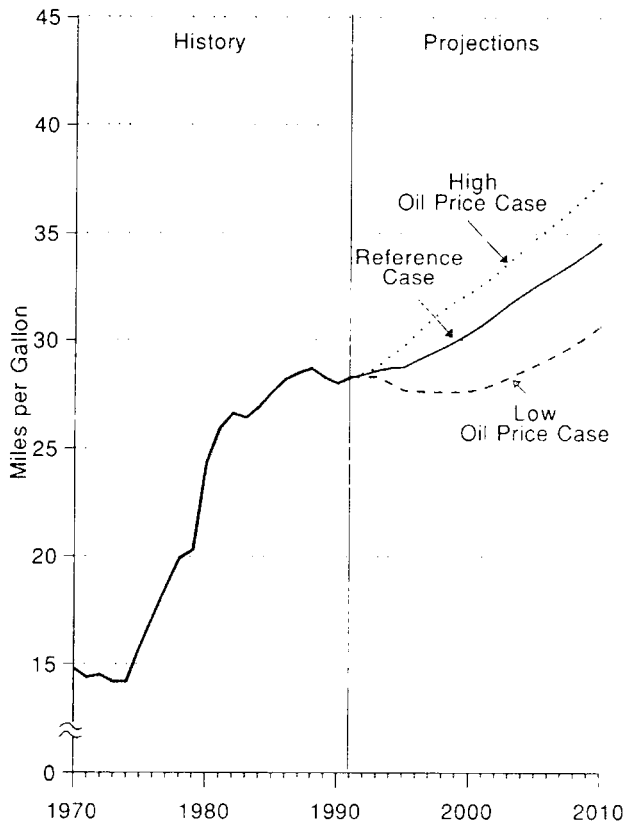
Many factors help explain the types of passenger vehicles purchased in the marketplace. All other things being equal, higher motor gasoline prices are expected to result in increased market interest in smaller, more fuel-efficient vehicles. Domestically, sharp increases in gasoline prices during the 1970s and early 1980s raised the vehicle characteristic, "fuel efficiency," to a previously unknown level of importance to automobile buyers. Initially, this demand for fuel efficiency was an important reason for the substantial increase in import vehicle sales. Automobile manufacturers in countries that had faced high gasoline prices (because of higher taxes) for many years had experience in producing smaller, more fuel-efficient cars. Over time, domestic manufacturers have downsized their vehicles, substituted lighter materials, and introduced new technologies to meet the demand for fuel-efficient cars. In addition, the line between domestic and import cars has become blurred. Many domestic manufacturers rely on engines and other components produced by foreign manufacturers, particularly in their small cars.

Corporate Average Fuel Economy (CAFE) standards, initiated in 1978, required automobile manufacturers to improve substantially the overall fuel economy of the fleet of vehicles they sold. CAFE standards for model year 1978 were set at 18.0 miles per gallon. By 1985, manufacturers had to achieve an average of 27.5 miles per gallon or face financial penalties. Combined, higher energy prices and fuel economy regulations have had a substantial influence on the automobile market. In recent years, automobile fuel economy has declined slightly in the face of stable real gasoline prices. Across all manufacturers, however, the CAFE standards are still being met.

In the forecast, energy prices influence the total level of oil consumption directly by affecting both the cost of travel and average vehicle fuel efficiency and indirectly by impacting the level of economic activity. Total transportation-sector energy consumption in 2010 is 1.7 million barrels (10 percent) lower per day in the High World Oil Price Case than in the Low World Oil Price Case. Variation in motor gasoline consumption in automobiles and light trucks account for most of this price sensitivity because the light-duty vehicle stock turns over far more rapidly than does the stock of vehicles in other modes of travel.

Historically, consumers have responded to gasoline price changes to a certain extent by altering their travel patterns and by placing a different level of emphasis on fuel efficiency attributes at the time of purchase of light-duty vehicles (Figure 10). The short-run response to a higher fuel cost per mile is limited, however, because manufacturers' production plans and consumers' travel behavior take time to adjust. Short-run responses to rising fuel cost will be further limited by the slow turnover of the vehicle stock. Comparing the Low with the High World Oil Price Case, light-duty vehicle travel declines by about 3 percent while the fuel cost of driving a mile increases by about 18 percent. Projections of new car fuel efficiency reflect net savings that consumers can realize if specific fuel efficiency improving technologies are introduced. New car fuel

Figure 10. New Car Fuel Efficiency in the United States, 1970-2010



Sources: **History:** *1970-1975*—U.S. Environmental Protection Agency, SAE Paper 840499 (March 1984); *1976-1990*—U.S. Department of Transportation, *Summary of Fuel Economy Performance* (February 1990). **Projections:** Tables A14, D14, and E14.

New car fuel efficiency in the United States almost doubled between 1973 and 1990 in response to the combined influences of oil price shocks and Federal regulations. Projections in the Reference and High World Oil Price Cases show a continued steady rise out to 2010. In the Low World Oil Price Case, little improvement in new car fuel efficiency is expected.

efficiency increases by nearly one-third between 1992 and 2010 in the High World Oil Price Case, reaching 37.4 miles per gallon. In the Low World Oil Price Case, new car fuel efficiency actually declines from current levels through 2000 in response to projected lower motor gasoline prices. By 2010, new car fuel efficiency in this case is 30.7 miles per gallon, 18 percent lower than in the High World Oil Price Case.

The demand for air transport is also sensitive to jet fuel prices. Fuel costs represent a significant component of the operating costs of airlines, and these costs are reflected in airline ticket prices. In the High World Oil Price Case, commercial air travel is almost 10 percent lower than in the Low World Oil Price Case. Continued technological advances in aircraft and engine design have improved aircraft efficiency. To the extent that higher jet fuel prices induce earlier and more widespread introduction of more fuel-efficient, high-technology engines, improved in-flight operations, and increased substitution of lighter materials in newer aircraft, the spread in jet fuel consumption forecasts between the Low and High World Oil Price Cases will be greater.

Economic Activity

Higher levels of economic activity have historically been associated with greater requirements for transportation services. The Low and High Economic Growth Cases examine how economic growth directly influences transportation energy-use projections. Transportation sector oil use in the High Economic Growth Case is 2 million barrels (15 percent) higher per day than in the Low Case and the level of GDP is 17 percent higher. More subtle influences of economic growth, such as the availability of funds for research and development, although not considered in the projections, would expand the gap between the High and Low Economic Growth Cases.

Travel by freight vehicles (trucks, rail, and ships) closely follows trends in economic activity (particularly industrial output). In the High Economic Growth Case, for example, the value of industrial output in 2010 is 20 percent higher than in the Low Economic Growth Case. Freight truck travel is 20 percent higher, while freight rail travel is 13 percent higher.

About 15 percent of the transportation sector's oil consumption in 1990 fueled aircraft. This share is expected to increase in all cases considered in this report. In recent years, air travel has grown substantially faster than the rate of economic growth, and the forecast of jet air travel and fuel consumption reflects this historical trend. In the High Economic Growth Case, travel by aircraft is 40 percent higher in 2010 than in the Low Economic Growth Case, increasing sectoral oil consumption by about 700,000 barrels per day.

For the economic and population growth rates assumed by the Low and High Economic Growth Cases, highway travel by light-duty vehicles is forecast to increase at an average annual rate of between 1.5 and 2.0 percent per year between 1990 and 2010. In 2010, comparing the High with the Low Economic Growth Case, light-duty vehicles are projected to travel 9.6 percent more vehicle-miles, consuming an additional 8.4 percent in motor fuels. Average light-duty vehicle fuel efficiency in the High Economic Growth case is about 1 percent higher than in the Low Case, based on significantly higher expected sales of more fuel-efficient light-duty vehicles.

Legislation

In meeting CAFE standards, auto manufacturers can earn credits under the Alternative Motor Fuels Act of 1988 if they build cars that save petroleum by using non-petroleum-based alternative fuels. The current CAFE standard of 27.5 miles per gallon is, however, lower than the fuel efficiency that domestic manufacturers, on average, have already achieved without using such credits. As a result, *AEO93* does not assume that these credits, by themselves, will bring any additional alternative-fuel vehicles into the U.S. fleet. If future Federal regulations should require additional improvements in light-duty vehicle fuel economy, this action would promote additional reliance on alternative-fuel vehicles.

CAAA90 require a phased reduction in vehicle emissions of regulated pollutants. These reductions can technically be accomplished using many combinations of fuel and hardware. The recent advent of cleaner burning reformulated gasolines, however, makes it most likely that these gasolines, in conjunction with relatively inexpensive additional equipment on conventional vehicles, will be used to achieve the required emissions reductions. Informal analysis indicates that only in the High World Oil Price Case can it be assumed that alternative-fuel vehicles become a cost-effective way of achieving the most stringent emissions reductions.

CAAA90 also established a clean-fuel pilot program in California with substantially tighter emissions standards than the national standards. Other States may choose the California program. Many States are actively

considering this alternative. New York and Massachusetts are furthest along in this process and are the only States, along with California, that are assumed to adopt the program in *AEO93*. Combined, these three States accounted for nearly one-fifth of all registered light-duty vehicles in 1990. One particularly interesting facet of the California program is its requirement that, beginning in 1998, manufacturers must sell "zero-emission" (electric) vehicles. By 2003, 10 percent of vehicle sales in States adopting the California program must be zero-emission vehicles.

The Energy Policy Act of 1992 promotes the use of alternative-fuel vehicles by requiring their phased-in use in certain classes of public and private fleet vehicles (Federal, State, and local government vehicles, utility company vehicles, and private business fleet vehicles) that are capable of being centrally fueled. In *AEO93*, these programs displace more than 120,000 barrels of oil per day by 2010.[3] In addition to saving oil, these programs are designed to accumulate experience in producing and maintaining alternative-fuel vehicles and provide on-the-road demonstrations that these vehicles are both reliable and cost effective.

Dispersed Renewable Energy

Renewable energy is developed from sources that are naturally replenished and generally do not have associated fuel costs. "Dispersed" renewable energy refers to energy sources available at the point of consumption; a rooftop solar collector that heats a home is an example. (An exception is alcohol fuels for transportation.) These end-use applications tend to be small, and end users typically own the energy-producing equipment. Dispersed renewable energy excludes electricity generation that is available to the grid.

The dispersed renewable sources examined and projected for this analysis are biomass (wood and municipal solid waste (MSW)), solar, geothermal heat pumps, and crops for ethanol production. Additional dispersed renewables, because of their complexity, minimal penetration, or special characteristics, are not explicitly included in the projections. These include solar thermal industrial uses, dispersed wind generation, direct heat uses of geothermal energy, and dispersed photovoltaics. Table 4 provides historical dispersed renewable consumption/displacement data

Table 4. Dispersed Renewable Energy Projections for 2010

(Quadrillion Btu)

Source	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High World Oil Price	Low World Oil Price
Biomass[a]	2.58	3.54	3.63	3.28	3.70	3.43
Solar[b]	0.05	0.43	0.43	0.43	0.43	0.43
Geothermal[c]	0.01	0.41	0.41	0.41	0.41	0.41
Crops to Ethanol[d]	0.06	0.24	0.24	0.24	0.24	0.24
Total	**2.70**	**4.62**	**4.71**	**4.36**	**4.78**	**4.51**

[a]Includes wood and wood wastes and municipal solid waste.
[b]Includes space heating and cooling, hot-water heating, and daylighting.
[c]Ground-source heat pumps.
[d]Primarily corn; woody crops have potential for later years.

Note: Forecasts of dispersed renewable energy for the High and Low Oil and Gas Recovery Cases are the same as for the Reference Case. Forecasts exclude solar thermal industrial uses, dispersed wind generation, direct heat uses of geothermal energy, and dispersed photovoltaics.

Sources: **1990:** Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. **Projections:** Tables A6, B6, C6, D6, and E6.

[3]U.S. Department of Energy, Office of Domestic and International Energy Policy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Ten: Analysis of Alternative-Fuel Fleet Requirements* (May 1992).

for 1990, and projections for 2010, yielding an average annual growth of 2.7 percent in the Reference Case.

Biomass includes wood in the industrial sector and heating in the residential and commercial sectors. The primary industries using wood for energy are the paper and pulp and lumber industries. Growth in wood use in the industrial sector is a function of demand for wood-based products. These industries are projected to grow steadily over the forecast horizon. Wood in the residential sector is affected by changes in housing stock and, to some degree, by fossil fuel and electricity prices. Biomass also includes the use of heat from combustion of MSW by the industrial and commercial sectors. This is a small part of MSW use, as most of it is used for electricity generation. Because MSW is primarily a waste disposal method with energy as a byproduct, no price impacts result.

Geothermal projections are limited to ground-source heat pumps and do not include direct heat applications, which are expected to be small. Geothermal heat pumps include a buried heat exchanger to permit the extraction of ground heat, resulting in a very efficient use of electricity for space heating. Geothermal heat pumps will become more common as the housing stock grows, and as they become an economically attractive substitute for fossil fuel heating.

Solar consumption forecasts represent energy for active water heating, space heating, and space cooling as well as passive space heating for both residential and commercial uses. Also, commercial daylighting[4] is included as a solar use. Solar energy market penetration is quite complex, involving such considerations as homeowner acceptance, utility pricing policies, and tax credits. The solar contribution increases slightly more than 10 percent per year through 2010.

Ethanol (primarily from corn) has potential for increasing use as a transportation fuel. This analysis assumes that all of the increase will be for gasoline blending. An important new influence is the passage of the CAAA90, which make the low emissions from use of ethanol-blended fuels attractive. The CAAA90 place specific requirements upon certain cities and regions of the country, and ethanol is expected to fulfill a portion of that demand. The Energy Policy Act of 1992 extends the current 5.4 cents per gallon exemption on the Federal excise tax on 10-percent ethanol blends with gasoline and provides an income tax deduction for the purchase of an alternative-fuel vehicle.

As shown in Table 4, biomass is the only dispersed renewable demonstrating variability in the Low and High Economic Growth Cases and the Low and High World Oil Price Cases. The wood component of biomass varies directly with industrial activity, which is in turn a function of economic growth and world oil prices. The MSW component of biomass changes only with economic growth, because more activity results in a larger waste stream for partial combustion. Conversely, lower economic growth yields less energy from a smaller waste stream.

Summary

In each end-use consumption sector, a continuing emphasis on energy efficiency and the introduction of new technology will affect energy consumption levels and the pattern of fuel use. The process of change will be gradual, however, given the relatively slow process of capital stock replacement. Electricity will gain an increasing share of end-use energy consumption, while overall efficiency of use will continue to improve. As a result of continued technological progress, government programs, and environmental considerations, renewable energy sources can be expected to continue to penetrate the various sectoral markets.

Oil and gas are the principal sources of energy in the United States. Chapter 3 examines the outlook for oil and gas.

[4]Systems that permit the use of sunlight to provide an enhanced portion of lighting needs. Examples are skylights, specialized glazings, and reflectors.

3. Oil and Gas Outlook

Domestic oil and gas exploration and production patterns in the United States have traditionally been sensitive to the market price of oil and gas and to price expectations based on expected future supply and demand relationships. Future supply depends heavily on the highly uncertain factors such as geologic distribution and volumes of the remaining economically recoverable domestic resources.

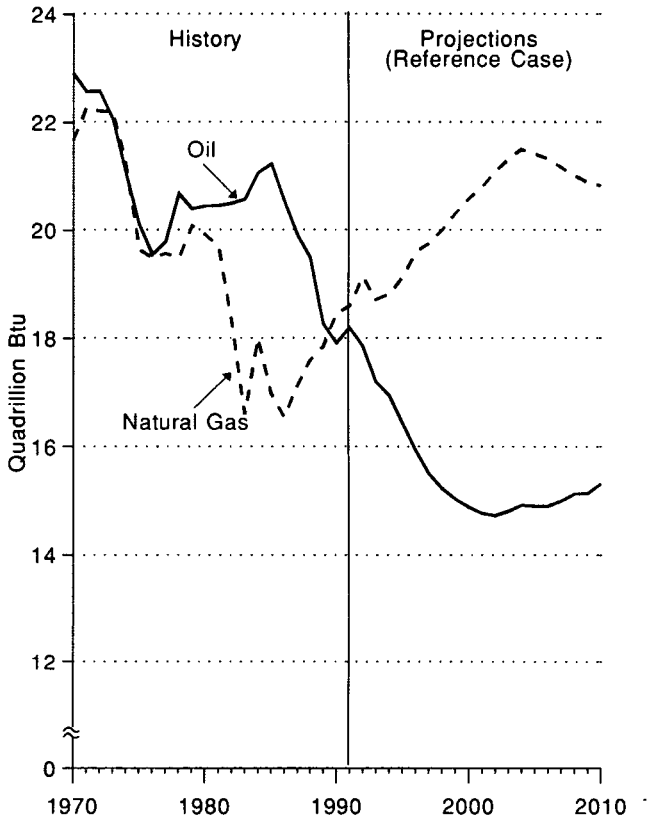
The mean domestic, undiscovered, economically recoverable conventional resource base most recently estimated by the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) is significantly less on a British thermal unit (Btu) basis for oil than for gas. The domestic oil industry is more mature than the gas industry, and many in the oil industry believe that no large oil fields remain to be discovered in the Lower 48 States. Oil reserve additions have been declining, and an overall decline of crude oil production in the Lower 48 States with some significant interruptions has occurred over the two decades. This trend is indicative of a general depletion of the Lower 48 oil resource base.

Over the past two decades, production of both oil and gas have generally declined, starting with roughly equivalent Btu production in the 1970s (Figure 11). A rough indication of the sensitivity of domestic oil and gas drilling activity to the market price is the number of rotary rigs in operation (Table 5). The rig count reached its peak in the United States in 1981 (3,970 active rotary rigs) when the domestic oil price reached its peak of $50.90 per barrel (in 1991 dollars).

Crude oil and petroleum products are easily and relatively cheaply transported in the international market. In 1991, net U.S. petroleum imports of 6.6 million barrels per day, although well below the historical peak of 8.6 million barrels per day in 1977, are more than double the 3.2 million barrels per day recorded in 1970. Integration of the United States into the world oil market has resulted in the domestic market price of oil being determined in the international oil market. Consequently, U.S. domestic investments in oil exploration and development and future patterns of domestic oil production will be determined by the oil price in the global economy and other investment opportunities.

Unlike oil, natural gas cannot be transported readily from outside North America to the United States. Because of high transportation and delivery costs, including terminal, refrigeration, and storage requirements, the gas that is transported as liquefied natural

Figure 11. Domestic Oil and Gas Production, 1970-2010



Note: Oil production includes lease condensate and natural gas plant liquids; gas production includes associated and dissolved gas.

Sources: **History:** *1970-1989*—Energy Information Administration, *Annual Energy Review 1991*; *1990-1991*—See source notes for Table A1. **Projections:** Reference Case, Table A1.

Domestic oil and gas production generally declined from 1970 to 1990, although gas production began to increase in the mid-1980s. Production trends diverge through 2010.

Table 5. Rotary Rigs in Operation and Domestic Crude Oil Price, 1970 to 1991

Year	Active Rotary Rigs	Domestic Oil Price
1970	1,028	11.54
1971	976	11.61
1972	1,107	11.07
1973	1,194	11.82
1974	1,472	18.71
1975	1,660	19.95
1976	1,658	19.77
1977	2,001	19.98
1978	2,259	20.59
1979	2,177	25.49
1980	2,909	39.53
1981	3,970	50.91
1982	3,105	43.59
1983	2,232	38.74
1984	2,428	36.68
1985	1,980	33.04
1986	964	17.89
1987	936	20.78
1988	936	16.60
1989	869	19.29
1990	1,010	23.41
1991	860	19.33

Note: The "Domestic Oil Price" is the crude oil refiner acquisition cost for domestic crude oil (1991 dollars per barrel).

Sources: **Rotary Rigs in Operation:** Hughes Tool Company, *Rotary Rigs Running—By State*, as published in Energy Information Administration, *Annual Energy Review 1991*. **Domestic Oil Price:** Derived from Table 71, "Crude Oil Refiner Acquisition Costs, 1968-1991," *ibid.*

gas (LNG) on the international markets typically has had difficulty competing for customers in the United States. Consequently, imported LNG is expected to have a limited role in traditional U.S. energy markets in the next 20 years.

Future domestic oil and gas production will depend on several uncertain factors. The most important factors include: prices; the size and geologic distribution of the remaining resources for each fuel; drilling costs; expected profitability of oil and gas; advancements in new drilling technologies that can make currently uneconomically recoverable resources into economic ones and reduce the cost of other economically recoverable resources; new geologic testing and seismic techniques that may significantly increase the success rate and volumetric reserve additions of exploratory wells; and new computerized evaluation techniques that help improve evaluation of the seismic tests to determine the size, location, depth, and potential economic viability of resource discoveries.

The world oil price scenarios illustrate the continued importance of the international oil market on projected domestic oil production. From 1990 to 2000, the Reference Case[5] world oil price projection provides the domestic oil industry insufficient incentives to stem the current declining trend in production.[6] In the second decade of the forecast, the world oil price increases toward $29 per barrel (in 1991 dollars) and provides sufficient incentives to the domestic industry to stabilize domestic crude oil production at approximately 5.5 million barrels per day.

In the Low World Oil Price Case, the crude oil price declines to $14 per barrel and then increases to about $18 per barrel by the end of the forecast period. Low-cost oil from international markets drives down domestic oil prices, which significantly limits domestic production. Domestic production in this case is projected to decline more rapidly than in the Reference Case through the first decade of the forecast, gradually becoming more stable through the remainder of the forecast. In the High World Oil Price Case, more rapidly increasing oil prices (to about $38 per barrel in 2010) generate increases in domestic investments in the oil industry relative to the Reference Case. Consequently, domestic oil production is projected to decline gradually to about 6.3 million barrels per day by 2003, and then to begin a slight increase to 6.5 million barrels per day by 2010.

The alternative World Oil Price scenarios significantly affect gas supply and production. That, in turn, changes the need for gas imports. In all cases, domestic gas production is projected to increase from the 1992 level of approximately 18.5 trillion cubic feet, peak near the middle of the next decade, and then decline gradually to 2010. Competition with coal in the electric utility sector limits gas prices and production profitability in the High World Oil Price and Reference Cases. In the Low World Oil Price scenario, low oil prices and competition in the electric generation markets limit profitability and gas production.

The timing, cost, and availability of Alaskan gas production is another important factor that can influence domestic gas production and gas competitive-

[5]Specific values from the projection analyses for all cases may be found in the eighth and ninth tables of Appendixes A through G (e.g., oil and gas values for the Reference Case are located in Tables A8 and A9, respectively).

[6]The provisions of the Energy Policy Act of 1992 were incorporated into all scenarios of *AEO93*.

ness. For all analyses performed in *AEO93*, Alaskan gas will be available for production, if economic, as early as 2006. Through 2005, Alaskan gas on the North Slope is expected to be dedicated to the production of crude oil. In the projections, Alaskan gas does not become economic in the Low World Oil Price Case, but does become economic in both the Reference (by 2009) and High World Oil Price Cases (by 2008). When Alaskan gas production is triggered, it moderates subsequent gas price increases.

The sensitivity of oil and gas production and domestic energy markets, given alternative estimates of economically recoverable oil and gas resources, was explored through the High and Low Oil and Gas Recovery Cases. These cases were based on economically recoverable resource estimates that reflect the relative shift indicated by the 5-percent and 95-percent confidence intervals for technically recoverable conventional domestic oil and gas resources, as generally developed by USGS and MMS. As expected, increased amounts of economically recoverable resources result in increased profitability and increased production of both oil and gas relative to the Reference Case. Reduced amounts of economically recoverable resources result in reduced profitability and reduced production of oil and gas relative to the Reference Case.

Oil and Gas Prices

Competition among oil, gas, and coal on the demand side determines the price of each commodity and, consequently, the production of each commodity. The degree to which oil and gas (and coal) markets are linked and compete depends primarily on the fuel-switchable markets, where fuel substitution can rapidly take place without significant capital investment. Almost all of such short-term substitution potential occurs in the industrial and electric generation boiler markets. In the long-term, the boiler markets are likely to continue to encourage the construction of dual-fuel-switchable boiler units to take advantage of any fuel price differentials. The oil and gas competition for customers in the boiler market is likely to provide one market mechanism for moderating the extent to which natural gas prices can rise. On the other hand, gas also competes with coal in electric generation. Natural gas risks some market loss if its price rises too much to take advantage of rising oil prices.

Because oil prices are expected to be determined in the international oil markets and since U.S. consumption of imported oil represents a small portion of world oil demand (8.9 percent in 1972 and 11.5 percent in 1991), changes in U.S. oil consumption will not substantially affect future world oil prices. Because natural gas prices are determined largely by domestic market forces and economic growth, however, competition in dual-fuel-switchable markets (oil and gas) will moderate gas demand and, consequently, gas prices.

Projected declines in oil production and increases in natural gas production occur in the presence of generally steady price increases for both fuels. However, the price of gas is projected to increase more rapidly than the price of oil. Because gas prices are projected to increase more rapidly than oil prices, the ratio of the domestic wellhead price of natural gas to the domestic wellhead price of oil, in terms of dollars per million Btu, is also expected to increase significantly over the 1990-to-2010 period in all scenarios examined. This projection continues a general trend of the past two decades.

Recent U.S. experience in the natural gas market suggests that the principal competitor to natural gas has been natural gas (referred to as "gas-on-gas" competition). (Gas-on-gas competition refers to an "oversupply" of gas which forces gas producers to compete against each other to satisfy gas demands.) The imminent disappearance of the so-called "gas bubble" (apparent excess gas deliverability over apparent demand) has been forecast for more than a decade. It has been difficult to reconcile statements by some gas producers, who claim to need much higher prices in the near term to ensure adequate gas supplies, with the reality that gas supplies in the United States have been more than adequate to provide sufficient gas to domestic markets at the prevailing low prices of recent years. To a large extent, lower gas prices of the 1980s have forced producers to become efficient on average, by eliminating less efficient projects and applying improved management techniques and technologies to remaining and new projects. It appears that efficiency induced by gas-on-gas competition (combined with advancements in drilling technologies) has more than compensated for the reduced drilling activity over the past decade. It is difficult to gauge at this juncture how producers will adjust their future behavior to changes in the competitive U.S. environment.

Oil and Gas Revenues

Despite declining domestic oil production, annual domestic revenues[7] for the production of oil (including lease condensate[8] and natural gas plant liquids) will be roughly 10 percent higher in 2010 than in 1990, because of increasing world oil prices. In contrast, annual domestic revenues for the production of natural gas (including associated and dissolved gas) are expected to increase much more rapidly. Natural gas revenues will be about 135 percent higher in 2010 than they were in 1990, driven by the combination of increasing wellhead gas prices and increasing domestic gas production. In fact, natural gas revenues are expected to surpass oil revenues by a slight margin for most of the 2000-to-2010 period.

In all cases examined, the gas share of total oil and gas revenues increases significantly. For example, in the Low World Oil Price Case, gas revenues are more than double oil revenues for most of the 2000-to-2010 period. In the High World Oil Price Case, however, gas revenues never increase beyond about 80 percent of oil revenues for the same period. This robust projection marks a major departure from the experience of the past two decades, when gas revenues never exceeded 65 percent of oil revenues and were generally less than 50 percent of oil revenues.

The increasing contribution of natural gas revenues to total oil and gas revenues could lead to significant changes in the domestic oil and gas industry, as firms adjust their activities accordingly. For example, in combination with the increasing deregulation of the domestic natural gas industry, the increasing contribution might lead to decisions by some large oil companies to increase their downstream investments (for example, in natural gas processing plants, pipelines, distribution systems, and marketing companies) in the domestic natural gas industry. Large oil companies could become more vertically integrated in their domestic natural gas sectors, which could significantly affect the behavior of domestic energy markets in complex ways not taken directly into account in *AEO93*.

The Outlook for Domestic Petroleum

During the past several decades, the search for oil has occurred in increasingly difficult (both physically and geologically), geographically remote, and therefore more expensive operating environments, including deep water offshore, Alaska both onshore and offshore, and the Rocky Mountains. In general, most large oil fields in the less difficult operating environments already have been discovered.

Over the past decade, unexpected field growth, including substantial positive changes to the net revisions (including adjustments) to old oil fields, has contributed greatly to domestic crude oil proved reserves. In large part, this growth results from an increasing emphasis on developmental drilling, including an emphasis on secondary recovery strategies such as infill drilling, extension drilling, and intrapool recompletions, as well as enhanced oil recovery technologies that go beyond conventional secondary recovery techniques. In addition, reserve levels have been sustained by an increasing emphasis, within exploratory drilling programs, on extending old fields and on discovering new reservoirs within old fields, rather than on discovering new fields.

To a large extent, these changes were motivated by compelling corporate requirements to increase cash flow during the 1980s. The major oil price decline in 1986, coupled with a major restructuring of the industry that in many cases induced significant increases in corporate debt levels, required increased cash flow for the industry. By developing oil fields more intensively while cutting back on new field exploration, firms tended to reduce their near-term expenditures relative to near-term revenues, thereby increasing their near-term cash flow. The oil price decline and industry restructuring also contributed to years of diminished drilling and concomitant declines in reserve additions.

In 1991, for example, the net revisions and adjustments for crude oil were only 386 million barrels (less than 25 percent of the average for the prior 10 years). Total

[7]Revenues have been computed as the product of domestic production and domestic wellhead price.

[8]Lease condensate is a natural gas liquid recovered from gas well gas (associated and nonassociated) in lease separators or natural gas field facilities. Lease condensate consists primarily of pentanes and heavier hydrocarbons.

discoveries were 554 million barrels (34 percent lower than the average for the prior 10 years), of which only 97 million barrels were new field discoveries (26 percent lower than the average for the prior 10 years). Overall, in 1991, crude oil reserves dropped by 6 percent, the largest decline since 1977 and more than four times the average annual decline experienced during the past 10 years.

The absolute level of oil production from enhanced recovery, offshore production, and Alaskan production, considered as a group, is projected to be about 25 percent lower in 2010 than in 1990. However, the group's relative contribution to total domestic oil production remains about 45 percent, because total production is also lower. In 1990, the contribution of enhanced recovery oil was less than 40 percent that of Alaska, while the contribution of offshore oil was about 55 percent that of Alaska. In 2010, in the Reference Case, however, all three are projected to be more nearly equivalent—a pattern generally true for most of the other scenarios examined.

Uncertainties in key assumptions could significantly affect these projections. For example, the costs of enhanced recovery will be significantly higher in fields where wells have been plugged and abandoned. More enhanced recovery production can be expected if costs are relatively low because abandonment rates are low. Low abandonment rates may result from tax policies and other economic circumstances that favor the continued operation of stripper wells. Conversely, less production can be expected if enhanced recovery costs are relatively high.

Projected levels of offshore production may vary significantly, depending on assumptions regarding Federal policies that restrict offshore leasing and regarding the relevant standards established for implementation of the Clean Air Act Amendments of 1990 (CAAA90) and the reauthorized Coastal Zone Management Act. The production of Alaskan oil may vary even more significantly, depending on whether restrictions on drilling in the Arctic National Wildlife Refuge are relaxed and, if so, the extent to which large economically recoverable deposits are discovered there.

Domestic Petroleum Market Outlook

On the surface, the petroleum product outlook for 2010 looks very similar to the situation today. Transportation fuels will represent about two-thirds of domestic petroleum product consumption and another one-fourth will be consumed in the industrial sector. However, the makeup of the fuels burned in the future will be notably different from those now in use (Figure 12). Cleaner burning fuels will be consumed in motor vehicles and by the electric utility industry as a result of initiatives in CAAA90. The composition of jet fuel used by military aircraft will also vary from the current standard as the military switches to kerosene-type fuel. These subtle changes in product composition will have a dramatic impact on petroleum refining and marketing operations and will translate into higher costs for consumers.

Gasoline refining and marketing will be greatly complicated because of the season- and city-specific nature of environmental legislation (Table 6). Beginning in 1992, gasoline became subject to tighter summertime limits on volatility, or Reid vapor pressure. The national limit was set at 9 pounds per square inch (psi), while a more severe 7.8 psi limit was placed on cities in the South that failed to meet ozone pollution standards. The tighter standards are aimed at reducing urban smog and will add an estimated 1 cent per gallon at the pump.[9]

The picture was complicated even further in the fall of 1992 when the first CAAA90 regulations for gasoline became effective. During the winter months, gasoline sold in the 39 metropolitan areas with the worst carbon monoxide problems must be "oxygenated" to contain at least 2.7 percent oxygen. As a result, nearly 15 percent of gasoline sold every year must be oxygenated gasoline,[10] which will cost about 3 to 5 cents per gallon more than conventional gasoline.[11]

Beginning in 1995, refiners and marketers will face a new challenge of supplying a "reformulated gasoline." Compared with conventional gasoline, the reformulated blend must meet tighter restrictions on a number of characteristics, including oxygen content and summertime volatility, and will cost an additional 4 to 15 cents per gallon according to a diverse group of petroleum industry and government estimates.[12] Gasoline price projections in *AEO93* reflect an 8 cent per gallon cost assumption. By 1997, reformulated gasoline must be blended according to a more comprehensive formula that must result in a 15-percent reduction of volatile organic compound (VOC) and air toxic emissions, compared with gasoline in 1990.

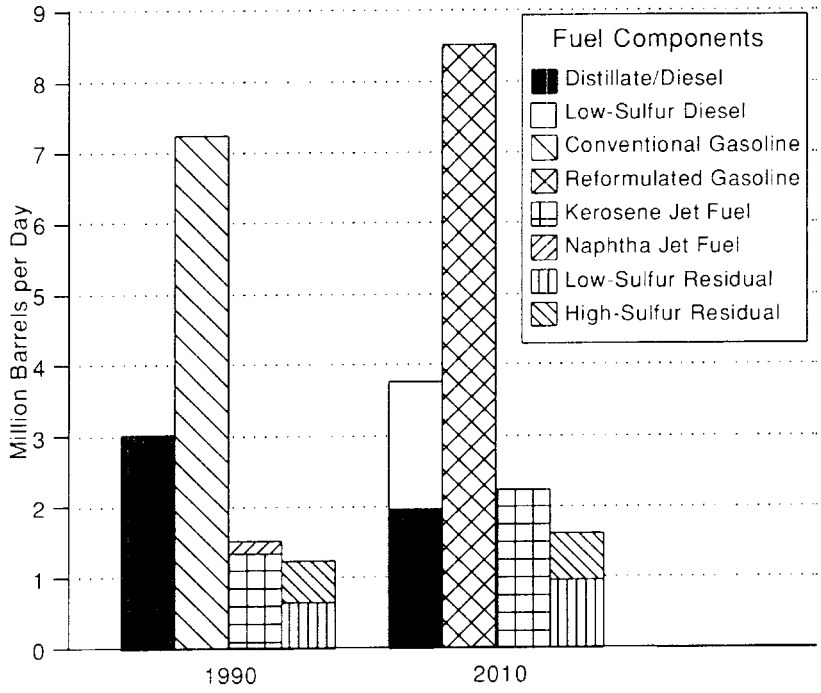
[9]Cost assumption based on *Federal Register*, Vol 55, no. 112, June 11, 1990, p. 23663.

[10]Market share estimate based on population of the 39 carbon monoxide nonattainment areas and the winter share of annual gasoline sales.

[11]Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(92/4Q) (Washington, DC, November 1992), p. 9.

[12]"Reformation Cost Estimates Reflect Wide Fluctuation," *The Oil Daily* (September 11, 1991), p. 1.

Figure 12. Fuel Composition of Petroleum Products, 1990 and 2010



Sources: *Aggregate Consumption*—Table A8. *Product Detail*—Estimated from model assumptions, unpublished model results, and data from Energy Information Administration, *Fuel Oil and Kerosene Sales 1990*, and Form EIA-782C, "Monthly Report of Petroleum Products Sold into States for Consumption."

Cleaner burning fuels will be consumed in motor vehicles as a result of the Clean Air Act Amendments of 1990.

Table 6. New Fuel Requirements

Program Requirement	Starting Date	Months of Coverage	Geographic Coverage
Rvp Compliance	5/92	May to mid-September	9.0 psi national 7.8 psi southern ozone cities
Oxygenated Gasoline	11/92	October to February[a]	39 cities failing CO standards
Low-Sulfur Diesel	10/93	All	National
Reformulated Gasoline	1/95	All	9 severe ozone cities plus opt-in
Reformulated Formula Change	1/97	All	9 severe ozone cities plus opt-in
Additional Reformulated Restrictions	Post-2000	All	Areas that continue to exceed ozone standards

[a]Proposed periods for carbon monoxide (CO) nonattainment areas are staggered over winter months. Beginning in 1993, the time of coverage in Spokane, WA, will begin in September and end in February. The period for the New York/New Jersey area will begin in October and extend through April.

Restrictions may be tightened even further after 2000, when VOC and air toxic emissions must be reduced by 25 percent.

Sales of reformulated gasoline will be mandatory year-round in the nine areas with the most severe ozone problems. These areas represent approximately 25 percent of total U.S. gasoline consumption. A larger market share for reformulated gasoline is anticipated because as many as 89 other areas with less severe ozone problems may be allowed to adopt the requirement. The forecast assumes that reformulated gasoline will be sold in all eligible cities, just under 60 percent of the market, by the year 2000.[13] By 2010, all gasoline sold in the United States is assumed to be reformulated, reflecting expectations of a growing environmental consciousness and a desire by refiners to simplify operations by reducing the number of gasoline products.[14]

The composition of on-highway diesel fuel will also undergo changes as the result of new national standards, effective in October 1993. The new CAAA90 standards will impose aromatic controls and reduce the level of sulfur content to about one-fifth of current levels, providing cleaner-burning diesel fuel. These changes will affect about 80 percent of distillate fuel used for transportation, or 48 percent of the total distillate fuel oil market.[15] Because the new restrictions do not extend to other distillate products such as heating oil, the low-sulfur diesel will have to be processed and stored separately from other distillates. The associated costs will be approximately 4 to 5 cents per gallon.[16]

The CAAA90 provisions aimed at the utility sector will indirectly cause the phase-out of residual fuel oil containing more than 1 percent sulfur. Although high-sulfur residual fuel will continue to be used for bunker fuel throughout the forecast, programs to reduce sulfur dioxide emissions will all but eliminate high-sulfur residual fuel consumption by electric utilities by 2010. The high-sulfur fuel will be replaced by more expensive, but cleaner burning, low-sulfur residual oil.

Another shift in fuel composition will occur as the military converts from naphtha-based (JP-4) to kerosene-based (JP-8) jet fuel. The military is currently the only user of naphtha jet fuel, representing about 12 percent of jet fuel consumption.[17] This fraction will disappear entirely by 1996 as kerosene jet fuel is phased in. The new standard will simplify jet fuel transportation and storage logistics by providing consistency across the branches of the Armed Services and with the North Atlantic Treaty Organization. Kerosene jet fuel will also provide a safer fuel for aircraft because it is less flammable than naphtha fuel. Kerosene jet fuel is the primary fuel of commercial airlines, and the military conversion will increase competition for the kerosene-based fuel. In addition, small refiners that had specialized in the production of naphtha jet fuel will have to adjust their output slate and compete in new markets.

Domestic Refining and Petroleum Imports

The wave of recent Federal and State environmental legislation has provided new elements of uncertainty for the petroleum industry. Details of many CAAA90 provisions set to take effect in the mid-1990s have yet to be determined by the U.S. Environmental Protection Agency (EPA), and discrepancies between Federal and State regulations have yet to be ironed out. Refining operations and new capital investments will be greatly affected by pending technological standards to reduce stationary source emissions. Decisions on refinery operations will also be influenced by the definition of a new "complex" formula for reformulated gasoline which will replace the "simple" definition by 1997.

Even after it becomes clear which types of emissions control and new downstream processing units will be needed to meet CAAA90 requirements, improving technology may increase uncertainty about costs. By the end of the decade, estimated environmentally related investments by the petroleum industry may range between $15 billion and $23 billion per year, according to the American Petroleum Institute (API).[18] These

[13]Market share estimates based on population of ozone nonattainment areas.

[14]In 2010, 15 percent of gasoline is assumed to contain ethanol; 20 percent to contain ethyl tertiary butyl ether; and 65 percent to contain methyl tertiary butyl ether.

[15]On-highway percentage of diesel consumption based on data from Energy Information Administration, *Fuel Oil and Kerosene Sales 1990*, DOE/EIA-0535(90).

[16]Cost range based on U.S. Environmental Protection Agency, final rule, "Regulation of Fuels and Fuel Additives: Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years" (Washington, DC, Aug. 8, 1990), pp. 7, 19; and Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(92/4Q) (Washington, DC, November 1992), p. 9.

[17]Based on data from Form EIA-782C, "Monthly Report of Petroleum Products Sold into States for Consumption."

[18]*Cost to the Petroleum Industry of Major New and Future Federal Government Environmental Requirements*, Discussion Paper #070, American Petroleum Institute (Washington, DC, Oct. 1991), p. 26.

Reid Vapor Pressure

In the 1970s, the Nation addressed the problem of air pollution by requiring new cars to include emissions-reducing catalytic converters. It was not until 1989 that the first wave of Federal controls aimed at reducing pollution by limiting the hydrocarbon-emitting characteristics of gasoline were enacted. As gasoline is vaporized, hydrocarbons known as volatile organic compounds (VOCs) are emitted into the atmosphere. Reacting with sunlight, VOCs contribute to urban ozone pollution, popularly known as smog. The 1989 regulations targeted VOC reduction by setting Federal limits on the Reid vapor pressure (Rvp), or volatility, of gasoline.

Rvp is a measure of gasoline volatility that indicates the ease with which molecules will be released into the atmosphere. The volatility of gasoline also reflects how easily the fuel will ignite in an engine. If the Rvp of the gasoline is too low, the engine will have cold start problems; if the Rvp is too high, the engine will become vapor locked. Because volatility depends upon both engine temperature and pressure, the ideal Rvp for gasoline varies by geographical location, altitude, and season. For example, in high-altitude areas where air pressure is lower, gasoline burns more easily, especially on hot days. In order to meet engine conditions, gasoline Rvp varies by area and season. Typically, Rvp has measured between 9 and 15 pounds per square inch (psi).

Rvp legislation was enacted as a two-phase program. Phase I went into effect in 1989 and set summertime limits at a maximum of 10.5, 9.5, or 9.0 psi, depending on the State and month. Petroleum refiners responded to the lower limits by removing butane, a high Rvp substance, from the gasoline pool.

Phase II of the program is more complicated because controls were extended from State to local areas. A nationwide summertime limit of 9 psi took effect in the spring of 1992. At the same time, an even lower 7.8 psi restriction was placed on 40 areas in the South that the Environmental Protection Agency (EPA) had designated as ozone nonattainment areas. Because of State legislation, the lower specification also became effective in nonattainment areas in Oregon and for the entire State of California. Pipelines handle the two different psi gasolines in separate shipments. However, the residual gasoline from one shipment can potentially alter the Rvp of the following batch. Allowing for a margin of error, most pipeline standards are about 0.3 psi below the EPA standards of 9.0 and 7.8 psi.

In Phases I and II of the program, gasoline containing 9 to 10 percent ethanol is permitted to have an Rvp of 1 psi above the standard. EPA granted this special allowance to prevent Rvp limitations from discouraging ethanol blending. Without the allowance, the Rvp limits would preclude ethanol blending at levels high enough to qualify for a Federal ethanol tax credit of 5.4 cents per gallon of gasoline.

In addition to the summertime Rvp limits, a wintertime requirement for oxygenated gasoline in 39 cities was also initiated in 1992. The control periods for the cities in the program are staggered between September and April. Only Spokane which requires oxygenated gasoline as early as September will have an overlap with the summertime Rvp limits effective between May 1 and September 18. In practice, the timing of the programs complicates gasoline distribution and makes gasoline sales less flexible between seasons. To safeguard against selling gasoline out of season, pipelines must begin phasing in gasoline for the next season about one month in advance.

Rvp is just one of the gasoline characteristics that will be tightened in 1995 under reformulated gasoline standards. During the summer months, reformulated gasoline that will be required in ozone nonattainment areas will have a new limit of 7.8 psi for the northern cities[19] and 7.2 psi for the southern cities. In addition to new Rvp limits, year-round requirements for reformulated gasoline include contents of 2.0 percent oxygen, no more than 1.0 percent benzene, no more than 25 percent aromatics, and no lead. In 1996, the State of California will require "severely reformulated" with additional restrictions on sulfur and olefin content, gasoline boiling range, and a tighter summertime Rvp of 7.0 psi.

In response to tighter Rvp specifications, refiners are likely to eliminate direct blending of the Rvp- and octane-rich streams of butane and pentane. These streams may be redirected to etherification units to produce oxygenates and to alkylation units to produce alkylate, a low Rvp and aromatics blending component.[20] Estimated investments for Phase II Rvp reductions alone range from $464 million by the EPA[21] to $1,490 million by the American Petroleum Institute (API).[22]

As with any product, refiners will be looking for the most efficient way to produce gasoline with all of the required characteristics. One important trade-off for producing reformulated gasoline will occur between oxygen content and Rvp. Refiners will be looking to enhance the oxygen content of gasoline by blending oxygenates such as MTBE, TAME, ETBE,[23] and ethanol. In addition to cost and oxygen content, Rvp will play an important role in choosing between oxygenates (Table 7).

Table 7. Fuel Blending Characteristics

Additive	Rvp (pounds per square inch)	Oxygen (percent weight)
MTBE	8-10	18.2
TAME	3-5	15.7
ETBE	3-5	15.7
Ethanol	17-22	34.7

Source: George H. Unzelman, "Fuel Composition in 2000," *Fuel Reformulation*, May/June 1992.

(See continuation and notes on page 37)

MTBE will be the most heavily used oxygenate because of its blending properties and the relative ease with which refiners can produce and ship it. Despite ethanol's exceptionally high Rvp, an EPA decision to grant a 1-psi waiver for ethanol blends in one-third of the northern reformulated gasoline market has preserved it as a viable blending option. Ethanol will also be used as an input to ETBE. While ETBE and TAME will play a relatively minor role in blending in the near term, their lower Rvps provide longer term potential, especially after 2000, when restrictions on hydrocarbon emissions will be tightened even further.

[19]The limit was originally set at 8.1 psi but was changed to 7.8 psi by President Bush in an announcement on Oct. 1, 1992.

[20]"Refiners Mull Strategies for Reformulated Fuel Production," *Fuel Reformulation* (March/April 1992), p. 32.

[21]U.S. Environmental Protection Agency, "Volatility Regulations for Gasoline and Alcohol Blends Sold in Calendar Year 1992 and Beyond," Final Rule, p. 23663.

[22]*Cost to the Petroleum Industry of Major New and Future Federal Government Environmental Requirements*, Discussion Paper #070, American Petroleum Institute, Washington, DC, October 1991, p. 4.

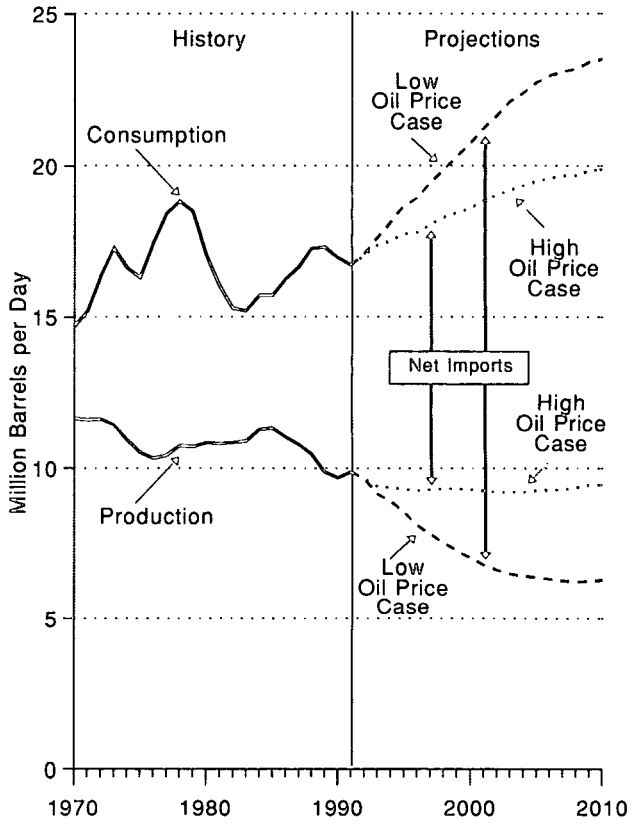
[23]MTBE is methyl tertiary butyl ether composed of methanol and isobutylene. ETBE is ethyl tertiary butyl ether, composed of ethanol and isobutylene. TAME is tertiary amyl methyl ether, composed of methanol and isoamylene.

costs include CAAA90 investments for production and marketing of new fuels and for conforming to source emissions standards for refineries that will be in place by 1996. Investments for implementing other standards from the Resource Conservation and Recovery Act (RCRA), related to water and waste management and product storage, will also be required.[24]

Future regulatory changes will force petroleum refiners to alter refinery configurations and invest heavily in downstream processes. In some instances, it may be more economic for certain refineries to close down partially or entirely rather than upgrade facilities to meet new environmental standards. Since 1990, approximately 355 thousand barrels per day of shut-down distillation capacity has been linked to growing environmental costs.[25] Of this amount, about one-third of the capacity losses occurred at small refineries shut down in their entirety, and the remainder occurred at larger refineries where the plants were only partially shut down. In addition, some refiners are avoiding costly upgrades by staying out of new fuels markets.

Despite the capacity losses mentioned above, total distillation capacity has remained quite stable since 1990 as a result of incremental additions at larger refineries. *AEO93* assumes capacity shutdowns will continue to be offset by expansions throughout the forecast. Coupled with ever-growing petroleum product demand, the petroleum outlook in all scenarios shows a growing reliance on petroleum imports (Figure 13). *AEO93* assumes that the addition of oxygenates to gasoline resulting from the Clean Air Act legislation will reduce requirements for petroleum imports by approximately 75 thousand barrels per day by 1995. Assuming that all gasoline supplied in 2010 will be

Figure 13. U.S. Petroleum Production and Consumption, 1970-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991*. **Projections:** Tables D8 and E8.

A growing reliance on petroleum imports is forecast across all scenarios.

[24]An additional cost of 1 cent per gallon was assumed for gasoline and distillate to account for upgrading underground storage facilities under RCRA.

