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ANNUAL ENERGY OUTLOOK

WITH PROJECTIONS TO 2010

Energy Information Administration

For Further Information . . .

The *Annual Energy Outlook* is prepared by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. General questions concerning energy demand or energy markets may be addressed to Mark E. Rodekohr (202/586-1130), Director of the Energy Demand and Integration Division. General questions regarding energy supply and conversion activities may be addressed to Mary J. Hutzler (202/586-2222), Director of the Energy Supply and Conversion Division.

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A brief description of the *Annual Energy Outlook 1992* Forecasting System and a list of key contacts for each subject area are contained in Appendix G of this report.

This year's *Outlook* has been expanded to include 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 1992*, the companion document to this report that will be available in February 1992. Quantitative assumptions underlying the *AEO* forecasts will be provided in *Assumptions for the Annual Energy Outlook 1992*, to be published during January 1992. Questions regarding these reports may be addressed to the following EIA analysts:

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Annual Energy Outlook 1992

With Projections to 2010

January 1992

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Administrator's Message

The Gulf war ended dramatically and quickly. Kuwait was liberated. Prices for crude oil and petroleum products fell to their pre-war levels or below. It appears that the Gulf war has had no major negative impacts on future world energy supplies. In real terms, energy prices have fallen significantly over the past decade; and Americans are continuing to drive, stay warm, and be cooled at costs which are not only among the lowest in the world, but low by historical standards in the United States as well.

A quick review of this recitation may create the feeling, from the consumers' perspective, that the energy problems in this country have been solved and there are other items on the Nation's agenda which are more pressing and severe. Clearly from the producers' point of view, the relatively low energy prices present formidable problems, at least in the short run. This Administrator's message does not question the relative priority of energy issues to this Nation, but it does challenge the belief held by a majority of Americans (if the polls are correct) that energy is not a major issue. The projections and analysis contained in the *Annual Energy Outlook 1992* (*AEO92*) should make the reader ponder the Nation's energy future by providing that reader with an understanding of what the future may hold if American energy policy remains essentially unchanged.

The United States is the world's largest energy consumer and the second largest energy producer. If the current unraveling of the economy in the former Soviet Union (including the energy sector) continues, then the United States may also become the leading producer nation as output and exports of fuel from the new Republics decline.

A quick review of the past 20 years and the scenarios in *AEO92* reveals two major trends. The first is that energy use in the United States has grown and an increasing percentage of that energy consumption is supplied by imports. For example, of the 17 million barrels per day of petroleum consumed in the United States in 1990, some 42 percent was imported. Depending on which of the five scenarios arrayed in *AEO92* is used, that figure will rise to between 53 and 69 percent by the end of the forecast period, 2010.

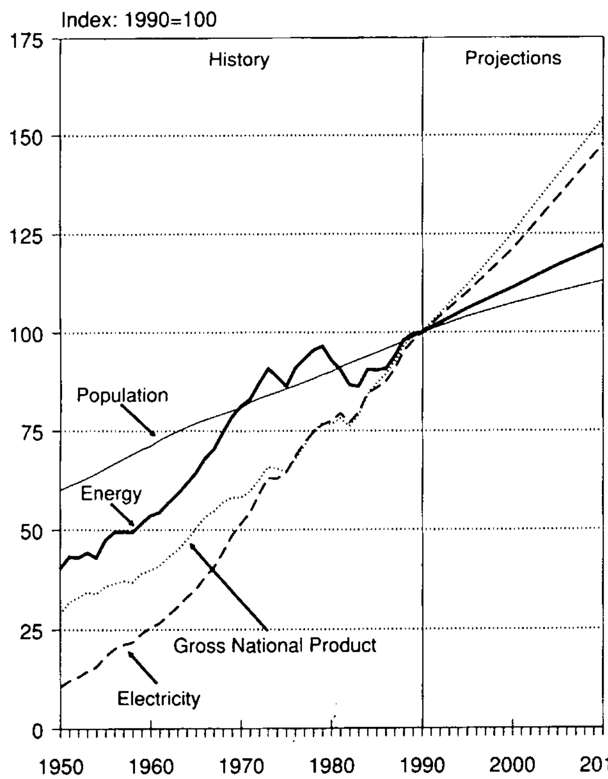
These projections raise concerns for the United States, the first being energy security. Our growing dependence on imported oil will focus on the Middle East, where the overwhelming majority of proven reserves are to be found. Many other producing nations will exhaust their potential for expansion and begin the decline that the United States is now experiencing in domestic production. Increasingly, oil-consuming nations will come to rely upon countries of the Mideast—principally Saudi Arabia, which has become the dominant producer in the Organization of Petroleum Exporting Countries (OPEC). That position is likely to strengthen in the years to come. The question is, to what extent do this Nation and others feel comfortable becoming increasingly dependent on oil from a politically unstable area? As long as this level of dependence continues to grow, diplomatic efforts for reducing tensions in the Middle East become even more critical.

There is a second major trend in the *AEO92* projections, which is much more positive than the first: the increased efficient use of energy in the United States. Over the past 20 years the energy efficiency in the United States has improved by some 25 percent; and as the *AEO92* projections indicate, this improvement will continue. According to the *AEO92* Reference Case, energy intensity, which is defined as thousands of Btu of energy consumed per 1982 dollar of gross national product (GNP), will decline from 20.46 in 1990 to between 15.87 and 17.24 by the year 2010. The most dramatic areas of improvement are likely to be in building shells, industrial motors, and transportation. As the U.S. housing and building stock slowly turns over, tighter and more efficient building shells will replace those constructed when energy efficiency was less of a concern. Industrial motors will be replaced with those having adjustable speeds and high efficiency. In the transportation area, efficiency will occur from the replacement of older, less efficient cars. In addition, the U.S. industrial output mix is projected to continue to shift from heavy, energy-intensive industries to industries which are less energy intensive.

The past few years have seen a dramatic change in the relationship between U.S. economic growth and the use of energy. The following graph shows that between

1950 and 1970 energy use had grown at about the same rate as did GNP. During the past two decades this began to change, and while GNP will grow in the forecast period by some 50 percent energy consumption will rise by only 25 percent. But this increase in energy efficiency will not lead to declining living standards, as population will only grow by some 13 percent. While electricity will continue to be the more favored form of energy use, the growth of electricity will continue the trend established in the 1980's of expanding at a slightly slower rate than the GNP. Recently the Energy Information Administration (EIA) released reports[1] prepared for reference in the development of the President's *National Energy Strategy* which indicate significant efficiencies are still capable of attainment beyond those already achieved and projected in *AEO92*.

Indices of U.S. Energy, Population, and Economic Growth, 1950-2010



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

Source: Energy Information Administration, *Improving Technology: Modeling Energy Futures for the National Energy Strategy* (January 1991).

In the upcoming year a tremendous amount of international attention will be focused on the highly controversial issue of global warming. Global climate change will be discussed at the U.N.-sponsored conference in Brazil, which is scheduled for June 1992. The data on the extent, cause, and impact of this phenomenon are contradictory and confusing, as recent reports from the National Academy of Sciences[2] demonstrate. *AEO92* does indicate a significant growth in U.S. use of coal and fossil fuels during the forecast period. The use of all fossil fuels will grow from 72.3 quadrillion Btu to 88.2 quadrillion Btu. The concomitant effect would be an increase in carbon emissions. In approaching the topic of global warming the need for reliable data on energy use and emissions is paramount. The public's loudest debates are often about those issues on which there is the least reliable information.

Global climate change and other issues present unique challenges to EIA in the years to come. As EIA attempts to better supply policymakers with the data and analysis they will need to address these issues, there are areas where better information and analysis are needed. One example is in the area of cost estimates for new technologies. The contribution of a particular technology to energy supply or conservation depends primarily on its costs. Developers of new technologies are often those with the knowledge and experience needed to estimate future costs of a new technology. But these are often advocates and may claim significant results at low costs—which leads to high projections of potential rates of penetration, often in short periods of time. Currently there exists no completely objective way to evaluate the claims made by either advocates or critics of new technologies as to their effectiveness or their potential. It is difficult for decisionmakers to choose among competing technology options, either in R&D budgeting or for required adoption. EIA will never be fully able to answer all the questions raised by new technologies, because we are not the appropriate agency to be an "honest broker" for claims regarding new technologies; but we hope to contribute to an improved consistency of treatment in the analysis of technological alternatives.

In addition, the current analytical tools are inadequate for ascertaining the full environmental costs and benefits of existing energy consumption and use as well as alternative policies to alter those patterns. It is well

[1]Energy Information Administration, *Improving Technology: Modeling Energy Futures for the National Energy Strategy* (January 1991); and *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy* (December 1990).

[2]National Academy of Sciences, *Policy Implications of Greenhouse Warming—Synthesis Panel* (National Academy Press, Washington, DC, 1991); and *Policy Implications of Greenhouse Warming—Mitigation Panel* (National Academy Press, Washington, DC, 1991).

recognized that the production and use of fuels involve "externalities," costs or benefits which are not included in the fuel price. For example, what is the full cost of electricity generated by nuclear plants including extraction, processing, use in electric generation, and waste disposal of uranium? In addition, proposed changes in energy consumption and use will often have unintended and unanticipated secondary effects which are not always fully included in policy considerations. Good energy policy depends upon assessing not only the initial impact of a proposed change on energy markets, but also the complex interactions with other energy markets, the economy, and the environment. Until those calculations can be made in a rational fashion, decisionmaking will continue to be hobbled.

EIA is responding to these and other challenges in the development of the National Energy Modeling System (NEMS). Due to EIA's reorganization this year, all mid- and long-term forecasting and analysis activities have been placed under the newly-created Office of Integrated Analysis and Forecasting (OIAF). Part of the responsibility of that office will be the development of the NEMS, which will use and update existing models where appropriate, as well as developing new ones, so that we can more adequately respond to the new challenges which energy policy analysis presents. Supplying policymakers with the data and analysis which can objectively portray the consequences of policy alternatives has been and will continue to be the quest of EIA, along with keeping the public, industry, and government fully informed of trends and developments in all areas of energy production and use.

Calvin A. Kent, Ph.D.
Administrator
Energy Information Administration

Highlights

Dramatic events over the past year show how international developments can affect domestic energy markets. Market reactions to events in the Persian Gulf and in what used to be called the Soviet Union reinforced the perception of *global* interdependence in regard to both energy supply and energy demand. The interdependence was reflected most visibly and promptly in world oil prices. With U.S. reliance on foreign oil expected to continue trending upward, any price changes tend to "feed back" throughout this Nation's economy.

Despite short-term fluctuations, the longer-range U.S. energy outlook has remained relatively constant since last year. Assuming that current laws and policies remain in force, this document addresses uncertainties by discussing four alternative scenarios in addition to a "reference" case. Two cases vary the assumption about the rate at which the U.S. national economy will grow, while the other two estimate effects if world oil prices should go lower or higher. Certain basic analytical observations remain largely intact across the five diverse cases:

Total U.S. energy consumption should continue to grow, but at a rate well below the rise in real GNP

Although total energy use has shown little increase for 2 years, the resumption of normal economic growth (2 to 3 percent per annum) and the prospect of relatively low energy prices (compared in constant-dollar terms with the peaks of the 1970's) are projected to raise total energy use in all sectors between now and 2010. However, the *rate* of growth in energy consumption should remain more than a full percentage point below the rate at which economic output rises. This reduction in "energy intensity" results as today's energy-using equipment is replaced with more efficient technologies, as the United States continues to import goods whose manufacture is energy-intensive (such as automobiles), as the U.S. economy shifts more from producing *goods* to providing *services*, and as real prices for oil, natural gas, and coal trend upward. Based on worldwide projections for supply and demand, real world oil prices (which averaged $22 per barrel in 1990) range across the cases between $18 and $32 per barrel (in 1990 dollars) by 2000 . . . and between $23 and $40 per barrel in 2010.

Petroleum imports are still likely to rise substantially by 2010

U.S. demand for petroleum is projected to grow to between 19.3 and 22.4 million barrels per day by 2010, compared with 17.0 million barrels per day in 1990. Such increases, coupled with eroding domestic oil production, presage net imports of at least 10.2 million barrels per day in 2010 in the High Oil Price Case (compared with 7.2 million barrels per day in 1990). The Low Oil Price scenario in *AEO92* shows U.S. dependence on foreign oil more than doubling—to 15.4 million barrels per day. All this despite the fact that domestic oil production in 2010 is now projected to be roughly 1 million barrels per day higher than was projected last year. (Enhanced industry performance in recent years warrants heightened optimism about the contributions of advanced technology to discovery and development.) Domestic crude oil production drops in the new projections from 7.4 million barrels per day in 1990 to between 4.2 and 6.1 million barrels per day in 2010. Much of the increase in imports is likely to be in petroleum *products*, because most of the expansion in the world's refinery system is expected to take place outside the United States.

Oil's market share is seen dropping, with some uses higher

Oil will still be the largest source of U.S. energy in 2010, but its market share should fall. Demand growth is centered in transportation and industry (more diesel and jet fuel, modest increases in gasoline, more petroleum feedstocks for chemicals and plastics). Petroleum use grows overall at an annual rate between 0.6 and 1.4 percent—well below the rates of increase assumed for GNP (1.8 to 2.7 percent). The explanation lies in higher energy efficiency, fuel switching (for example, under new Clean Air Act requirements) and technological advances in transportation.

Domestic natural gas production is expected to peak around 2005, then to fall slightly

U.S. production of natural gas is seen at a peak around 2005—ranging between 18.6 and 20.7 trillion cubic feet that year (versus 17.6 trillion cubic feet in 1990). After 2005, production declines modestly; and this raises gas imports from 1.4 trillion cubic feet in 1990 to about 3.3 trillion cubic feet in 2010. Electric utilities account for the trend in production. Through 2005, increases in gas prices are moderate and most additions to generating capacity are clean-burning gas-fired plants—which have low capital costs and can be built quickly. After 2005, utilities rely more heavily on new coal-fired plants due to continued escalation in gas prices, the need for more *baseload* capacity, and the expected availability of clean coal technologies.

Stable electricity prices should play a role in steady growth

Electricity's share of the energy market keeps on growing. Real electricity prices are expected to rise, on average, less than 1 percent per year—while oil, natural gas, and coal become relatively more expensive. Capital expenditures on new plants are expected to lag behind growth in sales, and the resultant savings should help offset rising fuel costs. A significant share of supply is likely to come from utility purchases of more economical power from nonutility generators rather than through investments in new power plants. By 2010, between 220 and 310 gigawatts of new generating capacity will be needed. Plans to build most of it have yet to be announced, but much capacity added before 2005 is expected to use natural gas. After 2005, coal-fired generators dominate capacity additions, for reasons cited above. Nuclear power seems destined for a smaller *percentage* share of total U.S. generation, even if orders for nuclear plants resume.

Coal exports and use are expected to show robust increases

Coal, the backbone of U.S. electricity production, is the most important U.S. fuel export too. Exports are projected to grow from 106 million short tons in 1990 to between 185 and 289 million short tons in 2010. Coal production in Europe should decline as a result of reduced subsidies, and Asia's use of coal to generate electricity should grow—while most countries find it more difficult than the coal-rich United States to keep increasing production. Sharply higher coal demand is foreseen during the second half of the forecast period, especially to make electricity—despite the fact that real coal prices rise almost as fast (in percentage terms) as oil prices. Domestic consumption of coal is seen rising from 895 million short tons in 1990 to between 1,130 and 1,270 million short tons in 2010.

Renewable energy use is expected to rise sharply by 2010

The use of all forms of renewable energy combined is expected to increase as new technologies are developed, their non-energy benefits are valued accordingly, and the prices of other energy sources increase. The most significant market penetration is expected from geothermal installations, the use of municipal solid waste as fuel, and various biomass applications. Hydropower has long dominated the renewable sources of U.S. electricity; but by 2010 the share of renewable generation from non-hydro sources may rise from about 16 percent in 1990 to almost 39 percent. Research efforts on other renewable energy sources are accelerating, and this could stimulate more widespread use—especially near the end of the projection period.

Framing the 1992 Energy Outlook

The combination of the Persian Gulf crisis and the dramatic attempted coup in Moscow, followed by sweeping political changes in the Soviet Union, refocused attention during 1991 on the pivotal role of Middle East oil reserves in determining the world's future oil prices and supplies. As the Middle East conflict reverberated through world markets, it renewed awareness of the importance of that region's oil supplies. The Soviet Union has been the world's largest petroleum producer since the 1970's; but its production had plummeted over the past 3 years, and the future availability of oil exports from whatever political entities succeed the former U.S.S.R. is uncertain. Production from the Middle East will play an increasing role in replacing this loss in world markets.

At the same time, economic and environmental issues—domestically and internationally—remain in the forefront of most serious discussions about energy. For instance, changes occurring in the awakening market economies of Eastern Europe could significantly modify their patterns of energy use, but the extent to which this happens will depend on such unknowns as the degree to which new national regimes may choose to shut down Soviet-built nuclear plants and the ways they attempt to curb pollution from coal plants. Another big question mark in the outlook for world energy markets concerns some populous developing countries, which hold the potential for very rapid growth in energy consumption.

Because of so many uncertainties associated with economic and political change, environmental issues, and technological developments in the years to come, it would be misleading (and futile) for the Energy Information Administration's *Annual Energy Outlook* to attempt a *single* set of predictions about energy supply, demand, and prices between now and 2010. Nevertheless, many individuals and groups are intensely interested in an objective analysis of general prospects and the reasons for possible variation in them. With all these factors in mind, *AEO92* examines a *range* of scenarios, comparing the effects of four selected variations from a "Reference Case." In this way, *AEO92* hopes to offer some useful insights into an energy future that bridges the end of one century and the beginning of the next.

1991 in Review

An economic recession, mild weather, and the spike in oil prices following Iraq's invasion of Kuwait in 1990 interacted to restrain total U.S. demand for energy during 1991. "Energy intensity" (the amount of energy consumed per unit of gross national product, or GNP) held steady. For the second year in a row, net imports of energy overall declined. Price effects from the Middle East conflict contributed to the first increase in domestic oil production since 1985, which was a factor in the drop in petroleum imports. Meanwhile, U.S. *exports* of petroleum products increased in this unusual year—as jet fuel was diverted to the war effort and the disruption of Middle Eastern sources affected the output of refined products as well as crude oil there. Use of electricity in the United States continued to grow, despite a stagnant economy; and the exports of U.S. coal to the world market remained high.

Even before the aborted Soviet coup in late summer, the output of crude oil in that country had been falling throughout the year; and hopes of reversing the downtrend in the next decade hinge on an influx of Western technology and capital. The collapse of central authority and declarations of independence by key Soviet Republics left a great deal of uncertainty about future production and exports from the newly independent entities—and the effects these events might have on both the world's supplies of crude oil and the nature of competition for those supplies.

Far-reaching legislative changes in this country began to spell out their energy effects for the future too, especially in regard to the Clean Air Act Amendments of 1990 (CAA90). Signed into law on November 15, 1990, the Amendments are aimed at reducing urban smog, airborne toxics, acid rain, and ozone-depleting chemicals. Provisions to cut down vehicle-related pollution by cleaning up motor fuels will shape the supply and demand for oil by emphasizing reformulated gasoline and various alternative fuels or energy sources that involve less petroleum or none at all. In February 1991, the Bush Administration sent Congress the first National Energy Strategy, with goals of fostering stable economic growth, achieving "energy security" against supply shortfalls or economically disruptive price fluctuations, and improving the environment. Even as these proposals were being studied and debated, a variety of other legislation was also introduced. Legislation now before Congress has the potential to increase competition in the electric utility industry, promote the use of nonpetroleum energy resources, encourage energy conservation, bring about greater fuel efficiency in motor vehicles, and open new areas to oil and gas drilling. Exactly how many and which of these proposals will actually become law remains to be seen.

Description of Five Scenarios

Five scenarios (detailed in Appendices A through E) are discussed in this report. Taken as a group, they present what now appears to be a reasonable "envelope" of possible outcomes over the next 20 years. Most cases are based on the current legislative and regulatory status, without incorporating any proposed changes. The exception is the High Economic Growth Case, which assumes that licensing reform legislation for new nuclear reactors is passed. For the most part, the divergence among cases results from projecting responses to different energy prices, economic growth rates, and capital stock turnover (Table 1).

The Reference Case uses *baseline* assumptions about economic growth and a *mid*-level trajectory for future world oil prices. It is discussed in connection with each consumption sector and every energy source, but it is not necessarily the most likely scenario. Its purpose is to facilitate comparisons—both among all five cases in this volume and with forecasts developed by other organizations.

The four complementary scenarios were constructed to examine the individual effects of contrasting assumptions, either about world oil prices or about macroeconomic growth for the United States. There are analytical benefits to keeping world oil prices constant across the three cases of "high," "mid-level," and "low" growth in GNP and *then* considering the effects of energy-price changes separately. In the contrasting world oil price cases, feedback effects on the economy are considered, but they do not alter the diverging long-run economic growth paths substantially. In practice, these two key variables (oil price and general economic growth) *do* interact with each other (as well as with numerous other factors); but the advantage of addressing them separately is that this approach isolates effects to a considerable extent and minimizes the need to prophesy precise combinations. In every instance, changes in the world oil price and GNP are viewed as taking place smoothly, even though history suggests that intermediate ups and downs (which may make substantial differences to the projections) are more likely in reaching a given endpoint. Appendix F examines briefly the effect of volatility in oil prices on economic growth; that effect is significant.

Some *AEO92* figures present only the cases that represent upper and lower boundaries to the composite projections, and case-details are omitted from the text where there are only slight variations from the Reference Case.