[25]Reasons for refinery closings have been widely reported in the trade press and in the *Wall Street Journal* article, "U.S. Oil Refiners May Cut Capacity by as Much as 15%" (Jan. 21, 1992).

reformulated or oxygenated, petroleum imports would be reduced by approximately 330 thousand barrels per day.[26] By 2010, between 52 and 72 percent of domestic petroleum consumed will be imported, compared with 42 percent in 1990. The greatest imports occur in the Low World Oil Price Case because lower oil prices discourage domestic oil production while stimulating consumption in all sectors.

Consumption in the transportation sector shows the greatest absolute response to variation in oil prices, followed by the industrial and utility sectors (Table 8). Although electric utilities account for a relatively small share of total petroleum demand, they respond most dramatically across oil price scenarios. In the electricity market, distillate and residual fuel compete against natural gas in dual-fired (oil and gas) combustion turbines, combined-cycle, and fossil-steam plants. Almost all of these multi-fuel units are currently consuming natural gas because the price of natural gas on a per Btu basis is well below the prices of distillate or residual fuel. As a result, higher world oil prices have virtually no impact on utility oil consumption because those utilities capable of reducing oil consumption have already done so. In the Low World Oil Price Case, however, electric utility consumption of oil in 2010 is nearly double the Reference Case level, reflecting the potential for utilities to switch out of natural gas.

Table 8. Petroleum Supply, Disposition, and Prices, with Projections for 2010
(Million Barrels per Day, Except Where Noted)

	1990	2010						
		Reference	High Economic Growth	Low Economic Growth	High World Oil Price	Low World Oil Price	High Oil and Gas Recovery	Low Oil and Gas Recovery
World Oil Price (1991 dollars per barrel)	**22.54**	**29.30**	**29.30**	**29.30**	**38.10**	**18.10**	**29.30**	**29.30**
Production								
Crude Oil[a]	7.35	5.66	5.62	5.58	6.49	3.54	6.73	4.62
Other[b]	1.64	2.16	2.23	2.07	2.22	2.07	2.29	2.01
Net Imports (Including SPR)[c]	**7.17**	**12.24**	**13.41**	**11.14**	**10.29**	**17.03**	**10.90**	**13.52**
Crude Oil	5.78	8.30	8.34	8.37	7.47	10.42	7.23	9.33
Petroleum Products	1.38	3.95	5.07	2.77	2.83	6.61	3.67	4.18
Refined Petroleum Products Supplied	**16.99**	**20.96**	**22.14**	**19.70**	**19.91**	**23.53**	**20.82**	**21.05**
Residential and Commercial	1.15	0.84	0.85	0.83	0.81	0.92	0.84	0.85
Industrial	4.34	5.48	5.70	5.23	5.16	6.25	5.43	5.55
Transportation	10.97	13.89	14.89	12.90	13.21	14.89	13.81	13.87
Electric Utilities	0.54	0.75	0.70	0.73	0.73	1.47	0.75	0.77
Product Prices (1991 dollars per gallon)								
Motor Gasoline (including taxes)	1.23	1.51	1.52	1.50	1.72	1.22	1.51	1.51
Diesel Fuel	1.24	1.46	1.48	1.44	1.67	1.19	1.46	1.46
No. 2 Heating Oil	1.12	1.25	1.28	1.21	1.44	0.99	1.25	1.25
Residual Fuel	0.50	0.72	0.74	0.69	0.90	0.48	0.72	0.72
Jet Fuel	0.80	0.88	0.90	0.86	1.09	0.60	0.88	0.88

[a]Includes lease condensate.
[b]Mainly natural gas liquids.
[c]SPR = Strategic Petroleum Reserve.
Sources: **History (1990):** Energy Information Administration, *Petroleum Supply Annual 1990* and *Petroleum Marketing Monthly* (prices) plus taxes. **Projections:** Tables A3, A8, B3, B8, C3, C8, D3, D8, E3, E8, F3, F8, G3, and G8.

[26]These figures differ from other estimates of oxygenate demand for the following reasons: 1) they represent only incremental changes from current levels, 2) only the non-petroleum/non-natural gas liquids portion of the oxygenates (i.e., ethanol and methanol) is included, and 3) they are not on a MTBE-equivalent basis.

The Outlook for Domestic Natural Gas

Since the mid-1980s, natural gas production has increased as the industry has continued its passage to a more competitive market structure. Unlike oil, domestic natural gas production is expected to increase during the first decade of the projection (1990 to 2000) and to begin to decline in the second decade. The pattern of initial production growth followed by a decline reflects the view that the domestic gas industry is less mature than oil, undiscovered domestic gas resources are much more abundant than oil, and gas investments will be more profitable than oil over the forecast horizon. As domestic natural gas production began increasing in the mid-1980s, proved reserves of dry natural gas in the Lower 48 States fell from a level of 169 trillion cubic feet in 1981, to 159 trillion cubic feet in 1986, and to 158 trillion cubic feet in 1991.

In 1991, Lower 48 net revisions and adjustments of 6.8 trillion cubic feet were added to proved reserves (60 percent higher than the average for the prior 10 years). Total discoveries for the Lower 48 States were 7.5 trillion cubic feet, or just 10 percent higher than the net of revisions and adjustments. Total discoveries for the United States as a whole were also 7.5 trillion cubic feet (35 percent lower than the average for the prior 10 years), of which only 0.8 trillion cubic feet were new field discoveries (55 percent lower than the average for the prior 10 years). Overall, natural gas reserves in the Lower 48 States declined by 1.6 percent between 1990 and 1991.

The Reference Case projects a continuation of recent increases in domestic natural gas production during the first decade of the projection. During the second decade of the projection, however, this growth begins to be reversed. The maintenance of relatively stable levels of production, expected during the second decade of the projection, is attributable in large part to the increasing use of unconventional gas recovery technologies. As in the case of oil, stable production levels are also supported by a major contribution from Alaska—in the case of gas, delivered through a newly constructed natural gas pipeline system running through Canada. The absolute contribution to total gas production from Alaskan, unconventional recovery, and offshore production, considered as a group, is projected to be somewhat greater in 2010 than it was in 1990 in almost all scenarios.

Numerous additional uncertainties also could affect these projections. They include virtually all the uncertainties enumerated at the end of the oil discussion. In addition, the exact volumes, methods, and costs associated with the various unconventional recovery techniques are generally highly speculative. It is widely recognized, for example, that gas from coalbeds and from very-low-permeability reservoirs may exist in very large quantities, but neither the potential volumes nor the associated extraction costs are understood with any precision.

Natural Gas Imports

Natural gas imports fill an increasing gap between domestic natural gas production and domestic natural gas consumption (Table 9). Virtually all of this increase is attributable to imports from Canada, based on the assumption that no significant difficulties will be encountered in building new pipelines or increasing existing pipeline capacity, as needed. Although gas trade with Mexico increases substantially over the period from 1990 to 2010, both imports and exports are affected. Consequently, net imports vary—from earlier net flows to Mexico to later net flows from Mexico. In addition, an increase in imports of liquefied natural gas from Algeria, and possibly from Venezuela, Nigeria, and Norway, is projected.

Natural Gas Markets

Significant structural changes, leading to increased competition, have taken place in all segments of the U.S. natural gas industry—producers, transporters, marketers, and local distribution companies (LDCs)—over the past 10 years. These changes include complete deregulation of the wellhead market, the subsequent unbundling of pipeline services so that customers may purchase gas and transportation services separately, and the introduction of competitive forces in pipeline expansion decisions and in transmission and distribution service pricing. Wellhead decontrol and unbundling have already had a significant impact on the market, while recent changes in pipeline expansion decisionmaking and transmission and distribution service pricing are just being implemented and have yet to make a significant impact.

With the evolution of the market, the roles of the various players have changed substantially. In addition to the traditional bundled service arrangements, pipeline companies are also offering a range of services, such as separate gas sales, gas transportation on both a firm and an interruptible basis, and storage near end-use markets. Some companies, such as Transcontinental Gas Pipeline Company (Transco), have eliminated bundled services entirely, restructuring all of their service so that LDCs must select separately the amounts

Table 9. Natural Gas Supply, Consumption, and Prices, with Projections for 2010
(Trillion Cubic Feet, Except Where Noted)

	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil and Gas Recovery	Low Oil and Gas Recovery
Production	**17.81**	**20.07**	**20.75**	**19.27**	**21.60**	**18.31**
Net Imports	**1.45**	**4.15**	**4.27**	**3.86**	**3.76**	**4.41**
Total Consumption[a]	**18.73**	**24.24**	**25.05**	**23.17**	**25.40**	**22.76**
Residential	4.38	4.50	4.59	4.42	4.61	4.37
Commercial	2.67	3.16	3.21	3.10	3.21	3.10
Industrial	6.98	8.87	9.26	8.52	9.33	8.44
Electric Utilities	2.79	5.46	5.64	5.01	5.88	4.69
Transportation	0.00	0.15	0.15	0.15	0.22	0.15
Wellhead Price (1991 dollars per thousand cubic feet)	1.77	3.68	4.07	3.30	3.19	4.44
Average Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	8.07	8.47	7.67	7.56	8.85
Commercial	4.99	7.12	7.52	6.73	6.61	7.91
Industrial	3.04	5.11	5.51	4.70	4.60	5.89
Electric Utilities	2.46	4.61	5.08	4.10	4.15	5.28
Transportation	4.64	[b]9.91	10.07	9.75	9.91	9.91
Average to All Sectors	4.03	5.91	6.31	5.51	5.40	6.71

[a]Total consumption includes lease and plant fuel and pipeline fuel not listed below.
[b]Equivalent to a gasoline price of about $1.20 per gallon (in 1991 dollars).
Sources: Tables A9, B9, C9, F9, and G9.

of firm gas and firm transportation they wish to purchase. Planning responsibilities have been shifted from pipelines to LDCs and end-use customers. LDCs, whose primary role is to distribute gas locally to end-users, now often contract for gas directly with producers and arrange transportation separately with the pipeline companies. Additionally, new players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users.

Competition in pricing natural gas transmission and distribution services can have far-reaching effects on the prices consumers pay, because the cost of these services represents a significant portion (often more than 50 percent) of the delivered price of gas to end users. Consumers of natural gas are generally grouped into two categories: "core" customers, who need firm or guaranteed service because gas is their only fuel option or they are willing to pay for the security of supply, and "noncore" customers, who do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. Pipeline companies and LDCs guarantee their core customers that they will provide peak-day service up to the maximum volumes specified under their contracts, even though these customers may not actually purchase or request transport of the gas on any given day. In return for this firm gas supply service guarantee, these customers pay monthly reservation fees (demand charges) for the gas and additional charges for transmission. Residential and most commercial gas customers generally purchase gas from LDCs and have no other alternative for fuel. Thus, they are considered core customers.

Users with flexible production schedules or with the capability to switch to other fuels, such as many industrial and electric utility customers and some larger commercial customers, usually contract for service on

Mexican-U.S. Natural Gas Trade

The North American Free Trade Agreement (NAFTA) formalizes the recent trend toward increased natural gas trade between the United States and Mexico. Currently, Mexico is the largest of producer of natural gas in Latin America and the eighth largest worldwide. Between 85 and 90 percent of Mexico's gas is associated with the production of crude oil—one of Mexico's primary exports. Despite this abundant resource base, however, Mexico remains a net importer of natural gas.

The history of natural gas trade between the United States and Mexico begins in the early part of this century. Multinational oil companies entered the country to capitalize on a vast and virtually untapped resource base. Worker disputes and perceived imperialism eventually caused the Mexican national government to expropriate the holdings of foreign oil companies on March 18, 1938. A state oil company, Petroleos Mexicanos (PEMEX), was established to control the nation's hydrocarbon resources. Further, Article 27 of the Mexican Constitution explicitly prohibits foreign ownership of natural resources.

Natural gas trade between the United States and Mexico began in 1949 with relatively minor volumes. Between 1957 and 1971, net Mexican exports averaged 40 billion cubic feet (Bcf) per year. In the 1970s, gas exports virtually disappeared, as attention shifted toward satisfying the high demand for oil. In 1980, exports resumed, averaging a net 86 Bcf per year until 1984. At the end of 1984, however, exports were suspended because of a decline in U.S. and Canadian price indices, which were used to set contract prices for exports of Mexican gas. In fact, PEMEX has stated that exports will not resume until prices reach $3.50 per thousand cubic feet, far above the estimated 1992 price of $1.80. Additionally, the softening of oil prices in the early 1980s, combined with rising interest rates, caused a serious debt crisis within Mexico, resulting in decreased investment in exploration and development and eliminating a gas supply surplus.

The majority of Mexico's current natural gas reserves lie in the Southern Isthmus area of the country. Much of this gas is already providing between 80 and 85 percent of the feedstock for Mexican petrochemical operations. Any increased production in the South is used to replace high-sulfur fuel oils in heavily polluted Mexico City. This arrangement has created a two-tier gas market within the country, because towns along the northern border of Mexico must obtain their gas elsewhere. In fact, these industrial areas are growing rapidly in part because they are benefiting from current low U.S. natural gas prices. In 1990, U.S. exports to Mexico averaged 16 Bcf, but jumped to more than 60 Bcf in 1991.

Although it is currently a net importer of natural gas, Mexico has enormous potential for future production. The expected recoverable resources in the country include proved reserves of 71.5 trillion cubic feet (Tcf) and undiscovered recoverable resources of 180 Tcf. The proved reserves include 26.7 Tcf of undeveloped reserves from the Chicontepec Basin, where low permeability (because of high clay content) and high water content make drilling economically undesirable. Based on current production rates, Mexico's reserves-to-production ratio (the number of years in which current annual production would exhaust known reserves) is about 54 years.

The gas transportation system in Mexico consists of 8,163 miles of pipeline. A major national trunkline runs from the southern producing areas such as Cactus north to Monterrey. In both the North and South, major arteries run from the East toward the western border. Currently, four cross-border lines, with a combined capacity of 469 million cubic feet per day, link Mexican fields to the United States. Additionally, cross-border expansion projects have been proposed that can increase capacity by almost 2 Bcf per day (Table 10).

Throughout most of the outlook period, Mexico will remain a net importer of natural gas. Eventually, however, the economic attraction of natural gas development will result in productive capacity that will accommodate both internal requirements and export demand. *AEO93* projects that Mexico will become a net exporter of gas to the United States by 2009, and by 2010, have net exports of 110 Bcf.

Table 10. Mexican-U.S. Cross-Border Links and Proposed Expansions

Company	Entry Point	Capacity (billion cubic feet per day)
Texas Eastern Transmission	McAllen, Texas	350
Valero Transmission	Eagle Pass, Texas	4
Western Gas Interstate	El Paso, Texas	90
El Paso Pipeline	Naco, Arizona	25
Valero Transmission	McAllen, Texas	400
Houston Pipeline	McAllen, Texas	600
El Paso Natural Gas	El Paso, Texas	100
ENSA	Laredo, Texas	500
Tri-National Power (NOVA)	Ehrenburg, Arizona	350

Source: National Petroleum Council, *The Potential Impact of Mexico on the North American Gas Market* (June 5, 1992).

an interruptible basis. The lower level of service provided under interruptible service contracts is reflected in substantially lower rates; customers that purchase interruptible service pay only a commodity charge. This fundamental difference in the pricing mechanisms in effect for the different classes of customers is reflected in the forecasts by substantially higher prices in the residential and commercial sectors than in the utility and industrial sectors.

As requirements of noncore customers are generally not taken into account in determining the peak-day deliverability requirements of pipeline systems, during peak consumption periods the availability of capacity to serve these customers can be very limited, and service interruptions can occur. Although certain areas of the country, such as the West, Northeast, and South Atlantic, experience very high capacity utilization, pipeline capacity is generally perceived to be adequate to serve the peak-day requirements of its core customers, and additionally to satisfy noncore customers with minimal interruptions. With natural gas use projected to increase 29 percent by 2010, however, capacity constraints could become binding in some regions unless the existing pipeline system is expanded.

The increased number of recent filings with the Federal Energy Regulatory Commission (FERC) requesting authorization for new pipeline construction and improvements to existing systems reflects an anticipated need for increased capacity in certain areas. Several of the proposed projects reflect either a need to meet a shift in supply sources or a shift in end-use markets. The shift in demand occurred because of the large population gains in the Southeast, Southwest, and West in contrast to the limited growth in the Central and Midwest regions. Supply and demand shifts, while bringing about a need to develop increased capability to move gas to growing markets on the West and East Coasts, may leave underused capacity on some pipelines.

According to the EIA report *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990: Regional Profiles and Analyses*, published in June 1992, the Nation's pipeline system operated in 1990 at a high level relative to system capacity, with use varying significantly from one area of the country to another (from a low of 37 percent to a high of 90 percent). Projects completed between 1990 and March 1992 have already expanded interregional capacity by 2.2 billion cubic feet per day or about 3 percent. One-third of the capacity added since 1990 links Canadian gas with U.S. markets, and the additional two-thirds is generally aimed at serving markets in the West and Midwest. Commitments to pipeline expansion projects have been made by a number of electric utilities, industrial cogenerators, and independent power producers. Interstate pipeline construction currently underway will significantly expand transmission capacity to growing new markets in the Northeast, Southeast, and West. If all projects proposed as of June 1992 are built, interregional capacity will increase by as much as 9.8 billion cubic feet per day, or about 13 percent. Because the economic basis of some of these proposed expansions may change as a result of new regulatory initiatives and the forces of the more competitive market, some projects may be modified, downsized, or abandoned.

Future Natural Gas Market Trends

Increased gas consumption is driven largely by new markets for natural gas, with most of the increase attributed to electricity generation by cogenerators, electric utilities, independent power producers (IPPs), and exempt wholesale generators (EWGs) introduced by the Energy Policy Act of 1992. Residential and commercial sector consumption remain relatively stable, with industrial sector consumption growing by more than 25 percent and utility sector consumption nearly doubling. Utility-sector growth is driven by both greater use of existing plants and a substantial increase in combined-cycle plants over the forecast period, with combined-cycle capacity increasing from 5.7 gigawatts in 1990 to 35.4 gigawatts in 2010. The significant utility-sector increase results in part from the impact of CAAA90, tightened State environmental regulations stemming from local environment and health concerns, and the increased confidence that natural gas is now plentiful and will remain competitive with oil product alternatives in the mid- to long term. With the projected increase in natural gas usage, pipeline capacity in addition to that currently proposed may be needed to accommodate both the previously indicated regional shifts in supply and demand and the increased overall consumption.

Additional new market areas for natural gas include commercial cooling and the use of compressed natural gas (CNG) vehicles in the transportation sector. Use of natural gas in CNG vehicles, which is encouraged by numerous incentives in the Energy Policy Act of 1992, begins to have an impact in the forecast in 1996 with an initial level of 10 billion cubic feet and grows steadily to 150 billion cubic feet by 2010.

Under alternative economic growth assumptions, gas continues to maintain the same market share, with overall consumption moving with the macroeconomic adjustments. Residential and commercial sectors remain relatively unaffected by varying economic growth assumptions, with most of the movement occurring in the fuel-switchable, price-sensitive industrial and utility markets.

Varying world oil price assumptions lead to a drop in the 2010 natural gas consumption forecast in the Low World Price Case of 1.2 Tcf and a slight increase in the High World Oil Price Case. The drop in natural gas consumption in the low price case while overall energy consumption increases is attributable to natural gas losing market share with respect to lower priced residual fuel oil. Although in the High World Oil Price Case natural gas gains slightly in market share with respect to residual fuel oil, it loses market share overall because of the slightly increased competitiveness of coal. Both natural gas and residual fuel prices increase in the High World Oil Price Case and coal prices decline, leading utilities to decrease consumption of natural gas and residual fuel oil and switch to coal-fired plants.

Thus, the World Oil Price and Economic Growth Cases provide an insight into the issue of interfuel competition in the electric-generation market. Economic growth changes have a relatively minor impact on fuel choices when compared with the impact of fuel prices. The marginal competition is between advanced coal and natural gas units (in combined cycle applications) in the Reference and High World Oil Price Cases, and not between oil and natural gas. In the Low World Oil Price Case, the marginal competition is between oil and gas (mostly low sulfur residual oil in steam units and distillate combined cycle), and the extended period of low oil prices leads to a substantial capture of gas markets for electric generation by oil. Consequently, oil and gas markets are weakly linked in the Reference to High World Oil Price range of oil prices and are more strongly linked in the Reference to Low World Oil Price range of oil prices.

Uncertainty Regarding the Natural Gas Market Forecasts

Natural gas currently provides about 23 percent of total U.S. energy consumption, and is projected to continue to do so throughout the forecast period. Although the forecast is for continued gas consumption growth, the market share for natural gas is projected to increase by less than 1 percent over the 1990 market share. Because natural gas is a clean-burning, relatively abundant fuel, a goal of both the Federal Government and the natural gas industry is to remove the barriers to a more efficient natural gas market and to increase natural gas usage. The form that initiatives in both areas may take is a key factor contributing to the uncertainty of the forecasts.

Regulatory Issues

On April 8, 1992, FERC issued Order 636, known as the Restructuring Rule, and on August 3, 1992, issued, on rehearing, Order 636-A further clarifying and refining the rule. Although these Orders (hereinafter Order 636) have been challenged on appeal and by numerous petitions for rehearing, the notion of open access is now widely accepted in the interstate market, and Order 636 will fundamentally alter the ways that natural gas will be sold, transported, and stored in the United States. The uncertainty that exists regarding Order 636 concerns the ultimate timing and method of implementation of some of the provisions.

Order 636 requires that interstate pipelines unbundle (i.e., separate) their sales and transportation services and provide all transportation services on an equal basis, whether the gas is purchased from the pipeline or from any other gas supplier. It seeks to make the natural gas transportation market more flexible by authorizing capacity-release programs that allow the creation of a secondary market for capacity rights. It requires pipelines to provide timely and equal access to all information necessary for buyers and sellers to arrange for capacity reallocation via electronic bulletin boards (EBBs). It restructures pipeline rates to more accurately reflect costs associated with providing each type of service unless the parties agree otherwise (with FERC approval). This is achieved by shifting all fixed costs, transmission and storage costs, plus return on equity and related taxes, to a one-part reservation charge for both allocation and billing purposes. The straight fixed variable (SFV) rate design would allow pipelines to recover all fixed costs in the demand (reservation) component of pipeline costs, and not the commodity (usage) component, as in the current modified fixed variable (MFV) rate design. This rate design change may cause a significant cost increase to firm, low-load-factor customers, many of whom are served by LDCs. FERC anticipated the possibility of high rate increases to certain customer classes. Should the use of SFV result in a 10-percent or greater increase in costs to any one customer class, pipeline companies must adopt cost-shift mitigation measures. These measures will phase in the rate increase over a 4-year period. Over the long term, low-load-factor customers can offset the increase in rates through revenues

obtained by releasing their capacity. Although it cannot be determined whether the revenue obtained via capacity releasing programs will fully offset the cost shift attributed to changes in rate design until the value of the released capacity is known, it is anticipated that in the long run the increased efficiency of the market will mitigate cost shifts and they will become insignificant.

The transition to fully unbundled pipeline services will cost money, and pipelines will need to propose mechanisms for recovering these costs during the transition period. Thus, pipelines can adjust contracts and certificate obligations during restructuring. Pipelines will be entitled to recover all eligible transition costs, including the costs of changing supply contracts, metering improvements, and other physical changes to the system. Interstate pipelines must file revised tariffs with FERC between October 1, 1992, and December 31, 1992. Also, the transition provision gives small customers two full winters to adjust to Order 636. FERC will modify each compliance filing so that full implementation can occur by the next spring for the 1993-1994 winter heating season.

Although under Order 636 interstate pipelines will continue to offer interruptible transportation service, it is expected that the nature and availability of the service will change significantly. Order 636 allows firm customers to release their capacity (all or portions of it) when it is not needed. How much capacity will be available is uncertain because many firms that can release capacity have an obligation to stand ready to serve their customers. If many of these firms release capacity, the increase in the number of sellers of capacity should help to push the price of interruptible service down. If some of the released capacity is packaged such that it very closely resembles firm service, the released capacity may be able to command a higher price than in the pre-Order 636 environment.

Industry Issues

Although previous limited growth in market share can be attributed in part to the complex regulatory environment that existed in the past, issues are changing as the market moves in the direction of an unregulated, more competitive marketplace. Many options that could significantly affect the opportunities for gas market growth in the United States are in the hands of industry rather than the Federal Government. Two key issues are of prime concern: 1) natural gas price certainty and 2) operational issues that have to be worked out between the natural gas and electric generating industries.

The long-term planning horizon of electric utilities and industry requires some certainty regarding fuel costs to allow investment in new gas-fired units. A number of contractual vehicles aimed at providing greater price certainty, including linking the cost of gas to the cost of alternate fuels on a Btu-equivalent basis, have been developed.

An important issue is the requirements of electric utility peaking and cycling units. Of major concern is the effect of daily and hourly fluctuations in electric load and the corresponding gas load requirements, along with the high delivery pressure requirements of the power generators. While base load utilities ramp up and can thus increase and decrease gas requirements gradually, the new peaking units come online and go offline within 15 to 20 minutes and can require up to 100 percent of their natural gas supply for a short time period. The effects on compression have impacts throughout the pipeline system, and there are issues to be resolved on pipeline capability to handle the sudden compression changes. Traditional firm and interruptible transportation services often require a 24- to 48-hour notification period before the commencement of deliveries, with deliveries to be made on an even basis over a 24 hour period. Resolution of this issue could be a determining factor in the choices the electric utility industry makes regarding the types of peaking and cycling units to be built to meet future demand for electricity.

Summary

The composition of many petroleum products will change significantly over the forecast period, largely because of CAAA90. Production of these new fuel formulations will require heavy investments by petroleum refiners, which will translate into higher costs to the consumer.

The most dramatic changes in fuel composition will occur in the transportation sector, as new CAAA90 standards for gasoline and diesel fuel come into play. Sales of the cleaner burning oxygenated and reformulated blends of gasoline will be required in areas of the country that failed to meet EPA carbon monoxide or ozone standards. Consumption of these new blends is expected eventually to replace traditional gasoline altogether.

Other changes in fuel makeup will be seen in the electric utility industry and the military. The CAAA90 will cause utilities to phase out high-sulfur residual oil in favor of low-sulfur residual oil by 2010. By 1996, changing military jet fuel standards will result in a transition from naphtha jet fuel to the safer kerosene-type jet fuel used by commercial airlines.

Reliance on petroleum imports will rise from 42 percent of domestic consumption in 1990 to between 52 and 72 percent in 2010, depending on the level of oil prices. The additional imports will be needed because domestic oil production and refining will not keep pace with growing petroleum demands.

Natural gas production and prices grow steadily through 2005, followed by a period of limited increases as demand abates. Natural gas consumption grows through 2010, at varying rates, with gas maintaining a steady market share. Consumption growth is spurred by new markets for natural gas, especially in combined-cycle electric generation, CNG vehicles, and commercial cooling.

4. Electricity Outlook

Electricity is an economical, clean, and versatile energy source. For these and reasons of convenience, it has become the fuel that powers much of this Nation's economy. In general, demand for electricity has been increasing for 30 years and is expected to do so for the foreseeable future. Most of the electricity consumed in the United States is provided by domestic utilities through the combustion of fossil fuels, nuclear reactions, and the use of renewable resources (such as water, wind, solar energy, geothermal, municipal solid waste, and biomass sources). Nonutilities (cogenerators, small power producers, and independent power producers) that produce electricity for self-use or delivery to the grid and, to a limited degree, utilities in Canada are a growing source of supply. In 1970, the energy consumed to generate electricity accounted for 24 percent of the total primary energy used in this country; by 1990, that figure had grown to 36 percent, and it is still growing today.

This chapter explores the factors that will affect electricity demand and planning in the future. Among them are regulatory and legislative initiatives, such as reform of the Public Utilities Holding Company Act of 1935 (PUHCA), transmission access requirements, and nuclear licensing reform. Other important factors include utilities' implementation of integrated resource planning programs and their treatment of environmental issues.

Electricity Demand and Resource Planning

Planning to meet the Nation's increasing demand for electricity is a difficult undertaking fraught with uncertainty. Competitive forces continue to grow in the electricity markets, and electric utilities are faced with the task of choosing the most economical resources that will enable them to provide the reliable supply of electricity that consumers expect. A typical electric power plant takes 3 to 10 years to plan and construct and is then expected to operate for at least 30 to 40 years. As a result, to plan appropriately, a utility must project the demand and prices of competing resource options for electricity generation 30 to 40 years in advance. Making this task even more difficult is the growing importance of environmental factors that must be considered in resource decisions. Over the next 20 years, power from utility plants will remain an important source of electricity supply, but the contributions from other sources, such as nonutilities, imported power, and investments in demand-side management programs, are expected to grow.

Recognizing the uncertainty inherent in such long-term planning, a range of projections, based on a variety of assumptions about economic growth and the supply of natural gas and oil, are presented below. These assumptions have significant impact on the quantity and type of electricity resources that will be required in the future.

Electricity Demand

Between 1960 and 1970, the demand for electricity grew at an annual rate of 7.3 percent, far outdistancing gross domestic product (GDP)—which increased by only 3.8 percent per year. Through the 1970s, the relationship between economic growth and increased electricity demand continued, but with a less dramatic difference: electricity demand grew by 4.2 percent, while GDP grew by 2.8 percent. During the 1980s, a growing emphasis on energy efficiency slowed the increase in electricity demand to an annual rate of 2.6 percent—the same rate as GDP.

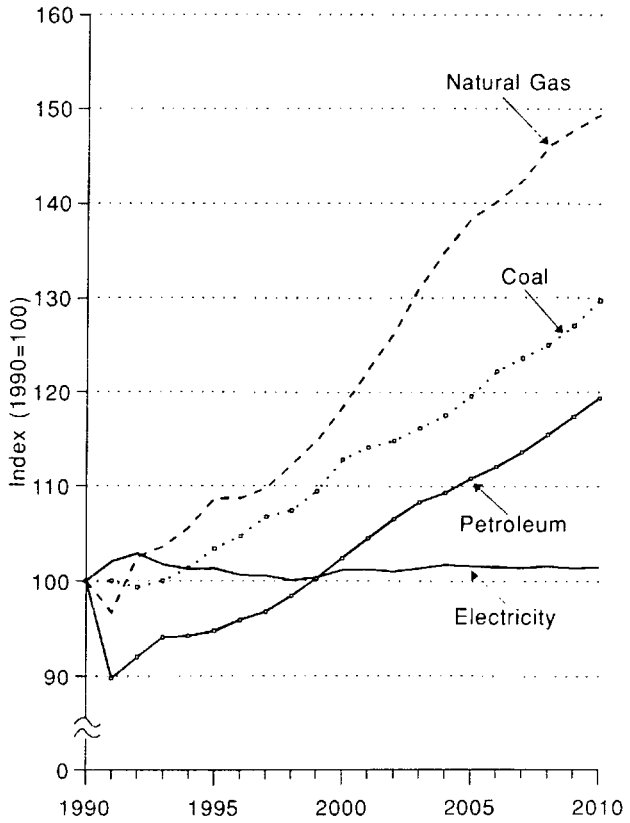
All of the current *AEO93* scenarios indicate that there will be a significant improvement in the efficiency of the U.S. economy during the next 20 years. The range of increase in *total* annual energy consumption is between 0.9 and 1.4 percent, which is much slower than the projected range for GDP growth of between 1.6 and 2.4 percent each year. Thus, the energy needed to produce each unit of output in the economy will be declining.

Electricity will garner a growing share of total energy consumption; however, price-induced conservation, legislative action, and utility investments in demand-side management (DSM) programs are expected to increase efficiency in end-use electricity markets and, thereby, dampen that growth. For instance, the Energy Policy Act of 1992 encourages utilities to use least-cost planning—a process that couples demand-side options

directly with supply-side resource options and should slow growth in demand. Nonetheless, economic growth and growth in demand for electricity are expected to parallel one another. As indicated in Table 11, between 1990 and 2010, the increase in demand for electricity will range from 1.3 to 1.9 percent each year, which is slightly slower than economic growth. This growth in electric demand will result from:

- **Stable prices.** Compared with the prices of other energy sources, the price of electricity is projected to rise at a lower rate (Figure 14).
- **End-use convenience and versatility.** At the point of end use—home, office, and factory—electricity has a wide array of uses. Consumer desire for convenient electric appliances, such as air conditioners, facsimile machines, and computers, is expected to stimulate growth in the demand for electricity and partially offset the effect of improved end-use energy efficiency.
- **Local environmental benefits.** While power plants have considerable environmental impacts, the consumption of electricity in appliances and industrial processes produces virtually no harmful emissions.

Within the end-use sectors, the demand for electricity will increase more robustly in the commercial and industrial sectors than in the residential sector. A projected population growth rate of less than 1 percent per year restrains growth in residential energy demand, while stronger economic growth—combined with the continued penetration of electricity-using technologies and processes, particularly in the industrial sector—leads to more rapid consumption of electricity in the commercial and industrial sectors.



Note: It should be noted that the line for petroleum reflects unusually high oil prices as a result of the invasion of Kuwait.

Source: Table A3.

Compared with other energy sources, the price of electricity is projected to be stable.

Resource Planning

Competitive forces continue to grow in the electricity arena, especially in the market for new resources. Moreover, a new planning paradigm is developing that requires utilities to review a wide array of options to meet growth in the demand for electricity. Among the options being considered are: increasing the output of existing generating plants, extending the lives of existing generators, importing power from other countries (including Canada and Mexico), increasing investment in DSM resources, purchasing power from nonutility generators, and constructing new power plants.

Extending Existing Plant Capabilities. As the demand for electricity grows, it is likely that utilities' first response will be to extend the lives and increase the output of existing plants. Slowed growth in the demand for electricity during the 1970s and 1980s resulted in the underutilization of the capacity of many utilities—especially those with coal-fired capacity. In 1970, for instance, coal-fired plants were operating at a 69-percent capacity factor; by 1978, that utilization rate had declined to 53 percent. Over the next decade, utilization of those plants is expected to increase, and by 2000, they should again be operating at the 1970 capacity levels where they remain through the rest of the forecast period. Few fossil-steam plants are expected to be retired over the forecast period. Utilities have reported plans to retire 10.8 gigawatts of fossil-steam capacity, and it is assumed that an additional 27.4 gigawatts of capacity will be retired rather than life-extended or repowered.

Table 11. U.S. Electric Power Projections for 2010

	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil and Gas Recovery	Low Oil and Gas Recovery
Net Demand[a] (billion kilowatthours)						
Sales by Utilities	2,713	3,730	3,927	3,523	3,724	3,731
Self-Generation by Nonutilities[b]	111	182	203	171	184	183
Net Energy for Load (billion kilowatthours)	**2,915**	**3,984**	**4,186**	**3,769**	**3,980**	**3,983**
Net Electricity Imports	2	54	54	54	54	54
Purchase from Nonutilities	106	408	549	286	387	435
Generation by Utilities	2,808	3,521	3,583	3,429	3,539	3,494
Generation by Fuel Type—Utility and Nonutility (billion kilowatthours)						
Coal	1,593	2,032	2,179	1,908	1,967	2,122
Oil	122	174	168	170	173	179
Gas	364	735	786	644	798	639
Nuclear	577	636	647	636	636	636
Renewables/Other[c]	371	536	554	527	536	536
Total	**3,026**	**4,112**	**4,335**	**3,885**	**4,110**	**4,112**
Capacity—Utility and Nonutility (gigawatts)						
Coal	305	352	377	332	341	370
Oil/Gas	216	282	302	257	293	264
Nuclear	100	102	105	102	102	102
Renewables	87	113	116	112	113	113
Other	23	31	31	31	31	31
Total	**732**	**880**	**930**	**834**	**879**	**880**
Fossil Fuel Consumption—Utility and Nonutility (quadrillion Btu)						
Coal	16.4	20.3	21.6	19.4	19.8	21.3
Oil	1.3	1.8	1.7	1.7	1.8	1.9
Gas	3.5	6.7	7.0	6.2	7.2	6.0
Cumulative Utility Retirements from 12/31/90 (gigawatts)	--	**47**	**47**	**47**	**47**	**47**
Cumulative Additions from 12/31/90 (gigawatts)	--	**195**	**245**	**149**	**194**	**195**
Utility (Announced)	--	59	59	59	59	59
Utility (Not Announced to Date)[d]	--	65	86	43	67	62
Nonutility (Announced)	--	21	21	21	21	21
Nonutility (Not Announced to Date)	--	50	78	26	47	53
Average Electricity Prices[e] (1991 cents per kilowatthour)						
Capital	2.9	2.1	2.1	2.0	2.1	2.1
Fuel	1.7	2.7	2.9	2.5	2.6	2.8
O&M	2.2	2.1	2.0	2.2	2.1	2.1
Total	**6.8**	**6.9**	**7.0**	**6.7**	**6.8**	**7.0**

[a]Demand is expressed net of demand-side management.

[b]Nonutilities include cogenerators, small power producers, independent power producers, and all other sources that produce electricity for self-use or for delivery to the grid, except electric utilities.

[c]For utilities, renewables include pumped storage hydroelectric plus a small quantity of petroleum coke. For nonutilities, this category also includes waste heat, blast furnace gas, coke oven gas, and anthracite culm.

[d]Additions in this category are primarily facilities whose construction is projected beyond 2000, which utilities and nonutilities are not required to report to EIA.

[e]Prices represent average revenue per kilowatthour of sales over all customer classes.

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

Sources: Tables A4, A5, B4, B5, C4, C5, F4, F5, G4, and G5.

Importing. Although not a major source of electricity at the national level, imported electrical power is very important to some regions of the United States that have access to Canadian or, to a lesser extent, Mexican generating resources. Historically, Canada, with its hydroelectric power generation sources, has provided electricity to a number of these areas. In recent years, however, a long-term drought has caused wide swings in Canada's ability to produce electricity from hydroelectric sources. Through the 1970s and mid-1980s, net U.S. imports grew steadily, reaching a high of 46 billion kilowatthours in 1987 (2 percent of supply), before the drought-induced reduction to only 2 billion kilowatthours in 1990. Based on power contracts between Canadian and U.S. utilities, net imports of electricity are projected to return to nearly 1.4 percent of electricity supply in the United States by 2010.

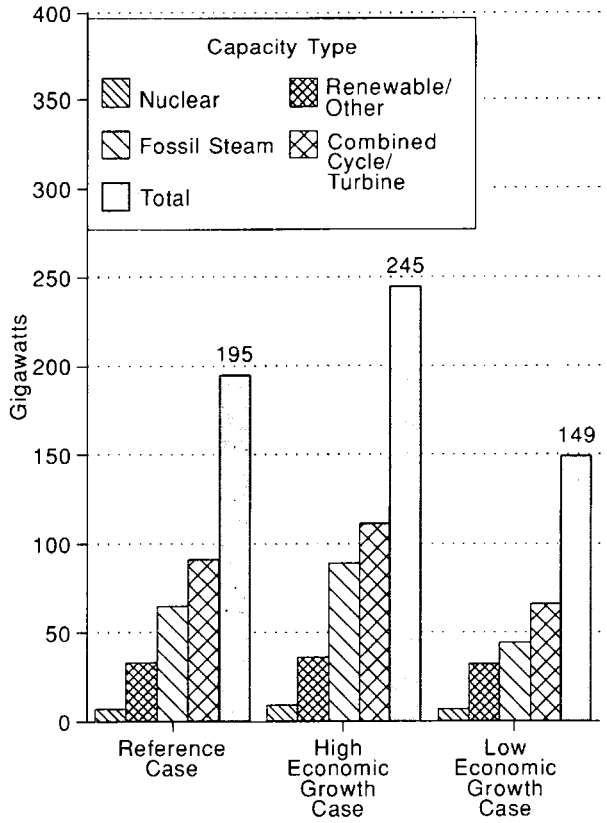
DSM Programs. According to utility reports, the impacts of utility-sponsored DSM programs, although uncertain, will be fairly significant. The Energy Policy Act of 1992 encourages the use of least-cost planning, which in turn provides additional stimulus to increase investments in DSM programs. Many utilities are already instituting programs designed to reduce their peak load and, thus, reduce their need for new generating resources. According to utility reports, investments in DSM programs reduced peak demand by 25 gigawatts in 1990 and will reduce it by 56 gigawatts by the year 2000, which accounts for approximately 10 percent of utility needs.

Purchasing from Nonutilities. The Energy Policy Act of 1992 is also spurring growth in purchases of electricity from nonutilities. Although some industries have generated their own power for many years, nonutility generators did not become important suppliers to utilities until after the Public Utility Regulatory Policies Act (PURPA) was enacted in 1978. PURPA guaranteed certain classes of nonutility generators (primarily cogenerators and small power producers) a market for any excess power they produced. As a result, beginning in the early 1980s, nonutility sales to utilities grew by more than 30 percent annually, and almost equaled the amount generated for their own use by 1990. Recent revisions to the Public Utility Holding Company Act of 1935 (PUHCA) are expected further to stimulate nonutility sales growth. By removing the obstacles to open competition between utility and nonutility suppliers, the revisions to PUHCA have created a new class of wholesale electric power generators. Electric power generated by nonutilities is expected to account for between 8 and 13 percent of the electric power that utilities provide by 2010.

Adding New Capacity. Even with increases in existing plant outputs, extensions in existing power plant lives, imports, and purchases of power from nonutilities, between 149 gigawatts and 245 gigawatts of new electric capacity will be needed over the entire forecast horizon (Figure 15). A small increase in the rate of growth in the demand for electricity, 0.6 percentage points annually across the Low and High Economic Growth Cases, for instance, results in a difference in capacity needs of nearly 100 gigawatts.

How much of this new capacity will be owned by utilities and how much will be owned by nonutilities is not certain. If historical trends continue, however, the nonutility share will be substantial. Between 1980 and 1985, nonutility capacity increased by 6 gigawatts,

Figure 15. Cumulative Additional Capacity Requirements, 2010



Sources: Table A5, B5, and C5.

Between 149 and 245 gigawatts of new electric capacity will be needed over the entire forecast horizon.

while utility capacity increased by 77 gigawatts. Between 1986 and 1990, however, nonutilities accounted for a larger share of the net capacity change, increasing by 20 gigawatts while utility capacity increased by 33 gigawatts.[27] Of the projected capacity needs, nonutilities are expected to supply between 33 percent and 41 percent.

Between 1990 and 2000, a total of between 81 gigawatts and 101 gigawatts of new capacity (both utility and nonutility) will be needed. Utilities and nonutilities have already announced plans to provide two-thirds or more of this capacity. In all cases, more than 50 percent of the needed additions through 2000 will come from gas-fired electricity generation. (Many utilities have excess capacity to serve baseload needs and will be adding gas-fired combined-cycle and combustion turbines to serve intermediate and peak needs.)

After 2000, existing capacity will be fully utilized and new capacity will be needed to serve all categories—baseload, intermediate, and peak load. At that time, coal-fired additions will be increasingly used to meet baseload requirements: they will account for 36 to 62 percent of capacity needs between 2000 and 2010. Many of the coal-fired plants added after 2005 are likely to be advanced clean-coal plants. The Energy Policy Act of 1992 increases research and development efforts for clean-coal technologies and will likely make them commercially available soon after 2000; gas-fired plants will still account for a large portion of new additions, however, as they continue to be added to serve mainly intermediate and peak load needs.

Ultimately, the quantity and types of capacity provided will be driven by the growth in demand for electricity and the relative costs of new resources.

Fossil Fuels for Electricity Generation

Throughout the forecast period, coal-fired power plants will continue to produce the bulk of electricity consumed in the United States, and by 2010, coal will fuel approximately half the power forecast—although there will be substantial increases in gas-fired capacity. In addition, gas will surpass nuclear power and become the second most important fuel for electricity generation, because it will be needed to provide capacity to serve intermediate and peak load requirements, and some baseload requirements, and because its relatively low emissions of sulfur dioxide, carbon, and nitrogen oxides make it an attractive option for environmentally conscious States and utilities.

The change in generation shares of the various fuels parallels the capacity additions situation described above. Gas accounts for an increasing share of total generation requirements with the addition of large numbers of the gas-fired plants needed between 1990 and 2000; however, coal-fired plants are added after 2000 to serve new baseload requirements—thus coal maintains its generation share. Over the entire forecast period, coal's share of total utility and nonutility generation declines from its 53-percent share in 1990. By 2000, its share ranges from 48 percent to 50 percent and by 2010 it ranges from 48 percent to 52 percent. The share of generation provided by natural gas increases from 12 percent in 1990 to between 15 and 19 percent in 2010—depending on assumptions about natural gas resources. (Higher gas recovery leads to greater dependence on gas and lower dependence on coal, while lower recovery has the opposite effect.)

Although utilities are expected to continue to rely heavily on coal-fired plants, compliance with the provisions of the Clean Air Act Amendments of 1990 (CAAA90) will necessitate some changes from current practices. Utilities are projected to increase their use of low-sulfur coal and natural gas, purchase sulfur dioxide allowances from other utilities, and add flue gas desulfurization equipment (scrubbers) to some older units (Table 12). Overall, however, the provisions of CAAA90 will have little effect on average national electricity prices, although some utilities' customers will be more severely affected. As a result of CAAA90, total utility emissions of sulfur dioxide will be reduced substantially during the next 20 years (Figure 16).

Nuclear Power for Electricity Generation

Nuclear plants produced a record 613 billion net kilowatthours of electricity in 1991—a 6-percent increase from the previous year. This level represented 21.7 percent of all the electricity generated by utilities and was up from 20.5 percent in 1990. During the first 6 months of 1992, the nuclear share was also 21.7

[27]Utility capacity data are from the Form EIA-860, "Annual Electric Generator Report"; nonutility data for 1980 and 1985 are from the Edison Electric Institute Statistical Yearbook 1988, page 7; and nonutility data for 1990 are from the Form EIA-867, "Nonutility Power Producer Report."

Table 12. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

Change in	2000	2010
Scrubber Retrofits (gigawatts)	6.9	9.7
Coal Production (million tons)		
Low Sulfur	90	110
Medium Sulfur	-28	-66
High Sulfur	-68	-72
Utility Natural Gas Consumption (quadrillion Btu)	-0.03	0.29
Electricity Price (1991 cents per kilowatthour)	0.06	0.06
SO_2[a] Allowances Traded (thousand tons)	903	880
SO_2[a] Allowance Cost (1991 dollars per ton)	375	666

[a]SO_2 is sulfur dioxide.

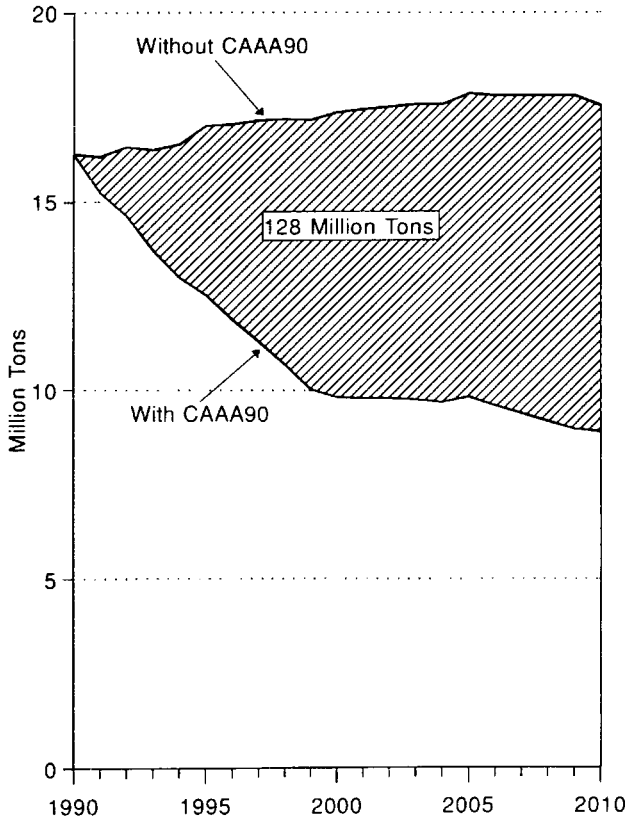
Note: The values for scrubber retrofits, coal production, utility natural gas consumption, and electricity prices in the table represent the difference in results from two scenarios, one incorporating CAAA90, the other without CAAA90.

Source: Energy information Administration, *AEO93* Forecasting System: Reference Case With CAAA90, run AEO93B.D0918921; Reference Case Without CAAA90, run NOCAA.D0924921.

percent. However, the nuclear share of total electricity generation, including nonutilities, was 19.8 percent in 1991. Moreover, the average nuclear capacity factor (utilization rate) increased for the second consecutive year, reaching 70.2 percent, an increase of 4.2 percentage points over the 1990 value and the highest level in the industry's history. The general improvement in plant performance resulted from: a greater emphasis and increased expenditures on plant maintenance; a gradual shift to longer fuel cycles; better operator training; improved instrumentation and control systems; and fewer units in the historically low-performing first fuel cycle. The effects of these factors are expected to be long term, thereby offsetting future age-related performance degradation and maintaining the average nuclear capacity factor slightly above its current level.

The progress of the U.S. nuclear power industry in 1991 and 1992 can be viewed from two perspectives: the operating performance and economics of currently operable units; and the progress on new plant designs and their prospects for future commercialization.

Figure 16. Expected Utility Sulfur Dioxide Emissions, 1990-2010



Source: *AEO93* Forecasting System.

Under the Clean Air Act Amendments of 1990, total utility emissions of sulfur dioxide will be reduced substantially during the next 20 years.

Current Nuclear Plant Status

In December 1991, there were 111 operable U.S. nuclear generating units with a total capacity of 100 gigawatts. For the second year in a row, no new units received operating licenses in 1992. Furthermore, no new reactors have been ordered since 1978, and many of the units ordered since 1971 have been canceled. Currently, eight nuclear units, with a total net capacity of 10 gigawatts, remain in the construction pipeline. Of these, five are in an indefinitely deferred construction status, and three (Comanche Peak 2 and Watts Bar 1 and 2) are actively under construction. In May 1991, the Tennessee Valley Authority (TVA) restarted its Browns Ferry 2 unit, which had been shut down since 1985 while safety, management, and technical concerns were resolved. And in November 1991, the Nuclear Regulatory Commission (NRC) established the procedures, criteria, and standards governing license

renewal for extending the operating licenses of nuclear power plants for up to 20 years beyond the original 40 years with its approval of the final rule on nuclear power plant license renewal.

Economics, sometimes influenced by regulatory considerations, have led to the retirement of some units prior to the expiration of their operating licenses. In February 1992, for instance, the Yankee Atomic Electric Company (YAEC) decided to permanently close its 32-year-old, 167-megawatt Yankee Rowe unit, which had not been operating since October 1991. The unit was officially shut down in August 1992, when the NRC granted YAEC a "possession-only" license. An announcement that the 24-year-old, 436-megawatt San Onofre 1 unit would be permanently retired also came in early 1992—that unit is expected to cease operation by the end of the year. Finally, in August 1992, Portland General Electric Company announced plans to permanently close its 17-year-old, 1,104-megawatt Trojan nuclear plant by 1996, when a capital investment of about $150 million would be required to replace the plant's steam generators.

Continuing Nuclear Activities

Although there have been no new orders for nuclear power plants that have not been subsequently canceled in almost 20 years, manufacturers would like to resume plant construction. To that end, the industry is developing new standard plant designs that include advanced light-water reactors (ALWRs)—which are classified as either evolutionary or mid-size advanced plants—and non-LWR modular advanced designs. The evolutionary designs, producing about 1,300 megawatts per unit, are improved versions of the LWR plants currently in operation. They incorporate engineering safety features that are simpler relative to those in current LWRs, as well as technological advances. The overall design of these evolutionary plants includes passive safety features that provide operators with increased time (over existing plants) to respond appropriately to safety-related events. The mid-size ALWR designs also build on current LWR technology; at 600 megawatts, however, they are roughly one-half the size of the evolutionary plant designs.

Both the evolutionary and mid-size ALWR plants are being designed to meet the industry criteria developed by the Electric Power Research Institute and nuclear utilities, with the close cooperation of the Department of Energy. The Department has also contributed funding for the design and demonstration of the ALWRs and mid-size advanced plants. The industry's goal is to have at least one evolutionary and one mid-size ALWR design available for commercial order by the mid-1990s, based upon completion of first-of-a-kind engineering and prior certification of the designs by the NRC.

The non-LWR modular advanced designs—the modular high-temperature gas-cooled reactor (MHTGR) and the advanced liquid metal reactor (ALMR)—are scheduled for commercial availability approximately one decade later. Both are standardized modular designs that allow for the incremental addition of generating capacity. Each relies on the reactor's inherent characteristics or passive safety systems to meet regulatory safety requirements. It is expected that these non-LWR modular advanced plants will require integrated testing of a full-scale prototype to support NRC design certification and to provide a demonstration of their performance capabilities.

In addition to the certification of new plant designs, legislated nuclear licensing reform, such as that contained in the Energy Policy Act of 1992, will be a necessary but not sufficient condition to prompt new orders. The licensing reform provides for one-step licensing, that is, a combined construction permit and operating license. The nuclear provisions of the Energy Policy Act of 1992 are taken into account in *AEO93*. *AEO93* further assumes that:

- Progress will be made on the high-level waste repository, and that interstate compacts (cooperative agreements) for the disposal of low-level nuclear waste will be established.
- The industry will continue to have access to financial protection through extension of the Price-Anderson Amendments Act of 1988 or a similar type of liability coverage.
- A form of turnkey pricing (vendor acceptance of fixed-price contracting) or risk-sharing will be available to utilities.
- Regulators will ensure utilities an adequate return on their investment in nuclear plants.
- All unit licenses will be redefined for all cases. Nuclear operating licenses are issued for a 40-year period. Through 1982, this period was defined to begin with the issuance of a construction permit; after 1982, the period was defined to begin with the issuance of an operating (low power) license. The NRC has issued a ruling that permits a utility holding a license issued before 1982 to apply for a redefinition of its license to recoup its construction time.

- Because capacity requirements are determined in part by economic growth, each projection is based on different assumptions. In particular, the projections assume different completion dates for plants that are currently under construction, or whose construction has been indefinitely deferred, and different numbers of new orders.

Nuclear Capacity Projections

The Reference Case projects that one newly ordered 600-megawatt unit will begin initial operation during the forecast period. Also, as the demand for electricity grows, two (Bellefonte 1 and WNP 1) of the five (Bellefonte 1 and 2, WNP 1 and 3, Perry 2) indefinitely deferred units are projected to be completed, and 5 of the 12 units eligible for license renewal during the forecast period are projected to have their operating licenses renewed (2.8 gigawatts) and to be life-extended for 20 years. Seven existing units, totaling 3.8 gigawatts, that are not life-extended are assumed to be retired after 40 years of operation.

The High Economic Growth Case assumes that two or three units, totaling 1,800 megawatts, will be ordered. It is assumed that all newly ordered units will be financed such that the risk is shared by the vendor, utility, and/or the government. In addition, assumed plant completion dates differ by scenario, with one additional deferred unit being completed as a result of higher demand for capacity in the High Economic Growth Case.

Renewable Energy Sources for Electricity Generation

Renewable energy is produced from fuel sources that are naturally replenished and do not generally have associated fuel costs. Although these fuels represent promise, reliability concerns are currently limiting their use by U.S. electricity producers. For example, the unpredictability of wind patterns and velocities can affect wind-powered generators, clouds can prevent sunlight from reaching solar panels, and patterns and levels of precipitation can affect hydroelectric generation. Thus, renewable energy must be considered a supplemental, rather than baseload, source of power—although technologies such as hydropower and geothermal are exceptions to this general rule.

All *AEO93* scenarios project that the generation of electricity from geothermal, municipal solid waste (MSW), and biomass sources will grow substantially during the next two decades, as renewable fuel sources solidify their role in electricity production (Table 13). Much of that increase will occur in the nonutility sector, where independent power producers, encouraged through the provisions of PURPA, will build smaller generating units for sales of electric power to the grid. Although no major technological breakthroughs are assumed, steady increases in market penetration will occur as a result of research and development, gradual acceptance of new technologies, and increases in the costs of conventional fuels. Provisions of CAAA90

Table 13. U.S. Renewable Electric Generating Capacity Projections for 2010
(Gigawatts)

Technology	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High World Oil Price	Low World Oil Price
Conventional Hydropower	75.1	76.9	76.9	76.9	76.9	76.9
Geothermal	2.6	8.5	8.5	8.5	9.7	7.3
Municipal Solid Waste	2.0	11.4	13.9	10.9	11.4	11.4
Biomass/Other Waste[a]	6.0	8.1	8.3	7.2	8.1	8.1
Solar Thermal	0.4	1.9	1.9	1.9	2.2	1.7
Solar Photovoltaic	0.0	([b])	([b])	([b])	([b])	([b])
Wind	1.4	6.3	6.3	6.3	7.3	5.3
Total Renewable	**87.4**	**113.1**	**115.9**	**111.7**	**115.5**	**110.7**

[a]Includes wood, wood waste, and other biomass.
[b]Less than 0.05 gigawatt.
Note: Forecasts of renewable electric generating capacity for the High and Low Oil and Gas Recovery Cases are the same as for the Reference Case.
Sources: **1990:** Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. **Projections:** Tables A6, B6, C6, D6, and E6.

should also play a role, because renewable fuels are generally pollution-free. The Energy Policy Act of 1992 contains several provisions that will affect renewables, as discussed later in this section. Growth in MSW generation is predicated on its increasing attractiveness as a major waste disposal method, especially with the growing scarcity of landfill sites.

Research and Development. Research and development activity has a major effect on market penetration because it can improve the cost and performance characteristics of various technologies. Photovoltaic cell efficiency, for example, has been improving rapidly; advances in materials for temperature and corrosion resistance are helping geothermal performance; and wind turbine designs with advanced features and operating characteristics are becoming available. As performance characteristics of new technologies improve, both in terms of cost and reliability, market acceptance will follow.

Energy Costs. Conventional energy costs also have the potential to influence the penetration of renewable generating technologies, both in terms of capacity additions and in terms of how capacity is dispatched. Although the projections in this report do not anticipate any dramatic shifts in these costs, they are expected to rise steadily throughout the period. In particular, after 2000, increased costs of natural gas may make renewable fuels an alternative for intermediate and peak load requirements for electricity producers.

Environment. Environmental considerations will continue to make renewable sources (other than hydroelectricity) attractive for electricity production. The emission allowance markets established under CAAA90 provide an advantage for renewables because replacing fossil fuel generation substantially reduces emissions. If a carbon tax was imposed, carbon-free renewables would have a second advantage. With the exception of hydropower, renewables generally result in small negative environmental impacts. Growth in hydropower has trailed off since the mid-1980s, principally because of heightened concern for environmental risks. New dam construction causes dramatic ecological changes; thus, many sites—such as rivers designated as "wild and scenic" and rivers flowing through wilderness areas—are now specifically prohibited by law as sites for dam construction. The need to maintain features that allow for fish passages and to maintain instream flows can also be a hurdle for new hydroelectric capacity and capacity scheduled for relicensing. There is an initial 2 gigawatts of capacity scheduled for relicensing in 1993, lesser amounts through 2000, and 1 to 2 gigawatts annually through 2010. Although all projections in this report assume that relicensing of existing capacity will occur, the process itself represents a significant uncertainty for the forecast.

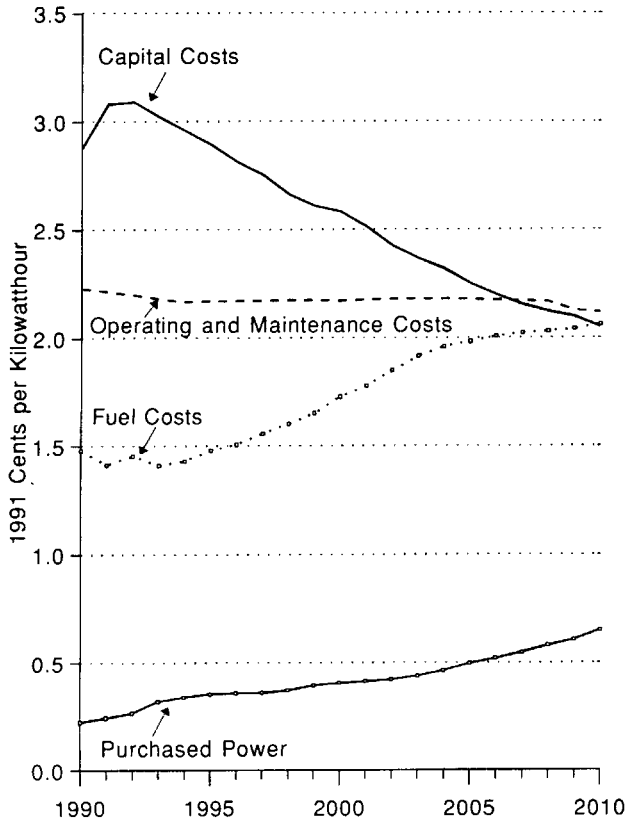
Legislative Effects. The Energy Policy Act of 1992 will have a measurable impact on certain renewable technologies. Its provisions include a permanent 10-percent investment tax credit for solar and geothermal projects, and a 10-year production credit for wind and biomass plants that are brought on line between 1994 and 1999. As part of the reform of PUHCA, provisions for access to utility transmission lines were provided. Such access will make it easier for small independent power producers to market power. It is expected that additional electric generating capability from wind, solar, and geothermal sources will result from that legislation. It is expected that the legislation will yield additional capacity for these technologies of almost 3 gigawatts by 2010. This increment is about 20 percent of the capacity that would have been expected without the legislation. For wind, the technology expected to show the greatest increase in capacity additions, the impact of the legislation on available capacity is about a 30-percent increase, compared with projected capacity absent the law. Additional biomass capability is not expected from the legislation because this fuel source is limited by available resources.

Oil Prices and the Economy. Table 13 shows the impacts of macroeconomic activity and world oil prices on projected renewable fuels generating capability in the Low and High Economic Growth and World Oil Price Cases. In general, lower economic activity and lower world oil prices should reduce expected capability, while higher economic growth and higher world oil prices would result in a capacity increase. The spread across the cases is not great, however, because most renewables will be limited by other factors, such as resources available and market acceptance, rather than oil prices and economic activity.

Electricity Prices

All *AEO93* scenarios presented here indicate that, during the 1993 to 2010 timeframe, the nationwide demand for electric power will increase, but that the average price per kilowatthour will remain relatively flat because rising costs per kilowatthour for fuel and purchased power will be offset by a decline in capital costs per kilowatthour (Figure 17). The decrease in the capital component of price (capital costs per kilowatthour) is driven mainly by a relatively flat return on invested assets (dollars returned on ratebase) spread

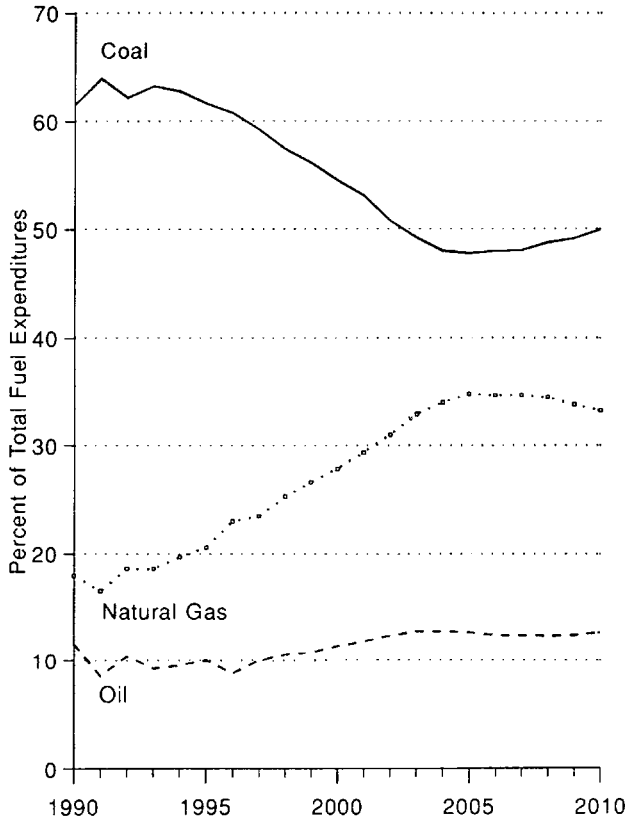
Figure 17. Components of Electricity Price, 1990-2010 (Reference Case)



Source: Table A4.

The average price per kilowatthour of electricity will remain relatively flat because rising costs per kilowatthour for fuel and purchased power will be offset by a decline in capital costs per kilowatthour.

Figure 18. Percent of Utility Fuel Expenditures by Fuel Type, 1990-2010 (Reference Case)



Source: *AEO93* Forecasting System run AEO93B. D0918921.

From 1990 to 2005, the share of fuel expenditures for coal decreases as the share for natural gas increases. After 2005, when new baseload capacity is required, the share of fuel expenditures for coal increases again.

over increasing sales. That is to say, utilities will meet growth in demand by increasing the output of existing plants and by purchasing electricity from nonutilities as well as by building new plants. The operation and maintenance component of price is expected to remain flat during this period.

The rise in fuel costs is attributable mainly to an increased reliance on natural gas to produce electricity (Figure 18). By 2005, it is expected that the consumption of natural gas for electric power generation will have nearly doubled from 1990 levels. Likewise, by 2010, the price of natural gas is expected to have nearly doubled relative to its 1990 price. (During the same period, the price of coal is only expected to rise by 30 percent.) Thus, the price increase of natural gas will have a large impact on the fuel component of the price of electricity.

If the economy grows more rapidly, as assumed in the High Economic Growth Case, higher fuel and purchased power costs will cause electricity prices to increase. Although higher economic growth will result in significant increases in the need for new capacity for utilities, the impact on capital costs per kilowatthour is insignificant because the effect of the increased asset base (ratebase) is offset by a lower rate of return on invested assets and higher electricity sales. The lower rate of return is the result of lower borrowing costs and lower returns on the equity component of the cost of capital.

The average electricity price (in 1991 cents per kilowatthour) was 6.8 cents in 1990 and rises to 6.9 cents in 2010 in the Reference Case (Table 11). This price reacts to influences in the High Economic Growth Case (rising to 7.0 cents with rising demand growth) and to those in the Low Economic Growth Case (falling to 6.7 cents with decreasing demand growth).

Issues Generating Uncertainty

Although the *AEO93* scenarios present the likely range of outcomes for variations in economic growth and gas and oil recovery, there remains a potential for more divergent results. Factors that could significantly alter the projections include the growing importance of environmental externalities (particularly carbon emissions) and the possibility that electricity's share of the energy markets could grow more rapidly than expected if there is stronger penetration into the various end-use markets.

Many State Public Utility Commissions require that utilities include explicit estimates of the costs of environmental impacts in their planning process. At least 17 States now have mechanisms for incorporating environmental externalities (social costs associated with environmental degradation that are not normally reflected in power pricing) into the processes utilities use for resource planning.[28] If this trend becomes more widespread, or if legislation restricting or taxing carbon emissions is enacted, it could have a significant impact both on the fuels used to generate electricity and on electricity prices. As a result of the higher electricity prices, investments in conservation would become more attractive and the demand for electricity would be lower than projected.

Still, the demand for electricity could grow more rapidly than projected. Electricity is expected to account for an increasing share of U.S. energy consumption as electric appliances and processes continue to penetrate the end-use markets. Many research and development efforts are now under way to develop new economical uses of electricity, such as improved heat pumps, industrial motors, electric vehicles, and lighting equipment. There is considerable uncertainty over whether the trend toward increasing penetration of electricity-consuming appliances in the end-use sectors will accelerate.

Paradoxically, the same growing environmental concerns could lead to higher demand for electricity. Although the consumption of fossil fuels at electric power plants causes significant environmental impacts, there are few, if any, impacts at end-use sites (homes, offices, and factories). Economies of scale and relative efficiencies make reducing environmental impacts at energy-generating sites less costly than at end-use sites. In addition, power plants are unlikely to be located within the major urban centers where some pollutants are now concentrated. CAAA90 mandated that zero-emissions vehicles account for a small share of vehicle sales in certain cities. As a result, manufacturers are investing heavily in research and design of electric vehicles. If this research leads to lower cost, longer range electric vehicles, their penetration could extend beyond the cities where the Act requires them.

Summary

Through 2000 and beyond, electricity's role in U.S. energy markets will continue to grow. Relatively stable prices and consumers' desire for convenient, versatile electric appliances combine to stimulate increased consumption of electricity. End-use efficiency improvements dampen growth in energy consumption, but, even so, growth in the demand for electricity lags only slightly behind economic growth.

Coal-fired plants continue to account for more than half of total electricity generation. However, the share of generation contributed by gas-fired plants, both utility and nonutility, increases significantly. By 2010, gas-fired plants surpass nuclear as the second most important generating resource. While utilities still continue to depend on coal-fired plants and increase their reliance of gas-fired plants, they are also expected to make investments in demand-side management programs.

[28]National Association of Regulatory Utility Commissioners, *A Survey of State PUC Activities to Incorporate Environmental Externalities into Electric Utility Planning and Regulation* (Washington, DC, May 1990).

5. Coal Outlook

The United States is endowed with vast quantities of coal. Even at significantly increased levels of demand, the Nation enjoys coal supplies that greatly exceed its reserves of oil and natural gas.

Having surpassed petroleum in 1984, coal now accounts for a greater share of U.S. primary energy production than any other fuel. Driven by a 30-percent increase in domestic electricity sector coal demand in the Reference Case and a 122-percent increase in exports, its importance is projected to be even greater by 2010 (Table 14 and Figure 19). Production gains are expected to occur both east and west of the Mississippi River, with producers east of the Mississippi increasing production by 22 percent and producers west of the river increasing their production by 48 percent, although in actual tons the gains are about the same (Figure 20).

Background

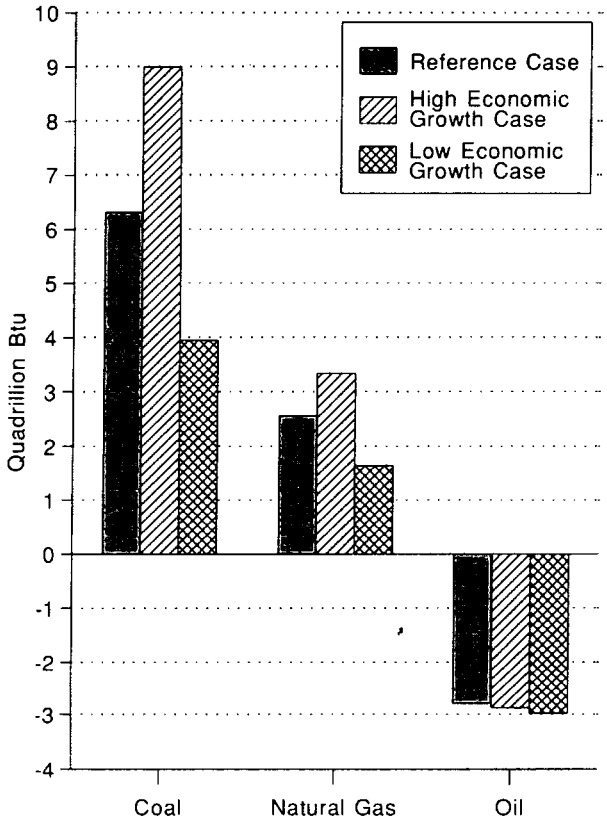
The single effect of the Energy Policy Act of 1992 on the *AEO93* coal supply forecasts relates to the future funding of the Health and Benefits Fund of the United

Table 14. Coal Supply, Disposition, and Prices, 1990 and 2010
(Million Short Tons)

	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil and Gas Recovery	Low Oil and Gas Recovery
Production	1,029	1,362	1,490	1,258	1,337	1,407
Exports	106	235	288	185	235	235
Imports	3	11	11	11	11	11
Stock Withdrawals[a]	-27	-4	-5	-2	-4	-4
Consumption						
Residential/Commercial	7	5	5	5	5	5
Industrial	76	93	95	92	93	94
Coke Plants	39	31	32	31	31	31
Electricity	774	1,006	1,079	956	981	1,051
Total	**895**	**1,135**	**1,210**	**1,084**	**1,111**	**1,181**
Discrepancy[b]	4	-1	-1	-1	-1	-1
Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	59.06	61.71	57.01	58.97	60.17
Industrial	34.77	41.22	42.61	39.82	40.78	41.55
Coking Plants	49.40	66.08	69.16	62.10	65.17	66.83
Electricity	31.52	37.49	39.09	36.31	37.22	38.16
Average Delivered[c]	**32.72**	**38.68**	**40.24**	**37.44**	**38.40**	**39.28**

[a]A negative (-) represents an increase to inventories.
[b]Balancing item: the sum of production, net imports, and stock withdrawals minus total consumption.
[c]Weighted average prices. The weights used are consumption values by sector.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Tables A10, B10, C10, F10, and G10.

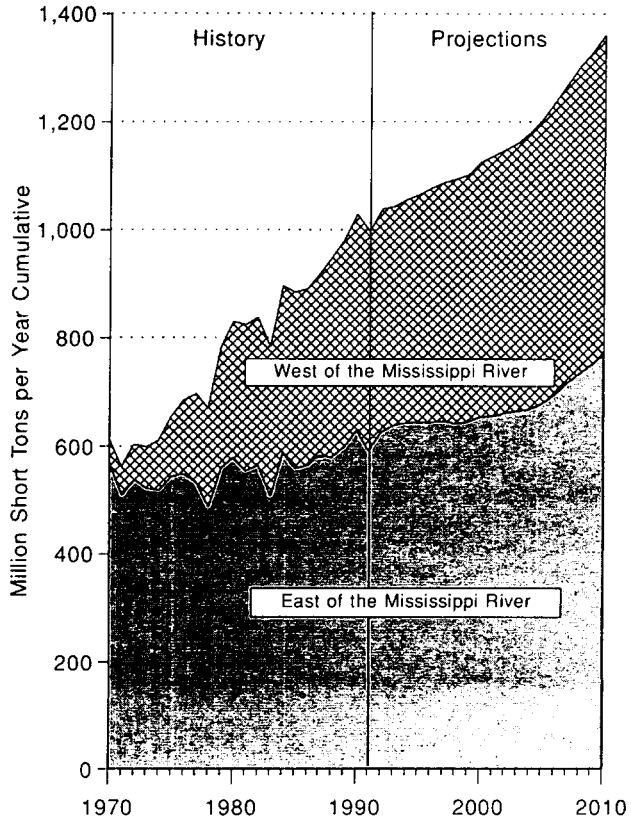
Figure 19. Change in Annual U.S. Production of Fossil Fuels, 1990-2010



Sources: Tables A1, B1, and C1.

In the Reference Case and the High and Low Economic Growth Cases, coal continues to account for a larger share of incremental production of fossil fuels than natural gas and oil from 1990 to 2010.

Figure 20. East-West Division of Coal Production, 1970-2010 (Reference Case)



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991*. **Projections:** Table A10.

Producers of coal east of the Mississippi River increase production by 22 percent and those west of the river increase production by 48 percent by 2010.

Mine Workers of America. As a result of this legislation, the liabilities of company contributions will likely be redistributed; however, because total program costs will remain relatively unaffected, there is no significant effect on estimated production costs. Thus, all *AEO93* coal forecast scenarios simply reflect the most recent increase in health care contribution levels devised to balance expenditures and contributions.

This chapter focuses on the growth in coal use for electricity generation—the country's principal use of this fuel—and in coal exports, which become an even more important factor by 2010, and notes that there will be only a moderate rise in coal prices between 1993 and 2010 in the Reference Case. The effects of the High and Low Oil and Gas Recovery Cases on the Reference Case price projections are slight (dropping from $38.68 per short ton of delivered coal to $38.40 in the High Oil and Gas Recovery Case and rising to $39.28 per ton in the Low Oil and Gas Recovery Case). Greater effects are seen in the High (a rise to $40.24) and Low (a drop to $37.44) Economic Growth Cases because of a wider spread in the demand for coal by electricity producers (Table 14).

Growth in Coal Use for Electricity Generation

The electricity sector accounts for 97 percent of the increase in total U.S. coal consumption over the Reference Case forecast period. Of the increased distribution of coal to this sector, 166 million short tons (or 81 percent) are projected to be met by coal producers west of the Mississippi. Net additions to

coal-fired power plant capacity occur primarily after 2005, although utilities and nonutilities together should increase net coal capacity by about 10 gigawatts by 2005.

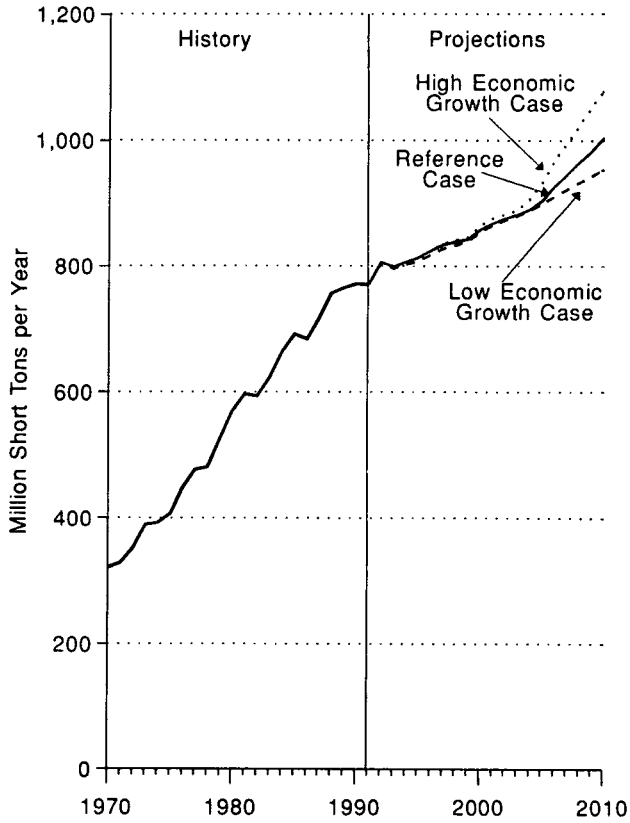
Through 2005, increases in coal consumption for electricity generation occur mainly as a result of increased utilization of coal-fired power plants. Nevertheless, with coal-fired power plants representing the largest share of total U.S. generating capability, coal continues to fuel 47 percent of the Nation's total electricity requirements in 2005.

Relative to the Reference Case, higher levels of electricity sector coal consumption occur in both the Low Oil and Gas Recovery and High Economic Growth scenarios. In the Low Oil and Gas Recovery scenario, less optimistic estimates of natural gas reserves lead to some displacement of gas-fired generation with coal-fired, resulting in a 5-percent higher level of electricity sector coal consumption. In the High Economic Growth scenario, electricity demand that is 4 percent higher than the Reference Case results in a rise of 3 percent in electricity sector coal consumption (Figure 21). Between 1990 and 2005, much of the variation in total electricity demand in the High and Low Economic Growth scenarios is accounted for by changes in gas-fired generation.

After 2005, however, a number of factors combine to make coal-fired power plants the first choice for new generating capacity, supplanting gas-fired combined cycle and turbine power plants. These factors include: rising natural gas prices; a growing need for baseload generating capacity;[29] and the expectation that new advanced coal-burning technologies (e.g., integrated gasification combined-cycle and fluidized-bed combustors) will become commercially feasible for electric power generation. Advanced coal-burning technologies are projected to reduce the total costs (capital, operating, and fuel) of coal-fired generation, primarily through improvements in conversion efficiencies. In addition, relative to flue gas desulfurization (FGD) equipment, these technologies offer enhanced capabilities for reducing sulfur dioxide emissions. The Energy Policy Act of 1992 provides for the continued funding of the Department of Energy's Clean Coal Technology Demonstration Program—the primary Federal program for supporting the development of new advanced coal-burning technologies.

As a result, 36 gigawatts (net of retirements) of new coal-fired capacity is added during the final 5 years of the Reference Case forecast, and coal fuels virtually all of the additional electricity generation required to satisfy demand. Despite these gains, coal captures only a 49-percent share of total U.S. electricity generation in 2010 in the Reference Case, compared with 53 percent in 1990. This decline is primarily attributable to the inroads made by natural gas during the preceding portion of the forecast period. In the Reference Case, growth in coal consumption for electricity generation during the final 5-year period comes close to matching that realized during the first 15 years, and is relatively evenly divided between consumers east and west of the Mississippi.

Figure 21. U.S. Coal Consumption for Electricity Generation, 1970-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1991*. **Projections:** Table A10, B10, and C10.

In the High Economic Growth Case, electricity demand that is 4 percent higher than in the Reference Case results in a rise of 3 percent in electricity sector coal consumption by 2010.

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

In 2010, the Low Oil and Gas Recovery and High Economic Growth Cases again show more coal consumption for electricity generation, 4 percent and 7 percent greater than in the Reference Case, respectively. This difference is the result of higher natural gas prices in the Low Oil and Gas Recovery Case and higher overall electricity demand in the High Economic Growth Case.

Coal consumption forecasts for the industrial steam and coking coal demand sectors in the Reference Case are marked by a 22-percent increase and a 21-percent decrease, respectively, between 1990 and 2010. In the industrial steam coal sector, the most significant change is the increased use of coal for cogeneration. The reduced level of domestic coke production (and, therefore, coking coal consumption) is supplanted with imports from other countries, reflecting a constant level of U.S. coke demand for domestic pig iron production. The decline in domestic coke production is expected because of increased environmental costs. There is virtually no difference in non-electricity coal demand across the High Economic Growth and Low Economic Growth scenarios by 2010, because demand in these sectors is less sensitive to changes in economic growth than to changes in industrial structure such as the closing of coke plants for environmental reasons and the shift to less energy-intensive industries.

Growth in Coal Exports

Rapid growth in U.S. coal exports, primarily after 2000, represents the second most important factor in the *AEO93* Reference Case coal forecasts. The 122-percent rise in U.S. coal exports projected over the forecast period is based on three major supply factors: declining coal production in Europe as trade barriers fall, limited availability of Russian natural gas for export, and limited capability of other coal exporting countries to increase their shipments after 2000. Steam coal imports by both Western Europe and Asia for electricity generation are projected to increase over the forecast. Virtually all of the additional shipments of U.S. export coal over the forecast are expected to go to Western Europe. More than 90 percent of U.S. coal exports should continue to originate from coal mines east of the Mississippi River.

The macroeconomic scenarios assume that economic growth rates in other countries will vary in the same direction as U.S. economic growth rates. Relative to the Reference Case, U.S. coal exports are 21 percent lower in the Low Economic Growth Case and 23 percent higher in the High Economic Growth Case, reflecting different levels of world coal demand. The spread between the High and Low Economic Growth scenarios widens over the forecast, reflecting the sensitivity of world coal trade to assumed changes in the economic drivers.

Price Patterns

In the Reference Case, both minemouth and delivered coal prices will rise moderately during the forecast period (1.6 and 0.8 percent per year on average, respectively, in 1991 dollars). For minemouth prices, the forecast reflects a reversal of the steady downward trend in real coal prices that started in 1978. Major factors contributing to this trend in minemouth prices are a decline in excess production capacity, and increased production of costly central Appalachian low-sulfur coal in response to provisions of the Clean Air Act Amendments of 1990 (CAAA90) and higher U.S. coal exports. Mitigating these effects somewhat is increased production of cheaper subbituminous coal in the West. The lower growth of delivered prices results from the fact that export coal is, on average, of higher quality and hence higher priced than the coal for domestic use, pushing up the average minemouth prices.

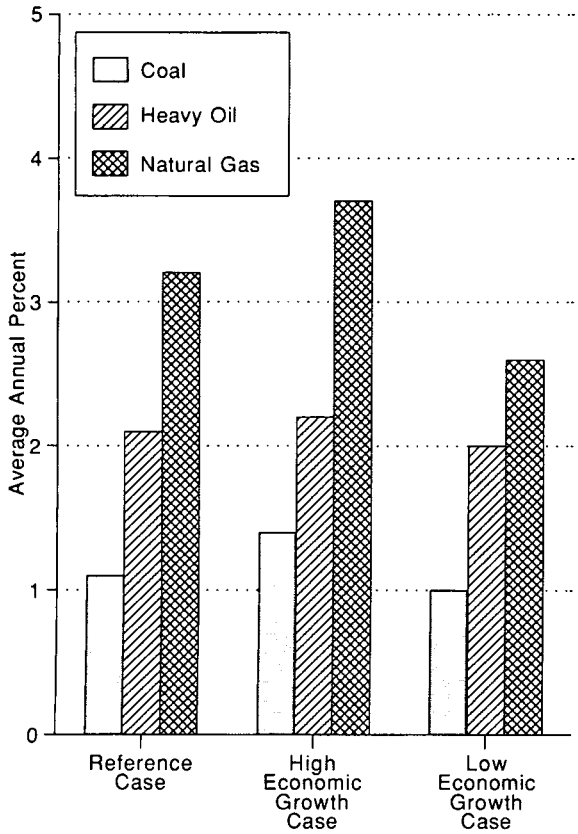
Coal's price advantage over oil and gas in the electricity sector increases over the forecast (Figure 22). Nevertheless, through 2005, natural gas prices remain low enough that new gas-fired generating capacity is generally more economical than new coal-fired plants for meeting increased electricity demand.[30] As a result, coal's 1990 share of 53 percent of total U.S. electricity generation erodes to a 49-percent share by 2010.

Response to the Clean Air Act Amendments of 1990

Projections of slow growth in electricity sector coal demand for the eastern United States, together with the more stringent sulfur dioxide emission restrictions of the CAAA90, suggest that in all scenarios domestic coal distribution from mines east of the Mississippi will increase by only a small amount during the forecast period (Table 15). Most of the increase in electricity sector coal demand projected for the East between 1990 and 2010 is forecast to be met by producers of low-

[30]The capital costs for gas-fired units are about 40 percent of those for coal-fired generating units.

Figure 22. Average Annual Growth Rates of Fossil Fuel Prices to Electricity Suppliers, 1990-2010



Sources: Tables A3, B3, and C3.

Coal's growing price advantage over oil and gas in the electricity sector is evident in these scenarios.

sulfur coal west of the Mississippi. Moreover, all scenarios show some shifts from the high-sulfur coal of northern Appalachia to the low-sulfur coal of central Appalachia.

The CAAA90 provides utilities with four viable options for bringing existing coal-fired generating units into compliance: (1) retrofit units with FGD equipment; (2) transfer or purchase excess sulfur dioxide emission allowances; (3) continue to burn high-sulfur coal but operate units at a lower capacity utilization rate; or (4) switch to low-sulfur fuels. The first two options essentially allow coal-fired generating units to continue burning high-sulfur coal, while the third and fourth options result in a displacement of high-sulfur coal with low-sulfur fuels, including low-sulfur coal, natural gas, low-sulfur oil, and renewables. A comparison of the Reference Case projections with a forecast that assumes CAAA90 was not enacted shows a shift in production of 110 million tons from medium- and high-sulfur coal to low-sulfur coal by 2010. This increased demand for low-sulfur coal occurs primarily because of the new sulfur dioxide emission restrictions placed on existing coal-fired generating capacity. Relative to the distribution of coal, the demand shift from medium- and high-sulfur coal to low-sulfur coal implies a 31-million-ton increase in western coal production (primarily low-sulfur coal from the Powder River Basin) in 2010 as a result of CAAA90, and a decrease of 64 million tons from the predominantly high-sulfur Interior region, as defined in Table 15.

The addition of new coal-fired generating capacity will, to a certain extent, offset the projected decline in high-sulfur coal demand attributable to fuel-switching at existing coal-fired plants. New coal-fired capacity must be equipped with the best available control technology (BACT) for reducing sulfur dioxide emissions, and, therefore, could use high-sulfur coal. The tendency to choose high-sulfur coal will be most pronounced for new coal-fired plants sited east of the Mississippi, as this is where most of the Nation's high-sulfur coal reserves are located, and for new advanced coal-burning technologies that offer enhanced capabilities for reducing sulfur dioxide emissions. The Reference Case projects that 64 gigawatts of new coal-fired generating capacity will come on line over the forecast period (although 18 gigawatts are planned for retirement).

Uncertainties

All *AEO93* coal forecasts incorporate provisions of CAAA90. Key in these forecasts is the assumption that utilities will be granted the full flexibility allowed under the legislation to meet the specified reductions in sulfur dioxide emissions. This flexibility, however, often directly conflicts with the least-cost planning objectives of State Public Utility Commissions (PUCs). For example, a utility's least-cost compliance strategy developed on the basis of CAAA90 may not be identical to a least-cost solution calculated by a State PUC if other considerations, such as the local economy, the State's environmental quality, and cost allocation to ratepayers, are factored into the solution. In addition, there have been efforts in some States to preserve or increase the use of local coal.

Furthermore, the uncertainty surrounding the outcome of the air toxics studies mandated by CAAA90 may influence a utility's decision regarding whether it should switch to low-sulfur coal or retrofit with FGD equipment. This uncertainty arises because FGD equipment, in addition to reducing sulfur dioxide

Table 15. U.S. Coal Distribution by Demand and Supply Regions, 1990, 2000, and 2010
(Million Short Tons)

Demand Region[a]	Supply Region[b]	1990	2000			2010		
			Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth
East		**335**	**339**	**341**	**337**	**368**	**389**	**353**
	Appalachia	279	286	282	283	294	304	286
	Interior	53	46	50	47	58	65	59
	Western	3	7	10	7	17	19	8
Central		**447**	**497**	**501**	**496**	**584**	**627**	**558**
	Appalachia	103	104	103	105	99	91	103
	Interior	151	167	164	171	207	217	189
	Western	194	225	234	220	278	319	266
West		**132**	**145**	**147**	**144**	**174**	**187**	**163**
	Appalachia	(c)	0	0	0	0	0	0
	Interior	(c)	0	0	0	0	0	0
	Western	132	145	147	144	174	187	163
Total Domestic Distribution		**914**	**981**	**990**	**977**	**1,127**	**1,202**	**1,073**
Exports		**104**	**144**	**177**	**111**	**235**	**288**	**185**
	Appalachia	99	129	159	101	203	250	160
	Interior	1	3	7	0	19	24	14
	Western	4	12	12	10	13	14	12
Total Distribution		**1,018**	**1,125**	**1,167**	**1,088**	**1,362**	**1,490**	**1,258**

[a]Demand Regions: **East:** CT, ME, MA, NH, RI, VT, NY, NJ, DE, DC, MD, PA, VA, WV, AL, FL, GA, KY, MS, NC, SC, TN; **Central:** IL, IN, MI, MN, OH, WI, AR, LA, NM, OK, TX, IA, KS, MO, NE; **West:** CO, MT, ND, SD, UT, WY, AZ, CA, NV, ID, OR, WA, AK.

[b]Supply Regions: **Appalachia:** PA, OH, MD, WV, VA, KY(eastern), TN, AL; **Interior:** IL, IN, KY(western), IA, MO, KS, AR, OK, TX, LA; **Western:** ND, SD, MT, WY, CO, UT, AZ, NM, WA, AK.

[c]Less than 500,000 short tons.

Notes: Historical data exclude some small shipments of unknown destination. Totals may not equal sum of components because of independent rounding.

Sources: **1990:** *Coal Distribution January-December 1990*, DOE/EIA-0125(90/4Q) (Washington, DC, April 1991). **Projections:** *AEO93* Forecasting System runs LMAC93.D0916924, AEO93B.D0918921, and HMAC93.D091692C.

emissions, reduces emissions of many air toxics. Thus, a utility could submit an acid rain compliance plan that reflects a decision to switch fuels, only to find that a few years later it must retrofit a unit with FGD equipment to reduce emissions of air toxics. The uncertainties that stem from these additional factors, which utilities and State PUCs must consider in formulating acid rain compliance strategies, could affect future CAAA90 compliance strategies and, as a result, patterns of coal production, demand, distribution, and pricing.

Also related to CAAA90 is the uncertainty surrounding coal transportation costs, and the implications of that uncertainty regarding future coal distribution patterns and prices. Transportation cost is an important determinant of delivered coal prices, particularly for shipments of coal from western fields, where average transportation distances to coal consumers are relatively great. With the large growth in low-sulfur coal demand resulting from CAAA90, the opportunity exists for the substantial penetration of western coal into markets east of the Mississippi River. The amount of this penetration will depend to a large extent on the transportation cost structure that western coal producers and their customers will face.

Another uncertain factor that could substantially affect the future of U.S. coal is the extent to which concern over possible climatic change from the burning of fossil fuels might limit the use of coal. Such concerns could instigate more vigorous energy conservation efforts, or even a tax based on the carbon content of fuels. To be compatible with future environmental goals, the hopes 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 on other Federal and State initiatives.

Summary

In summary, the highlights of the *AEO93* coal forecasts, as reflected in the Reference Case, are as follows:

- U.S. coal production east of the Mississippi River increases by 22 percent, while production west of the river increases by 48 percent over the forecast period. Although producers east of the Mississippi are positioned to capture most of the growth in exports, producers west of the Mississippi will capture much of the growth in electricity sector coal demand.

- Over the forecast period, a 232-million-ton-per-year increase in electricity sector coal consumption and a 129-million-ton-per-year increase in U.S. coal exports represent the two most important factors underlying the projected rise in U.S. coal production. The electricity sector is projected to account for 97 percent of the increase in total U.S. coal consumption over the forecast period. Most of the additional exports of U.S. coal will go to Western Europe to meet increased demand for coal for electricity generation and to supplant expected declines in domestic coal supply.

- Demand for industrial steam coal is projected to rise by 17 million tons over the forecast period, accounting for the only increase expected in the non-electricity demand sectors. Increased use of coal for cogeneration represents the primary factor underlying the increase in industrial steam coal demand.

- Minemouth and delivered coal prices are projected to rise moderately over the forecast period, by 1.6 and 0.8 percent per year on average, respectively.

- The stringent sulfur dioxide emission restrictions of CAAA90 will cause coal production to shift 110 million tons from medium- and high-sulfur coal to low-sulfur coal by 2010. For the most part, this shift is attributable to the sulfur dioxide emission reductions mandated for existing coal-fired generating capacity.

Coal combustion is an important contributor to incremental carbon emissions that are released into the atmosphere. The effects of carbon emissions and the projected levels of those emissions are discussed in Chapter 6.

6. Carbon Emissions

In 1990, energy-related activity in this Nation caused 1,340 million metric tons of carbon to be emitted into the atmosphere.[31] Reference Case projections indicate that these emissions will reach an annual level of 1,641 million metric tons by the year 2010. Although carbon emission levels will also increase under each of the other scenarios, the level of increase varies. As shown in Table 16, emission level projections differ most in the High and Low Economic Growth Cases, which show levels of 1,725 million metric tons and 1,555 million metric tons, respectively. The High and Low Oil and Gas Recovery Cases, with levels of 1,640 and 1,643 million metric tons, respectively, indicate that, although emission levels will increase, the difference between these two scenarios will be only 3 million metric tons.

Following a brief description of the processes that create atmospheric carbon and the possible effects of carbon emissions on the world's climate, this chapter discusses emission trends by sector of the U.S. economy and by fuel.

Some believe that the accumulation of certain gases in the atmosphere may cause potentially dangerous climate changes worldwide. Commonly referred to as greenhouse gases, these gases absorb radiation emitted from the Earth and trap heat that would otherwise be dissipated out of the atmosphere. When emitted through naturally occurring processes, greenhouse gases maintain the Earth's mean surface temperature at life-sustaining levels. In fact, without them and the natural warming effect they produce, the Earth's surface would be 60 degrees Fahrenheit cooler than it is today.[32]

The dynamics of atmospheric carbon dioxide production and control within the global ecological system are only partially understood, despite substantial research

Table 16. Summary of Carbon Emissions by Sector and Fuel, with Projections for 2010
(Million Metric Tons)

	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil and Gas Recovery	Low Oil and Gas Recovery
Emissions by Sector						
Residential	91.5	84.4	85.7	82.9	85.8	82.6
Commercial	60.9	64.0	64.9	62.9	64.7	63.1
Industrial	272.5	310.0	320.4	299.6	317.0	303.3
Transportation	435.0	555.8	595.9	515.6	553.5	555.1
Electric Utilities	480.6	626.4	658.3	593.6	619.2	639.2
Total Emissions	**1,340.5**	**1,640.6**	**1,725.2**	**1,554.6**	**1,640.1**	**1,643.3**
Emissions by Fuel						
Petroleum	581.6	704.0	744.6	660.5	700.0	705.3
Natural Gas	272.6	354.3	366.1	337.8	371.1	332.4
Coal	486.3	582.3	614.5	556.2	568.9	605.7
Total Emissions	**1,340.5**	**1,640.6**	**1,725.2**	**1,554.6**	**1,640.1**	**1,643.3**

Note: Totals may not equal sum of components because of independent rounding.
Sources: Tables A15, B15, C15, F15, and G15.

[31]Carbon emissions are typically expressed in metric tons to facilitate comparisons among countries. One metric ton equals 1.102 short tons.

[32]The information in this and the following paragraphs is from U.S. Congress, Office of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases*, OTA-O-482 (Washington, DC, U.S. Government Printing Office, Feb. 1991), Chap. 2.

efforts currently under way. The interaction of carbon emissions with the natural control mechanisms of oceans, clouds, and forests is a complex and difficult system to model. Nevertheless, large, complex models are being developed and used to study the dynamics of weather and carbon dioxide concentrations in order to forecast the effects on global climate change. Scientific opinion remains divided on whether global climate change has been detected.

Water vapor and carbon dioxide are the two primary naturally occurring greenhouse gases. Of these, water vapor is the more significant. Global water vapor concentrations are not materially affected by human economic activity. Carbon dioxide emissions also occur naturally; for example, the decomposition and respiration of plants each results in emissions of about 50 billion metric tons of carbon per year. But the photosynthesis process in plants absorbs about the same amount (100 billion metric tons). The oceans also emit about 90 billion metric tons of carbon each year, but they absorb slightly more—about 93 billion metric tons. Despite the apparent balance between emission and absorption of carbon, scientists do not yet understand how much carbon dioxide the oceans can absorb. Furthermore, the relationship between carbon dioxide levels and increased cloud cover (clouds block some of the energy that normally passes through the atmosphere before getting trapped) is not well understood.

Human activity contributes between 6 billion and 7 billion metric tons of carbon annually, most of which is the byproduct of the incomplete combustion of fossil fuels. Although this contribution is relatively small, emissions are incremental in nature and, over time, they have increased the concentration of carbon dioxide in the atmosphere. According to many general climate models, this increase will eventually lead to a rise in the mean temperature of the Earth and, thereby, result in changes in global climate patterns.

The fact that fossil fuel combustion is the major source of incremental carbon emissions makes projections of fossil fuel consumption of interest to those concerned with increases in the concentration of atmospheric carbon dioxide.

Calculating Emissions

The combustion of fossil fuels results in emissions of carbon in the form of both carbon dioxide and carbon monoxide. Carbon monoxide emissions oxidize to become carbon dioxide in a relatively short time. Fuel type and the efficiency of the combustion process are the primary determinants of the ultimate level of carbon emissions. Emission level determinants for carbon are most readily calculated by applying carbon coefficients to fossil fuel combustion. Fossil fuels that are consumed for noncombustion purposes—such as petrochemical feedstocks, asphalt, road oils, and lubrication oils—are usually excluded from the energy balances before these calculations are made.

The carbon coefficients used in *AEO93* projections are given in millions of metric tons of carbon per quadrillion British thermal units (Btu) of energy consumed (Table 17).[33] For purposes of these calculations, carbon emitted as a result of biomass combustion is assumed to be offset by photosynthesis of living plants.

Table 17. Carbon Coefficients
(Million Metric Tons of Carbon per Quadrillion Btu)

Fuel	Carbon Coefficient
Coal	**25.45**
Natural Gas	**14.54**
Petroleum Products	
Distillate	19.97
Diesel	19.97
Kerosene	19.46
Jet Fuel	19.46
Liquefied Petroleum Gas	17.26
Motor Gasoline	19.42
Residual Fuel Oil	21.66

Source: Gregg Marland and Angela Pippin, "United States Emissions of Carbon Dioxide to the Earth's Atmosphere by Economic Activity," *Energy Systems and Policy*, Vol. 14 (1990), pp. 319-336. Note that the carbon coefficients given in this source were in kilograms of carbon per billion joules. This measure is converted to million metric tons of carbon per quadrillion Btu by multiplying by 1.055.