Reference Case

The Reference Case combines the assumption of an annual economic growth rate of 2.2 percent and 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 $22 per barrel in 1990, hover in the $18 to $20 range (in constant 1990 dollars) for the next few years, then rise to $33 (in 1990 dollars) by 2010. The macroeconomic assumption about GNP represents a mainstream projection—accepting the demographic premise that slower growth in the U.S. labor force for the next couple of decades will constrain the growth in real output of goods and services. Total demand for energy grows at an annual rate of 1.1 percent per year under these assumptions, increasing by 2010 to 21 quadrillion Btu above the 1990 level. Demand for electricity as a specific form of end-use energy grows at a rate of 2.0 percent per year—closely paralleling GNP. Conservation and efficiency trends, grounded in current legislation and based on reactions to price changes, are fully recognized.

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 (2.7 percent per year). Such a combination produces the highest level of energy demand of any of the five cases. This case also assumes that licensing reform legislation for new reactors is passed, resulting in new nuclear orders and the construction of new nuclear power plants. 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—having risen 1.4 percent per year over the two decades. Electricity sales in this case grow by 2.2 percent per year—a rapid rate of increase, but distinctly below that of overall economic growth.

Table 1. A Range of Projections for 2010—Summary

	1990	2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
Primary Production (quadrillion Btu)						
Petroleum	17.9	14.8	15.1	14.8	16.2	11.9
Natural Gas	18.3	20.1	21.0	20.2	20.2	18.7
Coal	22.2	31.2	33.7	28.3	30.9	31.3
Nuclear Power	6.2	6.9	7.5	6.8	6.8	6.9
Renewable Energy/Other	6.6	10.4	10.9	9.8	10.6	10.1
Total Primary Production	**71.2**	**83.4**	**88.2**	**79.9**	**84.6**	**78.8**
Net Imports (quadrillion Btu)						
Petroleum (including SPR)	15.3	24.6	27.1	22.9	21.7	32.3
Natural Gas	1.5	3.4	3.4	3.4	3.4	3.4
Coal/Other (- indicates export)	-2.5	-4.9	-6.3	-3.6	-4.7	-5.0
Total Net Imports	**14.1**	**23.1**	**24.2**	**22.7**	**20.4**	**30.7**
Net Stock Withdrawals	-1.1	-0.2	-0.3	-0.2	-0.2	-0.2
Discrepancy	0.8	-0.2	-0.3	-0.2	-0.2	-0.3
Consumption (quadrillion Btu)						
Petroleum Products	33.8	39.6	42.3	37.8	38.0	44.2
Natural Gas	19.4	23.4	24.3	23.5	23.4	22.0
Coal	19.1	25.2	26.3	23.6	25.0	25.2
Nuclear Power	6.2	6.9	7.5	6.8	6.8	6.9
Renewable Energy/Other	6.6	11.0	11.6	10.5	11.4	10.7
Total Consumption	**85.0**	**106.1**	**111.9**	**102.1**	**104.6**	**109.0**
Prices (1990 dollars)						
World Oil Price (dollars per barrel)	21.78	33.40	33.40	33.40	40.20	22.60
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.72	4.65	4.80	4.62	4.46	4.00
Domestic Coal at Minemouth (dollars per short ton)	22.18	31.63	32.90	29.98	31.59	31.40
Average Electricity Price (cents per kilowatthour)	6.69	6.99	7.13	6.96	7.02	6.74
Economic Indicators						
Real Gross National Product (billion 1982 dollars)	4,156	6,404	7,050	5,923	6,363	6,481
(annual change, 1990-2010)	--	2.2%	2.7%	1.8%	2.2%	2.2%
GNP Implicit Price Deflator (index, 1982=1.00)	1.315	2.812	2.432	3.402	2.816	2.799
(annual change, 1990-2010)	--	3.9%	3.1%	4.9%	3.9%	3.8%
Real Disposable Personal Income (billion 1982 dollars)	2,894	4,128	4,477	3,903	4,121	4,147
(annual change, 1990-2010)	--	1.8%	2.2%	1.5%	1.8%	1.8%
Index of Manufacturing Gross Output (index, 1982=1.00)	1.218	2.008	2.208	1.887	1.986	2.047
(annual change, 1990-2010)	--	2.5%	3.0%	2.2%	2.5%	2.6%
Energy Intensity (thousand Btu per 1982 dollar of GNP)						
Oil and Gas Use	12.79	9.83	9.44	10.35	9.65	10.21
Electricity End-Use	2.22	2.13	2.04	2.21	2.11	2.13
Total Energy Use	20.46	16.57	15.87	17.24	16.44	16.81

Note: Quantities are derived from historical volumes and assumed heat rates.

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, and E7.

Low Economic Growth Case

This case also assumes the mid-level world oil price path, but combines it with low macroeconomic growth (1.8 percent per year). This combination produces the lowest energy demand of any of the five 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 over the two decades. In this case, growth in electricity sales is still 1.8 percent per year—exactly matching the rise in GNP.

High Oil Price Case

This case combines the baseline economic growth trend (2.2 percent) with a higher world price path for oil (starting at $20 per barrel in 1991 and rising gradually to $40 in 2010). Because the world oil price is higher than that assumed for the Reference Case, feedback effects cause the effective rate of economic growth and the level of GNP in 2010 to be slightly lower than in the Reference Case. Low demand for energy results in a rise of only 20 quadrillion Btu (1.0 percent per year) above 1990's total consumption of primary energy. Electricity sales are also slowed somewhat, with a growth rate of 1.9 percent per year that drops behind that of the Nation's total economic output.

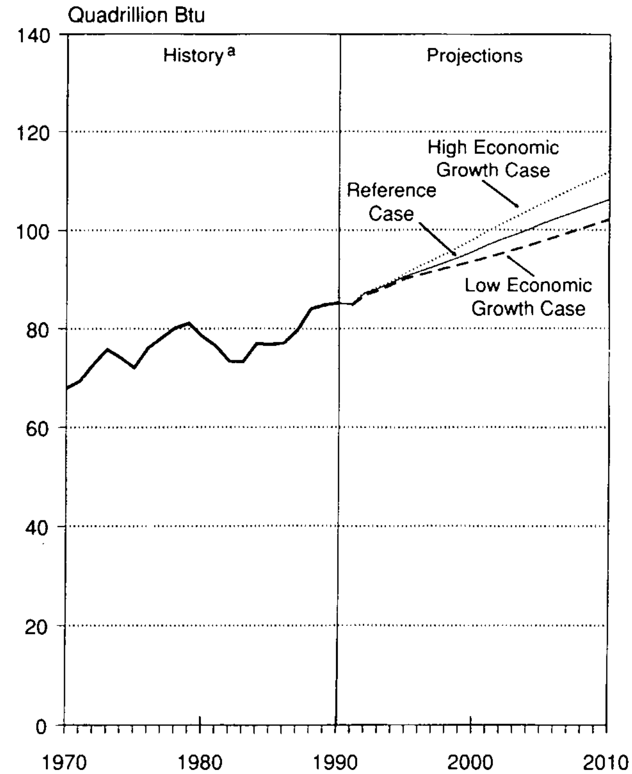
Low Oil Price Case

This case starts with the same baseline economic growth (2.2 percent per year), but combines it with an assumption that world oil prices will go down to about $15 per barrel (in real terms) and then rise only to about $23 per barrel in the same terms by 2010. Such relatively low prices could result from various factors, such as improved oil production capacity around the world, new discoveries, or the breakdown of discipline within the Organization of Petroleum Exporting Countries (OPEC). With oil prices lower than in the Reference Case, feedback effects cause the economic growth path and the level of GNP in 2010 to be somewhat higher than in the Reference Case. Considering the combined effects of lower oil prices and macroeconomic feedback, energy demand could be expected to increase more rapidly—by 24 quadrillion Btu above the 1990 level (1.3 percent per year between now and 2010). Electricity sales in this case still grow at about 2.0 percent per year, in much the same relationship to GNP as in the Reference Case.

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 continues to grow strongly compared with both petroleum and natural gas. As electricity demand rises, the use of coal for electric generation increases too—but at a slightly lower rate, because natural gas and renewable energy sources

Figure 1. Total U.S. Energy Consumption, Projected to 2010 with a Range of Uncertainty



[a]Includes an estimate for each year to account for dispersed consumption of wood and other forms of renewable energy, in addition to the use of renewables actually measured in the utility sector.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1990* (May 1991), *Monthly Energy Review* (July 1991). **Projections:** Tables A1, B1, C1, and D1.

Table 2. Summary of Energy Consumption by Sector and Source, with Projections for 2010
(Quadrillion Btu)

	1990	Alternative Projections for 2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
Consumption by Sector						
Residential	10.2	12.1	12.4	11.7	12.0	12.1
Commercial	6.7	8.8	8.9	8.7	8.8	8.8
Industrial	25.3	29.1	30.8	28.0	28.9	30.2
Transportation	22.1	27.4	29.8	25.8	26.5	29.1
Total End-Use Consumption	**64.2**	**77.4**	**81.9**	**74.2**	**76.2**	**80.2**
Electrical Generation and Distribution Losses	20.8	28.8	30.0	27.9	28.5	28.8
Total Consumption of Primary Energy	**85.0**	**106.1**	**111.9**	**102.1**	**104.6**	**109.0**
Consumption by Source						
Petroleum	33.8	39.6	42.3	37.8	38.0	44.2
Natural Gas	19.4	23.4	24.3	23.5	23.4	22.0
Coal	19.1	25.2	26.3	23.6	25.0	25.2
Other[a]	12.8	17.9	19.1	17.2	18.2	17.6
Total Consumption of Primary Energy	**85.0**	**106.1**	**111.9**	**102.1**	**104.6**	**109.0**
Electricity (End Use)	9.2	13.6	14.4	13.1	13.4	13.8

[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, D1, D2, E1, and E2.

increase their respective shares as primary inputs to electric power production.

In comparison with these projections, the *actual* total energy consumption in the United States 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 during the 1970-90 period in the composition of end-use demand—away from other fuels to electricity. There was also strong growth in the consumption of coal and nuclear energy for use in *generating* electricity.

Table 2 summarizes the breakdown among major energy sources and consumption sectors for each of the five projections in 2010, as compared with actual 1990 statistics.

Major Assumptions and Rationale

World Oil Market Developments

The Persian Gulf war is expected to have only a limited effect on long-term world energy trends. In fact, that conflict in itself may have diverted public attention somewhat from the energy implications of what is likely to be a *more* significant international development: the end of the cold war and the rapid changes still occurring in the former Soviet Union and in Eastern Europe.

China has avoided such radical changes thus far, but economic reforms in that country have already produced privately owned firms, foreign-funded firms, "township industries" (collective industries under decentralized operation), and a stock market in Shanghai. All these changes—in a populous, developing nation with significant natural resources—could have important consequences for world energy markets.

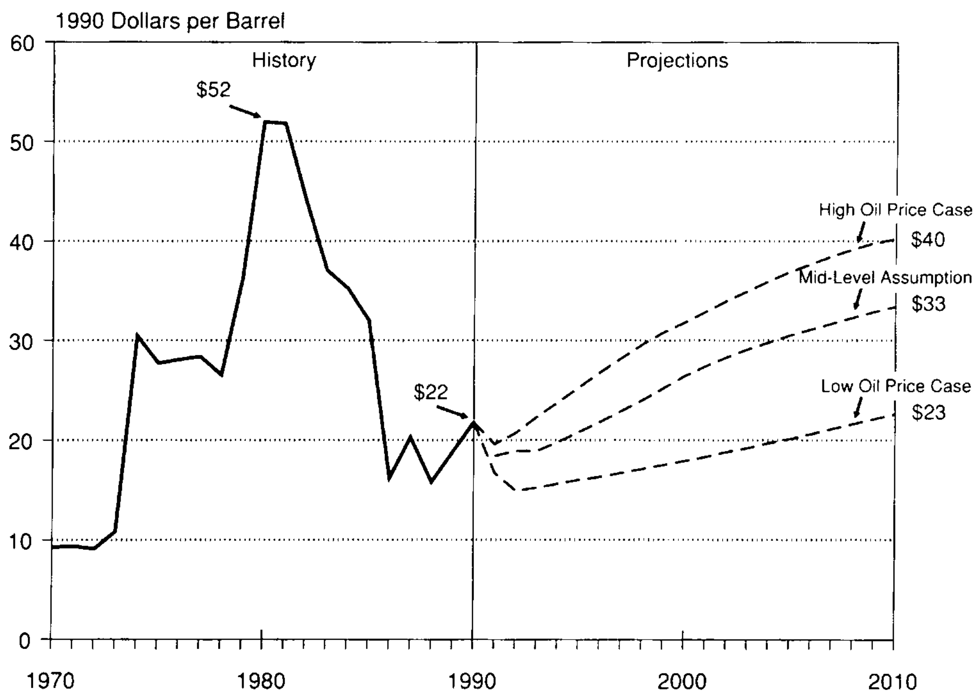
Perhaps the major focus of uncertainty in the world oil market for several years, however, rests on the former Soviet Union. Considered as a unit, the area is currently still the world's leading oil producer (claiming 20 percent of all worldwide output as recently as 1988) and the second largest oil *consumer*. But tremendous political and economic changes are still underway, and their outcome is highly uncertain in either the near or the long term. Projections of oil production *and* consumption levels in the various old Soviet republics both cover a wide range. Total production has already dropped sharply, and it is expected to continue declining until the mid-1990's. In the hope of recovering and augmenting production in the future, current leaders have sought assistance from the West; but no significant increase in oil production as a result of Western involvement is expected before the latter half of the decade. Beyond that, a wide range of outcomes is possible—depending on the success of the reforms underway and the investment climate for Western firms. Similarly, the share of world oil consumption throughout the former U.S.S.R. is expected to drop (at least temporarily) during the coming years. The range of uncertainty over the size of the drop is very wide—also reflecting the uncertainty over the success of the economic restructuring.

In the Middle East, where about two-thirds of the Earth's known petroleum reserves are located, the major continuing impact on oil markets from Saddam Hussein's invasion is in the near term. Restoring oil production capacity fully in both Iraq and Kuwait could take a couple of years; but the long-term damage to production facilities and wells in Iraq appears to be limited. Even in Kuwait, where wells were set on fire and as much as 5 percent of the oil reserves may have been eliminated, the loss will account for less than 1 percent of total world oil reserves. While planned increases in production capacity in Kuwait and Iraq will be delayed, such increases are still expected to occur eventually. Until production returns in Iraq and Kuwait, however, other countries (such as Saudi Arabia) can expand capacity and—at least in the short run—produce the oil needed to meet rising global demand.

Oil Price Trends

Beyond the mid-1990's, world oil prices are expected to rise (Figure 2). The world's reliance on oil from the Organization of Petroleum Exporting Countries (OPEC) has increased since the world oil price collapse in 1986. Total production outside OPEC is expected to peak and level off by the end of the decade—as known fields mature (fall off in flow rates), and production from new fields is insufficient to offset these declines. Crude oil

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



Sources: **History:** Energy Information Administration, *Annual Energy Review 1990* (May 1991). **Projections:** Tables A1, B1, and D1.

output in the United States (the world's oldest and most intensely explored area of commercial oil production) is expected to continue its long-term trend downward. At the same time, world oil demand is expected to keep rising—partly in association with economic growth and particularly in response to the relatively low world oil prices of the past few years. Even with a firming of world oil prices, they would still be low in real terms (compared with prices of other commodities) when matched against historical levels since the early 1970's. Based on past experience with price swings and the recent increases in demand, the relatively low prices expected through the mid-1990's will probably result in demand growth that could cause prices to rise again in the late 1990's.

The degree to which oil prices rise or fall in the future depends largely on OPEC's decisions concerning the expansion of production capacity. Because Middle Eastern members of OPEC are low-cost producers with large hydrocarbon reserves, they find it much easier than the rest of the world to expand production capacity and output. Thus, agreements reached by the OPEC producers—or even some actions taken unilaterally by certain members of the group—play a large role in determining the price of oil. Market share and revenue goals, as well as political and security considerations, affect those decisions. The most likely course is that the pressure to earn more revenue, along with a desire to gain leverage in OPEC's production decision-making process, will encourage at least some OPEC nations to expand their production capacities in the future. Saudi Arabia's announcement that it will boost its output to more than 10 million barrels per day in the near future was influenced heavily by its desire to become the undisputed leader in making future OPEC decisions.

Higher production capacity should moderate increases in oil prices in the future. As a surplus of production capacity in OPEC declines over the next 10 years, however, higher prices will be necessary to balance world demand and supply—primarily by dampening demand, but also by encouraging the development of additional non-OPEC production. Many factors will determine when this happens, including economic growth, conservation, fuel substitution, and non-OPEC supply (including net exports from what were formerly the Centrally Planned Economies). *AEO92* defines world oil prices as the average cost to U.S. refiners of acquiring imported oil. These prices are projected to increase to between $18 and $32 in 2000 and to between $23 and $40 in 2010 (all in 1990 dollars). The Reference Case (at $33.40 in 2010) does not represent the most likely case, but simply a representative mid-level peg. If prices should move outside the projected price range for very long, market forces would be likely to push them back inside it. The low end of the price range presupposes some combination of aggressive conservation, vigorous expansion of OPEC capacity, and high production outside OPEC. Prices near the high end of the range would be more likely to result from higher economic growth, less conservation, declines in non-OPEC production, and relatively low expansion of OPEC capacity.

While this discussion has focused mainly on the supply side, developments on the demand side can also have a major impact on oil prices. If everything else remained equal, higher-than-expected oil demand from any quarter (such as the fast-growing Pacific Rim countries) would tend to push prices toward the higher range shown in these projections. A further expansion in demand *anywhere* might result from a change in conservation trends, faster economic growth than anticipated, or a tighter supply of other fuels (for example, natural gas). Higher demand for petroleum products could also raise the prices of those products if the world's refinery system should have difficulty satisfying expanded requirements.

Domestic Economic Growth Paths

The prognosis for growth in GNP is a key determinant in the outlook for energy markets. Everything else being equal, higher output of goods and services for the Nation as a whole means that more energy will be consumed—not only because of greater activity in the industrial and commercial sectors, but also because an increase in living standards *tends* to signify that energy-using equipment in the residential sector will boost *its* demand in a variety of ways too. Transportation use of energy is linked both to productive work and to leisure. After all energy conservation efforts and all the possible changes in the mixture of goods and services are taken into consideration, additional GNP is bound to generate *some* additional energy demand (as compared with consumption under the same circumstances, but at a lower level of activity). A primary question thus concerns the *rate* of economic growth to be assumed in any future projections.

What determines long-term economic growth rates? Fundamentally, it is the rate at which an economy expands its resource base (principally its labor force and the capital available to it) and how effective the Nation is in raising its productivity (an ongoing process). This means that the path of U.S. economic growth between now and 2010 is bound by two major considerations: (1) a general expectation that the labor force will continue to grow more slowly, as has been the tendency recently, and (2) the great uncertainty attached to productivity growth.

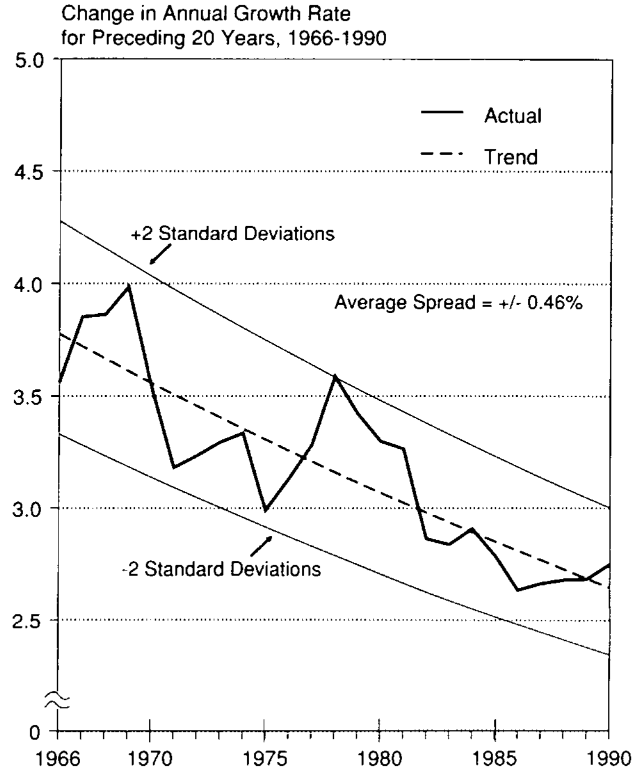
Demographic trends suggest that the rate of growth for the labor force will decline steadily through 2010 and beyond. This need not imply any decrease in per-capita income, but it constrains the prospects for total economic growth significantly. While the U.S. labor force grew by an average annual rate of 2.1 percent between 1970 and 1990, yearly growth rates over the forecast period are expected to average only about 1 percent. 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.

Even with common assumptions about labor force growth, projections of future economic growth can diverge. Views differ about the prospects for new capital formation, improvements in technology, and the extent to which education and training of the labor force meet the challenges of rapid technological change. Greater optimism about these factors leads to projections of higher rates of growth in real GNP through enhanced labor productivity. As capital (and/or more productive technology) is substituted for labor, slower growth in the labor force can be offset by improvements in labor productivity.

Given such a spread of opinion about prospects for economic growth, this year's *AEO* focuses on three distinct paths to capture a range of uncertainty about this key element. In the Reference Case, the labor force grows by 1.0 percent annually over the 20-year period. This, coupled with an annual rate of increase of 1.2 percent for labor *productivity*, yields baseline growth of 2.2 percent in real GNP. Inflation (measured by the change in the implicit GNP price deflator) averages 3.9 percent—with prices increasing at a higher rate during the second decade of the forecast period. The Consumer Price Index (CPI), a measure of prices paid for consumer purchases, rises by an average of 4.2 percent per year. Interest rates are assumed to recover in the early part of the forecast period, as the economy rebounds from the slow growth of 1990 and 1991. After 1995, interest rates remain relatively stable—as the economy settles into its long-term economic growth pattern.

In the Reference Case, total industrial output is projected to grow at a rate of 2.3 percent annually through 2010; but manufacturing output grows at a

Figure 3. Change in Annual GNP Growth Rate for Preceding 20 Years, 1966 to 1990



Sources: Energy Information Administration, *Annual Energy Review 1990* (May 1991), Table 8; and Council of Economic Advisers, *Economic Report of the President* (February 1991), Table B-2.

slightly higher rate (2.5 percent), although the composition of manufacturing growth is uneven. Production of machinery (Standard Industrial Classifications 34-38) is expected to rise most rapidly (3.3 percent per year), driven by export-related demand. Production in the chemical and plastic sectors (SIC 28 and SIC 30) shows steady growth throughout the forecast period. For most other sectors, growth is at or below the aggregate growth in real GNP.

History has helped guide the development of the various economic growth cases in *AEO92*. Figure 3 shows how 20-year growth rates—viewed retrospectively in successive years—trace a relatively tight and obvious pattern. The first point along the jagged solid line in the center represents the 20-year growth rate in real GNP from 1946 to 1966 (about 3.6 percent). The second point (which is a bit higher) represents the 20-year growth rate from 1947 to 1967, and so forth. The latest point covers 1970 to 1990—during which average annual growth was less than 2.8 percent. The downward trend supports a baseline projection only slightly above 2 percent for the 20-year span that will end in 2010.

Two standard deviation bandwidths around the dashed trend line measure the extent to which the successive 20-year growth rates varied from the trend over more than two decades. The average variation was ±0.46 percentage points, indicating that recent history supports a total spread of perhaps 0.9 percentage points from high to low for a moving 20-year average. This is exactly what *AEO92* has used—a 2.2-percent annual increase for the Reference Case, rising to 2.7 and dropping to 1.8 in the alternative growth scenarios.

Figure 3 carries another significant message. Even from the perspective of 20-year growth rates the short-term path of the economy is uneven. If the past is a guide, the U.S. economy can be expected to experience some periods of recession or near-zero growth in the future—followed each time by expansion, leveling off, and a repetition of the cycle. This trough-to-peak pattern might occur as many as three or four times between now and 2010. As with the oil price projections, the macroeconomic growth cases represent smooth trends without cycles in economic activity.

As a competitor in world markets, the United States is very much affected by world events and decisions that extend beyond energy; but—as events of the last 20 years have indicated—volatility in oil prices is of continuing concern. Regardless of how the two are related in terms of cause-and-effect, slow or declining economic growth has accompanied upward spurts in energy prices in the past two decades. The ability to attain high average growth in the economy will be enhanced if markets (both energy and non-energy) are relatively stable in the future. But instability itself may lead to lower growth. This issue of instability (specifically oil price volatility) will be discussed further in the next section of this chapter and in Appendix F.

The High Economic Growth Case incorporates higher labor force growth than the Reference Case (1.3 percent instead of 1.0), and it also assumes faster growth in capital stock. Its growth in labor productivity is 1.4 percent, compared with 1.2 percent in the Reference Case. As a result, real GNP grows at an annual rate of 2.7 percent between 1990 and 2010—0.5 percentage point above the Reference Case. The High Growth Case comes close to matching the economic growth achieved in this country from 1970 to 1990.

Inflation in this case is somewhat lower—an average of 3.1 percent for the implicit GNP price deflator and 3.4 percent for the CPI. Interest rates are consistently about three-quarters of a percentage point below those in the baseline case. Lower interest rates, combined with a somewhat higher level of disposable income, boost the housing and automotive sectors of the economy.

Total industrial output in the High Economic Growth Case is projected to grow, therefore, at an average annual rate of 2.8 percent through 2010; and manufacturing output registers 3.0-percent growth. Despite some differences in the composition of the U.S. economy, production of machinery (SICs 34-38) continues to lead the groupings—at 3.9 percent per year. Production in the chemical and plastic sectors (SIC 28 and SIC 30) is expected to experience strong expansion too, averaging 3.2 percent annually.

Such increased economic activity would induce higher demand for petroleum. Because (by assumption) this case accepts the same oil-price pattern as the Reference Case, however, no response in world oil price to higher U.S. consumption is considered—so domestic *production* of petroleum does not increase. The higher demand assumed in the High Economic Growth Case must be met entirely through increased imports. Once again, this is a conceivable scenario: greater supplies could be forthcoming from outside the United States on the basis of factors other than price—for example, the political climate or lower production costs.

In the Low Economic Growth Case *AEO92* has constructed, U.S. production factors are scarcer. Growth in the labor force averages only 0.8 percent per year, and the increase in labor productivity drops to 1.0 percent. This yields a growth rate for real GNP of 1.8 percent through 2010—0.4 percentage points lower than the Reference Case. Inflation is assumed to be higher by both measures—an average rate of 4.9 percent for the implicit GNP price deflator and 5.2 percent for the CPI. Interest rates are consistently about one percentage point above those in the Reference Case. These high interest rates, in conjunction with a lower level of disposable income, slow the interest-rate-sensitive sectors of the economy and overall investment.

Total industrial output is projected under these conditions of low economic growth (but with world oil prices identical to those in the Reference Case) to expand at an annual rate of 2.0 percent through 2010. Manufacturing output rises by 2.2 percent. As in all other cases, production of machinery leads the way, registering growth of 2.9 percent. The only other sectors to grow faster than the overall economy are the chemical and plastic sectors (at 2.4 percent) and the paper sector (at 2.2 percent).

In this case, the demand for oil declines relative to the Reference Case. In a fashion analogous to the High Economic Growth Case, domestic production remains at the Reference Case levels. Imports of oil decline.

Oil Price Effects on Economic Growth

Whenever world oil prices rise perceptibly, U.S. consumers feel the effects in more than one way. First, households, facing higher prices for energy, will try typically to consume less of it. They can also be expected to spend somewhat less on other goods and services—possibly affecting others' jobs. Nevertheless, higher energy prices probably take up a larger share of each family's budget, and a given level of nominal income provides less residual purchasing power. Workers will try to bargain for higher wages. To the extent they are successful, the cost of producing all goods and services goes up. Energy services of various types also represent intermediate inputs in the production of all goods and services. Substitution away from energy is limited in the near term, and the prices of other inputs do not fall automatically as energy prices rise. This raises the production costs per unit of output for almost all firms. Prices rise generally. Over time, consumers and producers adjust; and the upward pressure on prices subsides.

The effect of oil prices on interest rates cannot be projected with certainty, because it depends on how monetary authorities react. If nonborrowed reserves in the Nation's banking system remain at the same level at which they stood before prices rose, however, the higher aggregate price level effectively reduces the real supply of money circulating in the economy. This puts pressure on interest rates to rise, and that in turn discourages investors from beginning new ventures or expanding old ones. Consumers are less likely to buy "on time."

The economy is also affected by changes in net energy imports. If there is a higher *nominal* level of imports (that is, if more dollars must leave the country, even if the physical volumes of energy imports remain the same), the trade balance worsens. That tends to push interest rates up too—with adverse consequences for the economy similar to those just mentioned, barring some sort of accommodation by the Federal Reserve Board.

In the Low Oil Price Case, the physical level of imports (measured in barrels of oil) *rises* as domestic demand for petroleum increases and domestic production falls. However, the nominal oil import bill (in dollars) *declines* relative to the Reference Case. The lower oil price more than offsets the increase in the physical quantity imported. This actually serves to improve the trade balance—and to reduce pressure on interest rates.

All these elements (and others) interact to influence the near- and long-term paths of the economy. The high and low world oil price paths considered in *AEO92* represent smooth trajectories, which diverge slowly from the mid-range path over a 20-year period. Under such conditions the world oil price *does* exert an influence on the economy, but it does not alter the underlying growth path of the economy appreciably.

Are there conditions under which future U.S. economic growth might be affected more drastically by changing oil prices? The degree of potential damage depends on how large the price swings are *and* on the volatility of the price path. Appendix F outlines a macroeconomic sensitivity analysis, in which two volatile world oil price paths are considered. The first rises to $40 in 2010 (just as in the High Oil Price Case) but gets there by following the same sort of vigorous fluctuations experienced between 1970 and 1990. This case boosts the *average* price over the entire forecast period to a considerable extent, and the penalty in diminished GNP is understandably quite dramatic. However, the difference in GNP loss that apparently can be ascribed to volatility *alone* is far from insignificant. The second case has the same pattern of volatility, but the *average* price is the same as in the High Oil Price Case. Under these conditions, volatility alone still results in a significant loss in GNP.

Price instability affects investment decisions adversely and yields a lower level of aggregate capital stock. The long-run potential output of the economy suffers. The fundamental point is that the price path matters. Any shift to higher world oil prices would have adverse impacts on the economy, but a smooth path would be far less onerous than one that bobs up and down.

Legislative Activity

A number of far-reaching energy bills were introduced in Congress during 1991, addressing many important energy issues simultaneously. Even before the crisis in the Middle East, both Congress and the Bush Administration had been studying options for dealing with future U.S. energy problems. In February 1991 a 2-year study of energy alternatives culminated in the Administration's publication of the *National Energy Strategy*. With the eruption of war in the Persian Gulf, lawmakers' interest in energy security had heightened—increasing the chance that major legislation would be adopted.

Toward the end of 1991, the debate over *comprehensive* energy legislation intensified. The National Energy Security Act (S. 1220), a bill that became the central focus in the Senate, was introduced by J. Bennett Johnston (D-LA) and Malcolm Wallop (R-WY) on June 5, 1991, in lieu of an earlier version (S. 341), which had been introduced on February 6 and approved by the Senate Energy and Natural Resources Committee on May 23. However, S. 1220 failed to muster a cloture vote to overcome an opposing filibuster on November 1; and, when Congress recessed at Thanksgiving, no comprehensive energy legislation had yet been brought to the Senate floor.

As presented, the Johnston-Wallop bill is a sweeping 16-title piece of legislation that covers issues ranging from automobile mileage standards to electric utility reform. It is similar to the bills sponsored by the Bush Administration (S. 570, H.R. 1301); and it offers weaker conservation measures and stronger production initiatives than the primary Democratic alternative in the Senate (S. 741, introduced by Timothy Wirth, D-CO). For most of the year, legislation moved more slowly in the House of Representative than in the Senate—in part because a comprehensive energy bill needs to be approved by more committees in the House.

As *AEO92* went to press, it was still uncertain what form final legislation will take. No final action on any of the all-encompassing bills could be expected during 1991. To provide a framework for discussing the major components of such comprehensive energy legislation, however, key areas covered by the Johnston-Wallop bill are discussed in the next section.[1] It should be understood that the Energy Information Administration does not support any bill nor predict which bills or elements thereof will survive the legislative process. Unless otherwise indicated, the forecasts in *AEO92* make no effort to incorporate initiatives that have merely been proposed or contemplated, but not actually adopted.

Comprehensive Energy Legislation

One of the most controversial provisions in comprehensive energy legislation introduced in 1991 is a proposal to allow drilling for oil and natural gas in the Arctic National Wildlife Refuge (ANWR). Proponents point out that increased domestic production (assuming commercial discoveries are made) will decrease the Nation's need for imported oil. Environmentalists oppose drilling in ANWR because it may threaten the fragile ecosystem of one of the last wilderness areas of Alaska. Other oil production measures are also being considered, such as ways to encourage offshore drilling on the Outer Continental Shelf (OCS).

Considerable controversy has also arisen over whether comprehensive energy legislation should include specific fuel-efficiency requirements for motor vehicles. Proponents of specific standards argue that this is the most effective way to reduce the demand for oil, whereas opponents generally maintain that the domestic auto industry will not be able to meet excessive standards without sacrificing vehicle safety and sales. In separate legislation (S. 279), Sen. Richard Bryan (D-NV) has proposed an increase in the Corporate Average Fuel Economy (CAFE) standards of 40 percent above the current 27.5 miles per gallon by the year 2001. Other proposals have called for an increase in CAFE standards to lower levels than the Bryan bill.

Another major element of comprehensive energy legislation is regulatory reform for electric utilities. One such reform would exempt wholesale electric generators from the 1935 Public Utility Holding Company Act (PUHCA), allowing them to operate in more than one State. Proponents of the provision argue that it could encourage more independent power producers to operate generating plants, increase competition, and lead to lower capital costs—ultimately lowering costs to consumers. Nevertheless, some critics are concerned that there will be insufficient safeguards to protect consumers from monopoly abuse. Others believe that the competitive forces spurred by amending PUHCA will be hindered unless utilities are obligated to make their transmission networks accessible to wholesale generators—an idea that sparks sharp controversy on its own.

In an effort to decrease U.S. dependence on oil, consideration is being given to streamlining the regulatory processes for nuclear power, hydroelectric power, and natural gas to facilitate the use of these energy sources. In the case of new nuclear power facilities, it has been proposed that only a single, "combined" license be required for both construction

[1]The discussion framework is provided by the version of the Johnston-Wallop bill (S. 1220) whose consideration on the floor was blocked by falling short in a cloture vote on November 1, 1991.

and operation—eliminating the need for two public hearings on the same plant unless it can be shown that a completed plant, as built, fails to meet the requirements of the combined license. Similarly, new natural gas pipelines and hydroelectric plants would face a streamlined regulatory path and environmental review if certain proposals are enacted. In the High Economic Growth Case alone, licensing reform legislation for new nuclear reactors is assumed to have *passed.*

Other major issues being considered by comprehensive national energy legislation include the following: (1) mandating the use of alternative fuels in government and private fleets; (2) promoting energy efficiency through building and appliance standards, and through research and development in industrial technologies; (3) expanding the Strategic Petroleum Reserve; (4) funding for research and development aimed at reducing U.S. dependence on oil in a variety of ways; and (5) sponsoring research and development on Clean Coal Technologies (CCT) and on the conversion of coal for use in transportation.

Other Developments

Continuing controversy surrounds the construction of permanent disposal sites for both civilian and weapons-related nuclear waste. At Yucca Mountain in Nevada, the basic examination of a potential site for a civilian waste repository has been delayed because State environmental permits have been withheld. On September 11, the House Energy and Commerce Subcommittee voted to allow this to proceed even without the permits. In New Mexico, the Waste Isolation Pilot Project (WIPP) still faces obstacles. Controversy has surrounded the transfer of land at the site from the Department of Interior to the Department of Energy, which must take place before testing can begin. In October 1991, Energy Secretary James D. Watkins took the land for the project by administrative fiat, but a judicial restraining order that blocked the testing was issued on November 26. As *AEO92* went to press, the House had not passed a bill allowing the transfer of land to take place.

Since the end of the Persian Gulf war, the push for additional taxation on oil and certain petroleum products has waned somewhat. In September, House Speaker Thomas Foley announced the end of the so-called "nickel for America" campaign, which proposed a 5-cent tax on motor fuels to help fund a 5-year highway transportation program. Proponents of a gasoline tax argue that it could provide needed funds while reducing U.S. demand for oil. Several bills were introduced in January 1991 proposing fees on oil imports (S. 215, S. 154, H.R. 93) but at the time of this writing no action had been taken on any of them in their respective committees.

Although certain aspects of the Clean Air Act Amendments of 1990 were addressed in last year's *Annual Energy Outlook*, more is known this year about the specifics of implementation. While the final result of the regulatory negotiation process is not expected to come for years, proposed rules now indicate the outcome in several key areas, such as these:

(1) Flexibility will be allowed in temporarily exceeding the emission limits specified by operating permits for stationary sources (Title V) if the relevant State agencies and the Environmental Protection Agency are notified 7 days in advance.

(2) A "source" of airborne toxic compounds has been interpreted more broadly than an entire production unit—enabling coke ovens, chemical plants, and oil refineries more easily to meet a 1994 deadline to reduce emissions by 90 percent.

(3) When electric power plants install pollution-control devices (such as "scrubbers"), the rule for determining whether a complete environmental review is required allows utilities to choose any of the previous 5 years as a baseline. No review will be required if higher emissions are due to increased electricity demand.

(4) Although alternative fuels (such as compressed natural gas) might well be used, there are preliminary indications that new automobiles and light trucks may also be able to meet emission standards through the use of reformulated gasoline and some improvements to vehicle pollution-control technology. Regulatory negotiations are continuing with regard to specific requirements in connection with oxygenated and reformulated gasoline.

U.S. Energy End Use

According to the assumptions of the *AEO92* Reference Case, the United States is projected to consume about 106 quadrillion Btu of energy resources (in all forms combined) during the year 2010. This would be 25 percent above the 1990 level of energy use; but by then the total population should have increased by about 13 percent and GNP (in the Reference Case) by some 54 percent.

Depending on the economic and oil price scenarios considered, estimates of total energy consumption for 2010 vary by nearly 10 percent (by some 9.8 quadrillion Btu). In both the High Oil Price and the Low Economic Growth scenario, energy demand is lower than in the Reference Case. High energy prices tend to induce more conservation because they provide greater incentives to improve efficiency in energy use. Low economic growth reduces the demands for energy-related services, particularly in the industrial and transportation sectors. Scenarios combining low world oil prices *and* high levels of economic growth project higher energy consumption. 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 requiring nearly one-fifth less energy input by the end of the 20-year forecast period.

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, total use of electricity goes up by nearly 50 percent—taking market share away from both oil and natural gas as end-use products. The fact that oil and gas also serve as primary fuels to *generate* electricity complicates the overall energy demand picture somewhat—a consideration that is reflected in other segments of *AEO92*.

Buildings Sector

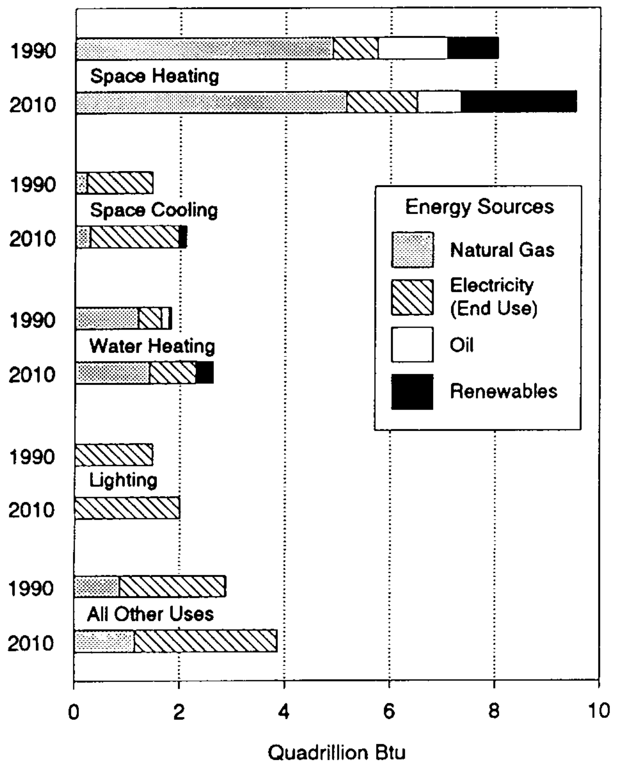
Buildings make up the largest part of the two energy consumption categories that statistical summaries customarily label "residential" and "commercial."[2] However, buildings have enough in common (and are important enough as end users of energy) to be analyzed as a demand sector in themselves. They include individual houses and apartments, commercial business establishments, and public institutions. Energy use in this combined "buildings sector" mainly involves space heating and cooling, water heating, and lighting. Appliances that are used within buildings range from cooking stoves, refrigerators, and TV sets in homes to computers and communications equipment in offices. Energy sources for the buildings sector include electricity, natural gas, distillate fuel oil, and—increasingly—renewable energy sources. Total consumption of end-use energy in the buildings sector during 1990 was estimated at 16.9 quadrillion Btu, approximately 26 percent of the Nation's end-use total. If the losses involved in generating and delivering electricity are included, the consumption of *primary* energy associated with the buildings sector amounted to 30.2 quadrillion Btu, or about 35 percent of the U.S. total.

Figure 4 represents the distribution among the major types of energy service in the buildings sector and also the relative significance of various energy sources within each type of use. A comparison between 1990 data and the Reference Case projection for 2010 shows graphically where growth and change might take place. Clearly, natural gas is an important source, with its use concentrated in space 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 essentially limited to space heating and water heating applications.

By 2010, electricity is projected to become more significant in each category of buildings-energy use;

[2]In some statistical series, the commercial sector includes some public services (such as lighting along streets). A discussion of energy consumption statistics and sectoral definitions is contained in Energy Information Administration, *Energy Consumption by End-Use Sector*, DOE/EIA-0533 (Washington, DC, April 1990).

Figure 4. Energy End Use in U.S. Residential and Commercial Buildings, 1990 and 2010 (Reference Case)



Sources: Tables A11 and A12.

and, if the primary energy sources required to generate the electricity are considered, the role is even more prominent. Natural gas becomes relatively less important, although growth in the sector's overall use of energy continues to support a strong demand for this particular fuel in absolute terms. The role for oil shrinks. Finally, the outlook is for increased reliance on "renewable" energy sources. These include such technologies as solar panels, "ground-source heat pumps," and the use of biomass (primarily for space heating). Ground-source heat pumps (sometimes also called "geothermal heat pumps") transfer heat between the air in buildings and the ground, via piping that is installed outside the building and a short distance below the Earth's surface. Although ground-source heat pumps derive most of their effectiveness from a renewable energy source (as do the currently more common outside-air-source heat pumps), operating these devices also requires electricity.

Total energy consumption in the buildings sector will change as the number of occupied buildings increases (based on additions to the existing stock, minus demolitions and abandonments). As the energy efficiency of building shells and equipment improves, however, the demand for energy will be dampened. Neither factor can be predicted with certainty; and both the range and fuel-mix patterns of energy consumption forecasts depend on the pace of building growth assumed (often a reflection of general economic conditions) and on the choice of more efficient technologies or the use of renewable energy to satisfy certain requirements.

As newly constructed houses and commercial buildings are added to the existing stock, the effects on energy consumption will be mixed. New buildings often require significantly less energy than existing buildings to offer the same level of energy service. However, new buildings tend to incorporate a greater *range* of energy-consuming services—such as air conditioning systems, office equipment, and enhanced amenities. Because of more stringent construction standards, new buildings are projected overall to be more efficient than those in place now; but the slow turnover in buildings and their equipment will limit the pace at which these improvements take place nationally. Nevertheless, the characteristics of newer buildings will become progressively more important in determining consumption levels. By 2010, the Reference Case assumes that about 30 percent of all residential units and 44 percent of the Nation's commercial buildings will be of post-1987 construction.