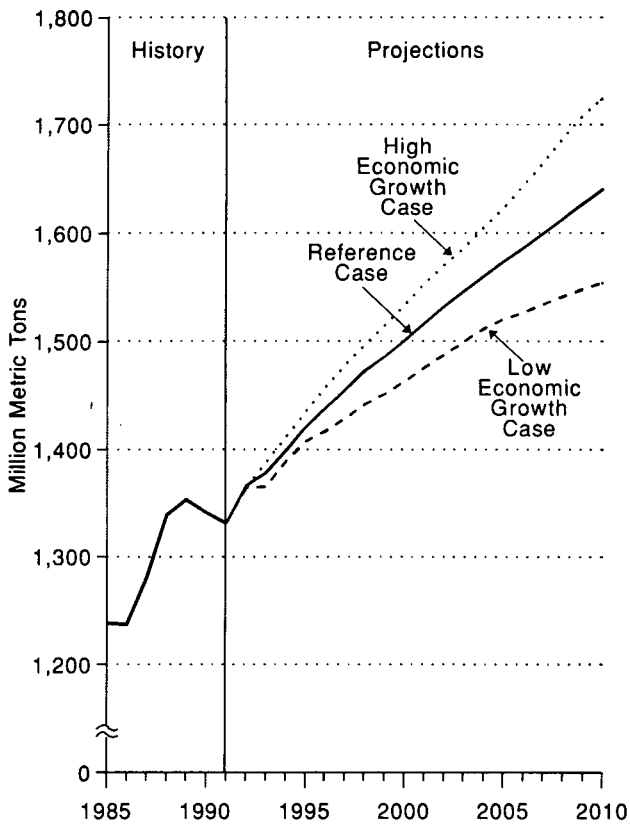
[33]These coefficients were developed by Gregg Marland and Angela Pippin, "United States Emissions of Carbon Dioxide to the Earth's Atmosphere by Economic Activity," *Energy Systems and Policy*, Vol. 14 (1990), pp. 319-336.

Emission Trends

In 1990, carbon emissions from fossil fuel combustion totaled 1,341 million metric tons. The electric utility and transportation sectors, with emissions of 481 million and 435 million metric tons, respectively, emitted the largest amounts of carbon. (Emissions attributable to self-generation of electricity by nonutility generators are included in the industrial sector.) Direct carbon emissions from the industrial and buildings sectors were substantially lower because their energy consumption is largely electricity, and emissions associated with purchased electricity are accounted for in electric utility sector calculations.

From 1990 to 2010, Reference Case projections indicate that carbon emissions will increase at an average annual rate of 1.0 percent, with total emissions reaching 1,641 million metric tons in 2010. In the High Economic Growth Case, increased energy consumption causes these emissions to grow at an annual rate of 1.3 percent, reaching 1,725 million metric tons in 2010 (Figure 23). Because of the lower energy consumption projected in the Low Economic Growth Case, emission growth is only 0.7 percent per year for a total of 1,555 million metric tons in 2010.

Figure 23. Total U.S. Carbon Emissions, 1985-2010



Sources: Tables A15, B15, and C15.

Increased energy consumption in the High Economic Growth Case, and decreased energy consumption in the Low Economic Growth Case, cause those two forecasts to diverge upwards and downwards, respectively, from the Reference Case.

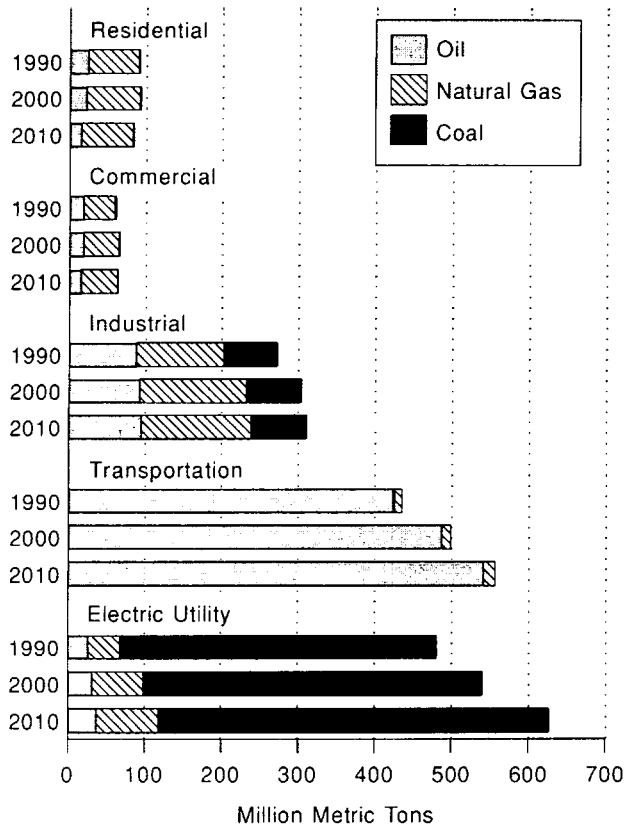
Emissions by Sector

Electric Utilities. The largest contributors to total carbon emissions in the United States, electric utilities emitted 481 million metric tons of carbon in 1990 and are expected to emit 626 million metric tons in 2010. Between 1990 and 2000, utilities are forecast to increase their natural gas consumption by 5 percent and their coal consumption by 0.7 percent each year. Because of this heavier reliance on cleaner-burning natural gas, which is a low-carbon fuel, carbon emissions from this sector are expected to increase by only 1.2 percent annually during that timeframe. After 2000, when utilities must meet new baseload demands for electricity, their consumption of coal will grow at twice the pre-2000 rate, to 1.4 percent per year. As a consequence, utility carbon emissions will increase at a 1.5-percent annual rate during the last 10 years of the forecast period (Figure 24).

Transportation. By 2010, transportation sector emissions are expected to increase from their 1990 level of 435 million metric tons per year to an annual rate of 556 million metric tons. Light-duty vehicles account for approximately half of the energy consumed and carbon emitted by the transportation sector. Although energy efficiency gains will be substantial during the forecast period, they will be outweighed by even larger increases in vehicle-miles traveled. Even though fuel economy of new cars is projected to increase by 24 percent, from 28.0 to 34.6 miles per gallon, it is expected that the fleet fuel economy of light-duty vehicles will increase by 15 percent, from 18.6 to 21.3 miles per gallon from 1990 to 2010. Further, vehicle-miles traveled will increase by 41 percent over that period, resulting in a 22-percent increase in energy consumption by light-duty vehicles.

Buildings. Relatively small quantities of oil and coal are consumed directly by the buildings sector, and increased electrification is expected to reduce direct consumption of these fuels even more. Furthermore, over the forecast period, the buildings sector is expected to increase modestly its use of natural gas, at

Figure 24. U.S. Carbon Emissions by Sector and Fuel, 1990, 2000, and 2010 (Reference Case)



Source: Table A15.

The transportation and electric utility sectors account for the bulk of carbon emissions.

the expense of petroleum and coal. This change will further reduce carbon emissions from this sector. In 1990, buildings emitted 152 million metric tons of carbon, 69 percent of which stemmed from the combustion of natural gas. By 2010, emissions from the buildings sector will decline to 148 millon metric tons, with 77 percent stemming from natural gas. Most newly constructed buildings are expected to rely primarily on electricity and natural gas during the forecast period; thus, only small changes in direct emissions in the buildings sector are projected, regardless of the economic growth rate (Table 16).

Industry. Industrial sector emissions are expected to increase from 273 million metric tons in 1990 to 310 million metric tons in 2010. In the Reference Case, total energy consumption in the industrial sector increases by 1.1 percent annually, while the consumption of electricity and petrochemical feedstocks each increase by 2.0 percent per year. Because electricity emissions are counted in the electric utility sector and feedstocks do not result in carbon emissions, industrial carbon emissions increase by only 0.6 percent annually from 1990 to 2010.

Industrial sector growth is greatly affected by the rate of economic growth. Consequently, in the High Economic Growth Case, industrial carbon emissions increase at a 0.8-percent annual rate, with 2010 emissions reaching 320 million metric tons, but they increase at an annual rate of 0.5 percent, to 300 million metric tons in 2010, in the Low Economic Growth Case. The trend in industrial sector carbon emissions also reflects increased energy efficiency, a greater reliance on electricity and natural gas, and a relative shift from more to less energy-intensive industries.

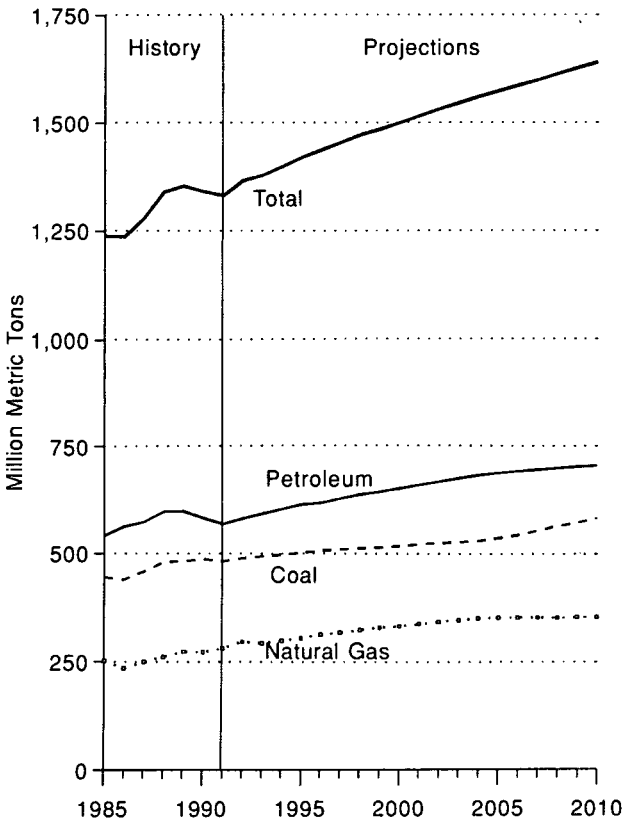
Emissions by Fuel

Oil remains the dominant fuel in the United States. Consequently, even though oil produces 20 to 25 percent less carbon per quadrillion Btu than does coal, combustion of oil results in the emission of more carbon into the atmosphere than the combustion of any other fossil fuel. The second largest source of emissions is coal, and the third is natural gas. In 1990, oil products contributed 43 percent of that year's carbon emissions (582 million metric tons), while coal produced 36 percent (486 million metric tons) and natural gas 20 percent (273 million metric tons). The Reference Case projects that carbon emissions will increase for all fossil fuels (Figure 25).

In 1990, the industrial sector accounted for 44 percent of the total consumption of natural gas, making it the largest consumer of this fuel for combustion purposes; the buildings sector used 38 percent and electric utilities used 15 percent. Over the forecast period, natural gas carbon emissions will grow more rapidly than emissions from either oil or gas. This growth is primarily the result of sharply higher electric utility consumption, which will increase by 3.4 percent annually from 1990 to 2010, and of industrial consumption which will increase by 1.1 percent each year during the same timeframe. By 2010, the industrial sector will produce 41 percent of the carbon emissions from natural gas, while the electric utility sector will account for 23 percent.

Between 1990 and 2010, total carbon emissions from coal are expected to increase at an annual rate of 0.9 percent. As noted above, utility consumption of and emissions from coal combustion will increase at an annual rate of 0.7 percent between 1990 and 2010, but

Figure 25. U.S. Carbon Emissions by Fuel, 1985-2010 (Reference Case)



Source: Table A15.

Under the Reference Case, carbon emissions increase for all fossil fuels.

will double to an annual rate of 1.4 percent thereafter. As a result, utilities will increase their share of coal carbon emissions from 85 percent in 1990 to 87 percent in 2010. Over the same period, the industrial share of emissions from coal will fall from 14 to 12 percent.

Summary

Because of its size and strength, the U.S. economy plays a major role in economic activity that contributes to carbon emissions. Although the Reference Case and other scenarios show that emission levels from U.S. economic activities will rise over the forecast period, important factors are acting as brakes on the velocity and amount of the increase. Notable among these factors are a turn to less energy-intensive industries, better use of energy-efficient technologies, an increase in the use of natural gas, and the efficiency standards contained in the Energy Policy Act of 1992.

This chapter concludes the *AEO93* examination of the outlook for fuels. Chapter 7 compares the EIA forecasts with those from other sources.

7. Comparison with Other Forecasts

This chapter compares this year's Energy Information Administration (EIA) projections with several non-EIA forecasts. The EIA projections incorporate the provisions of the Energy Policy Act of 1992, whereas the non-EIA forecasts were completed before enactment of this law, which accounts for some of the differences between the projections. The Reference Case projections are compared for all four energy sources: oil, natural gas, coal, and electricity. For electricity and coal, the forecasts are compared with projections of High and Low Economic Growth, since these scenarios provide the largest ranges for projections of those energy sources. Because the High and Low World Oil Price Cases best represent the uncertainty involved in the world oil market, the forecasts of the oil industry are compared with these two cases. Gas forecasts are compared with the High and Low Oil and Gas Recovery Cases to demonstrate how the uncertainty inherent in the recovery of oil and natural gas affects the natural gas market. Of the five non-EIA forecasts, only those by the WEFA Group (WEFA), DRI/McGraw Hill (DRI), and the Gas Research Institute (GRI) have projections for all energy sources through 2010. Although the *1992 AGA-TERA Base Case* (AGA) does project prices for all energy sources, it contains only projections of production and consumption for natural gas. The National Economic Research Associates (NERA) and the North American Electric Reliability Council (NERC) provide only electric-utility projections through 2000, while the Edison Electric Institute (EEI) projects electricity sales for both 2000 and 2010. As a result, comparisons with these three forecasts are limited. The Independent Petroleum Association of America (IPAA) published its production and consumption projections, but not its price projections, for petroleum and natural gas through 2000.

Macroeconomic Assumptions

The *AEO93* assumes gross domestic product (GDP) growth rates (based in 1987 dollars) between 1990 and 2010 that range from 1.6 percent per year in the Low Economic Growth Case to 2.4 percent per year in the High Economic Growth Case (Table 18), very similar to

Table 18. Comparison of Macroeconomic Forecasts
(Average Annual Percentage Change, 1990-2010)

Projection	EIA *AEO93*			Other Forecasts			
	Reference	High Economic Growth	Low Economic Growth	WEFA	GRI	DRI	AGA
Real Gross Domestic Product (GDP)[a]	2.0	2.4	1.6	2.4	2.0	[c]2.2	[e]2.2
Inflation[b]	3.9	3.3	5.3	3.6	4.1	[d]3.7	[f]4.1
Real Disposable Income	1.8	2.1	1.5	2.1	NA	NA	2.1

[a]Real GDP in 1987 dollars except where noted.
[b]Based on GDP deflators in 1987 dollars, except where noted.
[c]Real GNP in 1982 dollars. Represents the average growth, assuming annual growth of 2.4 percent between 1990 and 2000 and 2.1 percent between 2000 and 2010.
[d]Average of 1990 to 2000 inflation (3.2 percent) and 2000 to 2010 inflation (4.1 percent), then rounded.
[e]GNP in 1982 dollars.
[f]Based on GNP deflators in 1982 dollars.
NA = not available.
Sources: **EIA:** *AEO93* Forecasting System runs AEO93B.D0918921 (Reference Case), HMAC93.D091692C (High Economic Growth Case), and LMAC93.D0916924 (Low Economic Growth Case). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook*, Vol. 1 (Second Quarter 1992). **GRI:** Gas Research Institute, *Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992), and *Draft of GRI93 Baseline Projections* (Aug. 21, 1992). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992). **AGA:** American Gas Association, *1992 AGA-TERA Base Case* (Jan. 1992).

last year's projections when considered on a comparable basis.[34] Like last year, WEFA assumes the highest base case rate of growth at 2.4 percent per year "based on the Census Bureau's assumptions about high net immigration which lead to a higher population estimate for 2010."[35] GRI and AGA assume the highest inflation rates, excluding the *AEO93* Low Economic Growth. Note that, because AGA and DRI express their macroeconomic assumptions in 1982 dollars for gross national product (GNP) (rather than 1987 dollars for GDP), their growth rates appear to be greater than those for *AEO93*. For the *AEO93* Reference Case, however, economic growth is 2.3 percent in 1982 dollars for GDP, when compared with AGA and DRI's growth rate of 2.2 percent for GNP in 1982 dollars.

Petroleum Projections

Price Projections

Table 19 shows that the base case world oil price projections for 2010 range from a high of $30.62 per

Table 19. Comparison of Petroleum Forecasts
(Million Barrels per Day, Except Where Noted)

Projection	EIA *AEO93*			Other Forecasts				
	Reference	High World Oil Price	Low World Oil Price	WEFA	GRI	DRI	AGA	IPAA
2000								
World Oil Price (1991 dollars per barrel)	**22.90**	**28.50**	**14.10**	**[a]19.44**	**[a]20.80**	**[a]23.15**	**[a]22.25**	**NA**
Crude Oil and NGL Production	**7.3**	**8.3**	**6.0**	**7.9**	**9.2**	**8.1**	**NA**	**7.4**
Crude Oil	5.6	6.6	4.4	6.2	7.5	6.4	NA	5.8
Natural Gas Liquids	1.7	1.7	1.6	1.8	1.7	1.7	NA	1.6
Total Net Imports	**10.8**	**9.2**	**13.6**	**9.3**	**7.6**	**9.2**	**NA**	**9.3**
Petroleum Demand	**19.3**	**18.6**	**20.7**	**18.2**	**17.8**	**18.0**	**NA**	**18.3**
Motor Gasoline	8.0	7.7	8.4	7.6	7.1	7.1	NA	7.3
Jet Fuel	1.9	1.8	2.0	1.6	1.8	1.7	NA	1.8
Distillate Fuel	3.5	3.4	3.7	3.1	3.4	3.4	NA	3.4
Residual Fuel	1.4	1.3	1.8	1.4	1.1	1.3	NA	1.4
Other	4.5	4.4	4.9	4.6	4.4	4.4	NA	4.3
2010								
World Oil Price (1991 dollars per barrel)	**29.30**	**38.10**	**18.10**	**[a]25.22**	**[a]27.23**	**[a]30.62**	**[a]29.15**	**NA**
Crude Oil and NGL Production	**7.4**	**8.3**	**5.1**	**6.8**	**9.3**	**6.9**	**NA**	**NA**
Crude Oil	5.7	6.5	3.5	4.8	7.5	5.2	NA	NA
Natural Gas Liquids	1.7	1.8	1.6	1.9	1.8	1.7	NA	NA
Total Net Imports	**12.2**	**10.3**	**17.0**	**11.4**	**8.8**	**12.1**	**NA**	**NA**
Petroleum Demand	**21.0**	**19.9**	**23.5**	**19.3**	**18.9**	**19.7**	**NA**	**NA**
Motor Gasoline	8.5	8.0	9.3	7.6	7.1	7.3	NA	NA
Jet Fuel	2.2	2.1	2.4	1.6	2.0	2.0	NA	NA
Distillate Fuel	3.8	3.6	4.3	3.2	3.8	4.0	NA	NA
Residual Fuel	1.6	1.5	2.2	2.0	1.2	1.7	NA	NA
Other	4.9	4.6	5.4	4.8	4.9	4.8	NA	NA

[a]Refiner's acquisition cost.
NA = not available.
Sources: **EIA:** *AEO93* Forecasting System runs AEO93B.D0918921 (Reference Case), HWOP93.D0920923 (High World Oil Price Case), and LWOP93.D0920923 (Low World Oil Price Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Summer 1992). **GRI:** Gas Research Institute, *Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992), and *Draft of GRI93 Baseline Projections* (Aug. 21, 1992). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992). **AGA:** American Gas Association, *1992 AGA-TERA Base Case* (Jan. 1992). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Forecast 1992-2000* (Mar. 1992).

[34]The 1992 growth rates ranged between 1.8 and 2.7 percent but were expressed in 1982 dollars for GNP and not 1987 dollars for GDP, as is the case this year. See Chapter 1 for a discussion of the effects of rebasing.
[35]WEFA, *U.S. Long Term Economic Growth Outlook*, Vol. 1, p. 1.11.

barrel for DRI to a low of $25.22 per barrel for WEFA. The *AEO93* Reference Case projects $29.30 per barrel. EIA's High and Low World Oil Price projections of $38.10 and $18.10 represent a wide price range that brackets the projections made by other forecasters for 2010. The forecasts as a group represent a significant reduction in oil price projections by all forecasters. This year's round of projections for the world oil price in 2010 decreased by an average of 15 percent from 1992 forecasts. Several factors account for this large reduction in price projections. The most important factors include a rise in non-OPEC oil production, improved drilling technologies, and the breakup of the Soviet Union. Unlike EIA, DRI does not note an expected rise in OPEC oil production, but simply mentions that increasing control over oil production and pricing policy by Saudi Arabia may put downward pressure on the price of oil. Nonetheless, DRI still projects the highest base case world oil price in both forecast years.

WEFA, in projecting the lowest base case price, expects to see a slowdown of demand growth, brought on by energy efficiency improvements and subsidization of low-carbon fuel use, which will coincide with an increase in supply of oil from 1995 to 1998. As a result, WEFA projects that "real crude prices will fall from 1990 to 2000 at an average annual rate of 1.7 percent. WEFA expects 0.5-percent growth over the entire forecast period from 1990 to 2010."[36]

Production Projections

Table 19 shows that forecasts for crude oil and natural gas liquids production in 2010 range from a high of 9.3 million barrels per day in the GRI forecast to a low of 5.1 million barrels per day in EIA's Low World Oil Price Case. Even though their price projections are about $10 lower, GRI's projection for crude oil production exceeds EIA's High World Oil Price Case by about 1 million barrels per day. In projecting the lowest level of net imports at 8.8 million barrels per day in 2010, GRI assumes that production of crude oil in the United States will see a significant increase during the forecast period as advanced recovery practices, such as horizontal drilling and slim hole technologies, begin to see widespread implementation. In projecting the lowest levels of oil production (other than EIA's low price case), WEFA and DRI predict a 1.3-percent annual decline in domestic oil production through 2010 as imports steadily increase to meet demand. The DRI forecast is based on the expectation that exploration and development spending will shift to foreign areas in the future.

Petroleum Demand

All three of the outside forecasts for petroleum demand fall below the range in the *AEO93* for both 2000 and 2010. EIA projects levels of petroleum demand that range from 19.9 million barrels per day in the High World Oil Price Case to 23.5 million barrels per day in the Low World Oil Price Case in 2010. The outside forecasts range from 18.9 million barrels per day for GRI to 19.7 million barrels per day for DRI. The major difference lies in the projections of motor gasoline consumption. Neither WEFA, GRI, nor DRI project motor gasoline demand to rise above EIA's low of 8 million barrels per day by 2010. Two factors cause this outcome. First, unlike some other forecasts, EIA includes oxygenates as part of motor gasoline consumption. Second, EIA assumes that only 75 percent of the U.S. Environmental Protection Agency (EPA) rated estimates of new car fuel efficiency will be realized on the road, while DRI and the other forecasts assume that on-road efficiency will represent 85 percent of the EPA-rated estimates. EIA based this assumption on an analysis of factors that tend to reduce on-the-road efficiency, such as traffic congestion, rural versus urban travel, and average speed.[37] This assumption significantly lowers EIA's estimate of gasoline efficiency in comparison to the other forecasts, which results in higher estimates of motor gasoline consumption.

Natural Gas Projections

Price Projections

WEFA and GRI's forecasts for the wellhead price of gas for 2010 fall slightly below the range set in the three *AEO93* cases, while DRI's and AGA's price forecasts fall within the range.[38] As Table 20 shows, WEFA and GRI are 9 and 10 cents, respectively, below EIA's lowest estimate of $3.19 per thousand cubic feet in the High Oil and Gas Recovery Case. GRI assumes that "the exploitation of the current inventory of proven advanced practices and new technology which is currently not being used will lead to reduced costs of

[36]WEFA, Summer 1992, p. 8.28.

[37]John D. Maples, *Light Duty Vehicle MPG Gap: Its Size Today and Potential Impacts in the Future.* University of Tennessee Transportation Center in cooperation with Phil Patterson, U.S. Department of Energy, Office of Conservation and Renewables (unpublished, 1992).

[38]The gas resource base assumed for the GRI baseline is equivalent to EIA's High Oil and Gas Recovery Case, based on a discussion between Paul Holtberg, GRI, and Andy Kydes, EIA, on Sept. 24, 1992.

Table 20. Comparison of Natural Gas Forecasts
(Trillion Cubic Feet, Except Where Noted)

Projection	EIA *AEO93*			Other Forecasts				
	Reference	High Oil and Gas Recovery	Low Oil and Gas Recovery	WEFA	GRI	DRI	AGA	IPAA
2000								
Wellhead Price (1991 dollars per thousand cubic feet)	**2.56**	**2.40**	**2.81**	**2.31**	**[a]2.20**	**2.54**	**[a]2.22**	**NA**
Dry Gas Production	**19.9**	**20.3**	**19.4**	**19.5**	**20.4**	**19.8**	**18.4**	**20.3**
Net Imports	**3.0**	**2.8**	**3.0**	**2.6**	**NA**	**2.7**	**NA**	**2.6**
Consumption	**22.8**	**23.1**	**22.4**	**23.6**	**23.0**	**22.2**	**22.3**	**23.3**
Residential	4.7	4.7	4.7	5.2	4.9	4.6	5.1	5.0
Commercial	3.1	3.1	3.1	3.2	3.3	3.1	3.3	3.1
Industrial	8.6	8.8	8.5	8.5	9.8	9.0	9.5	8.3
Electric Utility	4.5	4.4	4.4	4.4	3.4	4.7	3.6	4.7
Other	2.0	2.0	1.9	2.4	1.6	0.9	0.8	2.2
2010								
Wellhead Price (1991 dollars per thousand cubic feet)	**3.68**	**3.19**	**4.44**	**3.10**	**[a]3.09**	**4.13**	**[a]3.35**	**NA**
Dry Gas Production	**20.1**	**21.6**	**18.3**	**21.2**	**22.2**	**20.0**	**21.8**	**NA**
Net Imports	**4.2**	**3.8**	**4.4**	**3.1**	**NA**	**3.3**	**NA**	**NA**
Consumption	**24.2**	**25.4**	**22.8**	**26.0**	**25.8**	**23.2**	**26.2**	**NA**
Residential	4.5	4.6	4.4	5.2	4.8	4.4	5.1	NA
Commercial	3.2	3.2	3.1	3.6	3.6	3.5	4.2	NA
Industrial	8.9	9.3	8.4	8.4	10.9	8.9	10.2	NA
Electric Utility	5.5	5.9	4.7	5.8	4.4	5.3	4.9	NA
Other	2.2	2.4	2.2	2.9	2.1	1.2	1.8	NA

[a]Average acquisition price.
NA = not available.
Sources: **EIA:** *AEO93* Forecasting System runs AEO93B.D0918921 (Reference Case), HGEO93.D0916924 (High Oil and Gas Recovery Case), and LGEO93.D0918923 (Low Oil and Gas Recovery Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Summer 1992). **GRI:** Gas Research Institute, *Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992), and *Draft of GRI93 Baseline Projections* (Aug. 21, 1992). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992). **AGA:** American Gas Association, *1992 AGA-TERA Base Case* (Jan. 1992). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Forecast 1992-2000* (Mar. 1992).

drilling and increased success rates in finding and recovering gas resources."[39] According to GRI, these cost reductions will keep the wellhead price in check beginning in the late 1990s, which is the reason their price projection for 2000, along with WEFA's, is below the lowest *AEO93* projection as well. DRI's projection for 2000 is very close to EIA's Reference Case, but because DRI expects "the wellhead price to rise drastically between 2000 and 2005 as electric utility plants build cheaper combustion turbines to meet their baseload demand,"[40] its 2010 price forecast rises well above the price projected in EIA's Reference Case.

Production Projections

For 2000, GRI's production projection is above the *AEO93* range, whereas AGA's projection is below the range. By 2010, however, both GRI and AGA's projections exceed the *AEO93* range. DRI and WEFA projections are within the *AEO93* range for both years. GRI exceeds EIA's production levels because GRI assumes that technological improvements will keep drilling costs and the wellhead price of gas down and bring increases in production as the exploration and drilling process becomes more efficient. AGA assumes

[39]GRI, "Implications of GRI Baseline Projection," Aug. 11, 1992, p. 17.
[40]DRI/McGraw Hill, Second Quarter, p. 36.

that production will remain demand-constrained through 2000. After 2000, however, AGA projects rapid increases in natural gas demand, which result in increased production over this period. At 20.3 trillion cubic feet (Tcf), which is about the same as GRI's and EIA's High Oil and Gas Recovery Case projections, IPAA projects one of the highest levels of production for the year 2000. Admittedly optimistic in their projection, IPAA assumes "that current regulatory uncertainties will be resolved favorably and that the level of drilling will rebound by 1995."[41]

Consumption Projections

As gas remains at relatively low price levels through 2005, all forecasts expect increased demand around the turn of the century when gas becomes more competitive with oil and coal in the industrial and electric utility sectors. Only one outside forecast falls within EIA's projected range for 2000 (GRI) and 2010 (DRI). At the high end of consumption forecasts for 2010, AGA and WEFA project that 26.2 and 26.0 Tcf, respectively, will be consumed in the United States. AGA projects a higher rate of consumption growth from 2000 (22.3 Tcf) to 2010 (26.2 Tcf) than any of the other forecasts. AGA predicts strong growth in consumption from the industrial and commercial sectors as they expect "natural gas consumption by cogenerators and independent power plants to more than offset expected declines in traditional uses of gas (such as lease and plant fuel, process heating, and steam raising) after the turn of the century."[42] AGA and GRI project the highest levels of consumption in the industrial sector for 2010, while WEFA and EIA (in the High Oil and Gas Recovery Case), counting on a shift from coal-powered to gas-powered generation of electricity after 2000, project the highest levels for electric utilities. AGA's high projection for industrial consumption of gas stems from its belief that gas will cost industrial users 380 percent less than electricity, giving gas a significant price advantage. *AEO93* projections for commercial consumption hover around 3.2 Tcf, lower than all outside projections for the sector because of lower expected growth in the use of commercial gas in the space-cooling market. The *AEO93* projections reflect increased efficiency and relatively lower consumption, attributable to the energy standards mandated in the Energy Policy Act of 1992.

Electricity Projections

Net Energy for Load Projections

Table 21 shows that, with the exceptions of NERA and DRI, all outside projections for net energy from load in 2000 fall within the range of the *AEO93* Low and High Economic Growth Cases (3,353 billion and 3,528 billion kilowatthours, respectively). All outside projections continue to fall within the *AEO93* Low and High Economic Growth Cases in 2010—3,768 billion and 4,186 billion kilowatthours, respectively (Table 21). Although GRI predicts the lowest wellhead price for gas in 2000 and 2010 (Table 20), it apparently does not believe this drop will translate to large increases in the use of gas for electric generation, as it also projects the lowest levels of gas use for electricity generation through 2010.

Capability Projections

EIA has the lowest utility capability projections for both 2000 and 2010. WEFA's capability projection is higher because nonutility capability is reported with utility capability in its projections. It is also important to note that for DRI and GRI, capability represents nameplate capability and not net summer capability. (Nameplate capability represents the manufacturer's reported capacity for each turbine generator, while net summer capability represents the actual tested capacity of the unit at peak demand.) Nameplate capability is generally 5 to 10 percent greater than net summer capability, which explains why the GRI and DRI projections of capability appear higher than the other forecasts.

Sales Projections

All outside forecasts except for EEI are within the range of electricity sales projections in *AEO93* for 2010. For 2000, however, NERA's projected electricity sales of 3,590 billion kilowatthours is almost 300 billion kilowatthours above the high end of the *AEO93* projections. EEI's projection of 3,340 billion kilowatthours is also higher than EIA's High Economic Growth projection.

[41]IPAA, Mar. 1992, p. 8.
[42]AGA, Jan. 1992, p. 1.5.

Table 21. Comparison of Electric Utility Forecasts

(Billion Kilowatthours, Except Where Noted)

Projection	EIA *AEO93*			Other Forecasts					
	Reference	High Economic Growth	Low Economic Growth	WEFA	GRI	DRI	NERC	EEI	NERA
2000									
Average End-Use Price									
(1991 cents per kilowatthour)	**6.89**	**6.97**	**6.77**	**6.92**	**6.11**	**6.27**	**NA**	**NA**	**NA**
Residential	8.25	8.35	8.08	8.34	6.89	7.25	NA	NA	NA
Commercial	7.43	7.54	7.27	7.57	6.50	6.72	NA	NA	NA
Industrial	5.19	5.30	5.08	4.85	4.95	4.90	NA	NA	NA
Net Energy for Load	**3,440**	**3,528**	**3,353**	**3,467**	**3,372**	**3,531**	**3,514**	**NA**	**3,870**
Coal	1,673	1,677	1,666	1,719	1,730	1,798	1,771	NA	1,790
Petroleum	137	153	115	150	105	144	77	NA	180
Natural Gas	418	452	375	418	318	401	375	NA	500
Nuclear	633	636	632	620	662	697	667	NA	630
Hydroelectric/Other[a]	324	325	324	353	293	324	264	NA	390
Nonutility Sales to Grid	215	247	201	170	238	143	262	NA	300
Net Imports	39	39	39	37	27	24	73	NA	80
Electricity Sales	**3,214**	**3,298**	**3,131**	**3,211**	**3,097**	**3,225**	**NA**	**3,340**	**3,590**
Residential	1,047	1,067	1,033	1,111	1,089	1,135	NA	1,061	1,200
Commercial/Other[b]	1,003	1,009	998	1,000	972	1,001	NA	1,019	1,140
Industrial	1,163	1,222	1,099	1,100	1,036	1,090	NA	1,259	1,250
Capability (gigawatts)[c]	**715.8**	**720.1**	**712.9**	**[d]744.9**	**808.1**	**823.1**	**727.0**	**NA**	**791.3**
Coal Steam	297.6	297.6	297.6	306.5	338.2	338.2	297.0	NA	345.0
Oil and Gas	213.6	216.5	210.7	231.7	264.3	270.6	231.0	NA	234.5
Nuclear	101.4	102.6	101.4	102.6	109.8	113.2	106.0	NA	111.8
Hydroelectric/Other[a]	103.2	103.5	103.2	104.1	95.8	101.1	93.0	NA	100.0
2010									
Average End-Use Price									
(1991 cents per kilowatthour)	**6.89**	**7.04**	**6.74**	**7.55**	**6.21**	**6.98**	**NA**	**NA**	**NA**
Residential	8.36	8.53	8.20	9.25	6.98	7.99	NA	NA	NA
Commercial	7.22	7.43	7.00	8.19	6.60	7.58	NA	NA	NA
Industrial	5.39	5.57	5.21	5.22	5.04	5.62	NA	NA	NA
Net Energy for Load	**3,985**	**4,186**	**3,768**	**4,129**	**3,892**	**4,053**	**NA**	**NA**	**NA**
Coal	1,868	1,911	1,821	2,074	1,931	2,112	NA	NA	NA
Petroleum	161	150	158	260	133	210	NA	NA	NA
Natural Gas	517	534	475	552	395	479	NA	NA	NA
Nuclear	636	647	636	620	643	713	NA	NA	NA
Hydroelectric/Other[a]	340	341	339	362	293	354	NA	NA	NA
Nonutility Sales to Grid	408	549	286	214	457	149	NA	NA	NA
Net Imports	54	54	54	47	40	36	NA	NA	NA
Electricity Sales	**3,730**	**3,927**	**3,523**	**3,823**	**3,542**	**3,691**	**NA**	**3,940**	**NA**
Residential	1,176	1,226	1,124	1,313	1,186	1,308	NA	1,134	NA
Commercial/Other[b]	1,144	1,161	1,128	1,197	1,096	1,107	NA	1,218	NA
Industrial	1,410	1,540	1,271	1,313	1,260	1,277	NA	1,588	NA
Capability (gigawatts)[c]	**766.3**	**788.6**	**743.8**	**[d]879.8**	**827.9**	**920.4**	**NA**	**NA**	**NA**
Coal Steam	322.2	329.5	315.0	365.7	339.0	377.6	NA	NA	NA
Oil and Gas	235.7	248.1	220.5	304.8	286.1	328.5	NA	NA	NA
Nuclear	102.4	104.8	102.4	102.2	107.0	113.2	NA	NA	NA
Hydroelectric/Other[a]	106.0	106.3	105.8	107.0	95.8	101.1	NA	NA	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 DRI and GRI, capability represents nameplate capacity; for the others, capability represents net summer capability.

[d]WEFA's capability projection is high because it includes nonutility capability.

NA = not available.

Sources: **EIA:** *AEO93* Forecasting System runs AEO93B.D0918921 (Reference Case), HMAC93.D091692C (High Economic Growth Case), and LMAC93.D0916924 (Low Economic Growth Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Summer 1992). **GRI:** Gas Research Institute, *Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992), and *Draft of GRI93 Baseline Projections* (Aug. 21, 1992). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992). **NERC:** North American Electric Reliability Council, *Electricity Supply and Demand 1992-2001* (June 1992). **EEI:** Edison Electric Institute, *Electricity Futures Project* (draft report). **NERA:** National Economic Research Association, *NERA Energy Outlook* (Dec. 1991).

Coal Projections

Price Projections

For WEFA, "slowing productivity growth in underground and surface mining along with a shift to low sulfur coal in response to the Clean Air Act Amendments of 1990 and other factors"[43] result in the highest coal price projection for 2000 among the forecasts. As can be seen in Table 22, WEFA's minemouth price projection of $28.64 per short ton exceeds the range of prices for *AEO93*. By 2010, however, WEFA's projection falls back within the *AEO93* range. DRI provided a projection only for the average delivered price. In comparing this projection with *AEO93* (Table 22), DRI falls short of the projected range of the *AEO93* for both 2000 and 2010. "DRI's low projection is a result of expected oversupply, combined with inter-regional and inter-carrier competition which will work to restrain prices throughout the forecast period."[44]

Table 22. Comparison of Coal Forecasts
(Million Short Tons, Except Where Noted)

Parameter	EIA *AEO93*			Other Forecasts		
	Reference	High Economic Growth	Low Economic Growth	WEFA	GRI	DRI
2000						
Minemouth Price (1991 dollars per short ton)	**26.79**	**27.44**	**26.02**	**28.64**	**NA**	**NA**
Average Delivered Price (1991 dollars per short ton)	**34.40**	**34.67**	**34.06**	**NA**	**NA**	**32.10**
Production	**1,125**	**1,167**	**1,088**	**1,098**	**1,067**	**1,095**
Net Coal Exports	**137**	**171**	**105**	**134**	**134**	**134**
Consumption	**987**	**996**	**983**	**964**	**935**	**969**
Electric Utility	859	866	856	843	816	846
Residential/Commercial/Industrial	92	93	91	83	112	123
Metallurgical Coal	37	37	36	38	36	37
2010						
Minemouth Price (1991 dollars per short ton)	**30.97**	**33.12**	**29.03**	**30.65**	**NA**	**NA**
Average Delivered Price (1991 dollars per short ton)	**38.68**	**40.24**	**37.44**	**NA**	**NA**	**36.63**
Production	**1,362**	**1,490**	**1,258**	**1,317**	**1,260**	**1,348**
Net Coal Exports	**224**	**277**	**174**	**156**	**223**	**223**
Consumption	**1,135**	**1,210**	**1,084**	**1,160**	**1,033**	**1,121**
Electric Utility	1,006	1,079	956	1,048	917	997
Residential/Commercial/Industrial	98	100	97	78	109	124
Metallurgical Coal	31	32	31	34	35	31

NA = not available.

Sources: **EIA:** *AEO93* Forecasting System runs AEO93B.D0918921 (Reference Case), HMAC93.D091692C (High Economic Growth Case), and LMAC93.D0916924 (Low Economic Growth Case). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Summer 1992). **GRI:** Gas Research Institute, *Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992), and *Draft of GRI93 Baseline Projections* (Aug. 21, 1992). **DRI:** DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992).

[43]WEFA, Spring 1992, pp. 5.9-5.10.
[44]DRI/McGraw Hill, Second Quarter 1992, p. 40.

Production Projections

Table 22 shows that the High Economic Growth Case and Reference Case have the highest projections of coal production in both 2000 and 2010. However, most of the other projections do exceed the production level projected in the Low Economic Growth Case and fall within the *AEO93* range. For 2000, WEFA's and DRI's projections are just higher than the low end of *AEO93* projections, while the GRI projection falls below the *AEO93* range. By 2010, all outside forecasts for coal production fall within the *AEO93* range. As a result of the Clean Air Act Amendments of 1990, all forecasts project a shift toward low-sulfur coal production.

Consumption Projections

For both 2000 and 2010, GRI projects the lowest level of coal consumption among the forecasts. Although GRI has one of the highest projections for industrial coal consumption, this high estimate is not enough to offset its extremely low projection for coal consumption in the electric utility sector. This outcome results from GRI's low projection for the price of gas, which GRI predicts will lead to more gas-burning combustion turbines. With the exception of the High Economic Growth Case in the *AEO93*, WEFA has the highest projection for electric-utility coal consumption for 2010. All outside projections for total coal consumption fall within the range set by *AEO93* in 2010.

References

1. The American Gas Association, *1992 A.G.A.-TERA Base Case* (Jan. 1992).
2. DRI/McGraw-Hill, *Energy Review* (Second Quarter 1992).
3. Edison Electric Institute, *Electric Futures Project* (Draft Report).
4. Gas Research Institute, *Implications of the GRI Baseline Projections of U.S. Energy Supply and Demand*, 1993 Edition (Aug. 11, 1992).
5. Gas Research Institute, *Draft of GRI93 Baseline Projections* (Aug. 21, 1992).
6. Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Forecast 1992-2000* (Mar. 1992).
7. National Economic Research Association, *NERA Energy Outlook* (Dec. 1991).
8. North American Electric Reliability Council, *Electricity Supply and Demand 1992-2001* (June 1992).
9. The WEFA Group, *Energy Analysis Quarterly* (Summer 1992).
10. The WEFA Group, *Energy Analysis Quarterly* (Spring 1992).
11. The WEFA Group, *U.S. Long-Term Economic Outlook*, Vol. 1 (Second Quarter 1992).

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

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	14.26	12.54	12.46	12.95	-1.0
Natural Gas Plant Liquids	2.17	2.18	2.35	2.44	2.37	.4
Dry Natural Gas [2]	18.47	19.13	20.58	21.41	20.83	.6
Coal	22.23	22.76	23.89	25.51	28.78	1.3
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy [3]	6.53	7.36	8.51	9.19	10.09	2.2
Total	71.34	72.54	74.78	78.06	81.95	.7
Imports						
Crude Oil [4]	12.78	14.56	18.21	18.34	18.02	1.7
Petroleum Products	4.36	6.25	6.38	8.48	9.61	4.0
Natural Gas [5]	1.46	2.57	3.10	3.52	4.28	5.5
Other Imports [6]	.11	.51	.64	.91	1.16	12.5
Total	18.70	23.89	28.33	31.25	33.06	2.9
Exports						
Coal	2.64	3.15	3.72	4.64	6.09	4.3
Petroleum	1.82	1.66	1.72	1.80	1.84	.1
Total	4.46	4.81	5.44	6.44	7.93	2.9
Net Stock Withdrawals	-1.36	-.20	-.13	-.16	-.15	-10.5
Discrepancy [7]	.41	-.04	-.07	-.10	-.26	-
Consumption						
Petroleum Products [8]	33.53	35.57	37.85	40.00	41.15	1.0
Natural Gas	19.31	21.62	23.54	24.84	24.99	1.3
Coal	19.11	19.68	20.30	21.03	22.88	.9
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.66	8.88	9.68	10.72	2.5
Total	84.63	91.38	97.47	102.61	106.68	1.2
Net Imports - Petroleum	15.31	19.15	22.87	25.02	25.78	2.6
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	19.90	22.90	26.10	29.30	1.3
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.04	2.56	3.40	3.68	3.7
Coal Minemouth Price ($ per ton)	22.52	23.62	26.79	27.90	30.97	1.6

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

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

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.91	0.70	0.57	0.47	-2.8
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.08	4.83	4.74	4.64	.1
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.48	3.57	3.79	4.01	1.2
Total	9.83	10.98	11.14	11.28	11.55	.8
Commercial						
Distillate Fuel	.49	.57	.53	.49	.44	-.5
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.0
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.08	3.17	3.23	3.25	.8
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.30	.37	7.1
Electricity	2.86	3.12	3.40	3.64	3.83	1.5
Total	6.72	7.42	7.80	8.06	8.27	1.0
Industrial [4]						
Distillate Fuel	1.18	1.27	1.37	1.42	1.46	1.1
Liquefied Petroleum Gas	1.61	2.00	2.22	2.43	2.53	2.3
Motor Gasoline [2]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	2.0
Residual Fuel	.41	.51	.51	.52	.50	1.0
Other Petroleum [5]	3.83	3.63	3.71	3.72	3.73	-.1
Natural Gas [6]	8.47	9.57	10.21	10.29	10.50	1.1
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	1.71	1.85	1.84	1.86	1.98	.7
Net Coal Coke Imports	.00	.00	.06	.12	.16	18.9
Renewable Energy [1]	2.07	2.30	2.36	2.42	2.52	1.0
Purchased Electricity	3.23	3.43	3.97	4.43	4.81	2.0
Total	24.84	27.01	28.80	29.86	30.92	1.1
Transportation						
Distillate Fuel	3.83	4.17	4.60	5.04	5.42	1.7
Jet Fuel	3.13	3.45	3.85	4.30	4.57	1.9
Motor Gasoline [2]	13.58	14.25	14.99	15.56	15.91	.8
Residual Fuel	1.02	1.09	1.24	1.39	1.51	2.0
Other Petroleum [7]	.24	.25	.27	.30	.32	1.4
Pipeline Fuel Natural Gas	.68	.66	.72	.76	.81	.9
Compressed Natural Gas	.00	.01	.02	.07	.15	60.4
Alcohol Fuels	.00	.01	.02	.08	.16	62.9
Electricity	.01	.02	.02	.05	.08	8.9
Total	22.50	23.90	25.74	27.56	28.93	1.3
Electric Utilities [8]						
Distillate Fuel	.09	.08	.17	.22	.19	3.9
Residual Fuel	1.14	1.07	1.30	1.58	1.53	1.5
Natural Gas	2.88	3.23	4.60	5.75	5.63	3.4
Steam Coal	16.20	16.63	17.35	18.15	19.96	1.0
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.28	4.63	5.01	5.48	2.3
Total	29.99	32.13	34.95	37.77	39.72	1.4
Primary Energy Consumption						
Distillate Fuel	6.42	7.00	7.37	7.72	7.99	1.1
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.45	3.85	4.30	4.57	1.9
Liquefied Petroleum Gas	2.06	2.54	2.69	2.85	2.93	1.8
Motor Gasoline	13.87	14.59	15.36	15.96	16.33	.8
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	2.0
Residual Fuel	2.82	2.88	3.24	3.65	3.68	1.3

- See footnotes at end of table.

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)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.85	3.95	3.98	4.01	0.0
Natural Gas	19.31	21.62	23.54	24.84	24.99	1.3
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	18.07	18.63	19.33	20.13	22.05	1.0
Net Coal Coke Imports	.00	.00	.06	.12	.16	18.9
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.65	8.80	9.48	10.41	2.4
Alcohols	.00	.01	.02	.08	.16	62.9
Total	84.63	91.38	97.47	102.61	106.68	1.2
Electricity Consumption (all Sectors)	9.26	10.05	10.97	11.91	12.73	1.6
Industrial Electricity						
Gross Consumption	3.58	3.96	4.55	5.03	5.43	2.1
Self-generation - Own Use	.39	.53	.58	.60	.62	2.3
Purchased Electricity	3.23	3.43	3.97	4.43	4.81	2.0

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.55	13.43	14.42	15.02	1.0
Primary Energy	6.48	6.55	7.04	7.80	8.11	1.1
Petroleum Products	9.04	8.01	8.69	9.43	10.16	.6
Distillate Fuel	8.08	7.19	7.76	8.38	8.98	.5
Kerosene	9.14	8.57	8.98	9.42	9.85	.4
Liquefied Petroleum Gas	11.20	9.61	10.34	11.16	11.95	.3
Natural Gas	5.82	6.19	6.71	7.55	7.83	1.5
Steam Coal	1.99	2.05	2.27	2.37	2.60	1.3
Electricity	23.34	23.86	24.18	24.43	24.50	.2
Commercial	12.40	12.43	12.99	13.61	13.88	.6
Primary Energy	5.06	5.24	5.80	6.62	6.99	1.6
Petroleum Products	6.04	5.47	6.17	6.93	7.68	1.2
Distillate Fuel	5.94	5.01	5.59	6.22	6.83	.7
Residual Fuel	3.57	3.36	3.87	4.44	5.00	1.7
Kerosene	6.96	6.22	6.64	7.11	7.58	.4
Other Petroleum [1]	9.69	9.27	10.09	11.00	11.82	1.0
Natural Gas	4.84	5.26	5.78	6.62	6.91	1.8
Steam Coal	1.96	2.01	2.23	2.33	2.56	1.3
Electricity	22.04	21.98	21.76	21.52	21.21	-.2
Industrial	5.73	5.66	6.29	7.06	7.51	1.4
Primary Energy	4.14	4.09	4.61	5.28	5.70	1.6
Petroleum Products	6.01	5.64	6.17	6.77	7.37	1.0
Distillate Fuel	5.94	4.96	5.53	6.15	6.75	.6
Liquefied Petroleum Gas	5.95	5.50	6.20	6.99	7.77	1.3
Motor Gasoline [2]	9.87	9.55	10.37	11.27	12.05	1.0
Residual Fuel	3.13	3.06	3.57	4.14	4.70	2.1
Other Petroleum [3]	6.14	5.96	6.40	6.88	7.37	.9
Natural Gas [4]	2.95	3.31	3.84	4.68	4.95	2.6
Metallurgical Coal	1.82	1.87	2.11	2.24	2.49	1.6
Steam Coal	1.48	1.54	1.67	1.77	1.94	1.4
Electricity	14.74	14.83	15.21	15.68	15.80	.3
Transportation	8.92	8.48	9.14	9.86	10.52	.8
Primary Energy	8.91	8.47	9.13	9.84	10.50	.8
Petroleum Products	8.91	8.47	9.13	9.85	10.50	.8
Distillate Fuel [5]	8.98	8.75	9.32	9.94	10.54	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.56	.5
Motor Gasoline [2]	9.86	9.59	10.41	11.30	12.08	1.0
Residual Fuel	3.22	3.00	3.43	3.91	4.34	1.5
Other Petroleum [7]	16.49	15.16	15.59	16.06	16.54	.0
Compressed Natural Gas	4.50	7.14	7.96	8.84	9.61	3.9
Electricity	23.74	24.30	22.02	19.55	18.95	-1.1
Total End-Use Energy	8.68	8.53	9.12	9.86	10.36	.9
Primary Energy	6.58	6.36	6.97	7.72	8.26	1.1
Electricity	19.94	20.19	20.18	20.26	20.19	.1
Electric Utilities						
Fossil Fuel Average	1.71	1.79	2.10	2.47	2.64	2.2
Petroleum Products	3.61	3.58	4.05	4.61	5.36	2.0
Distillate Fuel	5.57	4.54	5.16	5.79	6.40	.7
Residual Fuel	3.46	3.51	3.91	4.45	5.24	2.1
Natural Gas	2.38	2.60	3.18	4.13	4.47	3.2
Steam Coal	1.45	1.51	1.64	1.73	1.89	1.3

- See footnotes at end of table.