The choice of home heating fuel in new construction is a major factor in determining the future pattern of energy consumption by the residential sector. Space heating accounts for more than half of all residential energy use. Since 1985, the percentage of newly constructed single-family homes using natural gas as the main heating fuel has risen on a nationwide basis. Electricity's share for space heating has declined, reversing an earlier trend—with use of home heating oil remaining fairly constant. Based on the most recent data (1990), 59 percent of the new single-family homes in this country use natural gas as their main heating fuel, 33 percent use electricity, and 5 percent use heating oil. In contrast, electricity captured a 49-percent share in 1985.[3] Given current relative fuel prices, natural gas can be expected to maintain its market share of new-home heating for the rest of this decade,

[3]U.S. Department of Commerce, Bureau of the Census, *Characteristics of New Housing: 1990*, C25-9013.

especially if additional pipelines make it available to new areas. In the latter half of the forecast, however, the consumption of natural gas for space heating begins to decline as the efficiency of all heating equipment stock improves and natural gas prices rise relative to electricity prices. The sharp rise projected for the use of renewable energy sources would also displace some natural gas in the buildings sector. The use of wood, primarily to provide space heat, increases by an average of 2.9 percent per year between 1990 and 2010 in the Reference Case.

Technology improvements are expected in both space heating and cooling. Heat-pump water heaters and condensing furnaces should be fully developed and widely available between now and 2010. With Federal efficiency standards for heating, cooling, water heating, and refrigeration technologies becoming effective early in the 1990's, all new and replacement purchases of appliances should help to raise the average efficiency level. Further revisions to Federal standards for appliance efficiency are anticipated during this decade; but, except for the update to refrigerator standards in 1993, such revisions are not reflected in this forecast.

Additional improvements in the thermal integrity of building shells will also reduce the requirements for both heating and cooling services. Nevertheless, future gains in energy efficiency may not match those achieved in the recent past. Between now and 2010, all fuel prices are projected to show more moderate increases than they did during the 1970's and early 1980's; and this lessens the price incentive for conservation. Many improvements have already been made in existing buildings, so certain specific technologies (such as conventional storm windows) cannot continue to penetrate markets at the rates they once did. The best prospects for continued gains in energy efficiency lie in new technologies and increased public awareness.

Historical trends for fuel consumption in commercial buildings closely resemble those for residential buildings. Oil use will continue to fall off. The share of electricity in the commercial sector has increased relative to other fuels since 1960. This has been due largely to regional shifts in economic activity (with most growth taking place in the South, where air conditioning is now used almost universally, and the West), restrictions on the supply of natural gas during the 1970's, and expansion in other electricity-using applications.

In the various *AEO92* projections, the use of electricity by the buildings sector increases at an annual rate of 1.7 to 2.0 percent—faster than either natural gas or oil use. This increase is spurred by the expectation that electricity-based energy services such as computer and communications equipment will assume increasing importance. Residential space cooling, which relies almost exclusively on electricity in new units, continues to penetrate the household market; by 2010, 95 percent of all new residential units in the South Census Region are assumed to have air conditioning. In the commercial sector, floor space is likely to grow most rapidly in regions that already use electricity intensively. Lighting increases in terms of absolute projected use, but it should account for a smaller percentage of all electricity consumption in the commercial sector (dropping from 39 to 36 percent by 2010) because of more efficient fluorescent lamp ballasts and other advances in interior lighting equipment.

By contrast, the level of use for natural gas changes little over the forecast period—because the higher *number* of gas appliances is actually offset by their increased *efficiency*. Natural gas cooling is not expected to be adopted to a significant extent in the residential sector by 2010, but this technology *is* projected to start affecting the commercial sector.

For 2010, total energy consumption for buildings varies by nearly 1 quadrillion Btu between the Low and High Economic Growth Cases. The High Growth Case counts on increased housing starts and greater need for new commercial floor space, accommodating higher growth rates in both total population and the labor force. Adding new, more efficient buildings to the existing stock in the High Economic Growth Case leads to higher absolute levels of energy consumption in spite of slightly improved average efficiency for *all* buildings.

The sensitivity cases that examine the effects of higher or lower world oil prices on energy consumption while holding macroeconomic growth essentially constant do not change total energy consumption in the buildings sector very much. Energy prices affect the average energy efficiency of purchased equipment directly; but such equipment in the buildings sector stays in use for many years, and the slow turnover limits the rate of change in average efficiency. The most noticeable variation in the two oil price cases is the significant increase in reliance on renewable energy sources as world oil prices increase.

Industrial Sector

The U.S. industrial sector accounted for almost 40 percent of all end-use energy consumed in 1990. As defined in the *Annual Energy Outlook*, the industrial

Measuring Efficiency Improvements

A certain amount of price-induced efficiency can be expected in all sectors of energy consumption over the next two decades. In the five cases examined in *AEO92*, both energy consumption and "energy intensity" (as measured by the ratio of energy consumption to GNP) are lower in the High Oil Price Case than in the Low Oil Price Case. On the other hand, in the High Economic Growth Case, energy consumption is higher—but energy intensity is *lower*—than in the Low Economic Growth Case. The improvement in energy intensity arises because new, more efficient technology is added to the existing stock more rapidly in the High Economic Growth Case.

Because efficiency Improvements are measured in different ways for different energy applications, it can be misleading simply to compare "percentages of improvement."

- *Automobile* efficiency is measured in average miles per gallon for the new car fleet. Using this gauge, the improvement by 2010 is projected to range between 16 and 39 percent, comparing the Low Oil Price Case with the High Oil Price Case.

- The usual way to express *industrial* energy efficiency is to divide industry's total energy consumption for a given year (in a common unit of measurement that can be applied to all fuels and sources, such as quadrillion Btu) by the value of industrial output for that year (in constant dollars). In this case, the lower the numerical result (the energy intensity) the higher the energy efficiency is deemed to be. By this standard, U.S. industrial energy efficiency is expected to improve by between 25 and 30 percent between now and the year 2010.

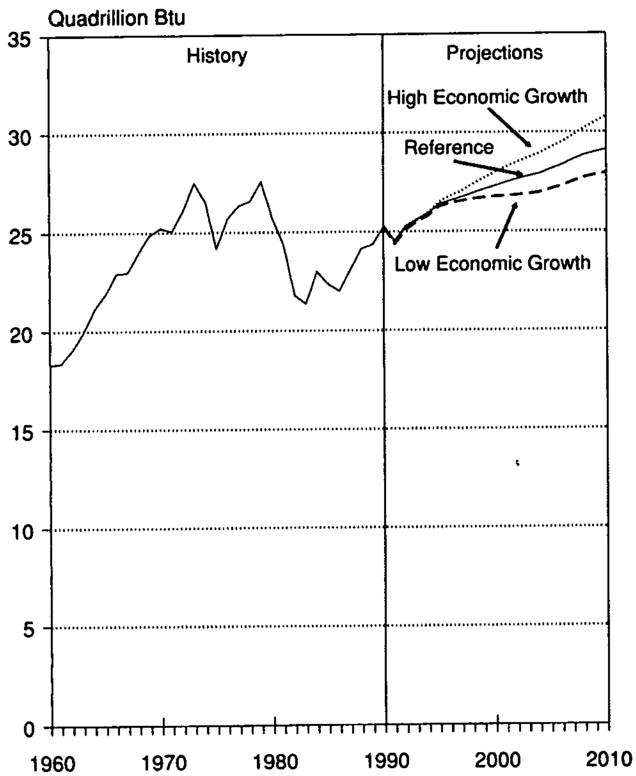
- For both residential and commercial *buildings*, the standard of efficiency is similar to that in the industrial sector, except that floor space or number of houses is substituted for the dollar value of output. Buildings that consume less energy per square foot or per home are deemed more energy efficient. Based on normal weather conditions, the projected range in efficiency improvement for the entire stock of U.S. homes by 2010 is from 7 to 8 percent. For all commercial buildings, the outlook is for a 9- to 10-percent improvement.

sector includes both manufacturing and nonmanufacturing industries. Manufacturing consists of all industries with Standard Industrial Classification (SIC) codes 20 through 39, while nonmanufacturing "industry" consists of agriculture, mining, and construction. Energy in the industrial sector is consumed for heat and power (which includes a wide range of end uses—such as powering equipment, process heating, and boiler use) and for use as feedstocks. In 1990, about 60 percent of industry's 25 quadrillion Btu of energy resource consumption was for manufacturing heat and power, 10 percent for nonmanufacturing heat and power, and 30 percent for feedstocks and other miscellaneous uses.

Figures 5 and 6 illustrate how the rise in U.S. consumption of energy within industry overall "tracks" GNP growth, as well as how industry's ability to apply energy more efficiently moderates growth in consumption (as energy intensity is projected to resume its downward trend in the face of higher fuel prices). More so than in other sectors, the industrial sector consumes a wide variety of fuels and energy for diverse end uses (Figure 7). In 1990, natural gas was consumed in the greatest amount (8.7 quadrillion Btu). Gas was followed closely by petroleum products (about 8.5 quadrillion Btu). Industrial establishments usually buy energy to satisfy their demands, but an increasing number of them "cogenerate" to some extent; that is, they use equipment to produce steam and electricity simultaneously—for their own use and/or for sales to utilities. According to the Energy Information Administration's 1988 Manufacturing Energy Consumption Survey (MECS), the paper industry was the leading industry group in on-site generation of electricity, closely followed by the chemical industry. The major fuels used for industrial cogeneration are renewables (chiefly wood and municipal solid wastes), natural gas, residual (heavy) oil, and coal. The paper and lumber industries are especially heavy users of renewable energy in cogeneration. In all, more than 2 quadrillion Btu of renewable energy was consumed by industry during 1990; and the sector generated about 0.7 quadrillion Btu of electricity for its own use and for sales to the grid.

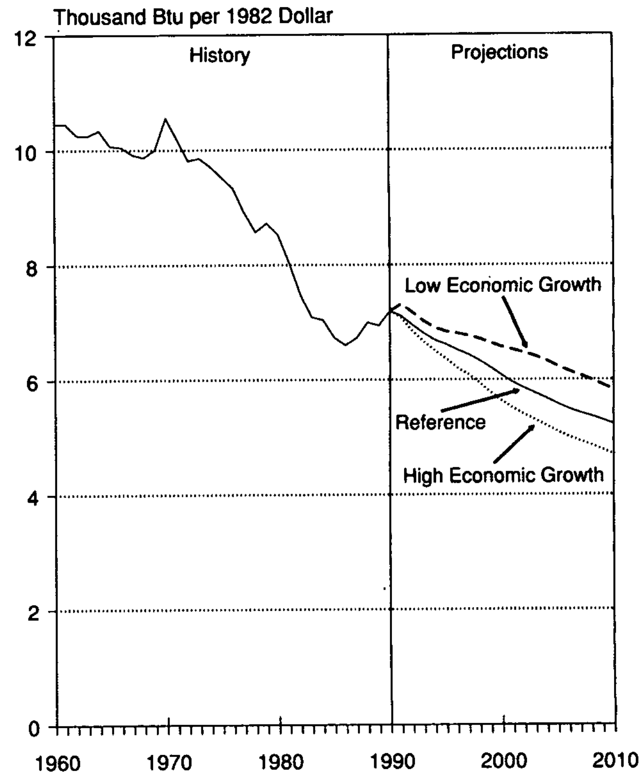
From the early 1960's to the early 1970's (before the Arab oil embargo), U.S. industry steadily increased its year-by-year energy consumption. After the first "oil crisis" (in 1974), industrial energy consumption generally declined for about a decade—until the economic expansion and the oil price collapse in the second half of the 1980's brought a sizeable new increase in industrial energy use. For almost all of the

Figure 5. U.S. Industrial Energy Consumption, 1960-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1989* (April 1991). **Projections:** Tables A2, B2, and C2.

Figure 6. U.S. Industrial Energy Intensity, 1960-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1989* (April 1991). **Projections:** Tables A13, B13, and C13.

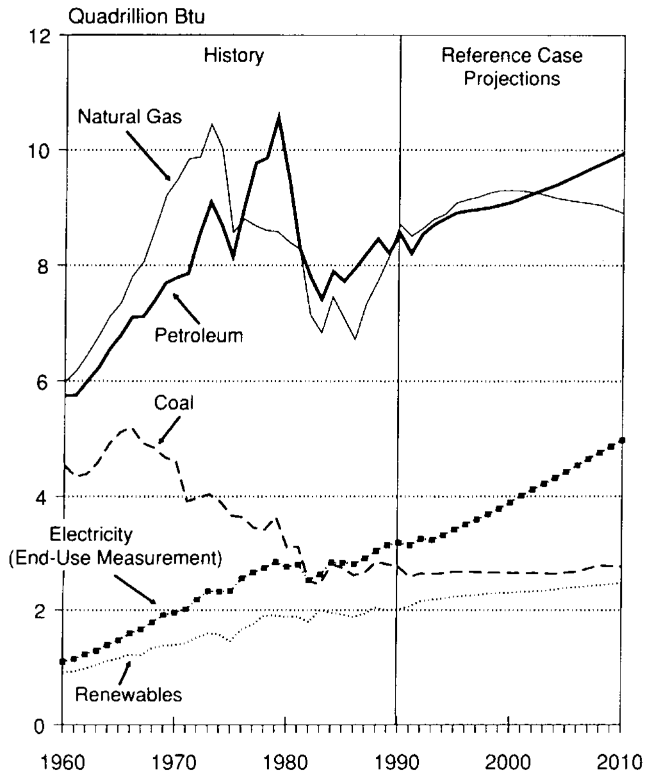
same period, however, energy consumption per dollar of output (energy intensity) generally shrank. This can be attributed to two major factors. First, the U.S. industrial output mix has shifted from the heavy, highly energy-intensive industries (such as primary metals) to industries like "metal durable products," which are less energy-intensive. Importing commodities whose production involves a great deal of energy-input per dollar of value has statistically reduced energy intensity in the United States. Second, technological changes have certainly helped the U.S. industrial sector to operate more efficiently in terms of energy use. For example, using electric arc furnaces to turn scrap into steel has reduced the demand for coke and decreased the need to use coke ovens. Energy intensity increased again during the late 1980's; but this was a short-term phenomenon due to the slowdown in industrial growth during those years. In the future, the U.S. chemical industry is expected to produce more high-value chemicals such as pharmaceuticals and pesticides in preference to more energy-intensive bulk chemicals. Also, the aluminum industry is continuing to shift toward secondary fabrication of primary aluminum that has been imported from abroad.

Historical trends in both consumption and intensity have varied greatly by energy source. End-use consumption of electricity by industry has grown gradually but steadily as new technology based on electricity has superseded the less precise application of production techniques that involve the direct burning of fuels. Direct consumption of coal in U.S. industry has been tapering off for a quarter-century. Industrial use of natural gas faltered after the oil crises of the 1970's, but started to increase again during the economic expansion and the natural gas price collapse of the 1980's. Demand for petroleum products by the industrial sector has fluctuated; it is sensitive to the movements of the world oil price and also to changing uses for petroleum products.

Energy-Intensive Industries

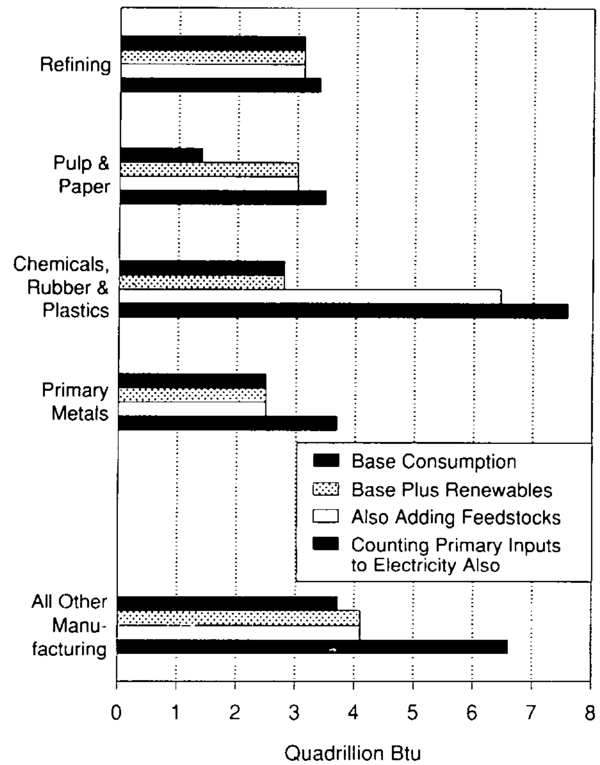
The most energy-intensive U.S. manufacturing industries include petroleum refining, pulp and paper,

Figure 7. U.S. Industrial Energy Consumption, by Energy Source, 1960-2010



Sources: **History:** Energy Information Administration, *State Energy Data Report 1989* (April 1991). **Projections:** Table A2.

Figure 8. Energy Consumed in Manufacturing— Four Ways of Measuring It (1990)



Sources: Detailed AEO Industrial Model Forecasts.

chemicals and plastics, and primary metals (Figure 8). But how much energy does each of these consume? Their ranking depends heavily on how energy consumption is defined; and this draws attention to the distinct character of each industry—an analytical complexity that needs to be explained if the statistics are to have full meaning.

- The petroleum refining industry consumes large amounts of still gas and petroleum coke, but these are byproducts and residues of the refining processes themselves. Together, they account for about two-thirds of all the energy consumed in refining; natural gas makes up about three-fourths of the rest.

- As pointed out earlier, the pulp and paper industry takes advantage of large amounts of wood and other wastes recovered in its various processes to burn these "renewable" fuels and thus supply a little more than half of all the energy this particular industry applies. Close to three-quarters of the remaining energy comes from natural gas and coal.

- The chemicals, rubber, and plastics industry requires large amounts of conventional fuels to produce heat and power, but it also uses large amounts of petroleum and natural gas as the chemical raw material from which it manufactures plastic resins, a variety of final-use chemicals, and fertilizers. In fact, such "feedstocks" (equivalent to about 3.5 quadrillion Btu if used as fuel) account for almost 60 percent of all "energy consumption" by the chemicals industry. Natural gas and electricity together account for more than 80 percent of the remaining consumption (with natural gas strongly predominating).

- The primary metals industry (iron and steel, aluminum, and other metals) consumes a large amount of one predominant fuel that is virtually unique to this industry. It is metallurgical coal, used as a feedstock to produce coke—which is, in turn, consumed in the iron and steel industry for heat and power. More than 40 percent of all energy consumption in the entire U.S. primary metals industry comes from this special form of coal—

which is marketed separately from the "steam coal" commonly used in generating electricity. Almost 90 percent of the remaining energy consumed is in the form of natural gas or electricity, with natural gas still making up a little more than half of this amount.

Energy Use Patterns

For this year's *AEO* projections, average annual GNP growth rates between 1990 and 2010 range from 1.8 percent (Low Economic Growth Case) to 2.7 percent (High Economic Growth Case). Industrial end-use energy consumption in 2010 will increase to a range of 28.0 to 30.8 quadrillion Btu, with the Low and High Growth Cases having the lowest and highest energy consumption, respectively. Thus, U.S. industry is projected to consume between 0.5 and 1.0 percent more energy each year while increasing the value of its output by a substantial multiple of that—2.0 to 2.8 percent. Energy-intensive domestic industries are expected to continue growing more slowly than those that are less energy-intensive; and improved energy-use technologies should be adopted, especially as rising energy prices spur conservation.

Total industrial energy consumption in 2010 for the Low Oil Price and High Oil Price cases is 30.2 and 28.9 quadrillion Btu, respectively. The sensitivity of industrial energy use to changes in world oil price is determined by the extent of petroleum consumption and the nature of its application in the various parts of this sector, because the combination of those two factors controls the extent of fuel switching likely to take place in response to changes in relative prices.

Petroleum products represent only about one-third of U.S. industrial energy consumption, and only a small portion of this petroleum (mostly residual oil and distillate oil) goes into heat and power uses that are particularly sensitive to price. Most industrial petroleum consumption consists of byproducts (such as petroleum coke and still gas) and feedstocks. In both instances, the level of use is sensitive primarily to the current economic activity in the respective industries involved. Rises in world oil price also tend to *increase* natural gas consumption, because the fuel of some boilers is switched from petroleum to natural gas when the latter becomes relatively cheaper. Finally, changes in world oil price affect the use of other fuels indirectly to the extent that they affect overall economic activity—and thus the prices of all energy sources via changes in total demand.

Measuring Energy Intensity

Interpreting statistics about energy consumption and intensity often depends on the context from which the numbers are drawn. For end-use consumption, electricity use is measured by the amount of electrical energy consumed at the site. When consumption is measured as "primary energy," however, the total energy content of the fuels that went into generating the electricity is included. In the case of hydroelectricity and nuclear power, equivalent primary inputs are estimated. Electricity consumption measured as primary energy is about three times end-use consumption.

Because the metal durables sector of American industry turns out relatively expensive items to which a high percentage of value is added during the production process, it appears to be the least energy-intensive segment of manufacturing in terms of heat and power and end-use consumption per dollar of output. If the wood and wastes used as fuel are counted, the most energy-intensive industry for heat and power is the paper industry. If renewables are not included, however, the most energy-intensive industry is primary metals—followed by stone, clay and glass. If feedstocks are included, the energy intensity in the chemical industry rises considerably. If the measure of electricity use is primary energy rather than end-use consumption, all industries show higher consumption levels; and those that use electricity intensively (such as aluminum) show much higher energy intensity in comparison with all other industries.

Figure 8 on the opposite page presents energy consumption levels for some key manufacturing segments, using several definitions of industrial energy consumption and showing how the ranking among these large consumers changes as different categories of "energy" are added or omitted.

U.S. industry is often regarded as being almost fully electrified, yet electricity accounted for only 13 percent of total industrial end-use energy consumption in 1990. Industrial electricity use is projected to increase significantly between 1990 and 2010, growing by 1.9 to 2.7 percent per year. The most common applications include motor drives, electrolytic processes, process heating, space heating, and lighting; but some (such as the use of lasers, infrared heating, electromagnetic curing, and so on) are considerably more sophisticated.

Many electricity-using technologies and processes produce higher quality products; and electrification often has environmental advantages at the point of use (although electric utilities emit various pollutants as they consume primary fuels at the point of electricity generation). For example, the chemical pulping process of the paper industry is under continuing pressure from environmental regulations, so a shift is expected to cleaner processes—such as mechanical pulping technologies—that are electricity intensive. In the steel industry, there has been increasing use of scrap rather than iron ore, and this requires electric arc furnaces. An increase in the use of the microwave and freeze-concentration technologies in the food industry adds further to the growth of industrial electricity consumption. Such penetration of electricity-using technologies, combined with electricity prices that are projected to increase at an annual rate of only 0.4 to 0.7 percent in real terms between 1990 and 2010, leads to a virtually flat forecast for greater electricity intensity.

The industrial sector finds various end-use applications for an assortment of petroleum products, including feedstocks, boilers, process heating, and off-road transportation (mainly in agriculture). Petrochemical and liquid petroleum gas feedstocks have already been cited. The most common petroleum boiler fuel is residual oil, although some distillates and liquefied petroleum gases are also used. Diesel motor fuel is widely used in the agricultural sector. The construction industry uses asphalt and road oil for paving and roofing. Petroleum coke and still gas are byproducts of refinery processes, used mainly for heat and power; but petroleum coke is also a raw material for electric anodes used in the primary metals industry.

Total petroleum consumption by the industrial sector is projected to increase from 1990 to 2010 at an average annual rate of 0.5 percent (High Oil Price Case) to 1.3 percent (Low Oil Price Case), reflecting its sensitivity to price. Because the total use of petroleum by industry is also strongly influenced by the amount that goes into feedstock, the future growth of the chemical sector will be an important determinant.

From the early 1970's to the mid-1980's, natural gas consumption by U.S. industry generally decreased. But it increased significantly from the mid-1980's to 1990, owing to the collapse of natural gas prices and to the economic expansion during that period. In 1990, natural gas had the highest share of total fuels consumed for all purposes (34 percent). Natural gas is used basically for boilers (for process steam, electricity generation, space heating and machine drive), for process heat, and as feedstock. The forecast for total natural gas consumption through 2000 shows a slight increase from the 1990 level, with annual growth rates ranging from 0.3 to 0.9 percent. From 2000 to 2010, consumption is expected to remain flat or decrease—possibly by as much as 0.7 percent per year. These forecasts reflect an expectation of higher gas prices, with annual increases ranging from 2.4 to 3.9 percent between 1990 and 2000, and from 2.6 to 4.7 percent in the decade following 2000.

From the mid-1960's to about 1980, U.S. industry cut its use of steam coal nearly in half. Its use rose slightly during the 1980's, but use of metallurgical coal fell off at the same time. Almost uniformly across the various cases, steam coal consumption is projected to grow slowly from 1990 to 2010 (0.4 to 0.5 percent annually). Domestic metallurgical coal consumption should decrease at an annual rate of 1.9 percent (for all cases) from 1990 to 2010—mainly because scrap replaces iron ore in making steel. However, net imports of the small amount of coke still being used will grow at a very high rate—20 to 21 percent. Since 1970, U.S. demand for coking coal has dropped from about 100 million short tons per year to about 40 million; and 20 years from now only 27 million tons per year is likely to be consumed, because some of the remaining coking plants in this country will have been retired and they are not expected to be replaced.

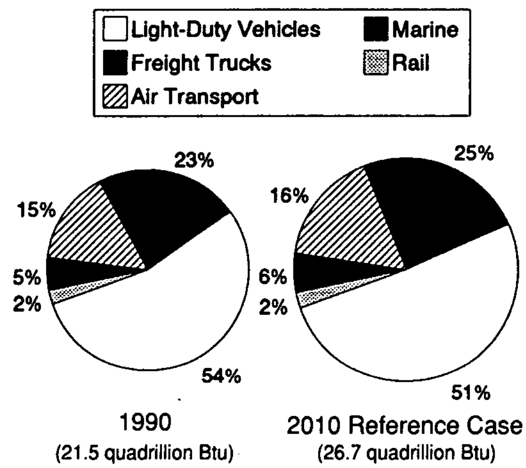
Transportation Sector

Sixty-four percent of all the petroleum products used in this country during 1990 went into providing transportation services, and this share is expected to rise slightly through 2010. By another measure, the transportation sector in 1990 consumed about 12 percent more petroleum than was produced domestically. Total U.S. oil consumption is expected to increase by about 3.2 million barrels per day between 1990 and 2010 in the Reference Case; and four-fifths of this net increase will be used to move goods and people around. By 2010, depending on which Oil Price Case is considered, the United States could be consuming between 43 and 107 percent more petroleum for transportation alone than is expected to be produced domestically.

U.S. transportation is almost entirely oil-dependent, deriving more than 97 percent of its energy from petroleum. Other end-use sectors have switched largely from petroleum to natural gas and electricity; but, as of late 1991, substitution of other fuels was not projected to play a major role in transportation during the forecast period. Uncertainty about the potential role of alternative vehicle fuels is highlighted in the section of this chapter entitled "Variables in Energy Use."

The principal sources of transportation energy are motor gasoline for light-duty vehicles (automobiles and light trucks), diesel fuel and motor gasoline for freight trucks, jet fuel and aviation gasoline in aircraft, the diesel oil 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—technically another form of commodity transportation. Petroleum-based lubricants add a relatively minor amount to the transport sector's use of energy resources. In 1990, total energy consumption for transportation was 22.1 quadrillion Btu. More than half of all transportation energy in 1990 was consumed by light-duty vehicles. Freight trucks used roughly one-fourth, and air transport accounted for most of the rest (Figure 9).

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



Note: This excludes natural gas used to operate pipeline pumps, as well as petroleum used in lubricants.
Source: Table A14.

Highway and air transportation are expected to generate most of the projected increase in total petroleum use by this sector between 1990 and 2010; but the level of oil consumption varies significantly with alternative assumptions about economic growth and oil prices. In 2010, total energy consumption for transportation is 4 quadrillion Btu higher in the High Economic Growth Case than in the Low Growth Case, while it is 2.6 quadrillion Btu lower in the High Oil Price Case than in the Low Oil Price Case. The high growth scenario assumes that there will be substantially more travel in each transportation mode as economic activity increases. Different levels of fuel prices are anticipated to lead to different levels of fuel efficiency for light-duty vehicles.

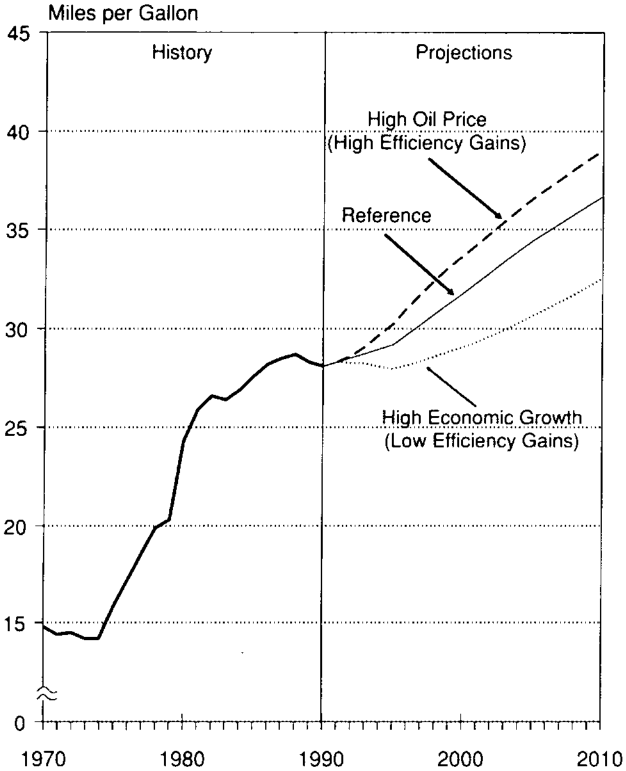
Motor gasoline is likely to remain the predominant highway fuel. In the High Economic Growth Case, gasoline consumption is about 16.6 quadrillion Btu in 2010—11 percent more than in the Low Economic Growth Case. With high oil prices, the growth rate for total gasoline consumption slows (to an average annual rate of 0.4 percent), because improvements in fuel efficiency for light duty vehicles closely match the increases in light-duty vehicle travel. In contrast, the High Economic Growth Case depicts a future in which higher growth rates for population and robust economic expansion boost travel by light-duty vehicles substantially—so that total gasoline consumption increases by 3 quadrillion Btu between 1990 and 2010.

For the economic and population growth rates assumed by the Low and High Economic Growth Cases, highway travel by autos and light trucks is forecast to increase at an average annual rate of between 1.5 and 2.0 percent per year between 1990 and 2010—somewhat slower than the rate of GNP growth. In 2010, comparing the High to the Low Economic Growth Case, autos and light trucks are projected to travel 10.4 percent more vehicle-miles. Because the driving-age population will be only about 7 percent higher in the High Economic Growth Case, these figures suggest that more time will be spent each day driving.

Gasoline prices affect total fuel consumption by light-duty vehicles. History shows that consumers respond to gasoline price to a certain extent by driving more or less and by changing their attitudes over time toward fuel efficiency in their purchases of light-duty vehicles. The short-run response to a higher cost per mile is generally limited, however, because manufacturers' design and production plans take time to adjust. Estimates of average fuel efficiency for new cars in the Reference Case are based on estimates of how vehicle technologies may vary as gasoline prices change over 20 years. The possible effect of legislatively mandated standards for higher fuel efficiency in vehicles is discussed in the next section of this chapter.

It is EIA's current judgment that higher gasoline prices in the High Oil Price case would increase potential fuel savings attributable to new technologies significantly. Specifically, compared with the Reference Case, in which new car fuel economy reaches an average of 36.7 miles per gallon by 2010, alternative assumptions about gasoline prices in the High and Low Oil Price Cases result in estimates for new car mpg by that time of 39.0 and 32.7, respectively (Figure 10).

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, B14, and D14.

In meeting the Federal standards of Corporate Average Fuel Economy (CAFE), auto manufacturers can earn credits under the Alternative Fuel Use Act of 1988 if they build cars that save petroleum by using non-petroleum-based alternative fuels. However, the current CAFE standard of 27.5 miles per gallon is lower than the fuel efficiency domestic manufacturers, on average, have already achieved without using such credits. As a result, *AEO92* does not assume that these credits by themselves will bring any additional alternatively-fueled vehicles into the U.S. fleet.

Although the Clean Air Act Amendments of 1990 (CAA90) may spur the use of alternative vehicles and fuels, they have already motivated the development of significantly improved reformulations of gasoline that may meet most of this Act's new requirements. The only specifications about vehicle technology that must be used are contained in California's independent clean air plan, which other States are free to adopt. It calls for 10 percent of all new vehicles sold after 2003 to have "zero emissions." Electric vehicles are the only ones that qualify under this criterion today. Alcohol and natural gas vehicles may achieve some additional market penetration under CAA90, primarily as fleet vehicles for businesses, utilities, and government agencies. The prospects for these vehicles improve as gasoline prices increase. As discussed in the next section of this report, if future national legislation significantly raises CAFE standards and if the California clean air program (emphasizing electric vehicles) is adopted in many States, total gasoline consumption in the post-2000 period may be considerably below the levels forecast in *AEO92*.

Freight trucks accounted for 23 percent of all oil use within the transportation sector during 1990, and this share remains stable over the forecast. Growth in truck travel follows trends in economic activity closely, although fuel consumption by trucks rises more slowly than GNP because fuel efficiency can be expected to keep on improving. For instance, the Reference Case assumes that diesel-powered trucks (used typically for long-haul freight travel) will improve their fuel efficiency by 11 percent between 1990 and 2010.

Diesel trucks are also being used increasingly in place of gasoline vehicles for short-haul activities. In 1989, 54 percent of all energy consumed by freight trucks came from diesel fuel. By 2010, diesel-powered trucks are expected to represent 63 percent of freight truck fuel consumption. This accounts for the robust growth in demand projected for diesel oil.

About 15 percent of the transportation sector's oil consumption in 1990 was used to fuel aircraft. This share is expected to increase as jet travel continues to grow. In recent years, air travel has grown at more than twice the rate of GNP and more than six times the rate of population growth. Over the forecast period, commercial passenger air travel is expected to grow at an average annual rate of about 3.9 percent per year in the Reference Case; and total consumption of jet fuel is expected to reach 4.2 quadrillion Btu—a larger percentage of a substantially bigger transport-fuel "pie." This estimate is particularly sensitive to the rate of macroeconomic growth. In the High Economic Growth Case, when real GNP is assumed to grow at an average annual rate of 2.7 percent, commercial air travel grows at an annual rate of 4.8 percent; total consumption of jet fuel alone would reach 4.9 quadrillion Btu in 2010. The fuel efficiency of commercial aircraft is assumed to improve at an average annual rate of 1.5 percent over the forecast in response to the retirement and retrofitting of older aircraft with more fuel-efficient (and quieter) engines, improved in-flight operations, and increased substitution of materials in newer aircraft. In the long term, the introduction of advanced technologies (such as ultra-high bypass turbofans and active controls to optimize aerodynamics) are expected to play an important role.

Variables in Energy Use

Beyond the variations in energy price and economic activity quantified in *AEO92*'s sensitivity cases, there are other possibilities that could substantially alter the levels of future energy consumption estimated in this report for each of the end-use sectors. These include technology developments, future Federal and State legislation, and public utility policies. While these factors have not been incorporated in the forecasts, several are discussed in this section to give a broader appreciation of the range of possible energy futures.

Buildings Sector

In the buildings sector, EIA has considered only incremental improvements over current building practices. If modular, factory-built pieces were assembled at the construction site, this would allow for better insulation and tighter construction overall. This method has been used widely in Scandinavia, saving substantial energy. Similarly, new technological advances in windows include the use of low-conductivity gas sealed between double panes. Such windows, which have much higher insulation value than those typically installed in new homes today, are likely to gain wide use in cold regions of the United States.

Utilities have initiated many programs which, in aggregate, may substantially reduce the demand for energy in the future. For example, *AEO92* assumes that higher energy efficiency standards for refrigerators will be met in new purchases. To push beyond such standards, however, some utility companies have offered rebates to consumers in which the size of the rebate depends on the efficiency of the appliance. Other utilities buy old, relatively inefficient refrigerators from homeowners—thus increasing the rate of capital stock turnover in an effort to curb the long-term need for adding costly new power plants. In some instances, public utility commissions (PUCs) have encouraged and even rewarded such programs in new rate structures. It is very uncertain, however, how widespread such programs may become in the future or what regions of the country they might cover, so these considerations could not be incorporated with any reasonable degree of confidence into the *AEO92* projections.

Industrial Sector

The Clean Air Act Amendments of 1990 will have a variety of important effects on the U.S. industrial sector—especially the chemical, petroleum refining, and primary metals groups.

The chemical and petroleum industries will be required to adopt different technologies to satisfy the stricter standards set for air toxins, although it is premature to try to quantify any change this might mean for energy consumption by these industries.

Petroleum refineries will clearly be affected by the requirements for clean fuels—both reformulated gasoline and such alternative fuels as methanol.

The coke ovens of the iron and steel industry will also be newly regulated; and it is expected that domestic production of coke will become completely uneconomical. The electricity-intensive primary aluminum industry will be affected to some extent by the requirements for electric utilities to reduce various emissions. Since primary aluminum establishments generally *purchase* electricity rather than generate it for themselves, they are located in areas where electricity prices are relatively low—usually areas with abundant hydropower. However, about half of the industry's smelting capacity still depends on utilities that consume combustible fuels; and these could be affected indirectly by the possible changes in the electric utilities sector.

Transportation Sector

The legislatively mandated Corporate Average Fuel Economy standard is set at 27.5 mpg for cars and about one-fourth lower for light trucks, depending on such specifics as whether the vehicle has 2- or 4-wheel drive. For several years, the average of all cars sold in the United States has met or slightly exceeded this target. The Reference Case estimates significant improvements in vehicle fuel efficiency as motor gasoline prices rise. The price of gasoline in 2010 in the Reference Case is estimated to be more than one-third higher than it was in 1990, and average new car fuel efficiency is projected on that basis to reach 36.7 mpg. Even in the Low Oil Price Case, the estimate is for 32.7 mpg. If new car fuel economy were to remain constant at 1990 levels, however, this would translate into about a one-sixth reduction in *average fleet* fuel efficiency compared with the Reference Case—and a nearly commensurate increase in gasoline consumed. On the other hand, one legislative proposal before Congress would require manufacturers to achieve an average new car fuel efficiency by 2001 that would be about 40 percent higher than current levels (see page 11). Assuming that efficiency remained constant after 2001, this might put overall fleet efficiency in 2010 about 14 percent above the Reference Case level, reducing fuel consumption by more than 10 percent below *AEO92* projections.

The Clean Air Act Amendments of 1990 establish a clean fuel pilot program in California with substantially tighter emission limits than the national standards. Other States may choose the California program if they feel it is a desirable way to clean up their own "nonattainment areas"; and no fewer than 15 States are considering adoption of the California standards—including New York, Massachusetts, Illinois, and Texas. Complete opt-in of all these States (including the requirement for a percentage of zero-emission vehicles) would mean sales of more than half a million electric vehicles a year by 2003. As of this writing, however, no other State had taken all the steps necessary to choose the program officially, so the *AEO92* projections assume that only vehicles sold in California will be affected.

Dispersed Applications of Renewable Energy

Because the *dispersed* use of renewable energy sources may be viewed as *reducing the demand* for commercially supplied energy, the various direct applications of renewables at the point of end use will be considered here according to consumption sector. Other forms of renewable energy (for example, hydroelectric dams, geothermal power, and large-scale solar arrays) are used to generate electricity at centralized locations, from which the electricity is then transmitted and distributed to end users as demand dictates. Those applications of renewables are clearly a constituent of energy *supply*, so they are treated later in this report.

Each of the end-use sectors (residential, commercial, industrial, and transportation) is capable of applying renewable energy at the point of demand. Technologies for dispersed applications include active and passive solar systems, groundwater heat pumps, wind turbines, photovoltaics, wood, and the production of ethanol from corn. Certain technologies, such as wind turbines and photovoltaics, have both centralized and dispersed applications.

The success of renewables in penetrating various dispersed and nonelectric markets will be contingent on improvements in technology, costs, performance over time, the acceptance of the respective technologies by consumers, the regulatory climate, the state of the domestic economy, and the level of conventional fuel prices. These components vary across the different scenarios. However, dispersed renewable technologies (except for hydropower) are not expected to provide a large portion of U.S. energy supply in any scenario. Oil prices would have to be much higher than anticipated in this report, a breakthrough in one of the renewable technologies would be needed, or more stringent environmental legislation would have to be passed to make renewables more cost-competitive.

Changes in world oil prices and in macroeconomic growth have asymmetrical effects on the market penetration by renewables during the forecast period (Table 3). Use of biofuels (consisting mainly of wood-burning in the residential and industrial sectors) increases most when macroeconomic growth is high, because higher GNP is correlated generally with the construction of more single-family residences, as well as with higher activity in the pulp and paper industry—a large decentralized user of wood wastes to produce energy. On the other hand, ground-source (geothermal) heat pumps and dispersed solar-thermal and photovoltaic applications make their maximum contributions if world oil prices are high. For these more technologically-oriented sources, high fuel prices (in particular, heating oil prices) are an incentive to faster market penetration. Ethanol consumption in the transportation sector does not vary across scenarios, because its high cost makes it infeasible on its own under any economic or oil price conditions examined. Ethanol penetrates only where requirements of the Clean Air Act Amendments of 1990 cannot readily be met any other way.

These differing penetration patterns should be kept in mind when looking at the aggregate consumption levels in the various cases, since each renewable source reacts differently in response to changes in the key variables.

The Reference Case projects the total use of renewables in dispersed applications to increase more than 70 percent—to 5.0 quadrillion Btu in 2010. This reflects an annual average growth rate of 2.8 percent. Total consumption of renewables in 2010 varies about 10 percent between the Low and High World Oil Price cases.

The major component of dispersed renewable energy in the *AEO92* projections is biofuels. This source includes both wood and municipal solid waste (MSW). In 1990, biofuels accounted for 95 percent of the nonelectric use of renewable energy, with wood contributing nearly 90

Table 3. Dispersed Renewable Energy—Consumption Summary
(Quadrillion Btu)

	1990	Alternative Projections for 2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
Biofuels	2.70	3.84	4.08	3.59	3.88	3.80
Solar	0.05	0.46	0.46	0.46	0.58	0.34
Geothermal	0.00	0.41	0.41	0.41	0.53	0.28
Transportation	0.08	0.24	0.24	0.24	0.24	0.24
Total	**2.84**	**4.95**	**5.19**	**4.69**	**5.22**	**4.66**

Sources: **History (1990):** Office of Coal, Nuclear, Electric and Alternate Fuels estimates. **Projections:** Tables A6, B6, C6, D6, and E6.

percent of the biofuel total. By 2010, consumption of biofuels is projected to increase by approximately 40 percent over the 2.7 quadrillion Btu generated in 1990. However, its share in total consumption for dispersed renewables declines in all cases. Geothermal and solar-thermal technologies increase their shares.

Wood, the major component of biofuels, is used in both the residential and the industrial sectors. Its use is concentrated in the paper and lumber industries in the form of direct combustion of wood residues. Residential wood-burning for home heating is another important application. Overall, wood in these two sectors accounts for slightly more than three-fourths of the total dispersed use of renewable energy. MSW accounts for only a small part of total biofuels consumption, and its use is distributed fairly equally between the commercial and industrial sectors. MSW incineration is viewed primarily as a waste-disposal option—with energy supply being a secondary consideration.