Table A3. Energy Prices by End-Use Sector and Source (Continued)
(1991 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	7.51	8.12	8.78	9.46	0.9
Distillate Fuel [5]	8.03	7.51	8.11	8.78	9.45	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.56	.5
Kerosene	8.80	8.28	8.61	8.97	9.30	.3
Liquefied Petroleum Gas	7.02	6.33	6.89	7.58	8.31	.8
Motor Gasoline [2]	9.86	9.59	10.41	11.30	12.08	1.0
Residual Fuel	3.33	3.23	3.67	4.20	4.79	1.8
Other Petroleum Products [9]	6.62	6.41	6.85	7.36	7.87	.9
Natural Gas	3.90	4.24	4.63	5.43	5.73	1.9
Coal	1.48	1.53	1.67	1.76	1.92	1.3
Electricity	19.94	20.19	20.18	20.26	20.19	.1

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run AEO93B.D0918921. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,603	1,673	1,738	1,868	0.9
Petroleum	117	104	137	169	161	1.6
Natural Gas	264	301	418	521	517	3.4
Nuclear Power	577	628	633	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	8.9
Renewable Sources/Other [1]	293	322	335	344	351	.9
Total	2,808	2,948	3,186	3,407	3,522	1.1
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	52	70	164	8.4
Petroleum	5	11	11	12	12	4.0
Natural Gas	100	151	181	215	218	4.0
Renewable Sources/Other [1]	80	119	141	164	196	4.6
Total	218	332	386	460	590	5.1
Sales to Utilities	106	175	215	285	408	7.0
Generation for Own Use	111	156	171	176	182	2.5
Electricity Sales by Sector						
Residential	924	1,021	1,047	1,112	1,176	1.2
Commercial/Other [3]	843	920	1,003	1,081	1,144	1.5
Industrial	946	1,005	1,163	1,298	1,410	2.0
Total	2,713	2,946	3,214	3,491	3,730	1.6
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.14	8.25	8.34	8.36	.2
Commercial/Other [3]	7.52	7.50	7.43	7.33	7.22	-.2
Industrial [5]	5.03	5.06	5.19	5.35	5.39	.3
Average	6.80	6.89	6.89	6.91	6.89	.1
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.90	2.58	2.25	2.05	-1.7
Fuel Component	1.70	1.82	2.13	2.48	2.72	2.4
O&M Component	2.23	2.17	2.17	2.18	2.12	-.2
Total	6.80	6.89	6.89	6.91	6.89	.1

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M = Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	301.8	322.2	0.4
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	14.1	30.2	35.4	9.6
Combustion Turbine/Diesel	46.4	54.9	68.6	76.0	80.1	2.8
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.6	83.3	84.9	86.1	.5
Total	688.6	699.9	715.8	741.0	766.3	.5
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	2.8	24.4	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.3	15.0	20.0	-
Combustion Turbine/Diesel	.0	1.6	5.1	12.3	16.4	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.7	1.7	2.7	3.9	-
Total	.0	2.2	7.6	33.4	65.4	-
Cumulative Total Additions	6.3	29.6	59.9	96.9	130.6	16.4
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	11.2	14.3	30.1	7.5
Petroleum	.8	3.2	3.5	3.7	3.8	8.0
Natural Gas	19.3	29.2	34.4	41.4	42.0	4.0
Renewable Sources/Other [3]	15.8	23.9	28.2	32.2	37.8	4.5
Total	43.0	67.1	77.3	91.6	113.8	5.0
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	.5	3.6	19.4	-
Petroleum	.0	.2	.4	.6	.7	-
Natural Gas	.0	.7	5.3	12.3	12.9	-
Renewable Sources/Other [3]	.0	3.6	7.4	11.4	17.0	-
Total	.0	4.7	13.6	27.9	50.0	-
Cumulative Additions	.0	24.1	34.3	48.6	70.8	-

[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] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report.* 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report.* All projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.67	5.18	6.85	8.51	6.2
Municipal Solid Waste	2.01	5.17	6.69	8.18	11.40	9.1
Biomass/Other Waste	6.01	7.43	7.65	7.83	8.06	1.5
Solar Thermal	.35	.50	1.32	1.63	1.93	8.9
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.37	3.56	4.95	6.33	7.8
Total	87.43	95.71	101.27	106.30	113.11	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	20.82	34.63	49.02	62.05	7.2
Municipal Solid Waste	10.45	18.28	24.33	33.03	53.67	8.5
Biomass/Other Waste	31.48	46.79	52.84	55.93	58.70	3.2
Solar Thermal	.66	.90	2.19	2.98	3.79	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.44	9.08	12.75	16.20	10.4
Total	348.23	400.60	431.27	460.82	500.87	1.8
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.22	.36	.51	.64	7.2
Municipal Solid Waste	.11	.19	.25	.34	.56	8.6
Biomass/Other Waste	.32	.48	.54	.58	.61	3.2
Solar Thermal	.01	.01	.02	.03	.04	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.09	.13	.17	10.4
Total	3.62	4.16	4.48	4.79	5.20	1.8
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.79	3.01	3.24	3.54	1.6
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	2.99	3.78	4.13	4.62	2.7
Total Renewable Energy	6.32	7.15	8.26	8.92	9.82	2.2

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A7. Macroeconomic Indicators (Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.320	1.585	1.956	2.432	3.9
Real Gross Domestic Product	4,885	5,392	6,051	6,692	7,287	2.0
Real Disposable Personal Income	3,538	3,895	4,281	4,669	5,041	1.8
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.139	1.353	1.545	1.694	2.5
AA Utility Bond Rate (percent)	9.66	9.22	8.89	8.88	8.79	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.30	5.79	5.68	5.63	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.95	16.11	15.33	14.64	-.8

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	19.90	22.90	26.10	29.30	1.3
Production						
Crude Oil [2]	7.35	6.52	5.60	5.50	5.66	-1.3
Alaska	1.77	1.33	.93	.67	.74	-4.3
Lower 48	5.58	5.18	4.67	4.84	4.92	-.6
Natural Gas Plant Liquids	1.56	1.57	1.69	1.76	1.71	.5
Other Domestic [3]	.08	.22	.31	.38	.45	9.1
Processing Gain [4]	.68	.67	.74	.74	.74	.4
Total	9.68	8.97	8.34	8.39	8.57	-.6
Imports (including SPR) [5]						
Crude Oil	5.89	6.76	8.43	8.52	8.37	1.8
Refined Products [6]	2.13	3.09	3.15	4.20	4.75	4.1
Total	8.02	9.85	11.58	12.71	13.12	2.5
Exports						
Crude Oil	.11	.09	.07	.06	.07	-2.0
Refined Products	.75	.69	.74	.79	.80	.3
Total	.85	.79	.81	.85	.87	.1
Net Imports (including SPR)	7.17	9.06	10.77	11.86	12.24	2.7
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.05	-.03	-.03	-.01	-11.9
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	17.96	19.06	20.19	20.78	1.1
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.61	7.99	8.32	8.52	.8
Jet Fuel [10]	1.52	1.68	1.87	2.09	2.23	1.9
Distillate Fuel	3.02	3.29	3.45	3.63	3.76	1.1
Residual Fuel	1.23	1.26	1.41	1.59	1.60	1.3
Other [11]	3.98	4.31	4.52	4.74	4.87	1.0
Total	16.99	18.15	19.25	20.38	20.96	1.1
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.28	1.08	.95	.84	-1.5
Industrial [12]	4.34	4.70	5.02	5.31	5.48	1.2
Transportation	10.97	11.67	12.50	13.33	13.89	1.2
Electric Utilities	.54	.50	.65	.79	.75	1.7
Total	16.99	18.15	19.25	20.38	20.96	1.1
Net Disposition	16.98	18.15	19.25	20.38	20.96	1.1

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A9. 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)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.45	19.86	20.65	20.07	0.6
Supplemental Gas [2]	.10	.10	.10	.12	.14	1.4
Net Imports	1.45	2.49	3.00	3.42	4.15	5.4
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	21.04	22.97	24.18	24.36	1.3
Consumption by Sector						
Residential	4.38	4.93	4.69	4.59	4.50	.1
Commercial	2.67	2.99	3.07	3.13	3.16	.8
Industrial [4]	6.98	8.10	8.63	8.66	8.87	1.2
Electric Utilities [5]	2.79	3.13	4.46	5.58	5.46	3.4
Lease and Plant Fuel [6]	1.24	1.18	1.27	1.32	1.31	.3
Pipeline Fuel	.66	.64	.69	.74	.78	.9
Transportation [7]	.00	.00	.02	.07	.15	60.4
Total	18.73	20.97	22.83	24.09	24.24	1.3
Unaccounted for [8]	.12	.08	.14	.09	.12	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.04	2.56	3.40	3.68	3.7
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.39	6.92	7.79	8.07	1.5
Commercial	4.99	5.42	5.96	6.83	7.12	1.8
Industrial	3.04	3.41	3.96	4.82	5.11	2.6
Electric Utilities	2.46	2.68	3.27	4.26	4.61	3.2
Transportation[7]	4.64	7.36	8.20	9.11	9.91	3.9
Average [9]	4.03	4.37	4.78	5.60	5.91	1.9

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	645	655	679	770	1.0
West of the Mississippi	399	420	470	525	591	2.0
Total	1,029	1,065	1,125	1,204	1,362	1.4
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	121	144	180	235	4.1
Total	-103	-117	-137	-170	-224	4.0
Net Stock Withdrawals [2]	-27	-2	-1	-3	-4	-9.3
Total Supply [3]	899	947	986	1,031	1,134	1.2
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	87	86	87	93	1.0
Coking Plants	39	40	37	34	31	-1.1
Electricity [5]	774	815	859	906	1,006	1.3
Total	895	947	987	1,032	1,135	1.2
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	23.62	26.79	27.90	30.97	1.6
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.06	52.62	54.77	59.06	.7
Industrial	34.77	32.84	35.94	38.02	41.22	.9
Coking Plants	49.40	49.86	55.94	59.58	66.08	1.5
Electricity	31.52	30.77	33.20	34.68	37.49	.9
Average [8]	32.72	31.87	34.40	35.88	38.68	.8

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A11. 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)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.4	102.0	105.9	109.1	0.8
Energy Consumption per Household (million Btu)	105.2	112.7	109.2	106.5	105.9	.0
End-Use Consumption						
Distillate						
Space Heating	.72	.82	.64	.54	.46	-2.3
Other Uses [1]	.11	.09	.05	.03	.02	-8.6
Total	.84	.91	.70	.57	.47	-2.8
Natural Gas						
Space Heating	3.15	3.50	3.26	3.16	3.07	-.1
Water Heating	1.06	1.27	1.29	1.30	1.30	1.0
Other Uses [1]	.31	.30	.28	.27	.27	-.7
Total	4.52	5.08	4.83	4.74	4.64	.1
Other Fuels [2]	.49	.57	.49	.43	.40	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.30	.30	-.3
Cooling	.51	.55	.50	.53	.55	.4
Water Heating	.39	.50	.56	.64	.71	3.0
Other Uses [1]	1.93	2.10	2.21	2.33	2.44	1.2
Total	3.15	3.48	3.57	3.79	4.01	1.2
Total Consumption	9.83	10.98	11.14	11.28	11.55	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A12. 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)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	117.5	124.8	130.1	134.5	1.0
Total Floorspace (billion square feet)	62.9	69.0	75.6	82.4	89.5	1.8
Energy Consumption per Square Foot (thousand Btu)	107.0	107.6	103.2	97.7	92.5	-.7
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.50	.46	.42	-.3
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.57	.53	.49	.44	-.5
Natural Gas						
Space Heating	1.80	1.99	2.01	1.99	1.93	.4
Cooling	.21	.23	.24	.25	.26	1.1
Other Uses [1]	.75	.86	.93	.99	1.06	1.7
Total	2.76	3.08	3.17	3.23	3.25	.8
Other Fuels [2]	.52	.49	.45	.41	.37	-1.7
Renewables [3]	.10	.15	.25	.30	.37	7.1
Electricity						
Space Heating	.52	.59	.65	.72	.81	2.3
Cooling	.73	.81	.89	.96	1.01	1.7
Lighting	1.14	1.20	1.27	1.29	1.27	.5
Other Uses [1]	.48	.52	.59	.66	.74	2.2
Total	2.86	3.12	3.40	3.64	3.83	1.5
Total Consumption	6.72	7.42	7.80	8.06	8.27	1.0

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2657	3155	3606	3953	2.5
Non-manufacturing	871	925	1022	1102	1183	1.5
Total	3274	3583	4177	4708	5136	2.3
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.36	.33	.30	.28	-1.2
Liquefied Petroleum Gas	.49	.56	.53	.52	.49	.0
Petrochemical Feedstocks	.34	.32	.32	.32	.32	-.3
Residual Fuel	.13	.14	.12	.11	.10	-1.3
Other Petroleum [1]	1.17	1.01	.89	.79	.73	-2.4
Natural Gas [2]	2.59	2.67	2.44	2.19	2.04	-1.2
Metallurgical Coal and Coke [3]	.32	.30	.25	.22	.19	-2.5
Steam Coal [4]	.52	.52	.44	.40	.39	-1.5
Renewables [5]	.06	.06	.06	.05	.05	-1.3
Electricity	.99	.96	.95	.94	.94	-.3
Total	7.59	7.54	6.90	6.34	6.02	-1.1
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.27	1.37	1.42	1.46	1.1
Liquefied Petroleum Gas	1.61	2.00	2.22	2.43	2.53	2.3
Motor Gasoline [6]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	2.0
Residual Fuel	.41	.51	.51	.52	.50	1.0
Other Petroleum [1]	3.83	3.63	3.71	3.72	3.73	-.1
Natural Gas [2]	8.47	9.57	10.21	10.29	10.50	1.1
Metallurgical Coal and Coke [3]	1.04	1.05	1.04	1.02	.99	-.3
Steam Coal [4]	1.71	1.85	1.84	1.86	1.98	.7
Renewables [5]	2.07	2.30	2.36	2.42	2.52	1.0
Electricity	3.23	3.43	3.97	4.43	4.81	2.0
Total	24.84	27.01	28.80	29.86	30.92	1.1

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.10	1.20	1.31	1.41	1.7
Freight Trucks	1.00	1.08	1.22	1.34	1.45	1.9
Air	.99	1.25	1.58	1.92	2.26	4.2
Rail	.99	1.03	1.11	1.20	1.28	1.3
Marine	.99	1.04	1.13	1.20	1.27	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.00	28.77	30.32	32.50	34.60	1.1
New Light Truck MPG [1]	20.70	21.64	22.73	24.07	25.37	1.0
Light Duty Fleet MPG [2]	18.58	19.28	19.88	20.56	21.31	.7
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.25	12.96	13.59	14.05	1.0
Freight Trucks	5.06	5.30	5.73	6.18	6.57	1.3
Air	3.20	3.53	3.94	4.40	4.68	1.9
Rail	.49	.50	.52	.56	.59	.9
Marine	1.39	1.49	1.68	1.87	2.02	1.9
Pipeline Fuel	.68	.66	.72	.76	.81	.9
Other	.17	.18	.19	.20	.22	1.1
Total	22.50	23.90	25.74	27.56	28.93	1.3

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989=1.0).
[4] Based on Btu per vehicle miles traveled (1989=1.0).
[5] Based on Btu per ton-miles traveled (1989=1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

Table A15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.2	21.4	17.8	15.3	-2.3
Natural Gas	65.7	73.9	70.3	68.9	67.5	.1
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	102.6	93.2	88.2	84.4	-.4
Commercial						
Petroleum	18.5	19.7	18.1	16.7	15.3	-.9
Natural Gas	40.1	44.8	46.1	46.9	47.4	.8
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.6	66.1	65.2	64.0	.2
Industrial [2]						
Petroleum	87.4	89.3	92.5	94.0	94.8	.4
Natural Gas [3]	115.0	130.2	139.3	140.6	143.6	1.1
Metallurgical Coal	26.5	27.0	24.9	22.9	21.2	-1.1
Steam Coal	43.6	47.2	46.9	47.4	50.4	.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	293.6	303.5	304.9	310.0	.6
Transportation						
Petroleum	425.1	452.9	487.3	519.3	541.8	1.2
Natural Gas[4]	9.9	9.6	10.7	12.1	14.0	1.7
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	462.5	498.0	531.5	555.8	1.2
Electric Utilities [5]						
Petroleum	26.4	24.6	31.6	38.6	36.8	1.7
Natural Gas	41.9	46.9	66.9	83.6	81.8	3.4
Steam Coal	412.3	423.3	441.7	461.9	507.8	1.0
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	494.8	540.1	584.1	626.4	1.3
Primary Energy Consumption						
Petroleum	581.6	613.7	650.9	686.4	704.0	1.0
Natural Gas	272.6	305.4	333.1	352.1	354.3	1.3
Metallurgical Coal	26.5	27.0	24.9	22.9	21.2	-1.1
Steam Coal	459.8	474.1	491.9	512.4	561.1	1.0
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1420.2	1500.8	1573.8	1640.6	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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run AEO93B.D0918921.

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

Supply, Disposition, and Prices	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	14.30	12.39	12.45	12.87	-1.0
Natural Gas Plant Liquids	2.17	2.22	2.41	2.52	2.45	.6
Dry Natural Gas [2]	18.47	19.51	21.07	22.09	21.53	.8
Coal	22.23	23.19	24.88	27.61	31.45	1.7
Nuclear Power	6.19	6.85	6.93	7.18	7.06	.7
Renewable Energy [3]	6.53	7.47	8.72	9.53	10.37	2.3
Total	71.34	73.55	76.40	81.38	85.74	.9
Imports						
Crude Oil [4]	12.78	14.74	18.36	18.36	18.11	1.8
Petroleum Products	4.36	6.31	7.52	9.94	11.87	5.1
Natural Gas [5]	1.46	2.57	3.18	3.74	4.40	5.7
Other Imports [6]	.11	.51	.65	.91	1.17	12.5
Total	18.70	24.14	29.71	32.94	35.55	3.3
Exports						
Coal	2.64	3.49	4.60	6.29	7.48	5.3
Petroleum	1.82	1.67	1.78	1.82	1.84	.1
Total	4.46	5.17	6.38	8.11	9.32	3.8
Net Stock Withdrawals	-1.36	-.21	-.14	-.21	-.19	-9.4
Discrepancy [7]	.41	-.03	.02	-.09	-.28	-
Consumption						
Petroleum Products [8]	33.53	35.91	39.03	41.52	43.47	1.3
Natural Gas	19.31	21.99	24.17	25.73	25.82	1.5
Coal	19.11	19.77	20.41	21.46	24.14	1.2
Nuclear Power	6.19	6.85	6.93	7.18	7.06	.7
Renewable Energy/Other [9]	6.50	7.77	9.09	10.02	11.01	2.7
Total	84.63	92.29	99.63	105.92	111.51	1.4
Net Imports - Petroleum	15.31	19.38	24.11	26.47	28.15	3.1
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	19.90	22.90	26.10	29.30	1.3
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.37	2.86	3.64	4.07	4.2
Coal Minemouth Price ($ per ton)	22.52	24.32	27.44	29.67	33.12	1.9

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

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

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.91	0.69	0.57	0.48	-2.8
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.05	4.85	4.79	4.73	.2
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.50	3.64	3.91	4.18	1.4
Total	9.83	10.96	11.22	11.46	11.82	.9
Commercial						
Distillate Fuel	.49	.57	.53	.49	.45	-.4
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.2
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.07	3.18	3.26	3.31	.9
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.16	.27	.32	.39	7.3
Electricity	2.86	3.12	3.42	3.68	3.88	1.5
Total	6.72	7.42	7.84	8.15	8.40	1.1
Industrial [4]						
Distillate Fuel	1.18	1.29	1.42	1.48	1.55	1.4
Liquefied Petroleum Gas	1.61	2.02	2.26	2.48	2.63	2.5
Motor Gasoline [2]	.18	.23	.26	.28	.30	2.5
Petrochemical Feedstocks	1.10	1.18	1.37	1.55	1.72	2.2
Residual Fuel	.41	.51	.54	.55	.55	1.4
Other Petroleum [5]	3.83	3.64	3.75	3.77	3.80	.0
Natural Gas [6]	8.47	9.62	10.34	10.57	10.95	1.3
Metallurgical Coal	1.04	1.07	.99	.91	.84	-1.0
Steam Coal	1.71	1.86	1.86	1.88	1.99	.8
Net Coal Coke Imports	.00	.00	.07	.12	.17	19.2
Renewable Energy [1]	2.07	2.32	2.41	2.52	2.63	1.2
Purchased Electricity	3.23	3.54	4.17	4.72	5.25	2.5
Total	24.84	27.27	29.43	30.83	32.39	1.3
Transportation						
Distillate Fuel	3.83	4.27	4.82	5.33	5.83	2.1
Jet Fuel	3.13	3.58	4.18	4.80	5.28	2.7
Motor Gasoline [2]	13.58	14.32	15.23	16.03	16.70	1.0
Residual Fuel	1.02	1.11	1.28	1.45	1.59	2.2
Other Petroleum [7]	.24	.25	.28	.31	.34	1.7
Pipeline Fuel Natural Gas	.68	.67	.73	.79	.87	1.2
Compressed Natural Gas	.00	.01	.02	.07	.15	60.3
Alcohol Fuels	.00	.01	.02	.08	.16	62.9
Electricity	.01	.02	.02	.05	.08	9.0
Total	22.50	24.23	26.58	28.91	31.00	1.6
Electric Utilities [8]						
Distillate Fuel	.09	.11	.15	.15	.15	3.0
Residual Fuel	1.14	.99	1.47	1.57	1.44	1.2
Natural Gas	2.88	3.58	5.05	6.24	5.82	3.6
Steam Coal	16.20	16.70	17.43	18.55	21.19	1.4
Nuclear Power	6.19	6.85	6.93	7.18	7.06	.7
Renewable Energy/Other [9]	3.49	4.36	4.78	5.24	5.64	2.4
Total	29.99	32.59	35.81	38.93	41.30	1.6
Primary Energy Consumption						
Distillate Fuel	6.42	7.14	7.60	8.01	8.46	1.4
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.58	4.18	4.80	5.28	2.7
Liquefied Petroleum Gas	2.06	2.55	2.73	2.91	3.03	1.9
Motor Gasoline	13.87	14.67	15.62	16.44	17.15	1.1
Petrochemical Feedstocks	1.10	1.18	1.37	1.55	1.72	2.2
Residual Fuel	2.82	2.83	3.48	3.73	3.71	1.4

- See footnotes at end of table.

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

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.87	4.00	4.05	4.10	0.1
Natural Gas	19.31	21.99	24.17	25.73	25.82	1.5
Metallurgical Coal	1.04	1.07	.99	.91	.84	-1.0
Steam Coal	18.07	18.71	19.42	20.55	23.30	1.3
Net Coal Coke Imports	.00	.00	.07	.12	.17	19.2
Nuclear Power	6.19	6.85	6.93	7.18	7.06	.7
Renewable Energy/Other [11]	6.49	7.76	9.00	9.82	10.69	2.5
Alcohols	.00	.01	.02	.08	.16	62.9
Total	84.63	92.29	99.63	105.92	111.51	1.4
Electricity Consumption (all Sectors)	9.26	10.18	11.25	12.37	13.40	1.9
Industrial Electricity						
Gross Consumption	3.58	4.08	4.81	5.39	5.95	2.6
Self-generation - Own Use	.39	.54	.64	.67	.69	2.9
Purchased Electricity	3.23	3.54	4.17	4.72	5.25	2.5

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.87	13.79	14.83	15.53	1.1
Primary Energy	6.48	6.87	7.34	8.05	8.48	1.4
Petroleum Products	9.04	8.31	8.99	9.73	10.46	.7
Distillate Fuel	8.08	7.45	8.02	8.64	9.24	.7
Kerosene	9.14	8.57	8.98	9.42	9.85	.4
Liquefied Petroleum Gas	11.20	10.02	10.75	11.56	12.34	.5
Natural Gas	5.82	6.52	7.02	7.80	8.21	1.7
Steam Coal	1.99	2.08	2.29	2.47	2.73	1.6
Electricity	23.34	24.06	24.46	24.86	24.99	.3
Commercial	12.40	12.68	13.30	13.97	14.35	.7
Primary Energy	5.06	5.52	6.07	6.84	7.33	1.9
Petroleum Products	6.04	5.61	6.32	7.08	7.83	1.3
Distillate Fuel	5.94	5.13	5.72	6.35	6.96	.8
Residual Fuel	3.57	3.50	4.03	4.58	5.13	1.8
Kerosene	6.96	6.22	6.64	7.11	7.58	.4
Other Petroleum [1]	9.69	9.47	10.28	11.17	11.98	1.1
Natural Gas	4.84	5.58	6.08	6.87	7.29	2.1
Steam Coal	1.96	2.05	2.26	2.43	2.69	1.6
Electricity	22.04	22.17	22.09	22.03	21.82	-.1
Industrial	5.73	5.94	6.60	7.39	7.92	1.6
Primary Energy	4.14	4.35	4.87	5.52	6.00	1.9
Petroleum Products	6.01	5.91	6.43	7.03	7.62	1.2
Distillate Fuel	5.94	5.07	5.64	6.26	6.86	.7
Liquefied Petroleum Gas	5.95	5.95	6.64	7.42	8.18	1.6
Motor Gasoline [2]	9.87	9.65	10.48	11.37	12.15	1.0
Residual Fuel	3.13	3.23	3.75	4.31	4.86	2.2
Other Petroleum [3]	6.14	6.22	6.64	7.12	7.60	1.1
Natural Gas [4]	2.95	3.64	4.15	4.93	5.34	3.0
Metallurgical Coal	1.82	1.93	2.15	2.36	2.61	1.8
Steam Coal	1.48	1.56	1.69	1.82	2.02	1.6
Electricity	14.74	15.01	15.53	16.12	16.32	.5
Transportation	8.92	8.58	9.23	9.93	10.58	.9
Primary Energy	8.91	8.57	9.21	9.91	10.55	.8
Petroleum Products	8.91	8.57	9.22	9.91	10.56	.8
Distillate Fuel [5]	8.98	8.90	9.48	10.09	10.69	.9
Jet Fuel [6]	6.00	4.83	5.43	6.07	6.68	.5
Motor Gasoline [2]	9.86	9.69	10.51	11.40	12.18	1.1
Residual Fuel	3.22	3.26	3.69	4.16	4.59	1.8
Other Petroleum [7]	16.49	15.46	15.88	16.35	16.83	.1
Compressed Natural Gas	4.50	7.31	8.12	8.99	9.76	3.9
Electricity	23.74	24.54	22.36	20.00	19.35	-1.0
Total End-Use Energy	8.68	8.74	9.34	10.08	10.63	1.0
Primary Energy	6.58	6.57	7.17	7.90	8.49	1.3
Electricity	19.94	20.33	20.43	20.66	20.63	.2
Electric Utilities						
Fossil Fuel Average	1.71	1.86	2.21	2.60	2.78	2.4
Petroleum Products	3.61	3.67	4.14	4.69	5.46	2.1
Distillate Fuel	5.57	4.73	5.33	5.96	6.57	.8
Residual Fuel	3.46	3.55	4.02	4.56	5.34	2.2
Natural Gas	2.38	2.87	3.49	4.44	4.93	3.7
Steam Coal	1.45	1.52	1.66	1.79	1.99	1.6

- See footnotes at end of table.

Table B3. Energy Prices by End-Use Sector and Source (Continued) (1991 Dollars per Million Btu)

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	7.67	8.25	8.93	9.61	1.0
Distillate Fuel [5]	8.03	7.66	8.29	8.98	9.63	.9
Jet Fuel [6]	6.00	4.83	5.43	6.07	6.68	.5
Kerosene	8.80	8.28	8.61	8.97	9.30	.3
Liquefied Petroleum Gas	7.02	6.77	7.32	8.00	8.70	1.1
Motor Gasoline [2]	9.86	9.69	10.51	11.40	12.18	1.1
Residual Fuel	3.33	3.37	3.86	4.37	4.94	2.0
Other Petroleum Products [9]	6.62	6.67	7.11	7.61	8.11	1.0
Natural Gas	3.90	4.52	4.91	5.66	6.12	2.3
Coal	1.48	1.55	1.69	1.82	2.02	1.6
Electricity	19.94	20.33	20.43	20.66	20.63	.2

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run HMAC93.D091692C. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,610	1,677	1,749	1,911	1.0
Petroleum	117	102	153	162	150	1.2
Natural Gas	264	327	452	564	534	3.6
Nuclear Power	577	628	636	659	647	.6
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	9.0
Renewable Sources/Other [1]	293	323	336	345	352	.9
Total	2,808	2,980	3,242	3,468	3,583	1.2
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	56	101	268	11.1
Petroleum	5	11	17	18	18	6.2
Natural Gas	100	152	206	250	252	4.8
Renewable Sources/Other [1]	80	127	156	187	213	5.0
Total	218	340	435	556	752	6.4
Sales to Utilities	106	182	247	360	549	8.6
Generation for Own Use	111	158	188	196	203	3.1
Electricity Sales by Sector						
Residential	924	1,026	1,067	1,147	1,226	1.4
Commercial/Other [3]	843	920	1,009	1,093	1,161	1.6
Industrial	946	1,037	1,222	1,385	1,540	2.5
Total	2,713	2,983	3,298	3,624	3,927	1.9
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.21	8.35	8.48	8.53	.3
Commercial/Other [3]	7.52	7.57	7.54	7.51	7.43	-.1
Industrial [5]	5.03	5.12	5.30	5.50	5.57	.5
Average	6.80	6.94	6.97	7.05	7.04	.2
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.88	2.57	2.28	2.09	-1.6
Fuel Component	1.70	1.90	2.26	2.65	2.91	2.7
O&M Component	2.23	2.16	2.14	2.13	2.04	-.4
Total	6.80	6.94	6.97	7.05	7.04	.2

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M = Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	303.5	329.5	0.5
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	15.6	40.2	45.4	10.9
Combustion Turbine/Diesel	46.4	55.5	70.0	76.8	82.5	2.9
Nuclear Power	99.6	101.3	102.6	105.6	104.8	.3
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.8	83.6	85.3	86.4	.5
Total	688.6	700.7	720.1	755.2	788.6	.7
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.7	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	7.0	9.5	9.5	7.3
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	53.6	64.7	66.4	12.5
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	4.4	31.7	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	1.7	25.0	30.0	-
Combustion Turbine/Diesel	.0	2.1	6.4	13.2	18.8	-
Nuclear Power	.0	.0	.0	.6	1.8	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.8	2.0	3.1	4.3	-
Total	.0	3.0	10.7	46.3	86.5	-
Cumulative Total Additions	6.3	30.3	64.2	111.1	152.9	17.3
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.9	11.8	19.5	47.6	9.9
Petroleum	.8	3.2	4.6	4.8	4.9	9.4
Natural Gas	19.3	29.2	39.1	48.2	48.7	4.7
Renewable Sources/Other [3]	15.8	25.1	30.3	35.6	40.3	4.8
Total	43.0	68.3	85.8	108.0	141.5	6.1
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	1.1	8.8	36.9	-
Petroleum	.0	.2	1.4	1.6	1.8	-
Natural Gas	.0	.8	10.0	19.0	19.5	-
Renewable Sources/Other [3]	.0	4.8	9.5	14.8	19.5	-
Total	.0	5.9	22.1	44.3	77.7	-
Cumulative Additions	.0	25.3	42.8	65.0	98.4	-

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes oil-, gas-, and dual-fired capability.

[3] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Non-utility Power Producer Report*. All projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.67	5.18	6.85	8.51	6.2
Municipal Solid Waste	2.01	6.48	9.00	11.87	13.92	10.2
Biomass/Other Waste	6.01	7.44	7.71	7.98	8.32	1.6
Solar Thermal	.35	.50	1.32	1.63	1.93	8.9
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.37	3.56	4.95	6.33	7.8
Total	87.43	97.04	103.64	110.14	115.90	1.4
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	20.82	34.63	49.02	62.05	7.2
Municipal Solid Waste	10.45	26.71	39.50	57.45	70.43	10.0
Biomass/Other Waste	31.48	46.86	53.16	56.76	60.18	3.3
Solar Thermal	.66	.90	2.19	2.98	3.79	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.44	9.08	12.75	16.20	10.4
Total	348.23	409.09	446.74	486.08	519.12	2.0
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.22	.36	.51	.64	7.2
Municipal Solid Waste	.11	.28	.41	.60	.73	10.1
Biomass/Other Waste	.32	.48	.55	.59	.62	3.3
Solar Thermal	.01	.01	.02	.03	.04	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.09	.13	.17	10.4
Total	3.62	4.25	4.64	5.05	5.39	2.0
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.80	3.05	3.32	3.63	1.7
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	3.01	3.82	4.21	4.71	2.8
Total Renewable Energy	6.32	7.26	8.46	9.26	10.10	2.4

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B7. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.321	1.521	1.798	2.160	3.3
Real Gross Domestic Product	4,885	5,509	6,314	7,081	7,854	2.4
Real Disposable Personal Income	3,538	3,920	4,377	4,869	5,373	2.1
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.181	1.433	1.660	1.848	3.0
AA Utility Bond Rate (percent)	9.66	8.68	7.67	7.95	7.90	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	5.87	4.57	4.86	4.85	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.75	15.78	14.96	14.20	-1.0

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

Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	19.90	22.90	26.10	29.30	1.3
Production						
Crude Oil [2]	7.35	6.54	5.53	5.49	5.62	-1.3
Alaska	1.77	1.33	.93	.67	.74	-4.3
Lower 48	5.58	5.20	4.60	4.83	4.88	-.7
Natural Gas Plant Liquids	1.56	1.60	1.73	1.81	1.77	.6
Other Domestic [3]	.08	.22	.31	.39	.46	9.2
Processing Gain [4]	.68	.68	.74	.74	.74	.4
Total	9.68	9.04	8.31	8.44	8.59	-.6
Imports (including SPR) [5]						
Crude Oil	5.89	6.84	8.50	8.52	8.41	1.8
Refined Products[6]	2.13	3.12	3.71	4.91	5.87	5.2
Total	8.02	9.97	12.21	13.44	14.28	2.9
Exports						
Crude Oil	.11	.09	.07	.06	.07	-2.0
Refined Products	.75	.70	.77	.80	.80	.3
Total	.85	.79	.84	.86	.87	.1
Net Imports (including SPR)	7.17	9.17	11.37	12.57	13.41	3.2
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.05	-.03	-.03	-.02	-8.0
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	18.13	19.63	20.96	21.95	1.4
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.65	8.12	8.58	8.94	1.1
Jet Fuel [10]	1.52	1.74	2.03	2.34	2.57	2.7
Distillate Fuel	3.02	3.36	3.57	3.77	3.98	1.4
Residual Fuel	1.23	1.23	1.51	1.62	1.62	1.4
Other [11]	3.98	4.33	4.59	4.84	5.03	1.2
Total	16.99	18.32	19.82	21.14	22.14	1.3
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.28	1.08	.95	.85	-1.5
Industrial [12]	4.34	4.73	5.13	5.45	5.70	1.4
Transportation	10.97	11.83	12.90	13.99	14.89	1.5
Electric Utilities	.54	.48	.71	.75	.70	1.3
Total	16.99	18.32	19.82	21.14	22.14	1.3
Net Disposition	16.98	18.32	19.82	21.14	22.14	1.3

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.82	20.34	21.30	20.75	0.8
Supplemental Gas [2]	.10	.10	.10	.12	.14	1.6
Net Imports	1.45	2.49	3.08	3.63	4.27	5.6
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	21.42	23.52	25.05	25.16	1.5
Consumption by Sector						
Residential	4.38	4.90	4.70	4.65	4.59	.2
Commercial	2.67	2.98	3.08	3.16	3.21	.9
Industrial [4]	6.98	8.13	8.74	8.90	9.26	1.4
Electric Utilities [5]	2.79	3.47	4.90	6.05	5.64	3.6
Lease and Plant Fuel [6]	1.24	1.20	1.29	1.35	1.36	.5
Pipeline Fuel	.66	.65	.71	.77	.84	1.2
Transportation [7]	.00	.00	.02	.07	.15	60.3
Total	18.73	21.33	23.44	24.96	25.05	1.5
Unaccounted for [8]	.12	.09	.08	.09	.11	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.37	2.86	3.64	4.07	4.2
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.73	7.24	8.04	8.47	1.7
Commercial	4.99	5.76	6.27	7.08	7.52	2.1
Industrial	3.04	3.75	4.28	5.08	5.51	3.0
Electric Utilities	2.46	2.96	3.60	4.58	5.08	3.7
Transportation[7]	4.64	7.53	8.37	9.27	10.07	3.9
Average [9]	4.03	4.66	5.06	5.84	6.31	2.3

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	659	683	736	826	1.4
West of the Mississippi	399	419	484	562	664	2.6
Total	1,029	1,078	1,167	1,297	1,490	1.9
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	134	177	242	288	5.1
Total	-103	-129	-171	-233	-277	5.1
Net Stock Withdrawals [2]	-27	-2	-1	-4	-5	-8.5
Total Supply [3]	899	947	995	1,061	1,209	1.5
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	87	87	88	95	1.1
Coking Plants	39	40	37	34	32	-1.0
Electricity [5]	774	815	866	934	1,079	1.7
Total	895	948	996	1,062	1,210	1.5
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	24.32	27.44	29.67	33.12	1.9
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.24	52.58	56.41	61.71	.9
Industrial	34.77	33.27	36.04	39.03	42.61	1.0
Coking Plants	49.40	51.33	57.18	62.66	69.16	1.7
Electricity	31.52	31.25	33.45	35.55	39.09	1.1
Average [8]	32.72	32.39	34.67	36.82	40.24	1.0

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	98.0	103.8	108.9	113.2	1.0
Energy Consumption per Household (million Btu)	105.2	111.8	108.0	105.2	104.4	.0
End-Use Consumption						
Distillate						
Space Heating	.72	.81	.64	.54	.46	-2.3
Other Uses [1]	.11	.09	.05	.03	.02	-8.6
Total	.84	.91	.69	.57	.48	-2.8
Natural Gas						
Space Heating	3.15	3.48	3.28	3.21	3.14	.0
Water Heating	1.06	1.26	1.29	1.31	1.32	1.1
Other Uses [1]	.31	.30	.28	.27	.27	-.6
Total	4.52	5.05	4.85	4.79	4.73	.2
Other Fuels [2]	.49	.57	.49	.43	.40	-1.0
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.31	.31	.31	-.1
Cooling	.51	.56	.51	.55	.58	.6
Water Heating	.39	.50	.58	.67	.75	3.3
Other Uses [1]	1.93	2.11	2.25	2.39	2.53	1.4
Total	3.15	3.50	3.64	3.91	4.18	1.4
Total Consumption	9.83	10.96	11.22	11.46	11.82	.9

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	118.2	127.0	133.3	139.3	1.2
Total Floorspace (billion square feet)	62.9	69.1	76.3	83.9	92.0	1.9
Energy Consumption per Square Foot (thousand Btu)	107.0	107.3	102.8	97.2	91.4	-.8
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.50	.46	.43	-.3
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.57	.53	.49	.45	-.5
Natural Gas						
Space Heating	1.80	1.98	2.01	2.00	1.95	.4
Cooling	.21	.23	.24	.25	.27	1.3
Other Uses [1]	.75	.86	.93	1.01	1.09	1.9
Total	2.76	3.07	3.18	3.26	3.31	.9
Other Fuels [2]	.52	.49	.45	.41	.38	-1.6
Renewables [3]	.10	.16	.27	.32	.39	7.3
Electricity						
Space Heating	.52	.59	.66	.74	.84	2.4
Cooling	.73	.81	.90	.97	1.02	1.7
Lighting	1.14	1.20	1.27	1.30	1.27	.5
Other Uses [1]	.48	.52	.59	.67	.76	2.3
Total	2.86	3.12	3.42	3.68	3.88	1.5
Total Consumption	6.72	7.42	7.84	8.15	8.40	1.1

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2755	3344	3872	4311	3.0
Non-manufacturing	871	959	1094	1190	1299	2.0
Total	3274	3714	4438	5063	5609	2.7
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.35	.32	.29	.28	-1.3
Liquefied Petroleum Gas	.49	.54	.51	.49	.47	-.2
Petrochemical Feedstocks	.34	.32	.31	.31	.31	-.5
Residual Fuel	.13	.14	.12	.11	.10	-1.3
Other Petroleum [1]	1.17	.98	.84	.74	.68	-2.7
Natural Gas [2]	2.59	2.59	2.33	2.09	1.95	-1.4
Metallurgical Coal and Coke [3]	.32	.29	.24	.20	.18	-2.8
Steam Coal [4]	.52	.50	.42	.37	.36	-1.9
Renewables [5]	.06	.06	.05	.05	.05	-1.5
Electricity	.99	.95	.94	.93	.94	-.3
Total	7.59	7.34	6.63	6.09	5.77	-1.4
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.29	1.42	1.48	1.55	1.4
Liquefied Petroleum Gas	1.61	2.02	2.26	2.48	2.63	2.5
Motor Gasoline [6]	.18	.23	.26	.28	.30	2.5
Petrochemical Feedstocks	1.10	1.18	1.37	1.55	1.72	2.2
Residual Fuel	.41	.51	.54	.55	.55	1.4
Other Petroleum [1]	3.83	3.64	3.75	3.77	3.80	.0
Natural Gas [2]	8.47	9.62	10.34	10.57	10.95	1.3
Metallurgical Coal and Coke [3]	1.04	1.07	1.05	1.03	1.01	-.2
Steam Coal [4]	1.71	1.86	1.86	1.88	1.99	.8
Renewables [5]	2.07	2.32	2.41	2.52	2.63	1.2
Electricity	3.23	3.54	4.17	4.72	5.25	2.5
Total	24.84	27.27	29.43	30.83	32.39	1.3

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.10	1.22	1.35	1.48	1.9
Freight Trucks	1.00	1.12	1.29	1.43	1.58	2.3
Air	.99	1.30	1.73	2.18	2.64	5.0
Rail	.99	1.05	1.15	1.26	1.36	1.6
Marine	.99	1.05	1.14	1.22	1.30	1.4
Energy Efficiency Indicators						
New Car MPG [1]	28.00	28.89	30.49	32.66	34.74	1.1
New Light Truck MPG [1]	20.70	21.73	22.85	24.18	25.46	1.0
Light Duty Fleet MPG [2]	18.58	19.31	19.94	20.64	21.38	.7
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.26	13.08	13.90	14.64	1.2
Freight Trucks	5.06	5.45	6.04	6.58	7.13	1.7
Air	3.20	3.66	4.27	4.91	5.40	2.6
Rail	.49	.51	.54	.59	.63	1.2
Marine	1.39	1.51	1.73	1.94	2.11	2.1
Pipeline Fuel	.68	.67	.73	.79	.87	1.2
Other	.17	.18	.19	.21	.23	1.4
Total	22.50	24.23	26.58	28.91	31.00	1.6

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989 = 1.0).
[4] Based on Btu per vehicle miles traveled (1989 = 1.0).
[5] Based on Btu per ton-miles traveled (1989 = 1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

Table B15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.1	21.3	17.8	15.4	-2.2
Natural Gas	65.7	73.4	70.5	69.7	68.8	.2
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	102.1	93.3	89.0	85.7	-.3
Commercial						
Petroleum	18.5	19.7	18.2	16.8	15.4	-.9
Natural Gas	40.1	44.6	46.2	47.4	48.1	.9
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.5	66.2	65.8	64.9	.3
Industrial [2]						
Petroleum	87.4	89.7	94.3	96.4	98.3	.6
Natural Gas [3]	115.0	131.0	141.3	144.7	149.9	1.3
Metallurgical Coal	26.5	27.2	25.1	23.2	21.4	-1.1
Steam Coal	43.6	47.3	47.4	47.9	50.8	.8
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	295.2	308.2	312.1	320.4	.8
Transportation						
Petroleum	425.1	459.2	503.4	545.4	581.2	1.6
Natural Gas[4]	9.9	9.8	11.0	12.5	14.8	2.0
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	469.1	514.4	557.9	595.9	1.6
Electric Utilities [5]						
Petroleum	26.4	23.6	34.9	36.9	34.3	1.3
Natural Gas	41.9	52.1	73.5	90.7	84.6	3.6
Steam Coal	412.3	425.1	443.5	472.0	539.4	1.4
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	500.7	551.9	599.7	658.3	1.6
Primary Energy Consumption						
Petroleum	581.6	619.3	672.1	713.2	744.6	1.2
Natural Gas	272.6	310.9	342.4	365.1	366.1	1.5
Metallurgical Coal	26.5	27.2	25.1	23.2	21.4	-1.1
Steam Coal	459.8	476.1	494.3	523.0	593.1	1.3
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1433.6	1534.0	1624.5	1725.2	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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run HMAC93.D091692C.

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

Supply, Disposition, and Prices	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	14.28	12.58	12.42	12.76	-1.0
Natural Gas Plant Liquids	2.17	2.15	2.27	2.34	2.27	.2
Dry Natural Gas [2]	18.47	18.89	19.91	20.56	20.01	.4
Coal	22.23	22.48	22.95	23.93	26.40	.9
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy [3]	6.53	7.24	8.33	8.94	9.73	2.0
Total	71.34	71.90	72.93	75.26	78.10	.5
Imports						
Crude Oil [4]	12.78	14.23	17.24	18.36	18.19	1.8
Petroleum Products	4.36	6.18	6.08	6.70	7.13	2.5
Natural Gas [5]	1.46	2.57	2.90	3.30	3.98	5.2
Other Imports [6]	.11	.51	.64	.90	1.15	12.4
Total	18.70	23.49	26.86	29.25	30.45	2.5
Exports						
Coal	2.64	2.96	2.86	3.26	4.77	3.0
Petroleum	1.82	1.64	1.66	1.72	1.76	-.2
Total	4.46	4.60	4.52	4.98	6.53	1.9
Net Stock Withdrawals	-1.36	-.17	-.12	-.13	-.10	-12.5
Discrepancy [7]	.41	-.08	-.10	-.12	-.25	-
Consumption						
Petroleum Products [8]	33.53	35.16	36.53	38.16	38.64	.7
Natural Gas	19.31	21.39	22.72	23.79	23.88	1.1
Coal	19.11	19.61	20.22	20.85	21.86	.7
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.54	8.69	9.42	10.36	2.4
Total	84.63	90.54	95.05	99.28	101.67	.9
Net Imports - Petroleum	15.31	18.76	21.66	23.34	23.56	2.2
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	19.90	22.90	26.10	29.30	1.3
Natural Gas Wellhead Price ($ per Mcf)	1.77	1.93	2.27	2.92	3.30	3.2
Coal Minemouth Price ($ per ton)	22.52	23.74	26.02	26.47	29.03	1.3

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

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

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.92	0.70	0.57	0.47	-2.9
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.31	-.8
Natural Gas	4.52	5.10	4.82	4.70	4.55	.0
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.48	3.53	3.69	3.84	1.0
Total	9.83	11.00	11.08	11.13	11.28	.7
Commercial						
Distillate Fuel	.49	.57	.53	.48	.44	-.5
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.12	.13	.13	.8
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.07	3.15	3.20	3.20	.7
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.29	.37	7.0
Electricity	2.86	3.12	3.38	3.61	3.77	1.4
Total	6.72	7.40	7.76	7.99	8.15	1.0
Industrial [4]						
Distillate Fuel	1.18	1.26	1.31	1.35	1.37	.7
Liquefied Petroleum Gas	1.61	2.03	2.19	2.34	2.41	2.1
Motor Gasoline [2]	.18	.22	.23	.24	.25	1.6
Petrochemical Feedstocks	1.10	1.15	1.29	1.43	1.52	1.6
Residual Fuel	.41	.52	.50	.50	.48	.7
Other Petroleum [5]	3.83	3.62	3.64	3.66	3.65	-.2
Natural Gas [6]	8.47	9.45	9.96	10.11	10.08	.9
Metallurgical Coal	1.04	1.04	.96	.89	.82	-1.2
Steam Coal	1.71	1.84	1.82	1.82	1.95	.7
Net Coal Coke Imports	.00	.00	.05	.11	.15	18.6
Renewable Energy [1]	2.07	2.19	2.20	2.20	2.23	.4
Purchased Electricity	3.23	3.35	3.75	4.11	4.33	1.5
Total	24.84	26.68	27.91	28.77	29.23	.8
Transportation						
Distillate Fuel	3.83	4.09	4.37	4.74	4.99	1.3
Jet Fuel	3.13	3.35	3.53	3.81	3.88	1.1
Motor Gasoline [2]	13.58	14.15	14.74	15.12	15.14	.5
Residual Fuel	1.02	1.08	1.21	1.33	1.42	1.7
Other Petroleum [7]	.24	.25	.26	.28	.30	1.1
Pipeline Fuel Natural Gas	.68	.65	.69	.72	.73	.4
Compressed Natural Gas	.00	.01	.02	.08	.16	60.7
Alcohol Fuels	.00	.01	.02	.08	.16	63.0
Electricity	.01	.02	.02	.05	.07	8.7
Total	22.50	23.59	24.87	26.21	26.86	.9
Electric Utilities [8]						
Distillate Fuel	.09	.07	.14	.16	.16	3.2
Residual Fuel	1.14	.96	1.09	1.44	1.51	1.4
Natural Gas	2.88	3.11	4.08	4.98	5.16	3.0
Steam Coal	16.20	16.58	17.31	18.02	18.97	.8
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.26	4.62	4.99	5.43	2.2
Total	29.99	31.83	34.12	36.64	38.17	1.2
Primary Energy Consumption						
Distillate Fuel	6.42	6.91	7.05	7.29	7.42	.7
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.35	3.53	3.81	3.88	1.1
Liquefied Petroleum Gas	2.06	2.57	2.65	2.76	2.80	1.6
Motor Gasoline	13.87	14.49	15.09	15.49	15.52	.6
Petrochemical Feedstocks	1.10	1.15	1.29	1.43	1.52	1.6
Residual Fuel	2.82	2.78	2.99	3.42	3.55	1.2

– See footnotes at end of table.