Decentralized solar energy technologies (which involve both active and passive applications) and dispersed geothermal energy (ground-source heat pumps) are used principally in the residential and commercial sectors. These technologies hold considerable prospects for growth and commercialization. By the end of 2010, even though most individual applications may be small in scale, their total combined contribution could range between 0.6 and 1.1 quadrillion Btu (0.9 quadrillion Btu in the Reference Case), compared with less than 0.1 quadrillion Btu in 1990. "Active" solar techniques use solar energy to activate a process that produces another form of energy (usually electricity), while "passive" solar applications include efforts to use solar radiation energy directly (for example, in heating water), to reduce heat losses (by systems such as thermal pane windows), and for lighting applications.

In the transportation sector, alcohol fuels from biomass (principally corn) constitute a *potentially* important dispersed application. However, the analysis for *AEO92* assumes that most of the increase in use of alcohol fuels between now and 2010 will be for motor gasoline blending; alcohols and alcohol-based ethers are used to enhance octane ratings and to raise the oxygen content of gasoline in accord with environmental regulations. The current contribution of alcohol fuels to overall energy use is quite small. Nevertheless, ethanol use should triple by 2010—from something under 0.1 quadrillion Btu today to about 0.25 quadrillion Btu. Future development will be influenced by various environmental considerations, by energy security concerns, and by the call for using alternative oxygenates, such as methanol. Methanol would probably be produced first in large commercial quantities by using natural gas—rather than biomass or coal—as the major feedstock.

Despite the uncertainties involved with renewables, their use will grow faster in percentage terms than most other components of the Nation's energy supply. The precise path this growth will take is less certain, due to the wide variety of technologies and states of development, as well as the uncertainties related to conventional fuel prices and total energy demand.

Oil and Gas Outlook

The Outlook for Petroleum

Crude Oil Production

Domestic production of crude oil is now nearly 25 percent below the peak of 9.6 million barrels per day it reached in 1970. The high point for the 1980's (9.0 million barrels per day) was touched in 1985, followed by a steady decline to 7.4 million barrels per day in 1990.

The decline has centered in the Lower 48 States, because production from Alaska's North Slope has remained reasonably stable. In fact, a boost in Alaskan production during 1991 (prompted by the loss of Persian Gulf sources) helped to halt—at least temporarily—the decline in total U.S. production for the first time in 6 years. The marked decline in total crude oil production since 1985 was caused by a dramatic fall in the price of crude oil between December 1985 and July 1986, when the price of imported crude (in 1990 dollars) plunged from more than $26 per barrel to below $11. Since that "crash" in the oil market, the price of crude oil has recovered somewhat. In 1988 it was slightly above $14.50; and its 1990 average was estimated at $21.78 per barrel. However, in 1990 dollars, the average annual price is not expected to reach 1985 levels again in the Reference Case for almost two decades.

The somewhat higher crude oil prices in 1990 failed to stimulate oil and gas drilling activity greatly, although there was some response to the sharp increase in prices following the Iraqi invasion of Kuwait. Only 29,360[4] wells were drilled—the second lowest number since 1973. Further, active rigs and wells drilled in the first 3 quarters of 1991 were below levels observed in the same period of 1990. Within the past year, though, several promising developments have occurred that provide some cause for optimism about future crude oil production. Higher output for the first 6 months of 1991 resulted primarily from enhancements to facilities and an accelerated well-fracturing program in Alaska during 1990; but some striking efficiency gains are of greater long-run significance. The success of horizontal drilling is particularly noteworthy, because its spread demonstrates the considerable role that technology can play in enhancing the economics of present and future projects. Finally, recent exploratory successes in the deep waters of the Gulf of Mexico have dramatically heightened optimism about the long-term prospects for offshore production of both crude oil and natural gas.

U.S. oil production is expected to decline during the projection period in all the cases considered in *AEO92* (Table 4). Production falls 0.9 percent annually in the High Oil Price Case, compared with an annual decline of 2.8 percent in the Low Oil Price Case. Thus, the range of projections for 2010 is from 6.1 to 4.2 million barrels per day.

Domestic crude oil production is divided basically into three sources: Lower 48 onshore, which is subdivided further into conventional and Enhanced Oil Recovery; Lower 48 offshore; and Alaska. Onshore wells in the Lower 48 States currently contribute about 63 percent of all domestic crude oil production. The onshore share has declined since 1970, but it is expected to recover somewhat as technological innovations and increased utilization of advanced technology that already exists enhance the economics. The rate of decline in onshore Lower 48 production from 1990 through 2010 ranges from 0.9 to 2.3 percent per year, depending on which set of oil prices is assumed. Given higher oil prices, the share of Lower 48 onshore production coming from Enhanced Oil Recovery (EOR) grows from 14 percent in 1990 to 22 percent by 2010. If lower world oil prices are assumed, EOR projects are affected more than conventional production; they contribute only 10 percent of the volume expected from onshore wells in the Lower 48 during 2010.

Production from Lower 48 offshore regions (Federal and State) is expected to decline until 1994—when large offshore projects in the Pacific begin operation. After that, total offshore production is projected to begin another gradual decline, lasting until after the turn of the century. A second wave of significant increases in offshore production is expected before 2010, however, as potentially large discoveries in the deep waters of the Gulf of Mexico are developed. By 2010, Lower 48

[4]Estimate published in the *Monthly Energy Review* (November 1991).

Table 4. Petroleum Supply, Disposition, and Prices, with Projections for 2010
(Quantities in Million Barrels per Day)

	1990	Alternative Projections for 2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
World Oil Price (1990 dollars per barrel)	**21.78**	**33.40**	**33.40**	**33.40**	**40.20**	**22.60**
Production						
Crude Oil[a]	7.35	5.51	5.57	5.49	6.14	4.16
Other[b]	1.64	2.06	2.15	2.06	2.06	1.97
Net Imports (including SPR)[c]	**7.16**	**11.64**	**12.88**	**10.79**	**10.22**	**15.35**
Total Product Supplied[d]	**16.99**	**20.13**	**21.50**	**19.25**	**19.30**	**22.40**
Motor Gasoline	7.23	8.32	8.88	7.98	7.89	9.08
Distillate	3.02	3.68	3.94	3.52	3.55	4.45
Jet Fuel	1.52	2.05	2.40	1.80	1.99	2.15
Product Prices (1990 dollars per gallon)						
Motor Gasoline[e]	1.17	1.58	1.58	1.57	1.74	1.30
Diesel Fuel	1.18	1.53	1.55	1.52	1.69	1.27
No. 2 Heating Oil	0.97	1.19	1.23	1.15	1.32	0.96
Residual Fuel	0.46	0.84	0.86	0.82	0.97	0.61
Jet Fuel	0.76	0.97	0.99	0.95	1.13	0.71

[a]Includes lease condensate.
[b]Mainly natural gas liquids.
[c]SPR = Strategic Petroleum Reserve.
[d]Total product supplied includes residual fuel and other petroleum products not listed below.
[e]Includes State and Federal taxes.
Sources: See source notes for Table A8.

offshore oil production is expected to be 8 percent higher than it is now, and the offshore share of total production should rise from 13 percent in 1990 to a level ranging from 18 to 20 percent in 2010 for the High and Low Oil Price Cases, respectively. Offshore production trends will depend heavily on environmental restrictions affecting leasing in these regions. As currently specified, the restrictions will limit leasing severely at least through the 1990's; but it will be legally possible to grant access to much of the offshore area after 2000. In the case of areas with such temporary access restrictions, *AEO92* assumes that after 2000 access will be granted to those with the greatest hydrocarbon-bearing potential.

In Alaska, considerable uncertainty surrounds the possibility of leasing acreage within the Arctic National Wildlife Refuge (ANWR).[5] The opening of the 1002 area of ANWR to oil and gas development could alter the *AEO92* crude oil production projections to a considerable degree;[6] but the projections are based on the continuation of restrictions that preclude such development. Without ANWR, total Alaskan production is expected to fall by 2.0 percent to 6.9 percent per year in the High and Low Oil Price Cases, respectively. Higher prices in the Reference and High Oil Price Cases result in a moderate turnaround in production toward the end of the projection period.

The Prudhoe Bay field on Alaska's North Slope provided more than 1.5 million barrels of crude oil per day from 1980 through 1988. In 1989, however, production from this field began to decline—dropping to 1.3 million barrels per day in 1990. Although this

[5]The opening of the entire 19 million acres within ANWR is not at issue. The area of interest for the leasing to oil and gas development consists of the 1.5 million acres on the coastal plain of ANWR, otherwise known as the 1002 area.

[6]Potential crude oil production from this area has been estimated to be in excess of 1 million barrels per day. For example, see Energy Information Administration, *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge,* SR/RNGD/87-01 (Washington, DC, October 1987), or U.S. Department of Energy, *Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?,* DOE/ID/01570-H1 (Washington, DC, January 1991).

flow increased to nearly 1.4 million barrels per day in early 1991, it is not expected to be possible to sustain this level of production during much of the projection period.

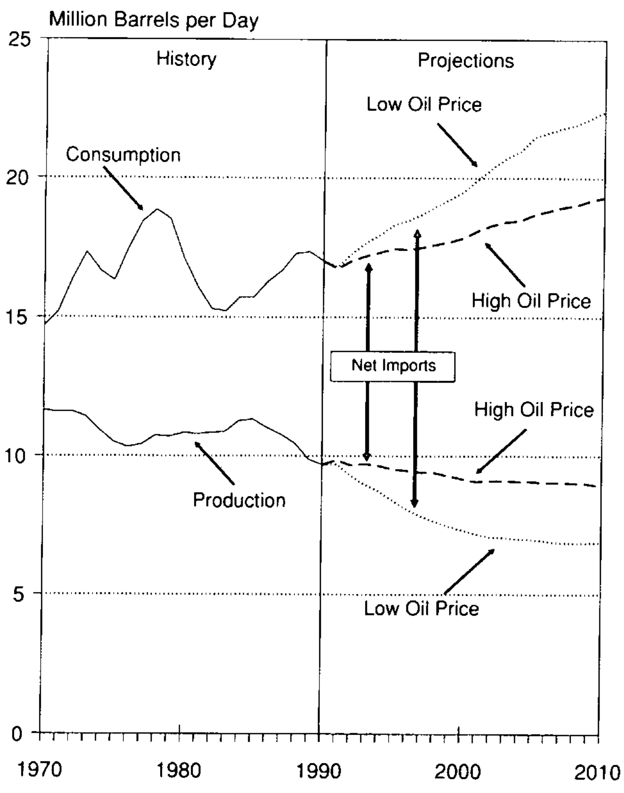
Natural gas plant liquids (propane, butane, and other liquid fuels that are extracted in the process of producing pipeline-quality natural gas) also contribute substantially to the total domestic supply of petroleum liquids. They provide between 19 and 22 percent of total domestic supply by 2010 in the High and Low Oil Price Cases, respectively. Other domestic sources (such as synthetic crude oil) make up a small but growing part of supply by 2010.

Petroleum Imports

Over the entire 20-year forecast period, U.S. demand for petroleum products is projected to grow by between 0.6 and 1.4 percent per year in the High and Low Oil Price Cases, respectively. This would place the Nation's requirements for oil (domestic *and* foreign) between 17.9 and 19.5 million barrels per day in 2000 and between 19.3 and 22.4 million barrels per day by 2010 (Figure 11). In 1990, demand was about 17.0 million barrels per day. Through 2005, petroleum demand is projected in most cases to grow more slowly than overall U.S. energy use, primarily because the price of natural gas—a ready substitute for oil in most non-transportation uses—is expected to give gas a competitive advantage that permits it to grow faster than the petroleum demand. After 2005, increased use of coal in the electric utility sector has a dampening effect on demand for both petroleum and natural gas.

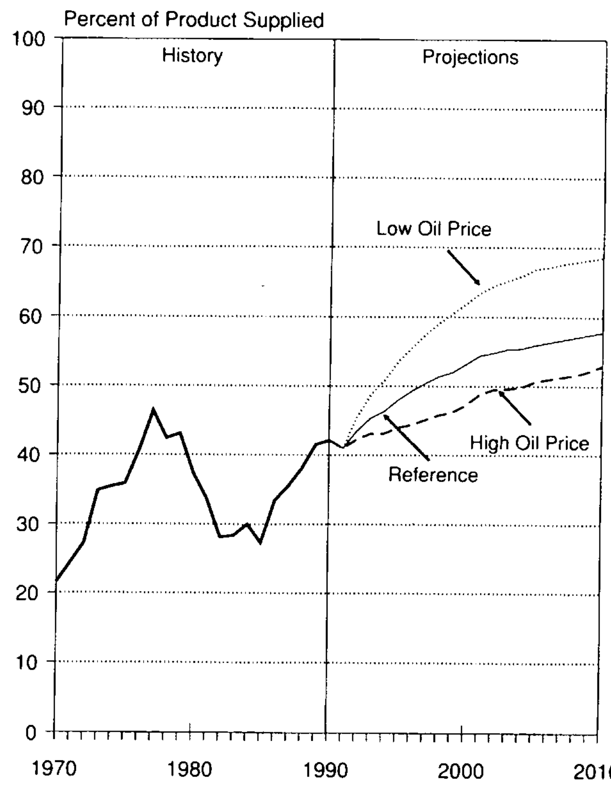
Nevertheless, the absolute growth in petroleum demand, in conjunction with the fall in domestic petroleum production, leads to expanded net petroleum imports of crude oil and refined products. Total imports are projected to rise from 7.2 million barrels per day in 1990 to between 10.2 and 15.4 million barrels per day in 2010, depending on the price of crude oil. Thus, net oil imports would account for between 53 and 69 percent of U.S. petroleum demand (Figure 12), in contrast to a 1990 level of 42 percent. The import quantities are highest when crude oil prices are low. In the Reference Case, imports in 2010 reach 11.6 million barrels per day.

Figure 11. U.S. Petroleum Production and Consumption, 1970-2010



Sources: **History:** 1970-1989—Energy Information Administration, *Annual Energy Review 1990*; 1990—*Petroleum Supply Annual.* **Projections:** Tables C8 and D8.

Figure 12. Percentage of U.S. Oil Consumption Supplied by Net Imports, 1970-2010



Sources: **History:** 1970-1989—Energy Information Administration, *Annual Energy Review 1990*; 1990—*Petroleum Supply Annual.* **Projections:** Tables A8, C8, and D8.

Most of the petroleum imports will enter as crude oil rather than as refined products (a statistical category that includes unfinished oils as well as final products). In most cases, however, the importation of refined products increases at a faster rate than that of crude oil. This reflects the assumption that crude oil refining capacity in this country (measured by atmospheric distillation capacity) will grow little beyond its January 1, 1991, level of 15.7 million barrels per day. Almost any increase in distillation capacity is expected to come through additions to existing refineries or reactivation of capacity that has been shut down. Even to maintain existing levels of capacity, domestic refineries must make significant pollution-reduction expenditures, adjust to changing crude oil streams, and find the capital at competitive rates to carry out these changes. To meet the expected increases in U.S. and foreign product demand, foreign refineries will have to increase their distillation capacity by almost 1 percent annually through 2010.

Petroleum Product Demand and Prices

Transportation will remain the leading end use of petroleum products throughout the projection period, accounting for more than half of the U.S. oil demand in all cases. In second place is the industrial sector, which (counting use in petrochemical feedstocks) accounts for more than one-quarter of U.S. oil demand in all cases. Demand for petroleum products in the residential and commercial sector drops in all cases. Home heating oil shows an especially obvious falloff because of a switch to other fuels in the buildings sector. The use of oil by electric utilities has dwindled in recent years (electricity generation consumed only 3 percent of the petroleum products used in this country in 1990), but it shows renewed growth (1.2 to 4.7 percent per year) from now through 2010. This happens because prices for residual fuel oil—the heavy type used in steam plants, rather than in combustion turbines—become more competitive with other fossil fuel prices.

Gasoline use will increase. This motor fuel continues to dominate U.S. petroleum consumption throughout the projection period, reaching levels of 7.9 to 9.1 million barrels per day in 2010 for the High and Low Oil Price Cases, respectively. This compares with the 1990 level of 7.2 million barrels per day.[7] The use of alternative transportation fuels (such as compressed natural gas, alcohol fuels, and electricity) begins to show up in the projections after 2000, particularly in the High Oil Price Case, but all those sources together satisfy no more than 1 percent of the transportation energy demanded in 2010. The decline in motor gasoline's *share* of transportation demand (from 62 percent in 1990 to 56-58 percent in 2010, depending on the price of oil) takes place largely because so much more jet fuel and diesel fuel comes into the picture. In most cases, diesel fuel is projected to experience the strongest relative increase in demand of any product in the transportation sector, partly because diesel fuel is generally priced below gasoline through 2010.

In the industrial sector, consumption of liquefied petroleum gas and petrochemical feedstocks increases faster than any other petroleum products, but the largest share of petroleum products consumed by industry continues to be in the form of a miscellaneous category that includes asphalt, road oil, petroleum coke, and lubricants. Liquefied petroleum gas consumption by industry grows at the rate of 1.9 to 2.8 percent annually, while petrochemical feedstock consumption grows at 1.6 to 2.2 percent.

The average price for all petroleum products is projected to go up, at a rate that ranges between 0.4 and 2.1 percent per year. It rises in all of the cases considered in *AEO92*, because real crude oil prices and the demand for products both increase. Prices for certain individual products also reflect special circumstances. For example, part of the reason the projected prices for motor gasoline and on-highway diesel fuel are higher than 1990 prices is the scheduled increase in California gasoline taxes; and the higher refining and distribution expenses anticipated to satisfy more rigorous environmental requirements are another factor.

Motor gasoline is the largest selling petroleum product in the United States. Its real price is expected to increase from about $1.17 per gallon in 1990 to somewhere between $1.30 and $1.74 per gallon by 2010, depending chiefly on the world oil price (Table 4). On-highway diesel fuel, which costs about $1.18 in 1990, is projected to range between $1.27 and $1.69 per gallon. These prices include State and Federal taxes, but exclude local taxes. The price of home heating oil is lower than that of diesel oil used for vehicles during this time period, because home fuels are not subject to motor fuels taxes or sulfur limitations—and also because the demand for heating oil is declining. Jet fuel prices, which averaged about 76 cents a gallon in 1990, are projected to range between 71 cents and $1.13 per gallon, depending on world oil prices.

[7]The forecast assumes that the percentage of the total supplied by "oxygenated" gasoline peaks at about 35 percent in 1994, and the declines when "reformulated" gasoline appears in 1995. By 2000 half of the gasoline in this country is assumed to be of the reformulated type; by the end of the projection period, *all* U.S. gasoline is assumed to be reformulated. It is estimated that oxygenated gasoline will cost an additional 2 cents per gallon and that reformulated gasoline will be 8 cents higher per gallon.

Residual fuel oil is now the least expensive of all major petroleum products. Although most petroleum products are more expensive than natural gas, this bottom-of-the barrel product was less expensive in 1990. Its price is likely to go up faster than other product prices, however, because the Clean Air Act requires utilities and industrial buyers to shift from high-sulfur to low-sulfur specifications. Residual fuel oil prices are expected to exceed natural gas prices slightly in the High Oil Price Case, but they stay below natural gas in all other cases. Residual fuel oil prices range between \$25.52 and \$40.79 per 42-gallon barrel in 2010, depending on the world oil price.

Variables in Petroleum's Future

During the next 20 years, regulations resulting from the 1990 Clean Air Act Amendments will change the composition of the Nation's most important transportation fuels. Not all of these regulations are defined yet, but many changes will have to be made in refinery operations, on pipelines, and at bulk terminals.

The composition of gasoline and on-highway diesel fuels will be changed in order to reduce pollution from motor vehicles. Approximately 40 U.S. localities have been unable to reduce carbon monoxide in the atmosphere sufficiently to meet Federal standards. So, starting no later than November 1992, gasoline sold in those areas --which consume about one-third of the gasoline in the Nation—must contain a minimum of 2.7 percent oxygen (by weight) during at least 4 cold-weather months, when the related pollution problems are worst. In the Los Angeles area these "oxygenated" fuels will be required for half the year; in the New York area they will be required all year round. The regulations may be waived temporarily if oxygenates (such as methyl tertiary butyl ether and ethanol) are in short supply, as they could be in some areas.

Starting in 1995, all gasoline sold in the nine areas that are farthest from satisfying the standards for ground-level ozone (one cause of smog) must be "reformulated." Under an agreement among refiners, environmentalists, auto makers, and Federal regulators, ozone-producing "volatile organic compounds" and specified toxic emissions must be reduced by 15 percent from 1990 model-year levels. Releases of benzene will be lessened and the oxygen content of gasoline will increase. The areas affected account for 25 percent of all U.S. gasoline supply: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York, Philadelphia, and San Diego. Some 80 other areas, representing another 25 percent of gasoline supply, could *choose* to join the program. At least 12 States have already announced plans to choose reformulated gasoline voluntarily. If too many areas choose reformulated gasoline, however, refiners might not be able to meet demand. By 2000, refiners must reduce emissions of volatile organic compounds and toxics by at least 20 percent as compared with 1990 levels.

California already has tighter gasoline specifications than the rest of the country and is in the process of tightening them further. The California Air Resources Board is proposing a reformulated gasoline from which emissions of volatile organic compounds could be as much as 70 percent below those from the reformulated gasoline stipulated in the Clean Air Act. New specifications will be phased in more quickly in the most polluted areas of California and will cover the entire State by 1996.

In addition, by October 1, 1993, the sulfur content of on-highway diesel fuel must be reduced to about one-fifth the level that is permitted in other distillate fuels, such as home heating oil and the fuel used in stationary generators. Highway diesel fuel makes up about 45 percent of all distillate fuel oil used in this country. Some of the options for reducing the amount of sulfur in finished diesel fuel are to begin the refining process with lower-sulfur crude oil and to increase the amount of hydrotreating.

All these new regulations will make it more difficult for the leading petroleum products to be interchangeable from one season to another or across geographical areas and uses. This affects refiners, shippers, storers, importers, and marketers; and the changes are expected to increase overall supply costs as well as the costs of production. Some of the new Clean Air Act Amendments might also increase the demand by electric utilities and other power generators for residual (heavy) fuel oil that is relatively low in sulfur.

U.S. refiners are likely to modify existing facilities and to expand certain downstream refining operations extensively to satisfy environmental regulations. More ether, isomerization, and alkylation units will be necessary to produce gasoline components; more new hydroprocessing and hydrocracking units will be added to convert unfinished oils into streams of lighter, cleaner hydrocarbons.

Refineries themselves will be the objects of new Clean Air Act regulations that seek to reduce airborne toxic emissions. These regulations will identify the best-demonstrated pollution control technologies, designate them as the "Maximum Achievable Control Technologies," and require refineries to implement them by 1994.

Although it can be assumed that refineries in the Caribbean and the rest of the world will provide *some* additional finished products for U.S. consumers, it also seems likely that U.S. refiners and marketers will import unfinished oils and blendstocks in many cases so they can process them further or blend them into products satisfying U.S. standards. As imports of crude oil and products increase, greater pressure will be placed on the U.S. transportation and distribution systems. Siting and permitting of import terminals, pipelines, and storage facilities to accommodate more imports, particularly in the High Economic Growth Case and the Low Oil Price Case, present a challenge in the face of increased emphasis on environmental concerns.

The Outlook for Natural Gas

Natural Gas Supply

The recent history of domestic natural gas production differs considerably from that of domestic crude oil production. After generally declining from 1979 to 1986 and dipping to its lowest level in 20 years, domestic natural gas production reversed in 1987. From 1986 to 1990 production went from 16.0 trillion cubic feet to 17.6 trillion cubic feet per year. The turnaround was led by shifts in demand. With substantial changes in regulatory structure, gas markets in the past several years have been capable of supplying more gas than could be sold. With such a glut, the average wellhead price of gas fell to $1.72 per thousand cubic feet in 1990, as compared with an average of $3.18 per thousand cubic feet (in constant 1990 dollars) for 1982 through 1985. These relatively low gas prices induced consumption increases, and production was able to rise to fulfill the requirements.

The current excess production capacity in the U.S. natural gas industry is expected to diminish over time; so wellhead prices are expected to rise gradually through 1998, then grow at a faster rate for the remainder of the forecast. Such price increases can occur without discouraging growth in the consumption of this fuel, however, because of the strength of its

Table 5. Natural Gas Supply, Consumption, and Prices, with Projections for 2010
(Trillion Cubic Feet)

	1990	Alternative Projections for 2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
Production	**17.61**	**19.30**	**20.21**	**19.43**	**19.42**	**17.99**
Net Imports	**1.41**	**3.31**	**3.31**	**3.27**	**3.31**	**3.31**
Total Consumption[a]	**18.80**	**22.67**	**23.54**	**22.74**	**22.73**	**21.35**
Residential	4.37	4.57	4.60	4.54	4.45	4.68
Commercial	2.62	3.19	3.19	3.18	3.21	3.18
Industrial	7.24	7.40	7.91	7.03	7.61	7.47
Electric Utilities	2.79	5.54	5.70	6.02	5.44	4.19
Transportation	0.00	0.03	0.03	0.02	0.07	0.00
Wellhead Price (1990 dollars per thousand cubic feet)	**1.72**	**4.65**	**4.80**	**4.62**	**4.46**	**4.00**
Average Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	8.93	9.09	8.89	8.74	8.24
Commercial	5.01	8.06	8.21	8.02	7.86	7.38
Industrial	3.03	6.09	6.25	6.04	5.89	5.43
Electric Utilities	2.40	5.61	5.83	5.57	5.40	4.79
Transportation	NA	[b]8.33	8.49	8.29	8.13	7.66
Average to All Sectors	3.94	6.89	7.04	6.83	6.68	6.28

NA = Not available.
[a]Total consumption includes lease and plant fuel and pipeline fuel not listed below.
[b]Equivalent to a gasoline price of about $1.01 per gallon (in 1990 dollars).
Sources: See source notes for Table A9.

demand—which rises with overall economic growth and with the rise in price for oil and other fuels. To satisfy expanding national requirements, there will probably be increases in both domestic production and imports of natural gas—tending to raise its costs and price.

Historically, natural gas used in this country has come primarily from domestic sources, although net imports (almost entirely from Canada) have grown from 4.7 percent of consumption in 1980 to 7.5 percent in 1990. The net import share is expected to keep on going up gradually, but the bulk of the U.S. natural gas supply through 2010 flows from domestic sources in each scenario. Production during the current decade is projected to continue the upward trend that began in 1987, rising from 17.6 trillion cubic feet in 1990 to a range of 18.9 to 19.8 trillion cubic feet in 2000 for the Low Oil Price and High Economic Growth Cases, respectively. The relatively low production level with low oil prices is due at least partially to the fact that a substantial amount of this country's natural gas is produced as a coproduct with oil from oil wells. If less oil is being produced (because of low market prices for it), the output of associated gas drops too.

U.S. natural gas production is projected by *AEO92* to peak during the first decade of the 21st century, declining thereafter to levels from 18.0 (with low oil prices) to 20.2 trillion cubic feet (with high economic growth) by 2010 (Table 5). The falloff in production during the later years of the projection is attributed to increased imports and lower consumption by electric utilities and industry. The Low Economic Growth projection of 19.4 trillion cubic feet actually exceeds the Reference Case value, because gas consumption grows strongly in the last years of the projection horizon. This aspect of the projection is discussed in the following section of this chapter.

The slightly higher production that accompanies somewhat lower prices in the final years of the Low Economic Growth Case may seem counterintuitive, but it is related to the production path in the preceding years.

The lower levels of production in the Low Economic Growth Case do not draw down reserves to the same extent as the production pace in the Reference Case. Because gas has been extracted more slowly in the Low Economic Growth Case, it is feasible to increase production later by raising the extraction rate—which costs relatively less than finding additional resources.

To date, most domestic natural gas has been produced in the Lower 48 States. Roughly 98 percent of all U.S. gas production during 1990 flowed from Lower 48 wells, with 70 percent of the Lower 48 total coming from onshore. The 30 percent of gas production that now takes place offshore is projected to drop to a 17 percent share of Lower 48 output in 2010. Leasing policy in the post-2000 period could affect the overall level of natural gas production greatly, however.

The relative increase in onshore production from the Lower 48 stems at least in part from the further development of Unconventional Gas Recovery (UGR). UGR consists principally of production from reservoirs with low permeability, such as tight sands; but it also includes methane from coal beds and gas from Devonian shales. UGR production of all types amounted to 1.4 trillion cubic feet in 1990—roughly 8 percent of total U.S. gas production. The potential for UGR production is vast in light of recent estimates for economically recoverable gas resources from unconventional sources.[8]

Production from unconventional sources is projected to expand significantly by 2010 in all cases, offsetting production declines of offshore and associated-dissolved (AD) natural gas. Nonetheless, the bulk of onshore natural gas in 2010 still is expected to flow from conventional sources, which provide 66 percent of the onshore total at that point (down from 69 percent in 1990).

The Cook Inlet Area of southern Alaska will continue to be a source of crude oil and natural gas. Natural gas production in the area is expected to remain stable, with no significant additions to reserves being projected. Southern Alaska natural gas that is produced in excess of local requirements will be converted to liquefied natural gas (LNG) and shipped to Japan. There are no LNG import facilities on the West Coast of the United States; and shipping from Alaska to East Coast terminals via LNG carriers is not economic. Gas from the North Slope of Alaska is expected to become economic to market in the Lower 48, using the Alaskan Natural Gas Transportation System, under the wellhead prices projected in the High Economic Growth Case by

[8]For example, the EIA estimated potential recovery in a range of 295 to 503 trillion cubic feet, depending on the level of technological advancement. See Energy Information Administration, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*, SR/NES/90-05 (Washington, DC, December 1990).

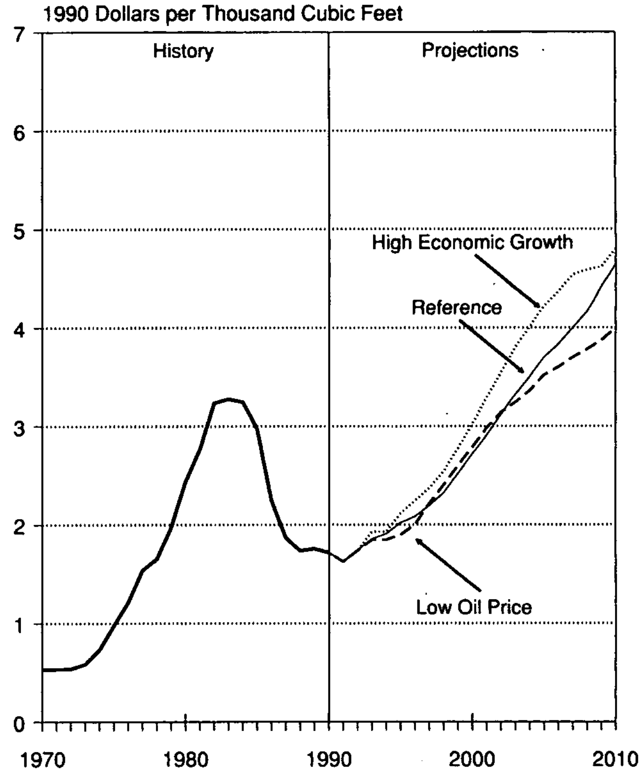
2008.[9] Prices through 2010 in all other cases are expected to be inadequate to bring Alaskan North Slope gas to markets in the Lower 48 States.

Canadian pipeline imports rise through 1997 with the construction of additional capacity to deliver natural gas to the United States. Annual pipeline imports from Canada are assumed to reach 2.2 trillion cubic feet per year, remaining constant thereafter. Canadian natural gas imports are assumed to be priced competitively with U.S. production throughout the projection period. *AEO92* assumes net *exports* to Mexico at relatively low levels through 2000, followed by a resumption of net *imports* from that country—reaching 90 billion cubic feet by 2010. The projected development of Mexico into a net exporter of natural gas would require changes in existing Mexican natural gas policy. Another factor that should affect U.S. gas trade with Mexico is the ongoing negotiation of a North American Free Trade Agreement. The final result of these negotiations could have a considerable effect on future developments in the U.S. natural gas industry.

LNG imports are expected to increase substantially—growing from 79 billion cubic feet in 1990 to levels of roughly 1.3 trillion cubic feet in 2010. Limits on the tanker capacity available for transoceanic shipping and on liquefaction capacity constrain the amount of LNG that the United States could receive during the next few years, but these relative shortages are assumed to be eliminated during the 1990's. If potential supplier countries are tempted by competing uses for this gas to limit the development of necessary liquefaction facilities, on the other hand, the LNG supply potential to this country could remain restricted. The two idle LNG import facilities in the United States are projected to resume operation during the 1990's. *AEO92* includes some expansion of capacity at existing sites, but none from construction at new locations.

In each of the *AEO92* cases, natural gas wellhead prices are projected to increase throughout the projection period, with prices in 2010 ranging from $4.00 to $4.80 per thousand cubic feet (Figure 13). This 4.3- to 5.3-percent annual increase is substantially less than the 12-percent average annual real increase in natural gas prices seen from 1970 to 1985. Natural gas consumption is projected to be highest in the High Economic Growth Case, leading to the wellhead price of $4.80 per thousand cubic feet. The price projected in the Low Oil Price Case corresponds to the lowest consumption and production levels. Although consumption is up in the High Oil Price Case, wellhead prices are somewhat lower than in the Reference Case because of the additional supplies of AD gas produced as a coproduct with oil, coupled with factors that limit the demand response to the change in relative prices between the two fuels. These demand-side aspects of the projection are discussed further in the next section. The additional AD gas supplies are produced as a coproduct with the higher level of oil production brought about by the higher world oil prices assumed for this case.

Figure 13. Average Wellhead Price of Natural Gas, 1970-2010



Sources: **History:** 1970-1989—*Annual Energy Review 1990*; 1990—*Short-Term Energy Outlook* (July 1991). **Projections:** Tables A9, C9, and D9.

[9]Alternative projects have been proposed for use of North Slope natural gas, including marketing it in the Lower 48 States via the Alaska Natural Gas Transportation System (ANGTS), exporting it to Pacific rim countries as liquefied natural gas, or use of the gas in enhanced oil recovery projects on the North Slope. For ANGTS, estimates of investment costs indicate that North Slope gas could be delivered to markets in the Lower 48 States when the Lower 48 wellhead price rises to $4.51 per thousand cubic feet. Other uses of this gas have not been incorporated explicitly in this analysis. The ultimate use of this gas is highly uncertain.

Natural Gas Consumption

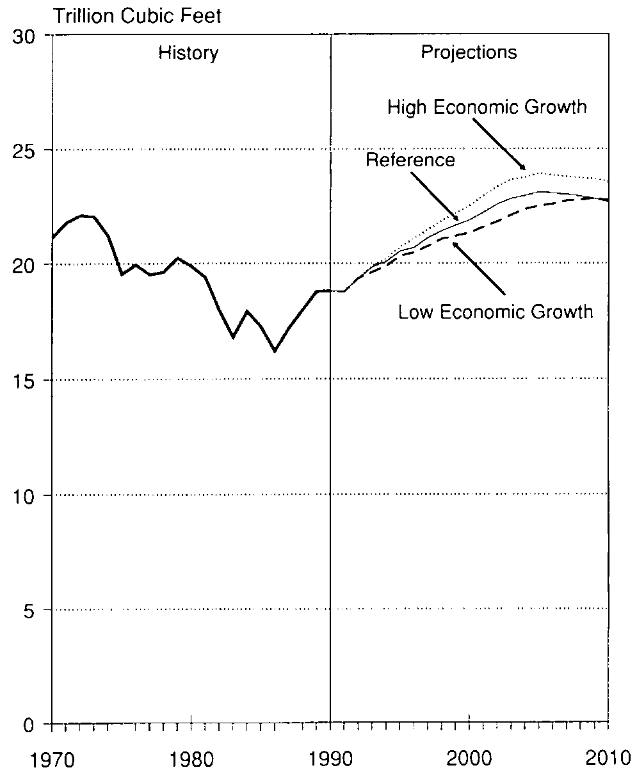
The assumed pace of economic growth affects total energy use and natural gas demand. Changes in natural gas demand, in turn, influence the levels at which U.S. natural gas will be produced. Generally, natural gas use (and, hence, its domestic production) relates directly to the level of macroeconomic activity. The *AEO92* projections conform to this expectation.

U.S. consumption of natural gas is not expected to reattain the historical peak of 22.1 trillion cubic feet (reached in 1972) until around 2000 (Figure 14). The anticipated growth in the use of natural gas to generate electricity (both by electric utilities and by nonutility generators) raises consumption by average annual rates ranging from 1.2 to 1.6 percent through 2005 in the Low and High Economic Growth Cases, respectively. The resulting consumption levels range between 22.5 and 23.9 trillion cubic feet by 2005, representing increases over the 1990 level of 3.7 trillion cubic feet to 5.1 trillion cubic feet. Varying market factors affect later consumption, yielding markedly different outlooks in the final years of the projection.

The *AEO92* Low Economic Growth Case shows an exception to ordinary premises. Lower macroeconomic activity levels result in lower levels of natural gas consumption and prices than in the Reference Case throughout most of the forecast period. Beyond 2000, however, the relatively low gas prices in the Low Economic Growth Case lead some consumers to change their mix of fuels—resulting in a bigger market share for natural gas. Natural gas consumption thus is projected in this case to increase through 2010, reaching consumption levels and prices in the final projection years that are roughly the same as those in the Reference Case.

Residential and commercial consumption of natural gas are projected to remain fairly stable. Homes will use more natural gas in the near future than they did in 1990 (when heating requirements were lower than usual because of warm weather); but eventually gas consumption should decline because efficiency improvements in gas use through changes in equipment, buildings, and behavior are expected to offset the greater number of appliances in service. Additionally, the gas consumption patterns are offset partially in the residential sector by an increase in energy derived from other sources—including electricity and dispersed renewables. Across the cases, residential consumption of natural gas varies only slightly—by less than about 0.2 trillion cubic feet.

Figure 14. Natural Gas Consumption, by Economic Growth Case, 1970-2010

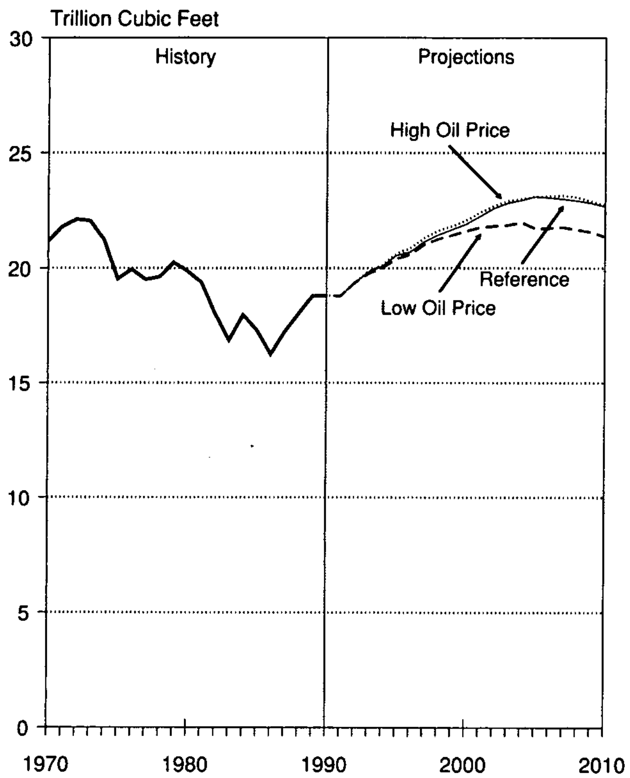


Sources: **History:** 1970-1989—*Annual Energy Review 1990*; 1990—*Short-Term Energy Outlook* (July 1991). **Projections:** Tables A9, C9, and D9.

Commercial sector consumption of natural gas grows slightly, yet steadily due to projected increases for cogeneration, space heating, and cooling uses. An average annual growth of 1.0 percent per year brings it from 2.6 trillion cubic feet in 1990 to 3.2 trillion cubic feet in all cases by 2010. The industrial and electric utility sectors, however, respond more robustly to changing conditions; and their consumption shows more variation across the cases.

The choice of natural gas by electric utilities represents the principal factor driving total gas consumption upward. Use of natural gas to generate electricity is projected to rise sharply, from 2.8 trillion cubic feet in 1990 to between 4.6 and 6.2 trillion cubic feet by 2005—an average annual growth rate of 3.3 to 5.4 percent. The rise in gas use by electric utilities reflects a substantial increase in combined-cycle generating capacity. Towards the end of the forecast period, however, electric utilities are expected to add more new coal-fired steam units, which will be utilized intensively to satisfy baseload demand. As gas prices continue to

Figure 15. Natural Gas Consumption, by World Oil Price Case, 1970-2010



Sources: **History:** 1970-1989—*Annual Energy Review 1990*; 1990—*Short-Term Energy Outlook* (July 1991). **Projections:** Tables A9, C9, and D9.

escalate more rapidly than coal prices, generation from these new coal-fired units will partially displace generation previously supplied by gas-fired combined-cycle units. As a result, gas consumption falls off in most cases as 2010 approaches.

Electric utilities represent the primary sector in which consumption of natural gas is not directly related to macroeconomic growth. The trend in utility gas consumption across cases is a result of the interaction between existing capacity and new capacity additions, most of which are expected to be coal-fired steam or gas-fired combined cycle units that are completed after 2005. Before 2005, higher growth in the level of macroeconomic activity *does* result in higher utility consumption of natural gas. However, after 2005, consumption of natural gas to produce electricity in the Reference Case is projected to be lower than in the Low Economic Growth Case. In the latter case, comparatively few new units are required to satisfy reserve margin requirements, so existing units are simply utilized more fully. This results in higher consumption of both gas and oil than in the Reference Case.

When the three oil price cases are compared, changes in consumption by electric utilities again drive the variations in gas consumption (Figure 15). Many utilities operate dual-fired power plants capable of burning either natural gas or residual fuel oil. The choice depends basically on the relative price and availability of these two fuels. In the Low Oil Price Case, the delivered price of residual fuel oil for electric utilities in some regions is less than the corresponding price of natural gas, particularly in the post-2005 period. As a result, utilities are expected to use more oil and less natural gas in their dual-fired units during these years. In the Reference Case, the delivered cost of residual fuel oil is projected to exceed the corresponding cost of natural gas, so utilities are expected to minimize oil consumption by switching to natural gas in the same units. Consumption of natural gas varies little between the Reference and High Oil Price Cases, because prices of residual fuel oil delivered to electric utilities have already reached the level in the Reference Case where utilities maximize their consumption of natural gas in dual-fired units. No further switching occurs if oil prices rise further.

Industrial use of natural gas increases gradually from the 1990 level of 7.2 trillion cubic feet, peaking around the turn of the century at a level of 7.5 to 8.0 trillion cubic feet. This reflects the increased use of natural gas in cogeneration, and it represents an average annual growth rate of 0.4 to 1.0 percent. Thereafter, industrial consumption declines steadily to 7.0 to 7.9 trillion cubic feet by 2010, because of the shift to less energy-intensive industries. Although the general path here is similar to that for electric utility consumption, the absolute growth is far less. This is due in part to increasing electricity use in certain industrial processes, which is seen as reducing industry's reliance on natural gas.