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

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.84	3.87	3.91	3.91	-0.2
Natural Gas	19.31	21.39	22.72	23.79	23.88	1.1
Metallurgical Coal	1.04	1.04	.96	.89	.82	-1.2
Steam Coal	18.07	18.57	19.25	19.96	21.03	.8
Net Coal Coke Imports	.00	.00	.05	.11	.15	18.6
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.53	8.62	9.24	10.06	2.2
Alcohols	.00	.01	.02	.08	.16	63.0
Total	84.63	90.54	95.05	99.28	101.67	.9
Electricity Consumption (all Sectors)	9.26	9.96	10.68	11.45	12.02	1.3
Industrial Electricity						
Gross Consumption	3.58	3.88	4.30	4.68	4.92	1.6
Self-generation - Own Use	.39	.53	.55	.57	.58	2.0
Purchased Electricity	3.23	3.35	3.75	4.11	4.33	1.5

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.40	13.01	13.78	14.50	0.8
Primary Energy	6.48	6.40	6.75	7.35	7.75	.9
Petroleum Products	9.04	7.71	8.38	9.11	9.86	.4
Distillate Fuel	8.08	6.93	7.49	8.11	8.71	.4
Kerosene	9.14	8.57	8.98	9.42	9.85	.4
Liquefied Petroleum Gas	11.20	9.20	9.94	10.75	11.57	.2
Natural Gas	5.82	6.08	6.42	7.06	7.44	1.2
Steam Coal	1.99	2.05	2.21	2.32	2.48	1.1
Electricity	23.34	23.74	23.68	23.71	24.04	.1
Commercial	12.40	12.35	12.65	13.03	13.40	.4
Primary Energy	5.06	5.12	5.54	6.21	6.66	1.4
Petroleum Products	6.04	5.32	6.00	6.77	7.51	1.1
Distillate Fuel	5.94	4.89	5.46	6.09	6.69	.6
Residual Fuel	3.57	3.22	3.72	4.29	4.87	1.6
Kerosene	6.96	6.22	6.64	7.11	7.58	.4
Other Petroleum [1]	9.69	9.06	9.90	10.82	11.65	.9
Natural Gas	4.84	5.14	5.49	6.14	6.53	1.5
Steam Coal	1.96	2.02	2.17	2.28	2.44	1.1
Electricity	22.04	21.93	21.31	20.75	20.55	-.4
Industrial	5.73	5.49	5.97	6.60	7.07	1.1
Primary Energy	4.14	3.93	4.35	4.94	5.39	1.3
Petroleum Products	6.01	5.36	5.90	6.51	7.12	.8
Distillate Fuel	5.94	4.85	5.41	6.03	6.63	.5
Liquefied Petroleum Gas	5.95	5.04	5.75	6.55	7.35	1.1
Motor Gasoline [2]	9.87	9.45	10.27	11.17	11.95	1.0
Residual Fuel	3.13	2.89	3.39	3.97	4.54	1.9
Other Petroleum [3]	6.14	5.71	6.15	6.64	7.14	.8
Natural Gas [4]	2.95	3.20	3.54	4.18	4.56	2.2
Metallurgical Coal	1.82	1.89	2.07	2.18	2.34	1.3
Steam Coal	1.48	1.55	1.66	1.75	1.87	1.2
Electricity	14.74	14.77	14.87	15.08	15.28	.2
Transportation	8.92	8.38	9.07	9.80	10.47	.8
Primary Energy	8.91	8.36	9.05	9.78	10.45	.8
Petroleum Products	8.91	8.36	9.06	9.79	10.45	.8
Distillate Fuel [5]	8.98	8.61	9.17	9.79	10.38	.7
Jet Fuel [6]	6.00	4.62	5.20	5.84	6.45	.4
Motor Gasoline [2]	9.86	9.50	10.31	11.21	11.99	1.0
Residual Fuel	3.22	2.75	3.18	3.65	4.09	1.2
Other Petroleum [7]	16.49	14.87	15.30	15.78	16.27	-.1
Compressed Natural Gas	4.50	6.97	7.79	8.67	9.45	3.8
Electricity	23.74	24.14	21.47	18.77	18.19	-1.3
Total End-Use Energy	8.68	8.41	8.90	9.53	10.08	.8
Primary Energy	6.58	6.22	6.77	7.46	8.02	1.0
Electricity	19.94	20.16	19.83	19.66	19.75	.0
Electric Utilities						
Fossil Fuel Average	1.71	1.75	1.98	2.26	2.48	1.9
Petroleum Products	3.61	3.44	3.92	4.45	5.23	1.9
Distillate Fuel	5.57	4.39	4.97	5.62	6.23	.6
Residual Fuel	3.46	3.38	3.79	4.32	5.12	2.0
Natural Gas	2.38	2.47	2.89	3.56	3.98	2.6
Steam Coal	1.45	1.51	1.63	1.71	1.83	1.2

- See footnotes at end of table.

Table C3. Energy Prices by End-Use Sector and Source (Continued)
(1991 Dollars per Million Btu)

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	7.36	8.00	8.66	9.32	0.8
Distillate Fuel [5]	8.03	7.35	7.94	8.62	9.28	.7
Jet Fuel [6]	6.00	4.62	5.20	5.84	6.45	.4
Kerosene	8.80	8.28	8.61	8.97	9.30	.3
Liquefied Petroleum Gas	7.02	5.88	6.46	7.16	7.91	.6
Motor Gasoline [2]	9.86	9.50	10.31	11.21	11.99	1.0
Residual Fuel	3.33	3.03	3.47	4.01	4.62	1.6
Other Petroleum Products [9]	6.62	6.15	6.60	7.11	7.62	.7
Natural Gas	3.90	4.14	4.38	4.97	5.35	1.6
Coal	1.48	1.54	1.66	1.73	1.86	1.2
Electricity	19.94	20.16	19.83	19.66	19.75	.0

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run LMAC93.D0916924. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,598	1,666	1,732	1,821	0.8
Petroleum	117	94	115	151	158	1.5
Natural Gas	264	291	375	455	475	3.0
Nuclear Power	577	628	632	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	9.0
Renewable Sources/Other [1]	293	321	335	344	350	.9
Total	2,808	2,922	3,112	3,318	3,429	1.0
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	55	60	87	5.0
Petroleum	5	11	11	12	12	4.0
Natural Gas	100	152	160	168	169	2.7
Renewable Sources/Other [1]	80	117	138	158	188	4.4
Total	218	329	364	398	456	3.8
Sales to Utilities	106	174	201	231	286	5.1
Generation for Own Use	111	155	163	167	171	2.2
Electricity Sales by Sector						
Residential	924	1,021	1,033	1,081	1,124	1.0
Commercial/Other [3]	843	918	998	1,072	1,128	1.5
Industrial	946	981	1,099	1,204	1,271	1.5
Total	2,713	2,920	3,131	3,356	3,523	1.3
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.10	8.08	8.09	8.20	.1
Commercial/Other [3]	7.52	7.49	7.27	7.07	7.00	-.4
Industrial [5]	5.03	5.04	5.08	5.15	5.21	.2
Average	6.80	6.88	6.77	6.71	6.74	.0
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.91	2.55	2.20	2.02	-1.8
Fuel Component	1.70	1.79	2.02	2.28	2.51	2.0
O&M Component	2.23	2.18	2.20	2.23	2.21	.0
Total	6.80	6.88	6.77	6.71	6.74	.0

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M -- Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	302.4	315.0	0.3
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	13.8	19.3	23.4	7.3
Combustion Turbine/Diesel	46.4	54.6	66.0	72.2	76.9	2.6
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.6	83.3	84.8	85.9	.5
Total	688.6	699.6	712.9	726.8	743.8	.4
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	3.3	17.2	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.0	4.2	8.1	-
Combustion Turbine/Diesel	.0	1.2	2.5	8.5	13.2	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.7	1.6	2.6	3.8	-
Total	.0	1.9	4.7	19.2	42.9	-
Cumulative Total Additions	6.3	29.2	57.0	82.7	108.1	15.3
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	11.7	12.5	17.1	4.5
Petroleum	.8	3.2	3.5	3.6	3.7	7.9
Natural Gas	19.3	29.2	30.7	32.4	32.6	2.7
Renewable Sources/Other [3]	15.8	23.6	27.6	31.3	36.5	4.3
Total	43.0	66.8	73.5	79.9	90.0	3.8
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	.9	1.8	6.4	-
Petroleum	.0	.2	.4	.5	.6	-
Natural Gas	.0	.7	1.5	3.2	3.4	-
Renewable Sources/Other [3]	.0	3.3	6.9	10.6	15.8	-
Total	.0	4.3	9.7	16.1	26.2	-
Cumulative Additions	.0	23.8	30.4	36.9	47.0	-

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes oil-, gas-, and dual-fired capability.

[3] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. All projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.67	5.18	6.85	8.51	6.2
Municipal Solid Waste	2.01	5.11	6.54	7.90	10.86	8.8
Biomass/Other Waste	6.01	7.12	7.16	7.15	7.17	.9
Solar Thermal	.35	.50	1.32	1.63	1.93	8.9
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.37	3.56	4.95	6.33	7.8
Total	87.43	95.35	100.63	105.34	111.68	1.2
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	20.82	34.63	49.02	62.05	7.2
Municipal Solid Waste	10.45	17.92	23.39	31.17	50.09	8.2
Biomass/Other Waste	31.48	44.99	49.99	52.07	53.67	2.7
Solar Thermal	.66	.90	2.19	2.98	3.79	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.44	9.08	12.75	16.20	10.4
Total	348.23	398.43	427.47	455.10	492.26	1.7
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.22	.36	.51	.64	7.2
Municipal Solid Waste	.11	.19	.24	.32	.52	8.2
Biomass/Other Waste	.32	.46	.52	.54	.55	2.7
Solar Thermal	.01	.01	.02	.03	.04	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.09	.13	.17	10.4
Total	3.62	4.14	4.44	4.73	5.11	1.7
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.69	2.86	3.05	3.28	1.2
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	2.90	3.64	3.94	4.36	2.4
Total Renewable Energy	6.32	7.04	8.08	8.66	9.47	2.0

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C7. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.317	1.730	2.353	3.155	5.3
Real Gross Domestic Product	4,885	5,295	5,778	6,291	6,691	1.6
Real Disposable Personal Income	3,538	3,864	4,202	4,505	4,757	1.5
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.104	1.274	1.431	1.534	2.0
AA Utility Bond Rate (percent)	9.66	9.61	11.45	11.57	11.34	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.73	8.52	8.54	8.46	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	17.10	16.45	15.78	15.20	-.7

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	19.90	22.90	26.10	29.30	1.3
Production						
Crude Oil [2]	7.35	6.53	5.62	5.49	5.58	-1.4
Alaska	1.77	1.33	.93	.67	.74	-4.3
Lower 48	5.58	5.19	4.69	4.83	4.84	-.7
Natural Gas Plant Liquids	1.56	1.55	1.63	1.69	1.63	.2
Other Domestic [3]	.08	.22	.30	.38	.44	8.9
Processing Gain [4]	.68	.66	.70	.74	.74	.4
Total	9.68	8.95	8.26	8.30	8.40	-.7
Imports (including SPR) [5]						
Crude Oil	5.89	6.60	7.98	8.52	8.44	1.8
Refined Products[6]	2.13	3.05	3.00	3.31	3.53	2.6
Total	8.02	9.66	10.98	11.84	11.97	2.0
Exports						
Crude Oil	.11	.09	.07	.06	.07	-2.0
Refined Products	.75	.68	.71	.75	.76	.1
Total	.85	.78	.79	.81	.83	-.1
Net Imports (including SPR)	7.17	8.88	10.20	11.02	11.14	2.2
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.04	-.02	-.02	.00	-15.2
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	17.77	18.42	19.28	19.51	.8
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.56	7.85	8.08	8.10	.6
Jet Fuel [10]	1.52	1.63	1.71	1.85	1.89	1.1
Distillate Fuel	3.02	3.25	3.31	3.43	3.49	.7
Residual Fuel	1.23	1.21	1.30	1.49	1.54	1.1
Other [11]	3.98	4.31	4.44	4.61	4.68	.8
Total	16.99	17.96	18.61	19.47	19.70	.7
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.28	1.08	.94	.83	-1.6
Industrial [12]	4.34	4.70	4.91	5.14	5.23	.9
Transportation	10.97	11.53	12.08	12.69	12.90	.8
Electric Utilities	.54	.45	.54	.70	.73	1.6
Total	16.99	17.96	18.61	19.47	19.70	.7
Net Disposition	16.98	17.96	18.60	19.47	19.70	.7

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.22	19.20	19.83	19.27	0.4
Supplemental Gas [2]	.10	.10	.10	.12	.13	1.3
Net Imports	1.45	2.49	2.81	3.20	3.86	5.0
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	20.82	22.12	23.14	23.26	1.1
Consumption by Sector						
Residential	4.38	4.94	4.67	4.56	4.42	.0
Commercial	2.67	2.98	3.06	3.10	3.10	.7
Industrial [4]	6.98	8.01	8.43	8.54	8.52	1.0
Electric Utilities [5]	2.79	3.01	3.96	4.83	5.01	3.0
Lease and Plant Fuel [6]	1.24	1.17	1.23	1.27	1.25	.1
Pipeline Fuel	.66	.63	.67	.70	.71	.4
Transportation [7]	.00	.01	.02	.07	.15	60.7
Total	18.73	20.74	22.04	23.07	23.17	1.1
Unaccounted for [8]	.12	.08	.08	.07	.10	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	1.93	2.27	2.92	3.30	3.2
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.27	6.62	7.28	7.67	1.2
Commercial	4.99	5.30	5.66	6.33	6.73	1.5
Industrial	3.04	3.30	3.65	4.31	4.70	2.2
Electric Utilities	2.46	2.55	2.98	3.67	4.10	2.6
Transportation[7]	4.64	7.19	8.03	8.94	9.75	3.8
Average [9]	4.03	4.27	4.52	5.12	5.51	1.6

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	637	622	634	703	0.6
West of the Mississippi	399	414	466	507	555	1.7
Total	1,029	1,051	1,088	1,141	1,258	1.0
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	113	111	127	185	2.8
Total	-103	-109	-105	-117	-174	2.6
Net Stock Withdrawals [2]	-27	-2	-1	-2	-2	-13.0
Total Supply [3]	899	940	982	1,023	1,083	.9
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.8
Industrial [4]	76	86	85	85	92	1.0
Coking Plants	39	39	36	34	31	-1.1
Electricity [5]	774	809	856	900	956	1.1
Total	895	941	983	1,024	1,084	1.0
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	23.74	26.02	26.47	29.03	1.3
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.16	51.23	54.11	57.01	.5
Industrial	34.77	32.95	35.50	37.64	39.82	.7
Coking Plants	49.40	50.21	54.83	57.84	62.10	1.2
Electricity	31.52	30.93	32.92	34.13	36.31	.7
Average [8]	32.72	32.03	34.06	35.30	37.44	.7

[1] Includes anthracite, bituminous coal, and lignite.

[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.

[3] Production plus net imports plus net storage withdrawals.

[4] Includes consumption by cogenerators.

[5] Includes consumption by independent power producers.

[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.

[7] Free-on-board price.

[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.2	100.2	102.8	104.9	0.6
Energy Consumption per Household (million Btu)	105.2	113.1	110.5	108.3	107.6	.1
End-Use Consumption						
Distillate						
Space Heating	.72	.83	.65	.54	.45	-2.4
Other Uses [1]	.11	.09	.05	.03	.02	-8.6
Total	.84	.92	.70	.57	.47	-2.9
Natural Gas						
Space Heating	3.15	3.52	3.25	3.14	3.01	-.2
Water Heating	1.06	1.27	1.29	1.30	1.28	1.0
Other Uses [1]	.31	.31	.28	.26	.26	-.8
Total	4.52	5.10	4.82	4.70	4.55	.0
Other Fuels [2]	.49	.57	.49	.43	.39	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.29	.29	-.6
Cooling	.51	.55	.50	.52	.53	.2
Water Heating	.39	.50	.55	.61	.67	2.7
Other Uses [1]	1.93	2.10	2.19	2.27	2.35	1.0
Total	3.15	3.48	3.53	3.69	3.84	1.0
Total Consumption	9.83	11.00	11.08	11.13	11.28	.7

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	116.0	121.4	125.7	128.4	0.8
Total Floorspace (billion square feet)	62.9	68.8	75.0	81.2	87.4	1.7
Energy Consumption per Square Foot (thousand Btu)	107.0	107.6	103.5	98.4	93.3	-.7
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.50	.46	.42	-.4
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.57	.53	.48	.44	-.5
Natural Gas						
Space Heating	1.80	1.99	2.00	1.98	1.91	.3
Cooling	.21	.23	.23	.24	.26	1.0
Other Uses [1]	.75	.86	.92	.98	1.03	1.6
Total	2.76	3.07	3.15	3.20	3.20	.7
Other Fuels [2]	.52	.49	.44	.40	.37	-1.8
Renewables [3]	.10	.15	.25	.29	.37	7.0
Electricity						
Space Heating	.52	.59	.64	.71	.78	2.1
Cooling	.73	.81	.89	.95	1.00	1.6
Lighting	1.14	1.20	1.27	1.29	1.27	.5
Other Uses [1]	.48	.52	.59	.66	.73	2.1
Total	2.86	3.12	3.38	3.61	3.77	1.4
Total Consumption	6.72	7.40	7.76	7.99	8.15	1.0

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2576	2972	3338	3580	2.0
Non-manufacturing	871	904	938	1007	1053	1.0
Total	3274	3480	3910	4345	4633	1.8
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.36	.34	.31	.30	-1.0
Liquefied Petroleum Gas	.49	.58	.56	.54	.52	.3
Petrochemical Feedstocks	.34	.33	.33	.33	.33	-.1
Residual Fuel	.13	.15	.13	.11	.10	-1.0
Other Petroleum [1]	1.17	1.04	.93	.84	.79	-2.0
Natural Gas [2]	2.59	2.72	2.55	2.33	2.18	-.9
Metallurgical Coal and Coke [3]	.32	.30	.26	.23	.21	-2.1
Steam Coal [4]	.52	.53	.46	.42	.42	-1.1
Renewables [5]	.06	.06	.06	.05	.05	-1.4
Electricity	.99	.96	.96	.95	.94	-.3
Total	7.59	7.67	7.14	6.62	6.31	-.9
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.26	1.31	1.35	1.37	.7
Liquefied Petroleum Gas	1.61	2.03	2.19	2.34	2.41	2.1
Motor Gasoline [6]	.18	.22	.23	.24	.25	1.6
Petrochemical Feedstocks	1.10	1.15	1.29	1.43	1.52	1.6
Residual Fuel	.41	.52	.50	.50	.48	.7
Other Petroleum [1]	3.83	3.62	3.64	3.66	3.65	-.2
Natural Gas [2]	8.47	9.45	9.96	10.11	10.08	.9
Metallurgical Coal and Coke [3]	1.04	1.04	1.02	1.00	.97	-.4
Steam Coal [4]	1.71	1.84	1.82	1.82	1.95	.7
Renewables [5]	2.07	2.19	2.20	2.20	2.23	.4
Electricity	3.23	3.35	3.75	4.11	4.33	1.5
Total	24.84	26.68	27.91	28.77	29.23	.8

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.09	1.19	1.28	1.35	1.5
Freight Trucks	1.00	1.06	1.15	1.25	1.32	1.4
Air	.99	1.21	1.42	1.68	1.88	3.2
Rail	.99	1.01	1.06	1.14	1.20	.9
Marine	.99	1.02	1.09	1.17	1.23	1.1
Energy Efficiency Indicators						
New Car MPG [1]	28.00	28.65	30.15	32.35	34.46	1.0
New Light Truck MPG [1]	20.70	21.55	22.60	23.96	25.28	1.0
Light Duty Fleet MPG [2]	18.58	19.25	19.81	20.47	21.23	.7
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.20	12.85	13.30	13.50	.8
Freight Trucks	5.06	5.19	5.40	5.76	5.98	.8
Air	3.20	3.42	3.60	3.90	3.98	1.1
Rail	.49	.49	.50	.53	.55	.6
Marine	1.39	1.47	1.63	1.79	1.91	1.6
Pipeline Fuel	.68	.65	.69	.72	.73	.4
Other	.17	.17	.19	.20	.21	.9
Total	22.50	23.59	24.87	26.21	26.86	.9

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989=1.0).
[4] Based on Btu per vehicle miles traveled (1989=1.0).
[5] Based on Btu per ton-miles traveled (1989=1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

Table C15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.4	21.5	17.8	15.1	-2.3
Natural Gas	65.7	74.1	70.0	68.3	66.2	.0
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	103.0	93.0	87.6	82.9	-.5
Commercial						
Petroleum	18.5	19.7	18.1	16.5	15.1	-1.0
Natural Gas	40.1	44.7	45.8	46.5	46.5	.7
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.5	65.7	64.6	62.9	.2
Industrial [2]						
Petroleum	87.4	89.1	90.6	91.7	91.7	.2
Natural Gas [3]	115.0	128.5	135.6	137.8	137.2	.9
Metallurgical Coal	26.5	26.6	24.6	22.7	20.9	-1.2
Steam Coal	43.6	46.9	46.3	46.5	49.7	.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	291.2	297.0	298.6	299.6	.5
Transportation						
Petroleum	425.1	447.0	470.5	493.5	502.7	.8
Natural Gas[4]	9.9	9.6	10.3	11.6	12.9	1.3
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	456.5	480.8	505.2	515.6	.9
Electric Utilities [5]						
Petroleum	26.4	22.2	26.4	34.3	35.9	1.5
Natural Gas	41.9	45.2	59.4	72.3	75.0	3.0
Steam Coal	412.3	422.0	440.4	458.5	482.7	.8
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	489.3	526.2	565.2	593.6	1.1
Primary Energy Consumption						
Petroleum	581.6	605.4	627.0	653.9	660.5	.6
Natural Gas	272.6	302.0	321.2	336.6	337.8	1.1
Metallurgical Coal	26.5	26.6	24.6	22.7	20.9	-1.2
Steam Coal	459.8	472.5	490.1	508.1	535.3	.8
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1406.5	1462.8	1521.2	1554.6	.7

[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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run LMAC93.D0916924.

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

Supply, Disposition, and Prices	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	14.97	14.59	14.21	14.67	-0.4
Natural Gas Plant Liquids	2.17	2.21	2.40	2.52	2.47	.6
Dry Natural Gas [2]	18.47	19.43	21.04	22.11	21.79	.8
Coal	22.23	22.92	23.84	25.37	28.23	1.2
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy [3]	6.53	7.42	8.67	9.42	10.38	2.3
Total	71.34	73.80	77.43	80.69	84.48	.8
Imports						
Crude Oil [4]	12.78	13.36	15.18	16.58	16.30	1.2
Petroleum Products	4.36	5.88	5.92	6.51	7.27	2.6
Natural Gas [5]	1.46	2.40	2.58	2.89	3.59	4.6
Other Imports [6]	.11	.51	.65	.94	1.23	12.9
Total	18.70	22.15	24.33	26.93	28.40	2.1
Exports						
Coal	2.64	3.32	3.72	4.64	6.03	4.2
Petroleum	1.82	1.64	1.69	1.76	1.84	.1
Total	4.46	4.97	5.41	6.40	7.87	2.9
Net Stock Withdrawals	-1.36	-.17	-.11	-.13	-.12	-11.4
Discrepancy [7]	.41	-.01	.08	.06	-.05	-
Consumption						
Petroleum Products [8]	33.53	34.85	36.60	38.31	39.12	.8
Natural Gas	19.31	21.73	23.53	24.91	25.29	1.4
Coal	19.11	19.67	20.26	20.92	22.41	.8
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.72	9.04	9.95	11.09	2.7
Total	84.63	90.82	96.32	101.15	104.84	1.1
Net Imports - Petroleum	15.31	17.60	19.41	21.33	21.73	1.8
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	24.60	28.50	33.70	38.10	2.7
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.08	2.57	3.48	3.89	4.0
Coal Minemouth Price ($ per ton)	22.52	24.02	26.17	27.53	30.14	1.5

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

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

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.89	0.67	0.52	0.42	-3.3
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.08	4.84	4.74	4.64	.1
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.48	3.57	3.78	4.00	1.2
Total	9.83	10.95	11.11	11.23	11.48	.8
Commercial						
Distillate Fuel	.49	.57	.52	.47	.42	-.7
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.0
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.08	3.17	3.23	3.25	.8
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.30	.37	7.1
Electricity	2.86	3.12	3.40	3.64	3.83	1.5
Total	6.72	7.41	7.79	8.04	8.24	1.0
Industrial [4]						
Distillate Fuel	1.18	1.24	1.30	1.33	1.37	.7
Liquefied Petroleum Gas	1.61	1.91	2.08	2.25	2.33	1.9
Motor Gasoline [2]	.18	.22	.24	.25	.27	1.9
Petrochemical Feedstocks	1.10	1.13	1.26	1.41	1.52	1.6
Residual Fuel	.41	.45	.44	.43	.42	.0
Other Petroleum [5]	3.83	3.57	3.64	3.64	3.64	-.2
Natural Gas [6]	8.47	9.68	10.35	10.49	10.62	1.1
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	1.71	1.85	1.84	1.86	1.99	.7
Net Coal Coke Imports	.00	.00	.06	.12	.16	18.9
Renewable Energy [1]	2.07	2.34	2.46	2.57	2.68	1.3
Purchased Electricity	3.23	3.42	3.91	4.34	4.70	1.9
Total	24.84	26.84	28.56	29.59	30.53	1.0
Transportation						
Distillate Fuel	3.83	4.14	4.55	4.95	5.29	1.6
Jet Fuel	3.13	3.38	3.76	4.17	4.40	1.7
Motor Gasoline [2]	13.58	14.01	14.49	14.79	14.91	.5
Residual Fuel	1.02	1.09	1.23	1.38	1.50	1.9
Other Petroleum [7]	.24	.25	.27	.30	.32	1.4
Pipeline Fuel Natural Gas	.68	.66	.71	.76	.83	1.0
Compressed Natural Gas	.00	.01	.02	.10	.21	63.0
Alcohol Fuels	.00	.01	.03	.12	.23	66.2
Electricity	.01	.02	.02	.05	.08	9.1
Total	22.50	23.56	25.09	26.61	27.76	1.1
Electric Utilities [8]						
Distillate Fuel	.09	.08	.14	.17	.17	3.5
Residual Fuel	1.14	1.01	1.21	1.54	1.49	1.3
Natural Gas	2.88	3.23	4.43	5.59	5.74	3.5
Steam Coal	16.20	16.63	17.31	18.03	19.48	.9
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.30	4.69	5.11	5.61	2.4
Total	29.99	32.09	34.68	37.50	39.43	1.4
Primary Energy Consumption						
Distillate Fuel	6.42	6.92	7.17	7.44	7.66	.9
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.38	3.76	4.17	4.40	1.7
Liquefied Petroleum Gas	2.06	2.45	2.55	2.67	2.73	1.4
Motor Gasoline	13.87	14.35	14.85	15.17	15.31	.5
Petrochemical Feedstocks	1.10	1.13	1.26	1.41	1.52	1.6
Residual Fuel	2.82	2.76	3.07	3.51	3.54	1.1

- See footnotes at end of table.

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

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.79	3.88	3.90	3.92	-0.2
Natural Gas	19.31	21.73	23.53	24.91	25.29	1.4
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	18.07	18.62	19.29	20.02	21.58	.9
Net Coal Coke Imports	.00	.00	.06	.12	.16	18.9
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.71	8.95	9.72	10.70	2.5
Alcohols	.00	.01	.03	.12	.23	66.2
Total	84.63	90.82	96.32	101.15	104.84	1.1
Electricity Consumption (all Sectors)	9.26	10.04	10.91	11.82	12.60	1.6
Industrial Electricity						
Gross Consumption	3.58	3.95	4.52	4.99	5.37	2.0
Self-generation - Own Use	.39	.53	.61	.65	.67	2.7
Purchased Electricity	3.23	3.42	3.91	4.34	4.70	1.9

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.67	13.54	14.66	15.41	1.1
Primary Energy	6.48	6.72	7.20	8.07	8.49	1.4
Petroleum Products	9.04	8.69	9.56	10.73	11.74	1.3
Distillate Fuel	8.08	7.83	8.56	9.55	10.35	1.2
Kerosene	9.14	9.26	9.80	10.54	11.14	1.0
Liquefied Petroleum Gas	11.20	10.32	11.27	12.56	13.64	1.0
Natural Gas	5.82	6.23	6.73	7.64	8.04	1.6
Steam Coal	1.99	2.08	2.23	2.37	2.56	1.3
Electricity	23.34	23.85	24.18	24.58	24.85	.3
Commercial	12.40	12.56	13.13	13.87	14.30	.7
Primary Energy	5.06	5.45	6.01	6.94	7.44	1.9
Petroleum Products	6.04	6.24	7.11	8.25	9.23	2.1
Distillate Fuel	5.94	5.79	6.53	7.52	8.33	1.7
Residual Fuel	3.57	4.02	4.69	5.60	6.37	2.9
Kerosene	6.96	6.91	7.46	8.23	8.88	1.2
Other Petroleum [1]	9.69	10.14	11.15	12.48	13.53	1.7
Natural Gas	4.84	5.29	5.79	6.70	7.12	1.9
Steam Coal	1.96	2.05	2.20	2.34	2.52	1.3
Electricity	22.04	21.99	21.78	21.68	21.54	-.1
Industrial	5.73	5.89	6.54	7.48	8.07	1.7
Primary Energy	4.14	4.35	4.91	5.79	6.35	2.2
Petroleum Products	6.01	6.25	6.97	7.94	8.76	1.9
Distillate Fuel	5.94	5.75	6.49	7.47	8.27	1.7
Liquefied Petroleum Gas	5.95	6.20	7.12	8.38	9.45	2.3
Motor Gasoline [2]	9.87	10.50	11.48	12.76	13.76	1.7
Residual Fuel	3.13	3.69	4.36	5.27	6.04	3.3
Other Petroleum [3]	6.14	6.46	7.04	7.85	8.53	1.7
Natural Gas [4]	2.95	3.34	3.85	4.75	5.15	2.8
Metallurgical Coal	1.82	1.91	2.08	2.24	2.42	1.5
Steam Coal	1.48	1.56	1.67	1.79	1.94	1.4
Electricity	14.74	14.83	15.16	15.73	15.98	.4
Transportation	8.92	9.34	10.15	11.23	12.08	1.5
Primary Energy	8.91	9.33	10.14	11.21	12.06	1.5
Petroleum Products	8.91	9.33	10.14	11.21	12.06	1.5
Distillate Fuel [5]	8.98	9.51	10.24	11.22	12.02	1.5
Jet Fuel [6]	6.00	5.54	6.30	7.31	8.13	1.5
Motor Gasoline [2]	9.86	10.54	11.52	12.80	13.79	1.7
Residual Fuel	3.22	3.43	3.99	4.75	5.33	2.6
Other Petroleum [7]	16.49	15.60	16.16	16.96	17.63	.3
Compressed Natural Gas	4.50	8.01	8.98	10.26	11.25	4.7
Electricity	23.74	24.66	22.41	19.99	19.70	-.9
Total End-Use Energy	8.68	8.97	9.63	10.61	11.28	1.3
Primary Energy	6.58	6.86	7.55	8.56	9.26	1.7
Electricity	19.94	20.20	20.20	20.41	20.50	.1
Electric Utilities						
Fossil Fuel Average	1.71	1.80	2.07	2.50	2.73	2.4
Petroleum Products	3.61	4.23	4.84	5.72	6.76	3.2
Distillate Fuel	5.57	5.29	6.04	7.06	7.87	1.7
Residual Fuel	3.46	4.15	4.69	5.57	6.63	3.3
Natural Gas	2.38	2.67	3.19	4.20	4.68	3.4
Steam Coal	1.45	1.47	1.57	1.66	1.81	1.1

- See footnotes at end of table.

Table D3. Energy Prices by End-Use Sector and Source (Continued) (1991 Dollars per Million Btu)

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	8.31	9.08	10.10	10.97	1.6
Distillate Fuel [5]	8.03	8.27	9.05	10.10	10.97	1.6
Jet Fuel [6]	6.00	5.54	6.30	7.31	8.13	1.5
Kerosene	8.80	8.97	9.44	10.08	10.59	.9
Liquefied Petroleum Gas	7.02	7.07	7.85	9.02	10.03	1.8
Motor Gasoline [2]	9.86	10.54	11.52	12.80	13.79	1.7
Residual Fuel	3.33	3.78	4.36	5.21	6.00	3.0
Other Petroleum Products [9]	6.62	6.90	7.50	8.33	9.04	1.6
Natural Gas	3.90	4.28	4.65	5.52	5.95	2.1
Coal	1.48	1.51	1.61	1.70	1.85	1.1
Electricity	19.94	20.20	20.20	20.41	20.50	.1

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run HWOP93.D0920923. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,603	1,669	1,737	1,848	0.8
Petroleum	117	99	128	161	156	1.5
Natural Gas	264	301	403	504	527	3.5
Nuclear Power	577	628	632	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	9.0
Renewable Sources/Other [1]	293	323	337	347	355	1.0
Total	2,808	2,943	3,158	3,385	3,511	1.1
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	52	57	124	6.9
Petroleum	5	11	11	12	12	4.0
Natural Gas	100	151	194	231	237	4.4
Renewable Sources/Other [1]	80	120	145	170	204	4.8
Total	218	333	402	470	578	5.0
Sales to Utilities	106	176	223	279	381	6.6
Generation for Own Use	111	156	179	191	197	2.9
Electricity Sales by Sector						
Residential	924	1,021	1,047	1,109	1,171	1.2
Commercial/Other [3]	843	920	1,004	1,083	1,146	1.5
Industrial	946	1,001	1,145	1,273	1,376	1.9
Total	2,713	2,942	3,196	3,465	3,694	1.6
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.14	8.25	8.39	8.48	.3
Commercial/Other [3]	7.52	7.51	7.43	7.39	7.34	-.1
Industrial [5]	5.03	5.06	5.17	5.37	5.45	.4
Average	6.80	6.89	6.89	6.97	7.00	.1
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.89	2.60	2.27	2.08	-1.6
Fuel Component	1.70	1.83	2.12	2.51	2.79	2.5
O&M Component	2.23	2.17	2.17	2.19	2.13	-.2
Total	6.80	6.89	6.89	6.97	7.00	.1

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M = Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	302.3	318.8	0.3
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	14.0	27.9	36.4	9.7
Combustion Turbine/Diesel	46.4	54.9	67.8	74.1	78.5	2.7
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.7	83.6	85.3	86.7	.5
Total	688.6	700.0	715.2	737.7	762.8	.5
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	3.2	21.0	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.2	12.7	21.1	-
Combustion Turbine/Diesel	.0	1.6	4.3	10.4	14.8	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.8	2.0	3.2	4.5	-
Total	.0	2.3	7.0	30.1	62.0	-
Cumulative Total Additions	6.3	29.7	59.3	93.6	127.1	16.2
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	11.2	12.1	23.4	6.1
Petroleum	.8	3.2	3.5	3.7	3.8	7.9
Natural Gas	19.3	29.2	36.8	44.2	45.3	4.4
Renewable Sources/Other [3]	15.8	24.2	29.0	33.5	39.6	4.7
Total	43.0	67.4	80.4	93.4	112.1	4.9
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	.4	1.3	12.7	-
Petroleum	.0	.2	.4	.5	.7	-
Natural Gas	.0	.7	7.6	15.0	16.1	-
Renewable Sources/Other [3]	.0	3.9	8.3	12.8	18.9	-
Total	.0	5.0	16.7	29.6	48.3	-
Cumulative Additions	.0	24.4	37.4	50.4	69.1	-

[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] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. All projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.87	5.71	7.71	9.71	6.9
Municipal Solid Waste	2.01	5.17	6.69	8.18	11.40	9.1
Biomass/Other Waste	6.01	7.43	7.65	7.83	8.06	1.5
Solar Thermal	.35	.54	1.42	1.79	2.15	9.4
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.54	4.00	5.67	7.33	8.6
Total	87.43	96.12	102.35	108.05	115.53	1.4
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	22.24	38.60	55.85	71.51	8.0
Municipal Solid Waste	10.45	18.28	24.33	33.03	53.67	8.5
Biomass/Other Waste	31.48	46.79	52.84	55.93	58.70	3.2
Solar Thermal	.66	.98	2.45	3.41	4.39	10.0
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.73	10.17	14.59	18.74	11.2
Total	348.23	402.38	436.59	469.92	513.47	2.0
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.23	.40	.58	.74	8.0
Municipal Solid Waste	.11	.19	.25	.34	.56	8.6
Biomass/Other Waste	.32	.48	.54	.58	.61	3.2
Solar Thermal	.01	.01	.03	.04	.05	10.0
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.11	.15	.19	11.2
Total	3.62	4.18	4.53	4.88	5.33	2.0
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.83	3.10	3.39	3.70	1.8
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	3.04	3.88	4.27	4.78	2.9
Total Renewable Energy	6.32	7.21	8.41	9.16	10.11	2.4

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D7. Macroeconomic Indicators (Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.326	1.594	1.965	2.442	3.9
Real Gross Domestic Product	4,885	5,366	6,010	6,642	7,217	2.0
Real Disposable Personal Income	3,538	3,881	4,260	4,651	5,021	1.8
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.130	1.336	1.524	1.662	2.4
AA Utility Bond Rate (percent)	9.66	9.36	9.09	9.15	9.15	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.41	5.89	5.82	5.79	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.93	16.03	15.23	14.53	-.9

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	24.60	28.50	33.70	38.10	2.7
Production						
Crude Oil [2]	7.35	6.85	6.58	6.34	6.49	-.6
Alaska	1.77	1.38	1.01	.81	1.01	-2.8
Lower 48	5.58	5.47	5.57	5.53	5.48	-.1
Natural Gas Plant Liquids	1.56	1.59	1.73	1.81	1.78	.7
Other Domestic [3]	.08	.22	.30	.37	.44	8.9
Processing Gain [4]	.68	.65	.70	.74	.74	.4
Total	9.68	9.31	9.30	9.27	9.46	-.1
Imports (including SPR) [5]						
Crude Oil	5.89	6.20	7.03	7.70	7.57	1.3
Refined Products[6]	2.13	2.91	2.92	3.22	3.60	2.7
Total	8.02	9.11	9.95	10.92	11.16	1.7
Exports						
Crude Oil	.11	.10	09	.08	.10	-.3
Refined Products	.75	.68	71	.75	.77	.2
Total	.85	.78	.80	.83	.87	.1
Net Imports (including SPR)	7.17	8.33	9.15	10.08	10.29	1.8
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.04	-.02	-.02	-.01	-13.4
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	17.59	18.41	19.31	19.72	.8
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.48	7.72	7.91	7.99	.5
Jet Fuel [10]	1.52	1.65	1.82	2.03	2.14	1.7
Distillate Fuel	3.02	3.25	3.37	3.50	3.60	.9
Residual Fuel	1.23	1.20	1.33	1.53	1.54	1.1
Other [11]	3.98	4.19	4.35	4.53	4.63	.8
Total	16.99	17.77	18.60	19.50	19.91	.8
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.27	1.06	.92	.81	-1.7
Industrial [12]	4.34	4.53	4.78	5.02	5.16	.9
Transportation	10.97	11.50	12.16	12.82	13.21	.9
Electric Utilities	.54	.48	.60	.75	.73	1.5
Total	16.99	17.77	18.60	19.50	19.91	.8
Net Disposition	16.98	17.77	18.60	19.50	19.91	.8

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.74	20.30	21.32	21.00	0.8
Supplemental Gas [2]	.10	.10	.10	.12	.14	1.5
Net Imports	1.45	2.33	2.50	2.81	3.48	4.5
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	21.17	22.91	24.25	24.62	1.3
Consumption by Sector						
Residential	4.38	4.92	4.69	4.60	4.50	.1
Commercial	2.67	2.99	3.07	3.13	3.15	.8
Industrial [4]	6.98	8.19	8.75	8.82	8.93	1.2
Electric Utilities [5]	2.79	3.13	4.30	5.42	5.57	3.5
Lease and Plant Fuel [6]	1.24	1.19	1.29	1.36	1.37	.5
Pipeline Fuel	.66	.64	.69	.74	.80	1.0
Transportation [7]	.00	.01	.02	.10	.20	63.0
Total	18.73	21.08	22.82	24.16	24.53	1.4
Unaccounted for [8]	.12	.10	.09	.09	.09	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.08	2.57	3.48	3.89	4.0
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.42	6.94	7.87	8.29	1.6
Commercial	4.99	5.46	5.97	6.91	7.34	1.9
Industrial	3.04	3.44	3.97	4.90	5.31	2.8
Electric Utilities	2.46	2.76	3.29	4.33	4.82	3.4
Transportation[7]	4.64	8.25	9.26	10.58	11.60	4.7
Average [9]	4.03	4.41	4.80	5.69	6.13	2.1

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	643	639	665	738	0.8
West of the Mississippi	399	426	486	536	604	2.1
Total	1,029	1,068	1,125	1,201	1,342	1.3
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	127	144	180	233	4.0
Total	-103	-122	-138	-170	-221	3.9
Net Stock Withdrawals [2]	-27	-2	-1	-2	-3	-10.9
Total Supply [3]	899	944	987	1,029	1,118	1.1
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	87	86	87	94	1.0
Coking Plants	39	40	37	34	31	-1.1
Electricity [5]	774	812	860	905	989	1.2
Total	895	945	988	1,031	1,119	1.1
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	24.02	26.17	27.53	30.14	1.5
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.42	51.62	54.63	58.35	.6
Industrial	34.77	33.28	35.93	38.33	41.24	.9
Coking Plants	49.40	50.83	55.16	59.47	64.25	1.3
Electricity	31.52	30.05	31.54	33.18	35.63	.6
Average [8]	32.72	31.34	32.92	34.59	37.00	.6

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.3	101.9	105.8	108.9	0.8
Energy Consumption per Household (million Btu)	105.2	112.5	109.1	106.2	105.4	.0
End-Use Consumption						
Distillate						
Space Heating	.72	.80	.61	.49	.41	-2.9
Other Uses [1]	.11	.09	.05	.03	.02	-8.8
Total	.84	.89	.67	.52	.42	-3.3
Natural Gas						
Space Heating	3.15	3.51	3.27	3.18	3.08	-.1
Water Heating	1.06	1.27	1.29	1.30	1.29	1.0
Other Uses [1]	.31	.30	.28	.27	.26	-.8
Total	4.52	5.08	4.84	4.74	4.64	.1
Other Fuels [2]	.49	.57	.49	.43	.40	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.30	.30	-.3
Cooling	.51	.55	.50	.53	.55	.4
Water Heating	.39	.50	.56	.64	.71	3.0
Other Uses [1]	1.93	2.10	2.21	2.32	2.43	1.2
Total	3.15	3.48	3.57	3.78	4.00	1.2
Total Consumption	9.83	10.95	11.11	11.23	11.48	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	117.2	124.5	129.9	134.4	1.0
Total Floorspace (billion square feet)	62.9	68.9	75.5	82.4	89.4	1.8
Energy Consumption per Square Foot (thousand Btu)	107.0	107.5	103.2	97.6	92.2	-.7
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.49	.44	.40	-.6
Other Uses [1]	.04	.04	.03	.03	.02	-3.2
Total	.49	.57	.52	.47	.42	-.8
Natural Gas						
Space Heating	1.80	1.99	2.01	1.99	1.93	.4
Cooling	.21	.23	.24	.25	.26	1.1
Other Uses [1]	.75	.86	.92	.99	1.05	1.7
Total	2.76	3.08	3.17	3.23	3.25	.8
Other Fuels [2]	.52	.49	.45	.41	.37	-1.7
Renewables [3]	.10	.15	.25	.30	.37	7.1
Electricity						
Space Heating	.52	.59	.65	.73	.82	2.3
Cooling	.73	.81	.89	.96	1.00	1.6
Lighting	1.14	1.20	1.27	1.29	1.26	.5
Other Uses [1]	.48	.52	.59	.66	.74	2.2
Total	2.86	3.12	3.40	3.64	3.83	1.5
Total Consumption	6.72	7.41	7.79	8.04	8.24	1.0

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2637	3118	3556	3878	2.4
Non-manufacturing	871	921	1015	1096	1176	1.5
Total	3274	3558	4133	4652	5054	2.2
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.35	.31	.29	.27	-1.4
Liquefied Petroleum Gas	.49	.54	.50	.48	.46	-.3
Petrochemical Feedstocks	.34	.32	.31	.30	.30	-.5
Residual Fuel	.13	.13	.11	.09	.08	-2.1
Other Petroleum [1]	1.17	1.00	.88	.78	.72	-2.4
Natural Gas [2]	2.59	2.72	2.50	2.26	2.10	-1.0
Metallurgical Coal and Coke [3]	.32	.30	.25	.22	.20	-2.4
Steam Coal [4]	.52	.52	.45	.40	.39	-1.4
Renewables [5]	.06	.07	.06	.06	.05	-.9
Electricity	.99	.96	.95	.93	.93	-.3
Total	7.59	7.55	6.91	6.36	6.04	-1.1
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.24	1.30	1.33	1.37	.7
Liquefied Petroleum Gas	1.61	1.91	2.08	2.25	2.33	1.9
Motor Gasoline [6]	.18	.22	.24	.25	.27	1.9
Petrochemical Feedstocks	1.10	1.13	1.26	1.41	1.52	1.6
Residual Fuel	.41	.45	.44	.43	.42	.0
Other Petroleum [1]	3.83	3.57	3.64	3.64	3.64	-.2
Natural Gas [2]	8.47	9.68	10.35	10.49	10.62	1.1
Metallurgical Coal and Coke [3]	1.04	1.05	1.04	1.02	.99	-.3
Steam Coal [4]	1.71	1.85	1.84	1.86	1.99	.7
Renewables [5]	2.07	2.34	2.46	2.57	2.68	1.3
Electricity	3.23	3.42	3.91	4.34	4.70	1.9
Total	24.84	26.84	28.56	29.59	30.53	1.0

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 1.0)						
Light Duty Vehicles	1.00	1.09	1.19	1.29	1.40	1.7
Freight Trucks	1.00	1.08	1.22	1.33	1.44	1.8
Air	.99	1.22	1.53	1.86	2.16	4.0
Rail	.99	1.02	1.10	1.19	1.27	1.2
Marine	.99	1.03	1.12	1.19	1.26	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.00	29.72	32.16	34.79	37.39	1.5
New Light Truck MPG [1]	20.70	22.35	24.11	25.76	27.40	1.4
Light Duty Fleet MPG [2]	18.58	19.39	20.39	21.42	22.49	1.0
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.02	12.47	12.85	13.13	.7
Freight Trucks	5.06	5.27	5.69	6.13	6.50	1.3
Air	3.20	3.46	3.84	4.26	4.51	1.7
Rail	.49	.50	.52	.56	.59	.9
Marine	1.39	1.48	1.67	1.85	2.00	1.8
Pipeline Fuel	.68	.66	.71	.76	.83	1.0
Other	.17	.17	.19	.20	.21	1.1
Total	22.50	23.56	25.09	26.61	27.76	1.1

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989=1.0).
[4] Based on Btu per vehicle miles traveled (1989=1.0).
[5] Based on Btu per ton-miles traveled (1989=1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

Table D15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	26.8	20.8	16.9	14.3	-2.6
Natural Gas	65.7	73.8	70.3	68.9	67.4	.1
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	102.2	92.6	87.4	83.2	-.5
Commercial						
Petroleum	18.5	19.7	17.9	16.3	14.8	-1.1
Natural Gas	40.1	44.7	46.1	46.9	47.2	.8
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.6	65.9	64.8	63.4	.2
Industrial [2]						
Petroleum	87.4	86.4	88.4	89.1	89.7	.1
Natural Gas [3]	115.0	131.9	141.5	143.6	145.3	1.2
Metallurgical Coal	26.5	26.9	24.8	22.9	21.1	-1.1
Steam Coal	43.6	47.0	47.0	47.4	50.6	.8
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	292.2	301.6	303.0	306.7	.6
Transportation						
Petroleum	425.1	446.2	474.1	499.6	515.9	1.0
Natural Gas[4]	9.9	9.7	10.7	12.5	15.1	2.1
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	455.9	484.9	512.1	531.0	1.0
Electric Utilities [5]						
Petroleum	26.4	23.3	29.2	36.8	35.7	1.5
Natural Gas	41.9	47.0	64.5	81.3	83.5	3.5
Steam Coal	412.3	423.1	440.5	458.9	495.7	.9
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	493.5	534.2	577.0	614.9	1.2
Primary Energy Consumption						
Petroleum	581.6	602.5	630.4	658.7	670.4	.7
Natural Gas	272.6	307.1	333.1	353.2	358.5	1.4
Metallurgical Coal	26.5	26.9	24.8	22.9	21.1	-1.1
Steam Coal	459.8	473.9	490.9	509.5	549.3	.9
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1410.3	1479.2	1544.3	1599.3	.9

[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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run HWOP93.D0920923.

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

Supply, Disposition, and Prices	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	13.34	9.97	8.60	8.49	-3.0
Natural Gas Plant Liquids	2.17	2.14	2.25	2.25	2.21	.1
Dry Natural Gas [2]	18.47	18.81	19.72	19.76	19.42	.3
Coal	22.23	22.75	23.90	25.81	28.89	1.3
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy [3]	6.53	7.30	8.39	9.00	9.85	2.1
Total	71.34	71.20	71.12	72.48	75.79	.3
Imports						
Crude Oil [4]	12.78	15.99	20.80	22.25	22.52	2.9
Petroleum Products	4.36	6.91	9.72	13.56	14.99	6.4
Natural Gas [5]	1.46	2.59	3.15	3.73	4.43	5.7
Other Imports [6]	.11	.51	.65	.92	1.18	12.6
Total	18.70	26.00	34.33	40.46	43.11	4.3
Exports						
Coal	2.64	3.14	3.73	4.65	6.11	4.3
Petroleum	1.82	1.68	1.81	1.77	1.76	-.2
Total	4.46	4.81	5.54	6.42	7.87	2.9
Net Stock Withdrawals	-1.36	-.25	-.18	-.20	-.15	-10.4
Discrepancy [7]	.41	-.09	-.16	-.27	-.51	-
Consumption						
Petroleum Products [8]	33.53	36.57	40.82	44.73	46.25	1.6
Natural Gas	19.31	21.32	22.79	23.44	23.72	1.0
Coal	19.11	19.69	20.31	21.32	22.97	.9
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.60	8.76	9.51	10.50	2.4
Total	84.63	92.04	99.57	106.06	110.37	1.3
Net Imports - Petroleum	15.31	21.22	28.71	34.04	35.74	4.3
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	15.00	14.10	15.30	18.10	-1.1
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.02	2.29	2.99	3.52	3.5
Coal Minemouth Price ($ per ton)	22.52	23.93	26.77	27.82	31.02	1.6

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

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

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.94	0.75	0.65	0.58	-1.8
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.08	4.86	4.77	4.64	.1
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.49	3.59	3.82	4.03	1.2
Total	9.83	11.01	11.24	11.43	11.68	.9
Commercial						
Distillate Fuel	.49	.58	.55	.52	.50	.1
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.0
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.08	3.18	3.25	3.26	.8
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.30	.37	7.1
Electricity	2.86	3.12	3.41	3.64	3.81	1.4
Total	6.72	7.42	7.84	8.12	8.31	1.1
Industrial [4]						
Distillate Fuel	1.18	1.33	1.55	1.72	1.80	2.1
Liquefied Petroleum Gas	1.61	2.13	2.53	2.84	2.96	3.1
Motor Gasoline [2]	.18	.23	.26	.28	.29	2.3
Petrochemical Feedstocks	1.10	1.22	1.47	1.68	1.82	2.5
Residual Fuel	.41	.62	.76	.82	.78	3.2
Other Petroleum [5]	3.83	3.71	3.87	3.89	3.88	.1
Natural Gas [6]	8.47	9.33	9.93	10.03	10.20	.9
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	1.71	1.84	1.83	1.84	1.96	.7
Net Coal Coke Imports	.00	.00	.07	.13	.17	19.2
Renewable Energy [1]	2.07	2.26	2.29	2.33	2.41	.8
Purchased Electricity	3.23	3.45	4.03	4.54	4.96	2.2
Total	24.84	27.18	29.56	30.99	32.05	1.3
Transportation						
Distillate Fuel	3.83	4.20	4.67	5.13	5.52	1.8
Jet Fuel	3.13	3.52	4.02	4.53	4.83	2.2
Motor Gasoline [2]	13.58	14.53	15.82	16.87	17.48	1.3
Residual Fuel	1.02	1.10	1.25	1.41	1.53	2.0
Other Petroleum [7]	.24	.25	.28	.30	.33	1.5
Pipeline Fuel Natural Gas	.68	.65	.70	.71	.73	.4
Compressed Natural Gas	.00	.01	.02	.08	.17	61.1
Alcohol Fuels	.00	.01	.02	.08	.17	63.5
Electricity	.01	.02	.02	.05	.09	9.5
Total	22.50	24.28	26.80	29.17	30.82	1.6
Electric Utilities [8]						
Distillate Fuel	.09	.11	.31	.68	.65	10.6
Residual Fuel	1.14	1.18	1.94	2.70	2.67	4.3
Natural Gas	2.88	3.18	4.10	4.60	4.72	2.5
Steam Coal	16.20	16.65	17.37	18.46	20.06	1.1
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.26	4.57	4.92	5.35	2.2
Total	29.99	32.24	35.19	38.41	40.39	1.5
Primary Energy Consumption						
Distillate Fuel	6.42	7.15	7.83	8.70	9.04	1.7
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.52	4.02	4.53	4.83	2.2
Liquefied Petroleum Gas	2.06	2.67	3.00	3.26	3.36	2.5
Motor Gasoline	13.87	14.88	16.20	17.28	17.91	1.3
Petrochemical Feedstocks	1.10	1.22	1.47	1.68	1.82	2.5
Residual Fuel	2.82	3.11	4.13	5.09	5.11	3.0

- See footnotes at end of table.

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

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.94	4.12	4.16	4.16	0.1
Natural Gas	19.31	21.32	22.79	23.44	23.72	1.0
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	18.07	18.64	19.33	20.42	22.14	1.0
Net Coal Coke Imports	.00	.00	.07	.13	.17	19.2
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.60	8.67	9.30	10.17	2.3
Alcohols	.00	.01	.02	.08	.17	63.5
Total	84.63	92.04	99.57	106.06	110.37	1.3
Electricity Consumption (all Sectors)	9.26	10.08	11.05	12.06	12.88	1.7
Industrial Electricity						
Gross Consumption	3.58	3.99	4.63	5.16	5.59	2.3
Self-generation - Own Use	.39	.53	.60	.62	.64	2.5
Purchased Electricity	3.23	3.45	4.03	4.54	4.96	2.2

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.39	12.87	13.64	14.42	0.8
Primary Energy	6.48	6.37	6.52	7.13	7.65	.8
Petroleum Products	9.04	7.25	7.10	7.40	8.04	-.6
Distillate Fuel	8.08	6.48	6.30	6.57	7.13	-.6
Kerosene	9.14	7.85	7.69	7.83	8.21	-.5
Liquefied Petroleum Gas	11.20	8.81	8.61	8.96	9.69	-.7
Natural Gas	5.82	6.17	6.44	7.13	7.64	1.4
Steam Coal	1.99	2.05	2.22	2.36	2.59	1.3
Electricity	23.34	23.77	23.66	23.62	23.86	.1
Commercial	12.40	12.26	12.44	12.82	13.25	.3
Primary Energy	5.06	5.02	5.24	5.89	6.46	1.2
Petroleum Products	6.04	4.63	4.56	4.94	5.61	-.4
Distillate Fuel	5.94	4.16	4.00	4.28	4.85	-1.0
Residual Fuel	3.57	2.65	2.50	2.75	3.27	-.4
Kerosene	6.96	5.50	5.35	5.53	5.94	-.8
Other Petroleum [1]	9.69	8.31	8.24	8.72	9.49	-.1
Natural Gas	4.84	5.23	5.51	6.21	6.74	1.7
Steam Coal	1.96	2.02	2.19	2.32	2.56	1.3
Electricity	22.04	21.87	21.27	20.78	20.62	-.3
Industrial	5.73	5.40	5.59	6.11	6.67	.8
Primary Energy	4.14	3.81	3.88	4.30	4.80	.7
Petroleum Products	6.01	4.94	4.69	4.90	5.45	-.5
Distillate Fuel	5.94	4.09	3.92	4.18	4.73	-1.1
Liquefied Petroleum Gas	5.95	4.70	4.44	4.76	5.49	-.4
Motor Gasoline [2]	9.87	8.53	8.48	8.97	9.71	-.1
Residual Fuel	3.13	2.37	2.23	2.47	2.99	-.2
Other Petroleum [3]	6.14	5.43	5.21	5.35	5.77	-.3
Natural Gas [4]	2.95	3.29	3.58	4.28	4.80	2.5
Metallurgical Coal	1.82	1.90	2.08	2.23	2.48	1.6
Steam Coal	1.48	1.55	1.65	1.76	1.93	1.3
Electricity	14.74	14.74	14.85	15.13	15.44	.2
Transportation	8.92	7.54	7.41	7.77	8.40	-.3
Primary Energy	8.91	7.53	7.40	7.75	8.38	-.3
Petroleum Products	8.91	7.53	7.40	7.75	8.38	-.3
Distillate Fuel [5]	8.98	7.93	7.75	8.01	8.56	-.2
Jet Fuel [6]	6.00	3.83	3.65	3.92	4.49	-1.4
Motor Gasoline [2]	9.86	8.57	8.52	9.01	9.74	-.1
Residual Fuel	3.22	2.53	2.41	2.60	3.00	-.3
Other Petroleum [7]	16.49	14.70	14.51	14.67	15.08	-.4
Compressed Natural Gas	4.50	6.19	6.13	6.60	7.34	2.5
Electricity	23.74	23.86	20.73	17.81	17.46	-1.5
Total End-Use Energy	8.68	8.05	8.04	8.46	9.03	.2
Primary Energy	6.58	5.82	5.83	6.28	6.86	.2
Electricity	19.94	20.09	19.70	19.54	19.62	-.1
Electric Utilities						
Fossil Fuel Average	1.71	1.73	1.94	2.22	2.50	1.9
Petroleum Products	3.61	2.89	2.66	3.03	3.65	.1
Distillate Fuel	5.57	3.74	3.61	3.90	4.47	-1.1
Residual Fuel	3.46	2.81	2.51	2.82	3.45	.0
Natural Gas	2.38	2.45	2.83	3.53	4.15	2.8
Steam Coal	1.45	1.51	1.63	1.74	1.92	1.4

- See footnotes at end of table.

Table E3. Energy Prices by End-Use Sector and Source (Continued)
(1991 Dollars per Million Btu)

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	6.63	6.37	6.62	7.25	-0.4
Distillate Fuel [5]	8.03	6.66	6.43	6.60	7.21	-.5
Jet Fuel [6]	6.00	3.83	3.65	3.92	4.49	-1.4
Kerosene	8.80	7.56	7.32	7.38	7.65	-.7
Liquefied Petroleum Gas	7.02	5.49	5.07	5.28	5.96	-.8
Motor Gasoline [2]	9.86	8.57	8.52	9.00	9.74	-.1
Residual Fuel	3.33	2.61	2.43	2.70	3.24	-.1
Other Petroleum Products [9]	6.62	5.87	5.66	5.82	6.26	-.3
Natural Gas	3.90	4.21	4.40	5.06	5.58	1.8
Coal	1.48	1.54	1.66	1.77	1.94	1.4
Electricity	19.94	20.09	19.70	19.54	19.62	-.1

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook,* DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run LWOP93.D0920923. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,605	1,675	1,752	1,863	0.9
Petroleum	117	119	217	323	320	5.2
Natural Gas	264	295	365	402	418	2.3
Nuclear Power	577	628	633	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	8.9
Renewable Sources/Other [1]	293	321	333	340	347	.8
Total	2,808	2,959	3,212	3,454	3,572	1.2
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	52	87	175	8.8
Petroleum	5	11	11	12	12	4.1
Natural Gas	100	152	190	208	220	4.1
Renewable Sources/Other [1]	80	118	138	158	188	4.4
Total	218	331	392	465	595	5.2
Sales to Utilities	106	174	216	284	408	7.0
Generation for Own Use	111	157	175	181	187	2.6
Electricity Sales by Sector						
Residential	924	1,023	1,053	1,119	1,181	1.2
Commercial/Other [3]	843	921	1,005	1,083	1,142	1.5
Industrial	946	1,011	1,181	1,331	1,452	2.2
Total	2,713	2,955	3,239	3,533	3,775	1.7
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.11	8.07	8.06	8.14	.1
Commercial/Other [3]	7.52	7.46	7.26	7.07	7.01	-.4
Industrial [5]	5.03	5.03	5.07	5.16	5.27	.2
Average	6.80	6.85	6.72	6.67	6.69	-.1
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.90	2.56	2.21	1.99	-1.8
Fuel Component	1.70	1.79	1.99	2.28	2.59	2.1
O&M Component	2.23	2.17	2.17	2.18	2.11	-.3
Total	6.80	6.85	6.72	6.67	6.69	-.1

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M = Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	303.5	320.0	0.4
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	14.5	25.0	33.2	9.2
Combustion Turbine/Diesel	46.4	55.0	69.3	88.5	96.2	3.7
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.5	83.1	84.5	85.5	.5
Total	688.6	700.0	716.6	749.5	777.4	.6
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	4.4	22.2	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.6	9.8	17.8	-
Combustion Turbine/Diesel	.0	1.7	5.8	24.8	32.6	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.6	1.4	2.3	3.3	-
Total	.0	2.3	8.4	42.0	76.6	-
Cumulative Total Additions	6.3	29.6	60.7	105.4	141.8	16.8
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	11.2	17.2	31.9	7.8
Petroleum	.8	3.2	3.6	3.8	3.9	8.1
Natural Gas	19.3	29.2	36.0	39.7	42.2	4.0
Renewable Sources/Other [3]	15.8	23.6	27.4	30.8	35.9	4.2
Total	43.0	66.8	78.2	91.5	113.9	5.0
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	.5	6.4	21.2	-
Petroleum	.0	.2	.5	.6	.8	-
Natural Gas	.0	.7	6.8	10.6	13.1	-
Renewable Sources/Other [3]	.0	3.3	6.6	10.1	15.2	-
Total	.0	4.4	14.4	27.8	50.2	-
Cumulative Additions	.0	23.8	35.2	48.5	70.9	-

[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] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report.* 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report.* All projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.47	4.65	5.98	7.31	5.4
Municipal Solid Waste	2.01	5.17	6.69	8.18	11.40	9.1
Biomass/Other Waste	6.01	7.43	7.65	7.83	8.06	1.5
Solar Thermal	.35	.47	1.22	1.47	1.71	8.2
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.20	3.11	4.22	5.33	6.9
Total	87.43	95.31	100.20	104.55	110.69	1.2
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	19.41	30.66	42.19	52.59	6.3
Municipal Solid Waste	10.45	18.28	24.33	33.03	53.67	8.5
Biomass/Other Waste	31.48	46.79	52.84	55.93	58.70	3.2
Solar Thermal	.66	.82	1.92	2.55	3.19	8.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.15	7.99	10.92	13.66	9.4
Total	348.23	398.81	425.94	451.72	488.27	1.7
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.20	.32	.44	.55	6.3
Municipal Solid Waste	.11	.19	.25	.34	.56	8.6
Biomass/Other Waste	.32	.48	.54	.58	.61	3.2
Solar Thermal	.01	.01	.02	.03	.03	8.3
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.04	.08	.11	.14	9.5
Total	3.62	4.14	4.42	4.69	5.07	1.7
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.75	2.94	3.15	3.43	1.4
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	2.96	3.71	4.04	4.51	2.6
Total Renewable Energy	6.32	7.10	8.13	8.73	9.58	2.1

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E7. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.313	1.570	1.940	2.421	3.9
Real Gross Domestic Product	4,885	5,418	6,112	6,777	7,382	2.1
Real Disposable Personal Income	3,538	3,911	4,312	4,704	5,065	1.8
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.149	1.376	1.581	1.738	2.6
AA Utility Bond Rate (percent)	9.66	9.08	8.58	8.45	8.31	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.19	5.61	5.47	5.42	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.99	16.29	15.65	14.95	-.7

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	15.00	14.10	15.30	18.10	-1.1
Production						
Crude Oil [2]	7.35	6.08	4.38	3.66	3.54	-3.6
Alaska	1.77	1.21	.81	.53	.41	-7.1
Lower 48	5.58	4.87	3.56	3.14	3.13	-2.9
Natural Gas Plant Liquids	1.56	1.54	1.62	1.62	1.59	.1
Other Domestic [3]	.08	.22	.31	.40	.48	9.3
Processing Gain [4]	.68	.69	.74	.74	.74	.4
Total	9.68	8.54	7.06	6.43	6.35	-2.1
Imports (including SPR) [5]						
Crude Oil	5.89	7.42	9.63	10.33	10.45	2.9
Refined Products[6]	2.13	3.42	4.79	6.71	7.41	6.4
Total	8.02	10.84	14.42	17.04	17.87	4.1
Exports						
Crude Oil	.11	.08	.05	.04	.03	-5.5
Refined Products	.75	.71	.80	.80	.80	.3
Total	.85	.79	.85	.84	.83	-.1
Net Imports (including SPR)	7.17	10.04	13.57	16.20	17.03	4.4
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.08	-.05	-.04	-.01	-10.3
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	18.48	20.55	22.56	23.34	1.7
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.76	8.43	9.01	9.34	1.3
Jet Fuel [10]	1.52	1.71	1.95	2.20	2.35	2.2
Distillate Fuel	3.02	3.37	3.67	4.09	4.25	1.7
Residual Fuel	1.23	1.36	1.80	2.22	2.23	3.0
Other [11]	3.98	4.47	4.90	5.23	5.36	1.5
Total	16.99	18.67	20.74	22.75	23.53	1.6
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.29	1.11	1.00	.92	-1.1
Industrial [12]	4.34	4.94	5.60	6.07	6.25	1.8
Transportation	10.97	11.87	13.05	14.18	14.89	1.5
Electric Utilities	.54	.57	.99	1.49	1.47	5.2
Total	16.99	18.67	20.74	22.75	23.53	1.6
Net Disposition	16.98	18.67	20.74	22.75	23.53	1.6

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.15	19.03	19.05	18.70	0.2
Supplemental Gas [2]	.10	.10	.10	.12	.13	1.3
Net Imports	1.45	2.51	3.06	3.62	4.30	5.6
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	20.76	22.19	22.79	23.13	1.0
Consumption by Sector						
Residential	4.38	4.92	4.71	4.63	4.50	.1
Commercial	2.67	2.99	3.09	3.15	3.16	.8
Industrial [4]	6.98	7.89	8.41	8.49	8.67	1.1
Electric Utilities [5]	2.79	3.09	3.98	4.46	4.58	2.5
Lease and Plant Fuel [6]	1.24	1.16	1.22	1.23	1.22	-.1
Pipeline Fuel	.66	.63	.68	.69	.71	.4
Transportation [7]	.00	.01	.02	.08	.16	61.1
Total	18.73	20.68	22.10	22.73	23.00	1.0
Unaccounted for [8]	.12	.08	.08	.05	.13	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.02	2.29	2.99	3.52	3.5
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.36	6.64	7.35	7.88	1.4
Commercial	4.99	5.39	5.68	6.40	6.94	1.7
Industrial	3.04	3.39	3.69	4.42	4.95	2.5
Electric Utilities	2.46	2.52	2.92	3.64	4.28	2.8
Transportation[7]	4.64	6.38	6.32	6.80	7.56	2.5
Average [9]	4.03	4.34	4.53	5.21	5.75	1.8

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	645	651	678	754	0.9
West of the Mississippi	399	416	476	547	623	2.3
Total	1,029	1,061	1,127	1,226	1,378	1.5
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	120	144	180	236	4.1
Total	-103	-116	-138	-170	-225	4.0
Net Stock Withdrawals [2]	-27	-2	-1	-3	-4	-9.7
Total Supply [3]	899	944	989	1,052	1,150	1.2
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	86	86	86	93	1.0
Coking Plants	39	40	37	34	31	-1.1
Electricity [5]	774	812	861	928	1,022	1.4
Total	895	944	990	1,053	1,151	1.3
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	23.93	26.77	27.82	31.02	1.6
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	47.67	51.10	54.21	58.95	.7
Industrial	34.77	32.97	35.24	37.59	40.81	.8
Coking Plants	49.40	50.60	55.31	59.16	65.74	1.4
Electricity	31.52	30.92	32.92	34.60	37.69	.9
Average [8]	32.72	32.04	34.06	35.73	38.80	.9

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.4	102.1	106.1	109.4	0.8
Energy Consumption per Household (million Btu)	105.2	113.0	110.1	107.6	106.7	.1
End-Use Consumption						
Distillate						
Space Heating	.72	.85	.70	.62	.56	-1.3
Other Uses [1]	.11	.09	.06	.03	.02	-8.4
Total	.84	.94	.75	.65	.58	-1.8
Natural Gas						
Space Heating	3.15	3.50	3.28	3.17	3.05	-.2
Water Heating	1.06	1.27	1.30	1.33	1.32	1.1
Other Uses [1]	.31	.30	.28	.27	.27	-.6
Total	4.52	5.08	4.86	4.77	4.64	.1
Other Fuels [2]	.49	.57	.49	.43	.40	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.30	.29	-.5
Cooling	.51	.55	.51	.54	.56	.5
Water Heating	.39	.50	.56	.64	.71	3.0
Other Uses [1]	1.92	2.10	2.22	2.34	2.46	1.2
Total	3.15	3.49	3.59	3.82	4.03	1.2
Total Consumption	9.83	11.01	11.24	11.43	11.68	.9

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	117.8	125.3	130.5	134.5	1.0
Total Floorspace (billion square feet)	62.9	69.0	75.6	82.5	89.6	1.8
Energy Consumption per Square Foot (thousand Btu)	107.0	107.7	103.6	98.3	92.8	-.7
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.51	.50	.48	.3
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.58	.55	.52	.50	.1
Natural Gas						
Space Heating	1.80	1.99	2.01	1.99	1.93	.3
Cooling	.21	.23	.24	.25	.26	1.2
Other Uses [1]	.75	.86	.93	1.00	1.07	1.8
Total	2.76	3.08	3.18	3.25	3.26	.8
Other Fuels [2]	.52	.49	.45	.41	.37	-1.7
Renewables [3]	.10	.15	.25	.30	.37	7.1
Electricity						
Space Heating	.52	.59	.65	.71	.78	2.1
Cooling	.73	.81	.90	.96	1.01	1.7
Lighting	1.14	1.20	1.27	1.30	1.27	.6
Other Uses [1]	.48	.52	.59	.67	.75	2.2
Total	2.86	3.12	3.41	3.64	3.81	1.4
Total Consumption	6.72	7.42	7.84	8.12	8.31	1.1

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2680	3210	3690	4055	2.6
Non-manufacturing	871	930	1031	1112	1192	1.6
Total	3274	3610	4241	4802	5246	2.4
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.37	.37	.36	.34	-.3
Liquefied Petroleum Gas	.49	.59	.60	.59	.56	.7
Petrochemical Feedstocks	.34	.34	.35	.35	.35	.1
Residual Fuel	.13	.17	.18	.17	.15	.8
Other Petroleum [1]	1.17	1.03	.91	.81	.74	-2.3
Natural Gas [2]	2.59	2.58	2.34	2.09	1.94	-1.4
Metallurgical Coal and Coke [3]	.32	.29	.25	.21	.19	-2.6
Steam Coal [4]	.52	.51	.43	.38	.37	-1.7
Renewables [5]	.06	.06	.05	.05	.05	-1.6
Electricity	.99	.96	.95	.95	.94	-.2
Total	7.59	7.53	6.97	6.45	6.11	-1.1
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.33	1.55	1.72	1.80	2.1
Liquefied Petroleum Gas	1.61	2.13	2.53	2.84	2.96	3.1
Motor Gasoline [6]	.18	.23	.26	.28	.29	2.3
Petrochemical Feedstocks	1.10	1.22	1.47	1.68	1.82	2.5
Residual Fuel	.41	.62	.76	.82	.78	3.2
Other Petroleum [1]	3.83	3.71	3.87	3.89	3.88	.1
Natural Gas [2]	8.47	9.33	9.93	10.03	10.20	.9
Metallurgical Coal and Coke [3]	1.04	1.05	1.05	1.03	1.00	-.2
Steam Coal [4]	1.71	1.84	1.83	1.84	1.96	.7
Renewables [5]	2.07	2.26	2.29	2.33	2.41	.8
Electricity	3.23	3.45	4.03	4.54	4.96	2.2
Total	24.84	27.18	29.56	30.99	32.05	1.3

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 1.0)						
Light Duty Vehicles	1.00	1.12	1.23	1.34	1.44	1.8
Freight Trucks	1.00	1.09	1.24	1.36	1.47	1.9
Air	.99	1.28	1.65	2.04	2.39	4.5
Rail	.99	1.04	1.12	1.22	1.30	1.4
Marine	.99	1.05	1.14	1.22	1.28	1.3
Energy Efficiency Indicators						
New Car MPG [1]	28.00	27.69	27.65	28.85	30.65	.5
New Light Truck MPG [1]	20.70	20.83	20.73	21.36	22.47	.4
Light Duty Fleet MPG [2]	18.58	19.15	19.18	19.22	19.49	.2
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.52	13.78	14.91	15.66	1.6
Freight Trucks	5.06	5.33	5.80	6.26	6.64	1.4
Air	3.20	3.60	4.10	4.63	4.93	2.2
Rail	.49	.51	.53	.57	.60	1.0
Marine	1.39	1.50	1.69	1.89	2.04	1.9
Pipeline Fuel	.68	.65	.70	.71	.73	.4
Other	.17	.18	.19	.21	.22	1.2
Total	22.50	24.28	26.80	29.17	30.82	1.6

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989=1.0).
[4] Based on Btu per vehicle miles traveled (1989 - 1.0).
[5] Based on Btu per ton-miles traveled (1989 1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table E15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.8	22.5	19.5	17.4	-1.6
Natural Gas	65.7	73.8	70.7	69.4	67.5	.1
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	103.2	94.7	90.4	86.4	-.3
Commercial						
Petroleum	18.5	19.8	18.5	17.4	16.3	-.6
Natural Gas	40.1	44.8	46.3	47.2	47.4	.8
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.7	66.6	66.2	65.1	.3
Industrial [2]						
Petroleum	87.4	93.9	104.1	109.5	110.3	1.2
Natural Gas [3]	115.0	126.7	134.9	136.3	138.7	.9
Metallurgical Coal	26.5	27.0	24.9	23.0	21.2	-1.1
Steam Coal	43.6	46.9	46.5	46.8	49.9	.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	294.4	310.4	315.6	320.0	.8
Transportation						
Petroleum	425.1	460.4	508.0	551.3	579.5	1.6
Natural Gas[4]	9.9	9.5	10.4	11.5	13.1	1.4
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	469.9	518.5	562.8	592.6	1.6
Electric Utilities [5]						
Petroleum	26.4	27.8	48.1	72.0	70.9	5.1
Natural Gas	41.9	46.3	59.6	66.9	68.6	2.5
Steam Coal	412.3	423.8	442.2	469.9	510.6	1.1
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	497.9	549.9	608.7	650.1	1.5
Primary Energy Consumption						
Petroleum	581.6	629.7	701.3	769.7	794.4	1.6
Natural Gas	272.6	301.1	321.9	331.3	335.3	1.0
Metallurgical Coal	26.5	27.0	24.9	23.0	21.2	-1.1
Steam Coal	459.8	474.3	492.0	519.8	563.4	1.0
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1432.1	1540.1	1643.7	1714.3	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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run LWOP93.D0920923.

Table F1. Total Energy Supply, Disposition, and Prices (Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	14.48	13.17	13.71	15.20	-0.2
Natural Gas Plant Liquids	2.17	2.19	2.40	2.56	2.56	.8
Dry Natural Gas [2]	18.47	19.20	21.03	22.46	22.41	1.0
Coal	22.23	22.75	23.88	25.40	28.26	1.2
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy [3]	6.53	7.36	8.51	9.19	10.09	2.2
Total	71.34	72.83	75.89	80.37	85.45	.9
Imports						
Crude Oil [4]	12.78	14.30	17.56	17.10	15.80	1.1
Petroleum Products	4.36	6.24	6.29	8.10	9.04	3.7
Natural Gas [5]	1.46	2.57	2.85	3.21	3.88	5.0
Other Imports [6]	.11	.51	.66	.95	1.25	12.9
Total	18.70	23.63	27.36	29.36	29.97	2.4
Exports						
Coal	2.64	3.15	3.72	4.64	6.09	4.3
Petroleum	1.82	1.67	1.74	1.82	1.92	.3
Total	4.46	4.82	5.46	6.47	8.00	3.0
Net Stock Withdrawals	-1.36	-.20	-.14	-.14	-.15	-10.5
Discrepancy [7]	.41	-.03	.00	-.04	-.08	-
Consumption						
Petroleum Products [8]	33.53	35.53	37.80	39.82	40.89	1.0
Natural Gas	19.31	21.69	23.77	25.54	26.19	1.5
Coal	19.11	19.68	20.29	20.94	22.35	.8
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.66	8.89	9.72	10.81	2.6
Total	84.63	91.40	97.65	103.08	107.19	1.2
Net Imports - Petroleum	15.31	18.87	22.11	23.37	22.93	2.0
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	19.90	22.90	26.10	29.30	1.3
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.01	2.40	2.99	3.19	3.0
Coal Minemouth Price ($ per ton)	22.52	23.97	26.79	28.04	30.67	1.6

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F2. Energy Consumption by End-Use Sector and Source (Quadrillion Btu per Year)

Sector and Source	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.91	0.69	0.56	0.46	-2.9
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.09	4.86	4.82	4.75	.3
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.48	3.57	3.79	3.99	1.2
Total	9.83	10.98	11.17	11.35	11.64	.8
Commercial						
Distillate Fuel	.49	.57	.53	.48	.44	-.5
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.0
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.08	3.18	3.27	3.31	.9
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.30	.37	7.1
Electricity	2.86	3.12	3.40	3.64	3.81	1.4
Total	6.72	7.42	7.81	8.09	8.31	1.1
Industrial [4]						
Distillate Fuel	1.18	1.27	1.37	1.42	1.46	1.1
Liquefied Petroleum Gas	1.61	2.00	2.20	2.38	2.47	2.2
Motor Gasoline [2]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.63	2.0
Residual Fuel	.41	.51	.51	.50	.49	.8
Other Petroleum [5]	3.83	3.63	3.71	3.72	3.73	-.1
Natural Gas [6]	8.47	9.60	10.40	10.73	11.04	1.3
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	1.71	1.85	1.84	1.85	1.98	.7
Net Coal Coke Imports	.00	.00	.06	.12	.16	19.1
Renewable Energy [1]	2.07	2.30	2.36	2.42	2.52	1.0
Purchased Electricity	3.23	3.43	3.96	4.43	4.81	2.0
Total	24.84	27.02	28.97	30.23	31.40	1.2
Transportation						
Distillate Fuel	3.83	4.17	4.59	5.00	5.36	1.7
Jet Fuel	3.13	3.45	3.86	4.31	4.59	1.9
Motor Gasoline [2]	13.58	14.25	14.99	15.51	15.80	.8
Residual Fuel	1.02	1.09	1.24	1.39	1.51	2.0
Other Petroleum [7]	.24	.25	.27	.30	.32	1.4
Pipeline Fuel Natural Gas	.68	.66	.72	.78	.80	.8
Compressed Natural Gas	.00	.01	.02	.11	.22	63.4
Alcohol Fuels	.00	.01	.03	.12	.24	66.5
Electricity	.01	.02	.02	.05	.09	9.5
Total	22.50	23.90	25.76	27.59	28.93	1.3
Electric Utilities [8]						
Distillate Fuel	.09	.08	.17	.20	.17	3.5
Residual Fuel	1.14	1.03	1.29	1.56	1.53	1.5
Natural Gas	2.88	3.26	4.57	5.84	6.06	3.8
Steam Coal	16.20	16.63	17.34	18.06	19.43	.9
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.28	4.63	5.01	5.48	2.3
Total	29.99	32.13	34.90	37.73	39.61	1.4
Primary Energy Consumption						
Distillate Fuel	6.42	7.00	7.35	7.66	7.90	1.0
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.45	3.86	4.31	4.59	1.9
Liquefied Petroleum Gas	2.06	2.54	2.67	2.80	2.87	1.7
Motor Gasoline	13.87	14.59	15.37	15.90	16.21	.8
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.63	2.0
Residual Fuel	2.82	2.85	3.22	3.62	3.66	1.3

- See footnotes at end of table.

Table F2. Energy Consumption by End-Use Sector and Source (Continued) (Quadrillion Btu per Year)

Sector and Source	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.85	3.95	3.98	4.01	0.0
Natural Gas	19.31	21.69	23.77	25.54	26.19	1.5
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	18.07	18.63	19.32	20.04	21.52	.9
Net Coal Coke Imports	.00	.00	.06	.12	.16	19.1
Nuclear Power	6.19	6.85	6.90	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.65	8.80	9.48	10.41	2.4
Alcohols	.00	.01	.03	.12	.24	66.5
Total	84.63	91.40	97.65	103.08	107.19	1.2
Electricity Consumption (all Sectors)	9.26	10.05	10.96	11.91	12.71	1.6
Industrial Electricity						
Gross Consumption	3.58	3.96	4.55	5.03	5.44	2.1
Self-generation - Own Use	.39	.53	.59	.61	.63	2.4
Purchased Electricity	3.23	3.43	3.96	4.43	4.81	2.0

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.53	13.29	14.06	14.58	0.8
Primary Energy	6.48	6.52	6.90	7.45	7.68	.9
Petroleum Products	9.04	8.01	8.68	9.42	10.17	.6
Distillate Fuel	8.08	7.19	7.76	8.38	8.98	.5
Kerosene	9.14	8.57	8.98	9.42	9.85	.4
Liquefied Petroleum Gas	11.20	9.61	10.33	11.14	11.93	.3
Natural Gas	5.82	6.16	6.55	7.14	7.33	1.2
Steam Coal	1.99	2.07	2.24	2.37	2.60	1.4
Electricity	23.34	23.86	24.09	24.19	24.28	.2
Commercial	12.40	12.41	12.87	13.28	13.49	.4
Primary Energy	5.06	5.21	5.68	6.29	6.60	1.3
Petroleum Products	6.04	5.47	6.16	6.93	7.68	1.2
Distillate Fuel	5.94	5.01	5.59	6.22	6.83	.7
Residual Fuel	3.57	3.36	3.87	4.44	5.00	1.7
Kerosene	6.96	6.22	6.64	7.11	7.58	.4
Other Petroleum [1]	9.69	9.26	10.09	11.00	11.81	1.0
Natural Gas	4.84	5.22	5.62	6.21	6.41	1.4
Steam Coal	1.96	2.03	2.21	2.33	2.56	1.3
Electricity	22.04	21.98	21.66	21.27	20.95	-.3
Industrial	5.73	5.65	6.20	6.84	7.25	1.2
Primary Energy	4.14	4.08	4.53	5.09	5.47	1.4
Petroleum Products	6.01	5.64	6.17	6.77	7.37	1.0
Distillate Fuel	5.94	4.96	5.53	6.15	6.75	.6
Liquefied Petroleum Gas	5.95	5.50	6.20	6.98	7.76	1.3
Motor Gasoline [2]	9.87	9.55	10.37	11.27	12.05	1.0
Residual Fuel	3.13	3.06	3.57	4.14	4.70	2.1
Other Petroleum [3]	6.14	5.96	6.40	6.88	7.37	.9
Natural Gas [4]	2.95	3.27	3.68	4.26	4.46	2.1
Metallurgical Coal	1.82	1.91	2.10	2.24	2.46	1.5
Steam Coal	1.48	1.55	1.67	1.77	1.93	1.3
Electricity	14.74	14.83	15.12	15.45	15.55	.3
Transportation	8.92	8.48	9.14	9.86	10.51	.8
Primary Energy	8.91	8.47	9.13	9.84	10.48	.8
Petroleum Products	8.91	8.47	9.13	9.84	10.49	.8
Distillate Fuel [5]	8.98	8.75	9.32	9.94	10.54	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.57	.5
Motor Gasoline [2]	9.86	9.59	10.41	11.30	12.08	1.0
Residual Fuel	3.22	3.00	3.43	3.91	4.34	1.5
Other Petroleum [7]	16.49	15.16	15.58	16.06	16.54	.0
Compressed Natural Gas	4.50	7.13	7.95	8.84	9.61	3.9
Electricity	23.74	24.29	21.77	19.07	18.41	-1.3
Total End-Use Energy	8.68	8.52	9.05	9.68	10.15	.8
Primary Energy	6.58	6.35	6.91	7.57	8.08	1.0
Electricity	19.94	20.20	20.09	20.03	19.93	.0
Electric Utilities						
Fossil Fuel Average	1.71	1.79	2.06	2.39	2.57	2.1
Petroleum Products	3.61	3.59	4.05	4.60	5.36	2.0
Distillate Fuel	5.57	4.55	5.16	5.79	6.41	.7
Residual Fuel	3.46	3.51	3.90	4.45	5.24	2.1
Natural Gas	2.38	2.57	3.02	3.73	4.02	2.6
Steam Coal	1.45	1.52	1.64	1.74	1.88	1.3

- See footnotes at end of table.

Table F3. Energy Prices by End-Use Sector and Source (Continued)
(1991 Dollars per Million Btu)

Sector and Source	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	7.51	8.12	8.79	9.45	0.9
Distillate Fuel [5]	8.03	7.51	8.11	8.78	9.45	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.57	.5
Kerosene	8.80	8.28	8.61	8.97	9.30	.3
Liquefied Petroleum Gas	7.02	6.33	6.89	7.58	8.31	.8
Motor Gasoline [2]	9.86	9.59	10.41	11.30	12.08	1.0
Residual Fuel	3.33	3.22	3.67	4.20	4.79	1.8
Other Petroleum Products [9]	6.62	6.41	6.85	7.36	7.87	.9
Natural Gas	3.90	4.20	4.47	5.02	5.24	1.5
Coal	1.48	1.54	1.67	1.76	1.91	1.3
Electricity	19.94	20.20	20.09	20.03	19.93	.0

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run HGEO93.D0916924. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,603	1,672	1,737	1,842	0.8
Petroleum	117	101	136	165	160	1.6
Natural Gas	264	303	416	528	561	3.8
Nuclear Power	577	628	633	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	8.9
Renewable Sources/Other [1]	293	322	335	344	351	.9
Total	2,808	2,948	3,182	3,410	3,539	1.2
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	52	60	125	6.9
Petroleum	5	11	12	12	13	4.3
Natural Gas	100	151	184	222	237	4.4
Renewable Sources/Other [1]	80	119	141	164	196	4.6
Total	218	332	390	459	571	4.9
Sales to Utilities	106	175	217	281	387	6.7
Generation for Own Use	111	156	172	178	184	2.5
Electricity Sales by Sector						
Residential	924	1,021	1,047	1,110	1,170	1.2
Commercial/Other [3]	843	920	1,003	1,082	1,143	1.5
Industrial	946	1,005	1,162	1,298	1,411	2.0
Total	2,713	2,946	3,212	3,490	3,724	1.6
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.14	8.22	8.26	8.29	.2
Commercial/Other [3]	7.52	7.50	7.39	7.25	7.13	-.3
Industrial [5]	5.03	5.06	5.16	5.27	5.31	.3
Average	6.80	6.89	6.85	6.83	6.80	.0
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.90	2.58	2.25	2.05	-1.7
Fuel Component	1.70	1.82	2.10	2.40	2.63	2.2
O&M Component	2.23	2.17	2.17	2.18	2.12	-.2
Total	6.80	6.89	6.85	6.83	6.80	.0

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M – Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Non-utility Power Producer Report*. Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	301.8	317.2	0.3
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	14.0	31.2	44.7	10.9
Combustion Turbine/Diesel	46.4	54.9	68.3	74.3	77.7	2.6
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.6	83.3	84.9	86.1	.5
Total	688.6	699.9	715.4	740.4	768.2	.5
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	2.8	19.4	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.2	16.0	29.3	-
Combustion Turbine/Diesel	.0	1.6	4.8	10.7	14.0	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.7	1.7	2.7	3.9	-
Total	.0	2.2	7.2	32.8	67.3	-
Cumulative Total Additions	6.3	29.6	59.5	96.3	132.5	16.5
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	11.2	12.7	23.5	6.1
Petroleum	.8	3.2	3.6	3.8	3.9	8.1
Natural Gas	19.3	29.2	35.0	42.9	46.0	4.4
Renewable Sources/Other [3]	15.8	23.9	28.2	32.2	37.8	4.5
Total	43.0	67.1	78.0	91.5	111.2	4.9
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	.5	1.9	12.8	-
Petroleum	.0	.2	.5	.7	.8	-
Natural Gas	.0	.7	5.8	13.7	16.8	-
Renewable Sources/Other [3]	.0	3.6	7.4	11.4	17.0	-
Total	.0	4.7	14.3	27.8	47.4	-
Cumulative Additions	.0	24.1	35.0	48.5	68.2	-

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes oil-, gas-, and dual-fired capability.

[3] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report.* 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Non-utility Power Producer Report.* All projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.67	5.18	6.85	8.51	6.2
Municipal Solid Waste	2.01	5.17	6.69	8.18	11.40	9.1
Biomass/Other Waste	6.01	7.43	7.65	7.83	8.06	1.5
Solar Thermal	.35	.50	1.32	1.63	1.93	8.9
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.37	3.56	4.95	6.33	7.8
Total	87.43	95.71	101.27	106.30	113.11	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	20.82	34.63	49.02	62.05	7.2
Municipal Solid Waste	10.45	18.28	24.33	33.03	53.67	8.5
Biomass/Other Waste	31.48	46.79	52.84	55.93	58.70	3.2
Solar Thermal	.66	.90	2.19	2.98	3.79	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.44	9.08	12.75	16.20	10.4
Total	348.23	400.60	431.27	460.82	500.87	1.8
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.22	.36	.51	.64	7.2
Municipal Solid Waste	.11	.19	.25	.34	.56	8.6
Biomass/Other Waste	.32	.48	.54	.58	.61	3.2
Solar Thermal	.01	.01	.02	.03	.04	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.09	.13	.17	10.4
Total	3.62	4.16	4.48	4.79	5.20	1.8
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.79	3.01	3.24	3.54	1.6
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	2.99	3.78	4.13	4.62	2.7
Total Renewable Energy	6.32	7.15	8.26	8.92	9.82	2.2

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F7. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.320	1.584	1.954	2.430	3.9
Real Gross Domestic Product	4,885	5,392	6,054	6,700	7,297	2.0
Real Disposable Personal Income	3,538	3,895	4,282	4,673	5,044	1.8
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.139	1.354	1.549	1.699	2.5
AA Utility Bond Rate (percent)	9.66	9.22	8.88	8.84	8.75	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.30	5.78	5.66	5.61	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.95	16.13	15.38	14.69	-.8

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	19.90	22.90	26.10	29.30	1.3
Production						
Crude Oil [2]	7.35	6.62	5.90	6.10	6.73	-.4
Alaska	1.77	1.42	1.05	.89	1.24	-1.8
Lower 48	5.58	5.20	4.84	5.21	5.49	-.1
Natural Gas Plant Liquids	1.56	1.58	1.73	1.84	1.84	.8
Other Domestic [3]	.08	.22	.31	.38	.45	9.0
Processing Gain [4]	.68	.67	.74	.74	.74	.4
Total	9.68	9.08	8.67	9.06	9.77	.0
Imports (including SPR) [5]						
Crude Oil	5.89	6.64	8.13	7.94	7.34	1.1
Refined Products[6]	2.13	3.09	3.10	4.00	4.47	3.8
Total	8.02	9.73	11.23	11.94	11.81	2.0
Exports						
Crude Oil	.11	.10	.08	.08	.11	.0
Refined Products	.75	.69	.74	.79	.80	.3
Total	.85	.79	.82	.86	.91	.3
Net Imports (including SPR)	7.17	8.93	10.41	11.08	10.90	2.1
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.05	-.03	-.02	-.01	-12.2
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	17.94	19.03	20.09	20.64	1.1
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.61	7.99	8.29	8.45	.8
Jet Fuel [10]	1.52	1.68	1.87	2.10	2.23	1.9
Distillate Fuel	3.02	3.29	3.45	3.60	3.72	1.0
Residual Fuel	1.23	1.24	1.40	1.58	1.60	1.3
Other [11]	3.98	4.31	4.51	4.71	4.83	1.0
Total	16.99	18.13	19.22	20.28	20.82	1.0
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.28	1.08	.94	.84	-1.6
Industrial [12]	4.34	4.69	5.00	5.27	5.43	1.1
Transportation	10.97	11.67	12.50	13.30	13.81	1.2
Electric Utilities	.54	.49	.64	.77	.75	1.7
Total	16.99	18.13	19.22	20.28	20.82	1.0
Net Disposition	16.98	18.13	19.22	20.28	20.82	1.0

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.52	20.29	21.67	21.60	1.0
Supplemental Gas [2]	.10	.10	.10	.12	.13	1.2
Net Imports	1.45	2.49	2.76	3.11	3.76	4.9
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	21.11	23.16	24.90	25.50	1.5
Consumption by Sector						
Residential	4.38	4.93	4.72	4.67	4.61	.3
Commercial	2.67	2.99	3.09	3.17	3.21	.9
Industrial [4]	6.98	8.13	8.80	9.03	9.33	1.5
Electric Utilities [5]	2.79	3.16	4.43	5.67	5.88	3.8
Lease and Plant Fuel [6]	1.24	1.18	1.29	1.37	1.38	.6
Pipeline Fuel	.66	.64	.70	.76	.78	.8
Transportation [7]	.00	.01	.02	.11	.22	63.4
Total	18.73	21.04	23.05	24.77	25.40	1.5
Unaccounted for [8]	.12	.08	.11	.12	.09	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.01	2.40	2.99	3.19	3.0
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.35	6.76	7.36	7.56	1.2
Commercial	4.99	5.38	5.79	6.40	6.61	1.4
Industrial	3.04	3.38	3.79	4.39	4.60	2.1
Electric Utilities	2.46	2.65	3.11	3.85	4.15	2.6
Transportation[7]	4.64	7.36	8.20	9.11	9.91	3.9
Average [9]	4.03	4.33	4.61	5.17	5.40	1.5

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	645	654	680	755	0.9
West of the Mississippi	399	416	471	520	582	1.9
Total	1,029	1,061	1,125	1,200	1,337	1.3
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	121	144	180	235	4.1
Total	-103	-116	-138	-170	-223	3.9
Net Stock Withdrawals [2]	-27	-2	-1	-2	-4	-9.3
Total Supply [3]	899	943	987	1,028	1,110	1.1
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	87	86	87	93	1.0
Coking Plants	39	40	37	34	31	-1.1
Electricity [5]	774	811	859	903	981	1.2
Total	895	944	988	1,029	1,111	1.1
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	23.97	26.79	28.04	30.67	1.6
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.25	51.98	54.84	58.97	.7
Industrial	34.77	33.07	35.70	37.88	40.78	.8
Coking Plants	49.40	50.79	55.71	59.36	65.17	1.4
Electricity	31.52	31.08	33.14	34.72	37.22	.8
Average [8]	32.72	32.20	34.31	35.90	38.40	.8

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.4	102.0	105.9	109.1	0.8
Energy Consumption per Household (million Btu)	105.2	112.8	109.5	107.1	106.6	.1
End-Use Consumption						
Distillate						
Space Heating	.72	.82	.64	.53	.45	-2.4
Other Uses [1]	.11	.09	.05	.03	.02	-8.6
Total	.84	.91	.69	.56	.46	-2.9
Natural Gas						
Space Heating	3.15	3.51	3.28	3.21	3.13	.0
Water Heating	1.06	1.27	1.30	1.33	1.35	1.2
Other Uses [1]	.31	.31	.28	.27	.28	-.5
Total	4.52	5.09	4.86	4.82	4.75	.3
Other Fuels [2]	.49	.57	.49	.43	.40	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.30	.30	-.4
Cooling	.51	.55	.50	.53	.56	.4
Water Heating	.39	.50	.55	.63	.69	2.8
Other Uses [1]	1.93	2.10	2.22	2.33	2.45	1.2
Total	3.15	3.48	3.57	3.79	3.99	1.2
Total Consumption	9.83	10.98	11.17	11.35	11.64	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	117.5	124.8	130.1	134.5	1.0
Total Floorspace (billion square feet)	62.9	69.0	75.6	82.4	89.5	1.8
Energy Consumption per Square Foot (thousand Btu)	107.0	107.6	103.4	98.1	92.9	-.7
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.50	.46	.42	-.4
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.57	.53	.48	.44	-.5
Natural Gas						
Space Heating	1.80	1.99	2.02	2.02	1.98	.5
Cooling	.21	.23	.24	.25	.26	1.2
Other Uses [1]	.75	.86	.93	1.00	1.07	1.8
Total	2.76	3.08	3.18	3.27	3.31	.9
Other Fuels [2]	.52	.49	.45	.41	.37	-1.7
Renewables [3]	.10	.15	.25	.30	.37	7.1
Electricity						
Space Heating	.52	.59	.65	.72	.79	2.2
Cooling	.73	.81	.89	.96	1.01	1.7
Lighting	1.14	1.20	1.27	1.30	1.27	.5
Other Uses [1]	.48	.52	.59	.66	.74	2.2
Total	2.86	3.12	3.40	3.64	3.81	1.4
Total Consumption	6.72	7.42	7.81	8.09	8.31	1.1

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2658	3158	3614	3964	2.5
Non-manufacturing	871	925	1022	1103	1184	1.5
Total	3274	3583	4180	4717	5148	2.3
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.36	.33	.30	.28	-1.2
Liquefied Petroleum Gas	.49	.56	.53	.50	.48	-.1
Petrochemical Feedstocks	.34	.32	.32	.32	.32	-.3
Residual Fuel	.13	.14	.12	.11	.09	-1.4
Other Petroleum [1]	1.17	1.01	.89	.79	.72	-2.4
Natural Gas [2]	2.59	2.68	2.49	2.27	2.14	-.9
Metallurgical Coal and Coke [3]	.32	.29	.25	.22	.19	-2.5
Steam Coal [4]	.52	.52	.44	.39	.38	-1.5
Renewables [5]	.06	.06	.06	.05	.05	-1.3
Electricity	.99	.96	.95	.94	.94	-.3
Total	7.59	7.54	6.93	6.41	6.10	-1.1
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.27	1.37	1.42	1.46	1.1
Liquefied Petroleum Gas	1.61	2.00	2.20	2.38	2.47	2.2
Motor Gasoline [6]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.63	2.0
Residual Fuel	.41	.51	.51	.50	.49	.8
Other Petroleum [1]	3.83	3.63	3.71	3.72	3.73	-.1
Natural Gas [2]	8.47	9.60	10.40	10.73	11.04	1.3
Metallurgical Coal and Coke [3]	1.04	1.05	1.04	1.02	.99	-.3
Steam Coal [4]	1.71	1.85	1.84	1.85	1.98	.7
Renewables [5]	2.07	2.30	2.36	2.42	2.52	1.0
Electricity	3.23	3.43	3.96	4.43	4.81	2.0
Total	24.84	27.02	28.97	30.23	31.40	1.2

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.10	1.20	1.31	1.41	1.7
Freight Trucks	1.00	1.08	1.23	1.34	1.45	1.9
Air	.99	1.25	1.58	1.93	2.26	4.2
Rail	.99	1.03	1.11	1.20	1.29	1.3
Marine	.99	1.04	1.13	1.20	1.27	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.00	28.77	30.32	32.55	34.66	1.1
New Light Truck MPG [1]	20.70	21.64	22.73	24.10	25.40	1.0
Light Duty Fleet MPG [2]	18.58	19.28	19.88	20.57	21.33	.7
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.25	12.97	13.58	14.03	1.0
Freight Trucks	5.06	5.30	5.74	6.18	6.57	1.3
Air	3.20	3.53	3.94	4.41	4.69	1.9
Rail	.49	.50	.52	.56	.59	1.0
Marine	1.39	1.49	1.68	1.87	2.02	1.9
Pipeline Fuel	.68	.66	.72	.78	.80	.8
Other	.17	.18	.19	.20	.22	1.1
Total	22.50	23.90	25.76	27.59	28.93	1.3

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989=1.0).
[4] Based on Btu per vehicle miles traveled (1989=1.0).
[5] Based on Btu per ton-miles traveled (1989=1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table F15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	High Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.2	21.3	17.7	15.1	-2.3
Natural Gas	65.7	73.9	70.7	70.0	69.1	.3
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	102.7	93.6	89.2	85.8	-.3
Commercial						
Petroleum	18.5	19.7	18.1	16.6	15.2	-1.0
Natural Gas	40.1	44.8	46.3	47.5	48.1	.9
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.7	66.3	65.7	64.7	.3
Industrial [2]						
Petroleum	87.4	89.2	92.5	93.7	94.6	.4
Natural Gas [3]	115.0	130.6	142.0	146.6	150.9	1.4
Metallurgical Coal	26.5	26.9	24.8	22.9	21.1	-1.1
Steam Coal	43.6	47.1	46.9	47.3	50.4	.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	293.8	306.1	310.5	317.0	.8
Transportation						
Petroleum	425.1	452.8	487.1	517.8	538.6	1.2
Natural Gas[4]	9.9	9.7	10.9	12.9	14.9	2.1
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	462.5	498.0	530.8	553.5	1.2
Electric Utilities [5]						
Petroleum	26.4	23.9	31.3	37.8	36.5	1.6
Natural Gas	41.9	47.4	66.5	84.9	88.1	3.8
Steam Coal	412.3	423.3	441.4	459.7	494.5	.9
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	494.6	539.2	582.4	619.2	1.3
Primary Energy Consumption						
Petroleum	581.6	613.0	650.3	683.6	700.0	.9
Natural Gas	272.6	306.4	336.3	361.9	371.1	1.6
Metallurgical Coal	26.5	26.9	24.8	22.9	21.1	-1.1
Steam Coal	459.8	474.0	491.6	510.0	547.8	.9
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1420.3	1503.1	1578.5	1640.1	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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run HGEO93.D0916924.

Table G1. Total Energy Supply, Disposition, and Prices (Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Crude Oil and Lease Condensate [1]	15.74	13.97	11.81	11.19	10.74	-1.9
Natural Gas Plant Liquids	2.17	2.18	2.30	2.25	2.16	.0
Dry Natural Gas [2]	18.47	19.13	20.09	19.76	19.02	.1
Coal	22.23	22.75	23.94	26.50	29.70	1.5
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy [3]	6.53	7.36	8.51	9.18	10.08	2.2
Total	71.34	72.24	73.55	75.94	78.64	.5
Imports						
Crude Oil [4]	12.78	14.84	18.93	19.61	20.21	2.3
Petroleum Products	4.36	6.25	6.51	8.79	10.08	4.3
Natural Gas [5]	1.46	2.57	3.13	3.87	4.54	5.9
Other Imports [6]	.11	.51	.64	.90	1.15	12.5
Total	18.70	24.17	29.21	33.18	35.99	3.3
Exports						
Coal	2.64	3.15	3.72	4.64	6.09	4.3
Petroleum	1.82	1.64	1.71	1.78	1.79	-.1
Total	4.46	4.79	5.43	6.43	7.87	2.9
Net Stock Withdrawals	-1.36	-.20	-.13	-.22	-.15	-10.5
Discrepancy [7]	.41	-.07	-.07	-.21	-.41	-
Consumption						
Petroleum Products [8]	33.53	35.57	37.88	40.02	41.28	1.0
Natural Gas	19.31	21.59	23.13	23.55	23.47	1.0
Coal	19.11	19.68	20.35	21.97	23.80	1.1
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	6.50	7.65	8.88	9.67	10.71	2.5
Total	84.63	91.34	97.14	102.26	106.19	1.1
Net Imports - Petroleum	15.31	19.45	23.73	26.63	28.50	3.2
Prices (1991 dollars per unit)						
World Oil Price ($ per barrel) [10]	22.54	19.90	22.90	26.10	29.30	1.3
Natural Gas Wellhead Price ($ per Mcf)	1.77	2.06	2.81	3.68	4.44	4.7
Coal Minemouth Price ($ per ton)	22.52	23.95	26.74	28.32	31.25	1.7

[1] Includes other hydrocarbons.
[2] Includes synthetic gas.
[3] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; alcohol fuels from renewable sources; and in addition to renewables, electricity from waste heat.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Represents net imports.
[6] Includes coal, coal coke (net), electricity (net), and methanol.
[7] Balancing item. Includes unaccounted for supply, losses, and gains.
[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids, such as ethanol.
[9] Includes utility and nonutility electricity from hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood; and in addition to renewables, electricity from waste heat, plus net coal coke imports, and net electricity imports.
[10] Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System.
Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G2. Energy Consumption by End-Use Sector and Source (Quadrillion Btu per Year)

Sector and Source	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Distillate Fuel	0.84	0.91	0.70	0.57	0.48	-2.7
Kerosene	.06	.07	.05	.03	.02	-5.7
Liquefied Petroleum Gas	.37	.44	.38	.34	.32	-.7
Natural Gas	4.52	5.08	4.79	4.68	4.51	.0
Coal	.06	.06	.06	.06	.06	-.1
Renewable Energy [1]	.83	.93	1.55	1.75	2.03	4.6
Electricity	3.15	3.48	3.57	3.80	4.02	1.2
Total	9.83	10.97	11.10	11.23	11.44	.8
Commercial						
Distillate Fuel	.49	.57	.53	.49	.45	-.4
Kerosene	.01	.01	.01	.01	.01	-3.0
Motor Gasoline [2]	.11	.12	.13	.13	.14	1.0
Residual Fuel	.24	.21	.18	.16	.14	-2.9
Natural Gas	2.76	3.08	3.15	3.20	3.19	.7
Other [3]	.16	.15	.13	.11	.10	-2.5
Renewable Energy [1]	.10	.15	.25	.30	.37	7.1
Electricity	2.86	3.12	3.40	3.64	3.83	1.5
Total	6.72	7.42	7.78	8.03	8.22	1.0
Industrial [4]						
Distillate Fuel	1.18	1.27	1.37	1.41	1.46	1.1
Liquefied Petroleum Gas	1.61	2.01	2.25	2.46	2.61	2.5
Motor Gasoline [2]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	1.9
Residual Fuel	.41	.51	.53	.54	.54	1.3
Other Petroleum [5]	3.83	3.63	3.71	3.72	3.72	-.1
Natural Gas [6]	8.47	9.55	9.98	9.97	9.97	.8
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	1.71	1.85	1.84	1.86	1.98	.7
Net Coal Coke Imports	.00	.00	.06	.12	.15	18.8
Renewable Energy [1]	2.07	2.30	2.36	2.42	2.52	1.0
Purchased Electricity	3.23	3.43	3.97	4.42	4.80	2.0
Total	24.84	26.99	28.64	29.57	30.49	1.0
Transportation						
Distillate Fuel	3.83	4.17	4.60	5.03	5.41	1.7
Jet Fuel	3.13	3.45	3.85	4.30	4.56	1.9
Motor Gasoline [2]	13.58	14.25	14.99	15.56	15.90	.8
Residual Fuel	1.02	1.09	1.24	1.39	1.51	2.0
Other Petroleum [7]	.24	.25	.27	.30	.32	1.4
Pipeline Fuel Natural Gas	.68	.66	.71	.72	.81	.9
Compressed Natural Gas	.00	.01	.02	.07	.15	60.4
Alcohol Fuels	.00	.01	.02	.08	.16	62.9
Electricity	.01	.02	.02	.05	.08	8.9
Total	22.50	23.90	25.72	27.50	28.90	1.3
Electric Utilities [8]						
Distillate Fuel	.09	.07	.16	.21	.20	4.3
Residual Fuel	1.14	1.07	1.31	1.58	1.56	1.6
Natural Gas	2.88	3.22	4.49	4.91	4.83	2.6
Steam Coal	16.20	16.63	17.40	19.08	20.87	1.3
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [9]	3.49	4.28	4.63	5.01	5.48	2.3
Total	29.99	32.11	34.88	37.84	39.87	1.4
Primary Energy Consumption						
Distillate Fuel	6.42	7.00	7.35	7.71	8.01	1.1
Kerosene	.08	.08	.05	.04	.03	-5.2
Jet Fuel	3.13	3.45	3.85	4.30	4.56	1.9
Liquefied Petroleum Gas	2.06	2.54	2.72	2.89	3.01	1.9
Motor Gasoline	13.87	14.59	15.36	15.95	16.31	.8
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	1.9
Residual Fuel	2.82	2.88	3.27	3.67	3.74	1.4

- See footnotes at end of table.

Table G2. Energy Consumption by End-Use Sector and Source (Continued) (Quadrillion Btu per Year)

Sector and Source	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Primary Energy Consumption						
Other Petroleum [10]	4.05	3.85	3.95	3.98	4.01	-0.1
Natural Gas	19.31	21.59	23.13	23.55	23.47	1.0
Metallurgical Coal	1.04	1.05	.98	.90	.83	-1.1
Steam Coal	18.07	18.62	19.37	21.06	22.97	1.2
Net Coal Coke Imports	.00	.00	.06	.12	.15	18.8
Nuclear Power	6.19	6.85	6.89	7.06	6.94	.6
Renewable Energy/Other [11]	6.49	7.65	8.80	9.48	10.40	2.4
Alcohols	.00	.01	.02	.08	.16	62.9
Total	84.63	91.34	97.14	102.26	106.19	1.1
Electricity Consumption (all Sectors)	9.26	10.05	10.96	11.91	12.73	1.6
Industrial Electricity						
Gross Consumption	3.58	3.96	4.56	5.02	5.43	2.1
Self-generation - Own Use	.39	.53	.58	.60	.62	2.4
Purchased Electricity	3.23	3.43	3.97	4.42	4.80	2.0

[1] Includes electricity generated by the sector for self-use from wood and wood waste, municipal solid waste, other biomass, and non-electric energy from renewable sources such as active and passive solar systems, groundwater heat pumps, and wood.
[2] Includes ethanol and ethers blended into gasoline.
[3] Includes liquefied petroleum gas and coal.
[4] Includes consumption by cogenerators.
[5] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[6] Includes lease and plant fuel.
[7] Includes aviation gas, liquefied petroleum gas, lubricants, and miscellaneous petroleum products.
[8] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.
[9] Includes electricity generated to serve the grid 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.
[10] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[11] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: 1990: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels estimates. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G3. Energy Prices by End-Use Sector and Source (1991 Dollars per Million Btu)

Sector and Source	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	12.39	12.57	13.63	14.68	15.65	1.2
Primary Energy	6.48	6.57	7.25	8.04	8.76	1.5
Petroleum Products	9.04	8.01	8.69	9.43	10.16	.6
Distillate Fuel	8.08	7.19	7.76	8.38	8.99	.5
Kerosene	9.14	8.57	8.98	9.42	9.85	.4
Liquefied Petroleum Gas	11.20	9.61	10.35	11.17	11.99	.3
Natural Gas	5.82	6.22	6.97	7.83	8.59	2.0
Steam Coal	1.99	2.07	2.24	2.41	2.63	1.4
Electricity	23.34	23.88	24.30	24.62	24.89	.3
Commercial	12.40	12.45	13.19	13.87	14.48	.8
Primary Energy	5.06	5.26	6.00	6.84	7.60	2.1
Petroleum Products	6.04	5.47	6.17	6.93	7.68	1.2
Distillate Fuel	5.94	5.01	5.59	6.23	6.83	.7
Residual Fuel	3.57	3.36	3.88	4.45	5.01	1.7
Kerosene	6.96	6.22	6.64	7.11	7.58	.4
Other Petroleum [1]	9.69	9.27	10.10	11.01	11.83	1.0
Natural Gas	4.84	5.28	6.03	6.90	7.67	2.3
Steam Coal	1.96	2.04	2.21	2.37	2.59	1.4
Electricity	22.04	22.00	21.92	21.79	21.69	-.1
Industrial	5.73	5.67	6.42	7.21	7.87	1.6
Primary Energy	4.14	4.10	4.72	5.41	6.03	1.9
Petroleum Products	6.01	5.64	6.17	6.77	7.38	1.0
Distillate Fuel	5.94	4.96	5.53	6.15	6.75	.6
Liquefied Petroleum Gas	5.95	5.50	6.21	7.00	7.80	1.4
Motor Gasoline [2]	9.87	9.55	10.38	11.27	12.05	1.0
Residual Fuel	3.13	3.06	3.57	4.14	4.71	2.1
Other Petroleum [3]	6.14	5.96	6.40	6.88	7.37	.9
Natural Gas [4]	2.95	3.33	4.09	4.95	5.71	3.4
Metallurgical Coal	1.82	1.91	2.10	2.29	2.52	1.7
Steam Coal	1.48	1.55	1.67	1.79	1.96	1.4
Electricity	14.74	14.85	15.36	15.91	16.20	.5
Transportation	8.92	8.48	9.15	9.86	10.52	.8
Primary Energy	8.91	8.47	9.13	9.85	10.50	.8
Petroleum Products	8.91	8.47	9.14	9.85	10.50	.8
Distillate Fuel [5]	8.98	8.75	9.32	9.94	10.54	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.56	.5
Motor Gasoline [2]	9.86	9.59	10.41	11.31	12.08	1.0
Residual Fuel	3.22	3.00	3.43	3.91	4.34	1.5
Other Petroleum [7]	16.49	15.16	15.59	16.06	16.55	.0
Compressed Natural Gas	4.50	7.14	7.96	8.84	9.61	3.9
Electricity	23.74	24.32	22.17	19.76	19.59	-1.0
Total End-Use Energy	8.68	8.54	9.22	9.98	10.65	1.0
Primary Energy	6.58	6.37	7.05	7.81	8.50	1.3
Electricity	19.94	20.22	20.32	20.50	20.62	.2
Electric Utilities						
Fossil Fuel Average	1.71	1.80	2.13	2.45	2.71	2.3
Petroleum Products	3.61	3.58	4.03	4.61	5.40	2.0
Distillate Fuel	5.57	4.54	5.16	5.82	6.44	.7
Residual Fuel	3.46	3.51	3.90	4.45	5.26	2.1
Natural Gas	2.38	2.62	3.42	4.31	5.12	3.9
Steam Coal	1.45	1.51	1.64	1.77	1.92	1.4

- See footnotes at end of table.

Table G3. Energy Prices by End-Use Sector and Source (Continued)
(1991 Dollars per Million Btu)

Sector and Source	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Average Price to All Users [8]						
Petroleum Products	7.93	7.51	8.11	8.78	9.45	0.9
Distillate Fuel [5]	8.03	7.51	8.11	8.79	9.44	.8
Jet Fuel [6]	6.00	4.72	5.31	5.95	6.56	.5
Kerosene	8.80	8.28	8.61	8.97	9.30	.3
Liquefied Petroleum Gas	7.02	6.33	6.89	7.59	8.32	.9
Motor Gasoline [2]	9.86	9.59	10.41	11.31	12.08	1.0
Residual Fuel	3.33	3.23	3.67	4.20	4.80	1.8
Other Petroleum Products [9]	6.62	6.41	6.85	7.36	7.87	.9
Natural Gas	3.90	4.26	4.89	5.73	6.50	2.6
Coal	1.48	1.54	1.67	1.80	1.95	1.4
Electricity	19.94	20.22	20.32	20.50	20.62	.2

[1] Average price for liquefied petroleum gas, motor gasoline, and miscellaneous petroleum products.
[2] Average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[3] Average price for petrochemical feedstocks and miscellaneous petroleum products.
[4] Excludes uses for lease and plant fuel.
[5] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[6] Kerosene-type jet fuel.
[7] Average price for liquefied petroleum gas and miscellaneous petroleum products.
[8] 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.
[9] Average price for petrochemical feedstocks and miscellaneous petroleum products.

Sources: 1990 prices for gasoline, distillate, jet fuel, residual fuel, liquefied petroleum gas, and kerosene are based on data from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (Washington, DC, January 1990 through December 1990). 1990 prices for all other petroleum products are derived from the Energy Information Administration, *State Energy Price and Expenditures Report: 1989*, DOE/EIA-0376(89) (Washington, DC, September 1991), applying the growth rate of the world oil price. Natural gas delivered prices for 1990 to residential and electric utilities are from the EIA *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1993 Forecasting System run LGEO93.D0918923. Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G4. Electricity Supply, Disposition, and Prices (Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Generation by Fuel Type						
Coal	1,560	1,603	1,671	1,774	1,905	1.0
Petroleum	117	103	138	168	165	1.7
Natural Gas	264	301	412	451	448	2.7
Nuclear Power	577	628	632	647	636	.5
Pumped Storage Hydroelectric	-2	-10	-11	-11	-11	9.0
Renewable Sources/Other [1]	293	322	335	344	351	.9
Total	2,808	2,947	3,177	3,373	3,494	1.1
Net Imports	2	38	39	46	54	17.4
Nonutilities [2]						
Generation by Fuel Type						
Coal	33	50	59	127	217	10.0
Petroleum	5	11	13	14	14	4.8
Natural Gas	100	151	181	188	191	3.3
Renewable Sources/Other [1]	80	119	141	164	196	4.6
Total	218	332	394	491	618	5.4
Sales to Utilities	106	175	223	314	435	7.3
Generation for Own Use	111	156	171	177	183	2.5
Electricity Sales by Sector						
Residential	924	1,020	1,047	1,114	1,179	1.2
Commercial/Other [3]	843	920	1,002	1,082	1,145	1.5
Industrial	946	1,005	1,164	1,295	1,408	2.0
Total	2,713	2,945	3,213	3,490	3,731	1.6
End-Use Prices [4]						
(1991 cents per kilowatthour)						
Residential	7.96	8.15	8.29	8.40	8.49	.3
Commercial/Other [3]	7.52	7.51	7.48	7.42	7.39	-.1
Industrial [5]	5.03	5.07	5.24	5.43	5.53	.5
Average	6.80	6.90	6.93	6.99	7.04	.2
Price Components [4]						
(1991 cents per kilowatthour)						
Capital Component	2.88	2.90	2.59	2.28	2.07	-1.6
Fuel Component	1.70	1.83	2.17	2.54	2.84	2.6
O&M Component	2.23	2.17	2.17	2.18	2.12	-.2
Total	6.80	6.90	6.93	6.99	7.04	.2

[1] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[2] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for delivery to the grid. The generation values shown for nonutilities represent gross generation rather than net generation (net of station use).

[3] Other includes sales of electricity to Government, railways, and street lighting authorities.

[4] Prices represent average revenue per kilowatthour of sales.

[5] Weighted average, including transportation. Weights used are consumption levels by sector.

O&M = Operating and Maintenance

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

Sources: 1990, except for nonutilities and prices: Energy Information Administration, *Electric Power Annual, January 1992*, DOE/EIA-0348(90) (Washington, DC, January 1992). 1990 nonutility: Energy Information Administration, Form EIA-867, *Annual Non-utility Power Producer Report.* Prices and all projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electric Utilities						
Capability						
Coal Steam	298.1	296.0	297.6	310.7	331.1	0.5
Other Fossil Steam [2]	143.8	137.6	130.9	123.8	120.2	-.9
Combined Cycle	5.7	9.7	13.8	17.9	22.0	7.0
Combustion Turbine/Diesel	46.4	54.9	68.7	75.6	81.3	2.8
Nuclear Power	99.6	101.3	101.4	104.4	102.4	.1
Pumped Storage Hydroelectric	17.4	19.8	19.9	19.9	19.9	.7
Renewable Sources/Other [3]	77.7	80.6	83.3	84.9	86.1	.5
Total	688.6	699.9	715.6	737.2	763.0	.5
Cumulative Planned Additions [4]						
Coal Steam	2.8	5.7	12.4	17.6	19.1	10.0
Other Fossil Steam	.0	.0	.7	.8	.8	-
Combined Cycle	.1	4.2	8.3	9.6	9.8	24.0
Combustion Turbine/Diesel	.7	7.8	18.3	19.7	19.8	18.3
Nuclear Power	2.3	4.6	5.8	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	2.4	2.5	2.5	2.5	-
Renewable Sources/Other [3]	.3	2.6	4.3	4.9	4.9	14.4
Total	6.3	27.4	52.3	63.5	65.2	12.4
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	11.7	33.3	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.0	2.7	6.6	-
Combustion Turbine/Diesel	.0	1.6	5.2	11.9	17.6	-
Nuclear Power	.0	.0	.0	.6	.6	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.0	.7	1.7	2.7	3.9	-
Total	.0	2.2	7.4	29.7	62.1	-
Cumulative Total Additions	6.3	29.6	59.8	93.1	127.3	16.2
Cumulative Retirements	1.4	13.4	27.9	39.6	48.0	19.2
Nonutilities [5]						
Capability						
Coal	7.1	10.8	12.3	23.8	39.0	8.9
Petroleum	.8	3.2	3.8	4.0	4.1	8.4
Natural Gas	19.3	29.2	34.3	35.5	36.1	3.2
Renewable Sources/Other [3]	15.8	23.9	28.2	32.2	37.8	4.5
Total	43.0	67.1	78.6	95.5	117.0	5.1
Cumulative Planned Additions [4]						
Coal	.0	3.5	3.6	3.6	3.6	-
Petroleum	.0	2.2	2.3	2.3	2.3	-
Natural Gas	.0	9.2	9.9	9.9	9.9	-
Renewable Sources/Other [3]	.0	4.6	5.0	5.0	5.0	-
Total	.0	19.4	20.8	20.8	20.8	-
Cumulative Unplanned Additions [4]						
Coal	.0	.2	1.6	13.0	28.3	-
Petroleum	.0	.2	.7	.9	1.0	-
Natural Gas	.0	.7	5.1	6.3	7.0	-
Renewable Sources/Other [3]	.0	3.6	7.4	11.4	17.0	-
Total	.0	4.7	14.8	31.7	53.3	-
Cumulative Additions	.0	24.1	35.6	52.5	74.0	-

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes oil-, gas-, and dual-fired capability.

[3] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power, plus a small quantity of petroleum coke. For nonutilities, also includes waste heat, blast furnace gas, and coke oven gas.

[4] Cumulative additions after December 31, 1989.

[5] Includes cogenerators, small power producers, independent power producers, and all other sources, except electric utilities, which produce electricity for self-use or for sales to the grid.

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

Sources: 1990 utility capability and announced additions: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and announced additions: Energy Information Administration, Form EIA-867, *Annual Nonutility Power Producer Report*. All projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G6. Renewable Energy
(Quadrillion Btu per Year, Unless Otherwise Noted)

Electricity and Non-Electric	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Electricity						
Capability (gigawatts)						
Conventional Hydropower	75.07	76.57	76.87	76.87	76.87	0.1
Geothermal	2.58	3.67	5.18	6.85	8.51	6.2
Municipal Solid Waste	2.01	5.17	6.69	8.18	11.40	9.1
Biomass/Other Waste	6.01	7.43	7.65	7.83	8.06	1.5
Solar Thermal	.35	.50	1.32	1.63	1.93	8.9
Solar Photovoltaic	.00	.00	.01	.01	.01	2.2
Wind	1.41	2.37	3.56	4.95	6.33	7.8
Total	87.43	95.71	101.27	106.30	113.11	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	287.94	309.35	308.19	307.11	306.46	.3
Geothermal	15.46	20.82	34.63	49.02	62.05	7.2
Municipal Solid Waste	10.45	18.28	24.33	33.03	53.67	8.5
Biomass/Other Waste	31.48	46.79	52.84	55.93	58.70	3.2
Solar Thermal	.66	.90	2.19	2.98	3.79	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	4.5
Wind	2.25	4.44	9.08	12.75	16.20	10.4
Total	348.23	400.60	431.27	460.82	500.87	1.8
Consumption/Displacement						
Conventional Hydropower	2.99	3.22	3.20	3.19	3.19	.3
Geothermal	.16	.22	.36	.51	.64	7.2
Municipal Solid Waste	.11	.19	.25	.34	.56	8.6
Biomass/Other Waste	.32	.48	.54	.58	.61	3.2
Solar Thermal	.01	.01	.02	.03	.04	9.2
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.02	.05	.09	.13	.17	10.4
Total	3.62	4.16	4.48	4.79	5.20	1.8
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.33	.37	.41	-
Biofuels	2.58	2.79	3.01	3.24	3.54	1.6
Solar Thermal	.05	.08	.33	.34	.43	10.9
Transportation						
Ethanol	.06	.10	.12	.18	.24	6.8
Total	2.70	2.99	3.78	4.13	4.62	2.7
Total Renewable Energy	6.32	7.15	8.26	8.92	9.82	2.2

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

Sources: 1990: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G7. Macroeconomic Indicators
(Billion 1987 Dollars, Unless Otherwise Noted)

Indicator	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GDP Implicit Price Deflator (index, 1987=1.000)	1.129	1.320	1.586	1.957	2.435	3.9
Real Gross Domestic Product	4,885	5,391	6,047	6,687	7,275	2.0
Real Disposable Personal Income	3,538	3,895	4,279	4,667	5,036	1.8
Index of Manufacturing Gross Output (index, 1987=1.000)	1.030	1.139	1.351	1.543	1.689	2.5
AA Utility Bond Rate (percent)	9.66	9.22	8.91	8.90	8.85	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.30	5.80	5.69	5.66	-
Energy Intensity (thousand Btu per 1987 $ of GDP)	17.33	16.94	16.06	15.29	14.60	-.9

Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990: Data Resources Incorporated (DRI), USCEN Databank. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G8. Petroleum Supply and Disposition Balance (Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
World Oil Price (1991 dollars per barrel) [1]	22.54	19.90	22.90	26.10	29.30	1.3
Production						
Crude Oil [2]	7.35	6.38	5.26	4.90	4.62	-2.3
Alaska	1.77	1.21	.81	.54	.40	-7.2
Lower 48	5.58	5.17	4.45	4.36	4.22	-1.4
Natural Gas Plant Liquids	1.56	1.57	1.65	1.62	1.56	.0
Other Domestic [3]	.08	.22	.31	.38	.45	9.1
Processing Gain [4]	.68	.67	.74	.74	.74	.4
Total	9.68	8.84	7.96	7.65	7.37	-1.4
Imports (including SPR) [5]						
Crude Oil	5.89	6.89	8.76	9.11	9.38	2.4
Refined Products[6]	2.13	3.09	3.21	4.35	4.98	4.4
Total	8.02	9.98	11.97	13.46	14.37	3.0
Exports						
Crude Oil	.11	.09	.06	.05	.05	-4.1
Refined Products	.75	.69	.74	.79	.80	.3
Total	.85	.78	.81	.84	.85	.0
Net Imports (including SPR)	7.17	9.20	11.17	12.61	13.52	3.2
Primary Stock Changes						
Net Withdrawals [7]	-.11	-.05	-.02	-.03	-.01	-11.9
SPR Fill Rate Additions (-) [5]	-.02	-.02	-.02	-.02	-.02	2.3
Total Primary Supply [8]	16.72	17.96	19.08	20.21	20.86	1.1
Unaccounted for Crude	.26	.19	.19	.19	.19	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.61	7.99	8.32	8.51	.8
Jet Fuel [10]	1.52	1.68	1.87	2.09	2.22	1.9
Distillate Fuel	3.02	3.29	3.45	3.63	3.77	1.1
Residual Fuel	1.23	1.26	1.42	1.60	1.63	1.4
Other [11]	3.98	4.31	4.54	4.77	4.93	1.1
Total	16.99	18.15	19.27	20.40	21.05	1.1
Refined Petroleum Products Supplied						
Residential and Commercial	1.15	1.28	1.08	.95	.85	-1.5
Industrial [12]	4.34	4.70	5.05	5.34	5.55	1.2
Transportation	10.97	11.67	12.49	13.32	13.87	1.2
Electric Utilities	.54	.50	.64	.79	.77	1.8
Total	16.99	18.15	19.27	20.40	21.05	1.1
Net Disposition	16.98	18.15	19.27	20.40	21.05	1.1

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols blended at refineries and downstream.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] SPR is the Strategic Petroleum Reserve.
[6] Includes imports of unfinished oils and natural gas liquids.
[7] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[8] Total production plus net imports plus net stock withdrawals minus SPR additions.
[9] Includes ethanol and ethers blended into gasoline.
[10] Includes naphtha and kerosene type.
[11] Includes aviation gasoline, kerosene, liquefied petroleum gas, petrochemical feedstocks, miscellaneous petroleum products, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, natural gas liquids, liquefied refinery gas, and other liquids.
[12] Includes consumption by cogenerators.

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

Sources: 1990: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991) and *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1993 Forecasting System. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production						
Dry Gas Production [1]	17.81	18.45	19.39	19.05	18.31	0.1
Supplemental Gas [2]	.10	.10	.10	.12	.15	1.7
Net Imports	1.45	2.49	3.03	3.75	4.41	5.7
Net Storage Withdrawals [3]	-.51	.00	.00	.00	.00	-
Total Supply	18.85	21.05	22.52	22.92	22.86	1.0
Consumption by Sector						
Residential	4.38	4.92	4.65	4.54	4.37	.0
Commercial	2.67	2.99	3.05	3.10	3.10	.7
Industrial [4]	6.98	8.09	8.45	8.44	8.44	.9
Electric Utilities [5]	2.79	3.12	4.35	4.76	4.69	2.6
Lease and Plant Fuel [6]	1.24	1.18	1.24	1.23	1.23	.0
Pipeline Fuel	.66	.64	.68	.70	.79	.9
Transportation [7]	.00	.00	.02	.07	.15	60.4
Total	18.73	20.94	22.44	22.84	22.76	1.0
Unaccounted for [8]	.12	.11	.09	.08	.10	-
Average Wellhead Price (1991 dollars per thousand cubic feet)	1.77	2.06	2.81	3.68	4.44	4.7
Delivered Prices (1991 dollars per thousand cubic feet)						
Residential	6.00	6.41	7.19	8.07	8.85	2.0
Commercial	4.99	5.44	6.22	7.11	7.91	2.3
Industrial	3.04	3.43	4.22	5.11	5.89	3.4
Electric Utilities	2.46	2.70	3.52	4.44	5.28	3.9
Transportation[7]	4.64	7.36	8.21	9.11	9.91	3.9
Average [9]	4.03	4.39	5.05	5.91	6.71	2.6

[1] Dry marketed production minus nonhydrocarbon gases removed.
[2] Includes synthetic natural gas (from the manufacture, conversion, or reforming of petroleum hydrocarbons) and propane/air mixtures.
[3] Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Represents natural gas used in the field gathering and processing plant machinery.
[7] Compressed natural gas used as vehicle fuel.
[8] 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.
[9] Weighted average price. Weights used are the sectoral consumption values excluding lease, plant and pipeline fuel.

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

Sources: 1990: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202(92/3Q) (Washington, DC, August 1992). Commercial, industrial, and transportation delivered prices for 1990 and projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G10. Coal Supply, Disposition, and Prices (Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Production [1]						
East of the Mississippi	630	646	657	706	795	1.2
West of the Mississippi	399	415	471	546	612	2.2
Total	1,029	1,061	1,127	1,252	1,407	1.6
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	121	144	180	235	4.1
Total	-103	-116	-138	-170	-224	4.0
Net Stock Withdrawals [2]	-27	-2	-2	-5	-4	-9.3
Total Supply [3]	899	943	988	1,076	1,180	1.4
Consumption by Sector						
Residential and Commercial	7	6	6	5	5	-1.7
Industrial [4]	76	87	86	87	94	1.0
Coking Plants	39	40	37	34	31	-1.1
Electricity [5]	774	811	861	951	1,051	1.5
Total	895	943	989	1,077	1,181	1.4
Discrepancy [6]	4	-1	-1	-1	-1	-
Average Minemouth Price [7] **(1991 dollars per short ton)**	22.52	23.95	26.74	28.32	31.25	1.7
Delivered Prices (1991 dollars per short ton)						
Residential and Commercial	51.63	48.10	52.01	55.31	60.17	.8
Industrial	34.77	33.07	35.87	38.34	41.55	.9
Coking Plants	49.40	50.77	55.79	60.72	66.83	1.5
Electricity	31.52	31.06	33.11	35.48	38.16	1.0
Average [8]	32.72	32.19	34.30	36.60	39.28	.9

[1] Includes anthracite, bituminous coal, and lignite.
[2] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. Computed as the end-of-year stock levels in the current period subtracted from the end-of-year stock levels in the preceding period. A negative (-) represents an increase to inventories.
[3] Production plus net imports plus net storage withdrawals.
[4] Includes consumption by cogenerators.
[5] Includes consumption by independent power producers.
[6] Balancing item: the sum of production, net imports, and net stock withdrawals minus total consumption.
[7] Free-on-board price.
[8] Weighted average prices. Weights used are consumption values by sector.

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

Sources: 1990: Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(91/4Q) (Washington, DC, May 1992); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Housing (millions)	93.4	97.4	102.0	105.9	109.1	0.8
Energy Consumption per Household (million Btu)	105.2	112.7	108.8	106.0	104.9	.0
End-Use Consumption						
Distillate						
Space Heating	.72	.82	.64	.54	.47	-2.2
Other Uses [1]	.11	.09	.05	.03	.02	-8.7
Total	.84	.91	.70	.57	.48	-2.7
Natural Gas						
Space Heating	3.15	3.50	3.24	3.13	3.00	-.2
Water Heating	1.06	1.27	1.27	1.28	1.25	.8
Other Uses [1]	.31	.30	.28	.26	.26	-.8
Total	4.52	5.08	4.79	4.68	4.51	.0
Other Fuels [2]	.49	.57	.49	.43	.40	-1.1
Renewables [3]	.83	.93	1.55	1.75	2.03	4.6
Electricity						
Space Heating	.32	.33	.30	.30	.31	-.3
Cooling	.51	.55	.50	.53	.55	.4
Water Heating	.39	.50	.56	.65	.73	3.1
Other Uses [1]	1.93	2.10	2.21	2.32	2.43	1.2
Total	3.15	3.48	3.57	3.80	4.02	1.2
Total Consumption	9.83	10.97	11.10	11.23	11.44	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate fuel), refrigeration and lighting (electricity), and other household appliances.
[2] Includes liquefied petroleum gas, kerosene and coal.
[3] Includes solar, geothermal, and wood energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G12. Commercial Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Total Employment (millions)	109.8	117.5	124.8	130.1	134.5	1.0
Total Floorspace (billion square feet)	62.9	69.0	75.6	82.4	89.5	1.8
Energy Consumption per Square Foot (thousand Btu)	107.0	107.6	102.9	97.4	91.8	-.8
End-Use Consumption						
Distillate						
Space Heating	.45	.53	.50	.46	.43	-.3
Other Uses [1]	.04	.04	.03	.03	.02	-3.3
Total	.49	.57	.53	.49	.45	-.5
Natural Gas						
Space Heating	1.80	1.99	1.99	1.97	1.89	.2
Cooling	.21	.23	.23	.25	.26	1.1
Other Uses [1]	.75	.86	.92	.99	1.04	1.7
Total	2.76	3.08	3.15	3.20	3.19	.7
Other Fuels [2]	.52	.49	.45	.41	.37	-1.7
Renewables [3]	.10	.15	.25	.30	.37	7.1
Electricity						
Space Heating	.52	.59	.65	.73	.82	2.3
Cooling	.73	.81	.89	.96	1.00	1.6
Lighting	1.14	1.20	1.27	1.29	1.26	.5
Other Uses [1]	.48	.52	.59	.66	.74	2.2
Total	2.86	3.12	3.40	3.64	3.83	1.5
Total Consumption	6.72	7.42	7.78	8.03	8.22	1.0

[1] Includes water heating, cooking, and other miscellaneous commercial uses.
[2] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[3] Includes solar, geothermal, wood and municipal solid waste energy.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2403	2657	3152	3600	3940	2.5
Non-manufacturing	871	925	1021	1101	1181	1.5
Total	3274	3583	4173	4701	5121	2.3
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.36	.36	.33	.30	.29	-1.2
Liquefied Petroleum Gas	.49	.56	.54	.52	.51	.2
Petrochemical Feedstocks	.34	.32	.32	.32	.32	-.3
Residual Fuel	.13	.14	.13	.12	.11	-.9
Other Petroleum [1]	1.17	1.01	.89	.79	.73	-2.3
Natural Gas [2]	2.59	2.67	2.39	2.12	1.95	-1.4
Metallurgical Coal and Coke [3]	.32	.29	.25	.22	.19	-2.5
Steam Coal [4]	.52	.52	.44	.40	.39	-1.5
Renewables [5]	.06	.06	.06	.05	.05	-1.2
Electricity	.99	.96	.95	.94	.94	-.2
Total	7.59	7.53	6.86	6.29	5.95	-1.2
Consumption (quadrillion Btu per year)						
Distillate	1.18	1.27	1.37	1.41	1.46	1.1
Liquefied Petroleum Gas	1.61	2.01	2.25	2.46	2.61	2.5
Motor Gasoline [6]	.18	.22	.24	.26	.28	2.1
Petrochemical Feedstocks	1.10	1.16	1.33	1.49	1.62	1.9
Residual Fuel	.41	.51	.53	.54	.54	1.3
Other Petroleum [1]	3.83	3.63	3.71	3.72	3.72	-.1
Natural Gas [2]	8.47	9.55	9.98	9.97	9.97	.8
Metallurgical Coal and Coke [3]	1.04	1.05	1.04	1.02	.98	-.3
Steam Coal [4]	1.71	1.85	1.84	1.86	1.98	.7
Renewables [5]	2.07	2.30	2.36	2.42	2.52	1.0
Electricity	3.23	3.43	3.97	4.42	4.80	2.0
Total	24.84	26.99	28.64	29.57	30.49	1.0

[1] Includes petroleum coke, asphalt, road oil, lubricants, and miscellaneous petroleum products.
[2] Includes lease and plant fuel.
[3] Includes net imports of coal coke.
[4] Includes consumption by cogenerators.
[5] Does not include renewables consumed for nonutility electricity generation in the industrial sector for sales to the grid.
[6] Includes ethanol blended into gasoline.

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.10	1.20	1.31	1.41	1.7
Freight Trucks	1.00	1.08	1.22	1.34	1.45	1.8
Air	.99	1.25	1.57	1.92	2.25	4.2
Rail	.99	1.03	1.11	1.20	1.28	1.3
Marine	.99	1.04	1.13	1.20	1.26	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.00	28.77	30.32	32.51	34.60	1.1
New Light Truck MPG [1]	20.70	21.64	22.73	24.07	25.37	1.0
Light Duty Fleet MPG [2]	18.58	19.28	19.88	20.56	21.31	.7
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.01	1.05	1.09	1.11	1.12	.5
Rail Efficiency Index [5]	1.00	1.01	1.04	1.06	1.07	.3
Domestic Shipping Efficiency Index	1.00	1.01	1.01	1.02	1.02	.1
Energy Use by Mode (quadrillion Btu)						
Light Duty Vehicles	11.51	12.25	12.96	13.58	14.04	1.0
Freight Trucks	5.06	5.30	5.73	6.17	6.55	1.3
Air	3.20	3.52	3.93	4.39	4.67	1.9
Rail	.49	.50	.52	.56	.59	.9
Marine	1.39	1.49	1.68	1.87	2.01	1.9
Pipeline Fuel	.68	.66	.71	.72	.81	.9
Other	.17	.18	.19	.20	.22	1.1
Total	22.50	23.90	25.72	27.50	28.90	1.3

[1] Unadjusted Corporate Average Fuel Economy estimates.
[2] Average *on-the-road* efficiency estimate including cars and light trucks.
[3] Based on estimates of passenger seat miles per gallon (1989= 1.0).
[4] Based on Btu per vehicle miles traveled (1989= 1.0).
[5] Based on Btu per ton-miles traveled (1989 = 1.0).

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

Sources: 1990 estimates: Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214(90) (Washington, DC, May 1992). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

Table G15. Carbon Emissions by End-Use Sector and Source (Million Metric Tons per Year)

Sector and Source	Low Oil and Gas Recovery					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential						
Petroleum	24.3	27.2	21.4	17.9	15.5	-2.2
Natural Gas	65.7	73.8	69.7	68.0	65.6	.0
Coal	1.6	1.5	1.5	1.5	1.5	-.1
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	91.5	102.6	92.6	87.4	82.6	-.5
Commercial						
Petroleum	18.5	19.7	18.2	16.7	15.3	-.9
Natural Gas	40.1	44.8	45.8	46.5	46.4	.7
Coal	2.4	2.1	1.8	1.6	1.4	-2.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	60.9	66.6	65.8	64.8	63.1	.2
Industrial [2]						
Petroleum	87.4	89.3	93.0	94.4	95.6	.5
Natural Gas [3]	115.0	130.0	136.2	136.1	136.1	.8
Metallurgical Coal	26.5	26.9	24.9	22.9	21.2	-1.1
Steam Coal	43.6	47.1	47.0	47.4	50.5	.7
Renewable Energy [1]	.0	.0	.0	.0	.0	-
Total	272.5	293.3	301.0	300.9	303.3	.5
Transportation						
Petroleum	425.1	452.8	487.0	518.9	541.0	1.2
Natural Gas[4]	9.9	9.6	10.5	11.6	14.1	1.8
Coal	.0	.0	.0	.0	.0	-
Alcohol Fuels	.0	.0	.0	.0	.0	-
Total	435.0	462.5	497.5	530.4	555.1	1.2
Electric Utilities [5]						
Petroleum	26.4	24.6	31.6	38.3	37.8	1.8
Natural Gas	41.9	46.8	65.3	71.4	70.3	2.6
Steam Coal	412.3	423.3	442.8	485.6	531.1	1.3
Renewable Energy/Other [6]	.0	.0	.0	.0	.0	-
Total	480.6	494.6	539.6	595.3	639.2	1.4
Primary Energy Consumption						
Petroleum	581.6	613.7	651.1	686.2	705.3	1.0
Natural Gas	272.6	305.0	327.4	333.6	332.4	1.0
Metallurgical Coal	26.5	26.9	24.9	22.9	21.2	-1.1
Steam Coal	459.8	474.0	493.1	536.1	584.5	1.2
Renewable Energy/Other [7]	.0	.0	.0	.0	.0	-
Alcohols	.0	.0	.0	.0	.0	-
Total	1340.5	1419.6	1496.5	1578.8	1643.3	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 active and passive solar systems, groundwater heat pumps, and wood.

[2] Includes consumption by cogenerators.

[3] Includes lease and plant fuel.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes consumption of energy by electric utilities, independent power producers, and small power producers that sell power to the grid.

[6] Includes electricity generated to serve the grid 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.

[7] Includes electricity generated to serve the grid and for self use from renewable sources, non-electric energy from renewable sources, excluding alcohol fuels, electricity generated from waste heat, and net electricity imports.

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

Sources: Projections: Energy Information Administration, AEO 1993 Forecasting System run LGEO93.D0918923.

AEO93 Forecasting System

The Energy Information Administration (EIA) projections presented in the *Annual Energy Outlook 1993* (*AEO93*) were prepared using a collection of individual computer models that forecast annual production, supply, distribution, and consumption of energy for the United States. These models produce an integrated energy market forecast through the use of the Intermediate Future Forecasting System (IFFS). As a system, IFFS accounts for many interactions of the different segments of the energy industries and provides an internally consistent forecast of prices and quantities for which supply equals demand. This equilibrium solution accounts for the principal economic factors affecting energy supply and demand (including interfuel competition) and accounts for policies and regulations that cause departures from purely economic behavior.

In general, each of the supply models in the *AEO93* Forecasting System determines the supply and delivered prices for each fuel, given the consumption levels projected by the demand models. The demand models compute consumption of each fuel, given the end-use prices of all competing fuels. The integrating methodology solves for the market equilibrium by balancing supply and demand for each fuel in every forecast year. Projections are generated through the year 2010.

Paths for the price of crude oil on the world market and baseline macroeconomic forecasts are key exogenous assumptions to the *AEO93* Forecasting System. The world oil price is derived from the Oil Market Simulation Model (OMS), which represents world oil demand and supply. Because OMS assumes that the Organization of Petroleum Exporting Countries (OPEC) remains the marginal supplier of crude oil, it computes the world oil price based on assumptions of OPEC productive capacity and non-OPEC production profiles.

Baseline macroeconomic projections are obtained by using the Data Resources, Inc. (DRI) Quarterly Model of the U.S. Economy, but introducing EIA forecasts of oil price. The basic DRI model also assumes a smoothly increasing path for world oil prices, but it is slightly different from the EIA path. The DRI model supplies the output of 11 major industrial sectors and 39 macroeconomic variables, including the real gross domestic product (GDP), the GDP price deflator, real disposable income, and the interest rate on utility bonds; these values are all functions of delivered energy prices. Then, a macroeconomic module in the *AEO93* Forecasting System revises those values, relative to the energy prices computed by the EIA modeling system—thus simulating the response of the DRI model to the EIA energy prices.

The Oil Market Module (OMM) represents the domestic refining and pricing of petroleum products and also computes the import requirements for both crude oil and petroleum products. A set of econometric equations determines refinery gate prices for the major categories of petroleum products, based on the assumed world oil price and the product demand. Delivered prices to the end-use sectors are computed by adding markups based on historical data for distribution costs, State and Federal taxes, and the costs of environmental regulations, such as the Resource Conservation and Recovery Act of 1984, the Clean Air Act, and the Clean Air Act Amendments of 1990.

The Coal Supply Transportation Model (CSTM) of IFFS determines the sources, distribution patterns, and minemouth and delivered prices of coal, representing a transportation network of 32 supply regions and 44 domestic demand regions. Projections of U.S. coal exports were developed with the International Coal Trade Model, which projects world coal flows from 20 export regions to 9 import regions. The coal supply curves for each of the 32 domestic supply regions were developed with the Resource Allocation and Mine Costing Model—based on mine costs by coal type and mining method, and on geologic and operating parameters of future mines.

The Gas Analysis Modeling System (GAMS) represents the domestic supply of natural gas, including imported and synthetic gas, and computes the average wellhead price as the market-clearing price in the United States. Delivered prices of natural gas are derived by adding regional and sectoral markups to the wellhead price. For the electric utility sector, prices for both firm and interruptible customers are developed based on plant type. As a component of GAMS, the Production of Onshore Lower 48 Oil and Gas Model (PROLOG)

calculates the domestic production of crude oil and natural gas, differentiating exploratory and developmental drilling activities. Imports of both Canadian and liquefied natural gas are explicitly represented, allowing for some expansion of current pipeline and terminal facilities.

The Electricity Market Module (EMM) represents the supply and price of electricity and computes the fuel requirements to generate electric power. A planning component determines the capacity expansion profiles of utilities, using a life-cycle cost methodology and assumptions of future fuel prices and electricity demand. A dispatch component allocates generation capacity to meet current demand by ranking the fuel and operating costs, subject to the constraints of the Clean Air Act Amendments. The financial component computes the price of electricity, accounting for all costs of construction and operation. Production of electricity by cogenerators and by independent and small power producers is forecast by the nonutility component, which competes with utility-generated electricity at the avoided cost of the utility sector.

Four end-use models calculate the consumption of each fuel in the residential, commercial, industrial, and transportation sectors as functions of price and macroeconomic variables. The residential and commercial sector models provide explicit representations of the different technologies used to provide the various end-use services that consume energy in buildings, such as space heating and cooling, water heating, and lighting. The transportation sector model consists of four distinct segments: personal highway travel, freight travel, aviation travel, and "other" transportation. Fuel efficiencies, vehicle-miles traveled, and other variables associated with energy consumption for each transportation mode are incorporated in the model. The residential, commercial, and transportation models all make it possible to evaluate changes in capital equipment that are designed to conserve energy use. The industrial model is econometrically based; it computes fuel consumption by the manufacturing and nonmanufacturing sectors for heat and power, consumption of feedstocks as raw materials to the industrial sector, and other fuel consumption. In the manufacturing sector, the major energy-consuming industries are represented explicitly.

All models in the *AEO93* Forecasting System use the most recently available data from EIA's supply and consumption surveys. A companion EIA report, *Assumptions for the Annual Energy Outlook 1993*, provides further information on the assumptions that underlie the *AEO93* forecasts, the models used to produce the forecasts, and changes made to these models specifically for *AEO93*. That volume also provides references to the model documentation reports, which are available from the National Energy Information Center.

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Carbon Emissions	T. Crawford Honeycutt	202/586-1420

Appendix I. Conversion Factors

Fuel	Units	Approximate Heat Content
Coal		
Production	million Btu/short ton	21.827
Consumption	million Btu/short ton	21.331
Coke Plants	million Btu/short ton	26.799
Industrial	million Btu/short ton	22.457
Residential and Commercial	million Btu/short ton	23.137
Electric Utilities	million Btu/short ton	20.929
Imports	million Btu/short ton	25.000
Exports	million Btu/short ton	26.202
Coal Coke	million Btu/short ton	24.800
Crude Oil		
Production	million Btu/barrel	5.800
Imports	million Btu/barrel	5.934
Petroleum Products		
Consumption	million Btu/barrel	5.411
Motor Gasoline	million Btu/barrel	5.253
Jet Fuel	million Btu/barrel	5.632
Distillate Fuel Oil	million Btu/barrel	5.825
Residual Fuel Oil	million Btu/barrel	6.287
Liquefied Petroleum Gas	million Btu/barrel	3.625
Unfinished Oils	million Btu/barrel	5.825
Imports	million Btu/barrel	5.540
Exports	million Btu/barrel	5.780
Natural Gas Plant Liquids		
Production	million Btu/barrel	3.804
Natural Gas		
Production, Dry	Btu/cubic foot	1,031
Consumption	Btu/cubic foot	1,031
Non-electric Utilities	Btu/cubic foot	1,031
Electric Utilities	Btu/cubic foot	1,031
Imports	Btu/cubic foot	1,031
Exports	Btu/cubic foot	1,031
Electricity Consumption	Btu/kilowatthour	3,412
Electricity Component		
Plant Generation Efficiency (Heat Rate)		
Fossil Fuel Steam	Btu/kilowatthour	10,335
Nuclear Energy	Btu/kilowatthour	10,680
Geothermal	Btu/kilowatthour	21,096

Sources: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/07) (Washington, DC, July 1992). Natural gas conversion factors used in the AEO93 Modeling Sytem are equal to 1,031 Btu per cubic foot.

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