The penetration of new consumption technologies, such as using natural gas for space cooling and compressed natural gas (CNG) in fleet motor vehicles, could affect these projections considerably. In some areas of the country, industry, local governments and gas distributors are experimenting with prototype programs to test the general applicability of cars, trucks, and buses fueled by natural gas. More general application of CNG, however, will require the development of an infrastructure to service these vehicles, so it is highly uncertain how fast or how far such technologies might progress. The *AEO92* Reference Case assumes a modest penetration level—beginning at 100 billion cubic feet in 2005, and growing to 300 billion cubic feet by 2010. Under higher world oil prices, consumption by CNG vehicles would increase from 100 billion cubic feet in 2000 to 700 billion cubic feet in 2010.

Regulatory Uncertainties for Gas

Two major factors creating uncertainty in the projections for natural gas within the U.S. energy economy have already been cited: technological advances and competition from imports. A third factor that could have considerable impact consists of potential changes to the institutional framework of the industry. Although Government regulation of this framework has already been transformed radically during the past 10 years, some regulatory issues remain.

Two important issues for interstate pipelines are: (1) the "comparability of service," and (2) rate structures. The principle of the first is that those who simply pay a pipeline to carry their gas should receive the same quality of service as that offered to customers who purchase gas from the pipeline. As for rates, an announced goal is that they should be structured to be both "fair" and competitive. The Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) on July 31, 1991, that addresses these issues. It does so by "unbundling" sales of gas and transportation services for interstate pipeline companies, instituting "open access" service in storing gas, and recommending the use of what is called a "straight fixed-variable rate design," in which *all* fixed costs (including return on equity and associated taxes) would be covered by the basic demand charge for pipeline service—exclusive of the amount of gas actually transported. Because the NOPR is subject to extensive public discussion and review, *AEO92* did not attempt to gauge the effects a final version might have. The projections in this document assume the existing rate structure, including a "modified fixed-variable rate design" that leaves pipeline operators at risk for some of their fixed costs by making these part of the "commodity component" of gas-transport tariffs. The proposed combination of incentives, if implemented, could increase competition in the natural gas market. Some U.S. producers believe the proposed rate structure will allow them to be more competitive with Canadian sources.

Another regulatory item that could have significant impact is Order No. 555, issued by FERC on September 20, 1991. Implementation of the Order has been stayed, pending rehearing; but its main intent is to expedite the process by which pipeline construction is authorized, consistent with all applicable environmental laws. One provision is a new, abbreviated procedure that might be used to change a pipeline company's existing rates in order to charge either incremental cost-based rates or negotiated rates for the new facilities. The possible effects of Order No. 555 on gas markets were not included in the *AEO92* projections. Although Federal regulatory changes of this type could affect natural gas consumption significantly, it should be noted that FERC has jurisdiction only over *interstate* wholesale operations; changes of this type in Federal regulation might be almost moot if complementary modifications did not take place at the State level.

A key *legislative* item relating to natural gas consumption is the proposed reform of the Public Utility Holding Company Act (PUHCA), which is not taken into consideration in the *AEO92* projections. This reform would further encourage independent power producers, many of whom use and will use natural gas as a fuel. Advocates of bills now before Congress to repeal or modify PUHCA feel that allowing holding companies to own independent generators will increase competition in the electric utility industry and incidentally increase the market for natural gas. Those opposing these bills argue that the addition of many more independent suppliers could reduce the overall reliability of the electric utility industry.

Electricity Outlook

U.S. electric utilities are both major *producers* and large *consumers* of energy, and because of this they will play a pivotal role in the Nation's energy future. By 2010, almost one-fifth of the energy consumed by end users will be in the form of electricity. Electric utilities, already the largest energy-consuming sector in the Nation, will use approximately 40 percent of all the primary energy consumed in 2010.

Planning for the years ahead, while always fraught with uncertainty, will be even more difficult because the electric utility industry appears to be evolving towards a more competitive framework. No matter what structure emerges, however, electricity consumers will still expect the same reliable supplies of electricity to which they have grown accustomed over the years.

Recognizing the uncertainties associated with economic growth and world oil prices, this forecast follows the format of the rest of *AEO92* in devising a range of projections rather than a single Reference Case. However, because relatively little oil is now used by electricity suppliers, variations in the world oil price make little difference to them directly. Therefore, only the economic growth scenarios are used to frame the discussion presented here. In addition, there are many proposed regulatory and legislative initiatives (pertaining to issues such as conservation, wholesale power generation, transmission access, and the environment), that may affect planning for future electricity supplies. Their possible effects on various projections are discussed only qualitatively.

Electricity Demand

Apart from weather, nothing exerts more influence on the demand for electricity in this country than variations in economic growth. Because electricity is used in the production and consumption of most goods and services, as well as directly by consumers, the demand for electricity increases during times of high economic activity. From 1970 through 1980, GNP grew at an average annual rate of 2.8 percent per year, while sales of electricity grew (on average) by 4.2 percent annually. During the 1980's, however, increased emphasis on energy efficiency led sales of electricity to grow by 2.6 percent per year while GNP grew at an average annual rate of 2.7 percent. Even though sales growth far outdistanced GNP growth in 1990 (primarily because of the recession), the overall trend for the 1980's is expected to continue over the next 20 years—approximately a one-to-one relationship. From 1990 through 2010, GNP is expected to increase on average between 1.8 and 2.7 percent per year while sales of electricity will grow by 1.8 to 2.2 percent per year (Table 6). Electricity, like other sources of energy, will be used more efficiently as the economy expands.

During the next 20 years, growth in the demand for electricity is expected to account for approximately 35 to 50 percent of the growth in total end-use energy consumption. Because of the growing use of electricity for space heating and water heating as well as for lighting and cooling, almost 90 percent of the increase in energy consumed for end uses in the commercial sector,[10] and 55 to 60 percent in the residential sector, will be attributed to electricity use. In the industrial sector, the penetration of new electricity-using technologies and processes, and growth in those industries where electricity is consumed most intensively will result in 60 to 100 percent of the increase in end-use energy consumption being attributable to electricity.[11]

Electricity is perceived by consumers as a clean and convenient form of energy. Its share of end-use energy consumption is expected to increase because the price of electricity (reflecting costs) is projected to rise much more slowly than the prices of other energy sources over the projection period. In fact, State regulatory authorities often structure electricity prices in such a way as to mitigate the impacts of events that might otherwise cause large price increases. For instance, regulators frequently require that the capital costs of expensive new generating facilities be phased in over a number of years to avoid the sudden price impacts that might otherwise result. Thus, even as the demand for

[10]For this calculation, the electricity generated by the commercial sector for self-use was considered end-use energy consumption. The fuel used by that sector in producing electricity (either for sale to the grid or for self-use) was considered primary energy consumption.

[11]This calculation followed the same rules for the industrial sector as those cited for the commercial sector in the preceding footnote.

Table 6. U.S. Electric Power Projections for 2010

	1990	Alternative Projections for 2010		
		Reference	High Economic Growth	Low Economic Growth
Net Demand[a] (billion kilowatthours)				
Sales by Utilities	2,705	3,996	4,218	3,834
Self-Generation by Nonutilities[b]	115	172	190	165
Net Energy for Load (billion kilowatthours)	**2,924**	**4,294**	**4,527**	**4,128**
Net Electricity Imports	2	62	62	62
Purchase from Nonutilities	115	400	504	319
Generation by Utilities	2,807	3,832	3,961	3,747
Generation by Fuel Type—Utility and Nonutility (billion kilowatthours)				
Coal	1,594	2,317	2,440	2,132
Oil	121	159	150	169
Gas	379	765	819	811
Nuclear	577	634	690	619
Renewables/Other[c]	367	530	555	502
Total	**3,037**	**4,404**	**4,655**	**4,231**
Capacity—Utility and Nonutility (gigawatts)				
Coal	306	395	417	364
Oil/Gas	209	287	303	288
Nuclear	100	102	113	99
Renewables	88	114	117	110
Other[c]	21	30	30	30
Total	**725**	**927**	**979**	**890**
Fossil Fuel Consumption—Utility and Nonutility (quadrillion Btu)				
Coal	16.4	22.9	24.0	21.4
Oil	3.6	6.8	7.1	7.3
Gas	1.3	1.7	1.6	1.8
Cumulative Utility Retirements from 12/31/90 (gigawatts)	—	47	45	47
Cumulative Additions from 12/31/90 (gigawatts)	—	**249**	**299**	**212**
Utility (Announced)	—	53	57	51
Utility (Not Announced to Date)[d]	—	130	156	110
Nonutility	—	65	86	51
Average Electricity Prices[e] (1990 cents per kilowatthour)				
Capital	3.0	2.2	2.3	2.1
Fuel	1.7	2.8	2.9	2.8
Operating and Maintenance	2.1	2.0	2.0	2.0
Total	**6.7**	**7.0**	**7.1**	**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, includes 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.

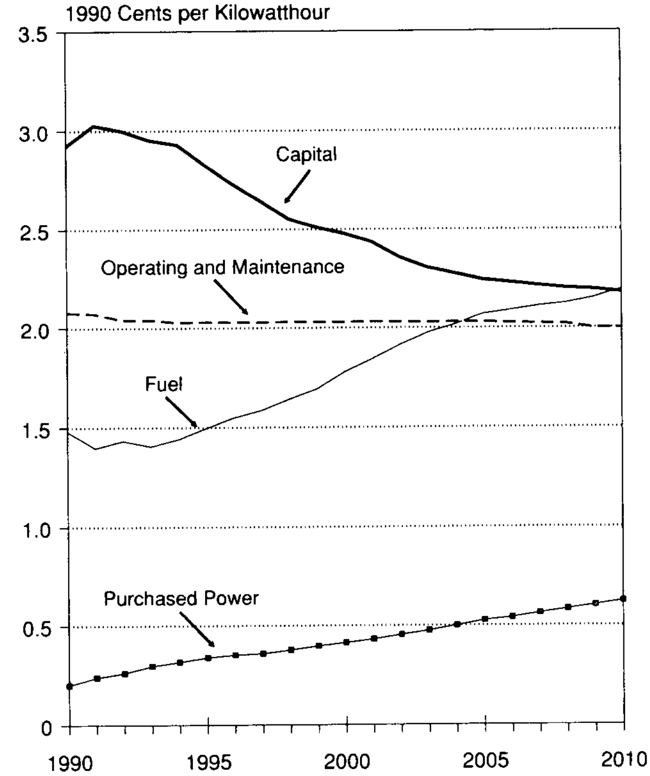
[d]Additions in this category are primarily facilities whose construction is projected beyond 2000, which utilities are not required to report to EIA.

[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.

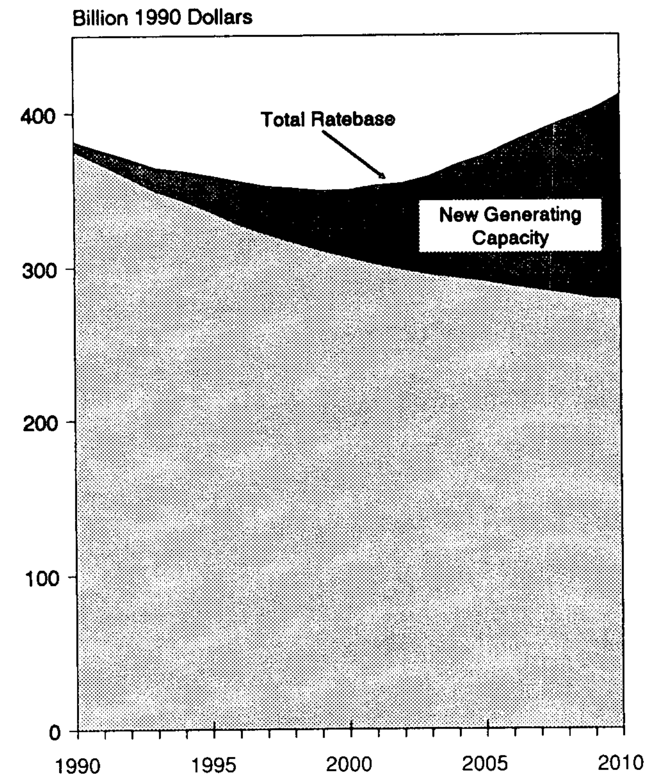
Sources: Tables A4, A5, C4, C5, D4, and D5.

Figure 16. Components of Electricity Price, 1990-2010 (Reference Case)



Source: Table A4.

Figure 17. U.S. Electric Utility Ratebase, 1990-2010



Source: Energy Information Administration, AEO 1992 Forecasting System.

electricity increases and new generating capability is needed, electricity consumers are likely to remain somewhat insulated from sharp price increases.

The Price Factor

Nationally, *average* electricity prices are expected to remain flat until the turn of the century and then rise slightly. This is true despite the fact that the price of all the fuels used to generate electricity (except nuclear fuel) will increase—with natural gas increasing at the greatest rate. The costs of purchased power per kilowatthour also increase as nonutilities command a greater share of electricity generation. Although fuel and purchased power costs per kilowatthour increase throughout the forecast period, these expenses will be offset by the fact that capital costs per unit of output will decline for the average utility (Figure 16).

Capital costs per unit of output decline in this timeframe for several reasons. First, utilities will extend the operating lives of many existing plants rather than build new plants to replace them. Since the capital cost to extend the life of a fossil-fueled steam plant is only about 20 percent as great as the cost of building a new power plant,[12] the return on invested capital and the depreciation expense will be lower than those for a newly built plant. Second, the increase in power purchases from nonutilities means that the generating capacity provided by those nonutilities will not have to be built by the utilities themselves. Third, as new baseload plants built by utilities enter service after 2000, revenues related to the total return on invested capital will grow more slowly than the increase in sales. There are two reasons for this. Old generating capacity becomes fully depreciated and is removed—unit by unit—from the ratebase.[13] And, because the electric utility industry is so capital intensive, investments in new plants may be relatively small compared with the amount already invested (Figure 17). Even at the peak of foreseeable construction activity, the $100 billion (in 1990 dollars) that the Nation's electric utilities will

[12]Energy Information Administration, *Estimating the Capital Costs of Life Extension for Fossil-Fuel Steam Plants*, DOE/EIA-0509 (Washington, DC, July 1988).

[13]The ratebase is the total prudent investment in plants and equipment, net of accumulated depreciation, on which regulated utilities are allowed to earn a return by ratemaking commissions.

spend on construction in 2010 will equal less than 25 percent of the total ratebase of $404 billion projected at that time; and it will take several years to bring most of this new outlay into rates.[14]

The spread in electricity prices between cases, while small, is driven by the difference in the costs for natural gas between the High and Low Economic Growth Cases. The greatest spread in price between these cases occurs around 2005, when the difference is about 0.5 cents per kilowatthour (7.1 cents per kilowatthour in the High Economic Growth Case and 6.6 cents per kilowatthour in the Low Economic Growth Case). In that year, the cost of natural gas to electric utilities in the High Economic Growth Case is calculated at $4.94 per million Btu, while it is $3.90 per million Btu in the Low Economic Growth Case.

Differences in Operation and Maintenance (O&M) costs and in the expenses associated with capital are offsetting between the two variant growth scenarios. The Low Economic Growth Case has higher O&M costs per kilowatthour (due to lower electricity sales volume over which to spread these costs), but the High Economic Growth Case has higher capital costs than the Reference Case after 1995 (because greater expansion in capacity is required).

Demand-side Management

Continued growth in the demand for electricity is expected to increase the need for new generating resources as the turn of the century approaches. However, many utilities plan to reduce their requirements through investments in conservation and demand-side management (DSM) programs. These programs, designed to modify the hourly, daily or seasonal variations in electricity demand for a utility, and generally to increase the efficiency of electricity production and consumption, come in many forms. They include informational efforts, time-of-use and interruptible rate programs, and rebates to customers for adopting more efficient appliances and equipment.

Utilities have reported plans to increase expenditures on DSM programs over the next decade, from around $1 billion annually now to about $3 billion a year by 2000.[15] In 2000, these additional investments are expected to reduce the peak load utilities must supply by approximately 6 percent and to lower total sales of electricity by about 2 percent.[16] Much uncertainty surrounds the effects of DSM programs because most of the current estimates of DSM savings are based on potential reductions rather than on measured, verified reductions. Over the next few years, as existing programs are evaluated and actual savings are measured, the future of DSM will be clearer.

Electricity Supply

Because the growth in U.S. demand for electricity slowed during the 1980's, many utilities were left with idle or underutilized capacity. Consequently, for the rest of this decade, utilities will be able to satisfy increasing demand in part by utilizing current capacity more intensively. Nationwide, the average capacity utilization factor for electric utilities is expected to increase from about 46 percent in 1990 to between 51 and 52 percent in 2000. Nevertheless, some new plant construction will be required before the turn of the century.

When a power supplier finds that it must build a new plant, the technology it chooses is determined in large part by how the new unit is to be used, what the relative prices of fuels in the area are expected to be, and what type of capacity already exists in the region. Because demand fluctuates during the day and because electricity cannot be stored easily, some capacity is operated more or less continuously (to handle the base load), while other units will be called on only when demand is at its highest (peak load capacity). Large coal, nuclear, and hydroelectric plants are especially suited for baseload operation because, though expensive to build, they use low-priced fuels—making them relatively cheap to operate. Conversely, combustion turbines are less costly to build, but they use relatively expensive fuels (such as oil and natural gas), making their operation economical only for short periods. Combined cycle plants tend to fill the area between base load and peak load, called intermediate or cycling load.

Much of the new capacity needed before 2000 will be used for intermediate and peak load operation. As a result, almost 45 to 50 percent of the 80 to 100 gigawatts of capacity added by the end of the century will be fueled by natural gas or oil. After 2000, existing capacity is expected to be utilized to its fullest extent. Therefore, power suppliers are expected then to begin adding new baseload capacity. Of the 130 to 200 gigawatts of capacity added after 2000, between 40 and 55 percent will burn coal.

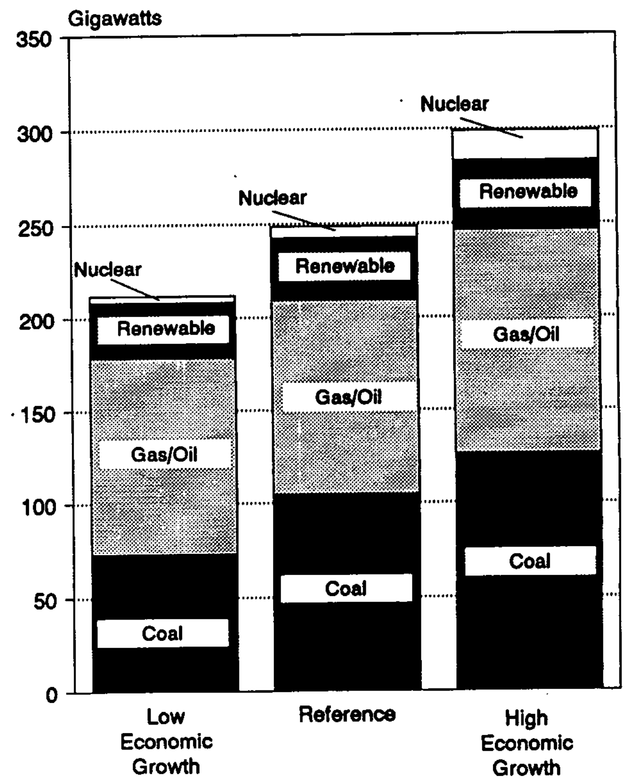
[14]In the cost-of-service method most ratemaking commissions use, the recovery of prudent construction outlays in rates takes many years; and ordinarily it is not even begun until construction is completed or very close to completion.
[15]Energy Information Administration, Form EIA-861, "Annual Electric Utility Report" (1990).
[16]These reductions are accounted for implicitly in the demand models as efficiency improvements.

Utilities and nonutilities have already reported plans to build between two-thirds and four-fifths of the capacity that will probably be needed by 2000. Many of the unannounced capacity additions are expected to be gas-fired or oil-fired plants which have relatively short construction times, allowing planners to bring capacity on-line quickly as it is needed. Little of the capacity expected to be built after 2000 has been reported yet as planned capacity, because utilities are only required to report plans for the upcoming 10 years, nonutilities for the upcoming 5.

It is still uncertain how the ownership of capacity to be built during the next 20 years will be divided between traditional utilities and nonutility sources. The Public Utility Regulatory Policies Act of 1978 (PURPA, Public Law 95-617) encouraged the growth of nonutility sources by obliging utilities to buy the power produced by nonutilities who qualify under the criteria of the law—at the cost the utilities avoid through those purchases. Nonutility sources can be divided into three categories: (1) cogenerators, who are generally large industrial power consumers that produce steam and electricity for their own needs and sell the excess to local utilities; (2) "small power producers" (electricity producers who, because of their small size or their use of renewable energy sources, receive qualifying status under PURPA); and (3) "independent power producers" (power producers without PURPA qualifying status and without market power in their service territory). Today, nonutilities form an important segment of the electricity supply market, and their significance is expected to increase in the future. Of the 210 to 300 gigawatts of capacity added by 2010 (Figure 18), approximately 25 to 30 percent is expected to be built by nonutility sources. By selling power to utilities and generating electricity for their own use, nonutilities will supply approximately 10 to 15 percent of U.S. electricity (including net imports) in 2010.

Net imports of electricity from Canada and Mexico are expected to reach 62 billion kilowatthours per year by 2010 (compared with an average of 25 billion kilowatthours annually over the past 5 years). Imports are expected to increase as water conditions in Canada improve, assuming normal precipitation, and as proposed contracts come into service. In 1990, net imports were only 2 billion kilowatthours, the lowest level in almost two decades, because exports of electricity from the Midwest to Ontario reached a record high.[17] Although electricity imports meet only a small percent of the Nation's total power needs, they

Figure 18. Prospective Additions to U.S. Generating Capacity by 2010



Sources: Tables A5, C5, and D5.

are an important source of reliable power in certain regions of the country.

The Fuel Mix

Fossil Fuels

The present mix of fuels used to generate electricity will be altered only slightly by the capacity added during the next 20 years. Coal was used to generate more than half of the electricity produced in 1990. Coal's share declines slightly before the turn of the century, but rebounds to its present level after 2000 because of the addition of new coal-fired plants.

Low-sulfur coal use will represent a greater share of coal consumption, as the requirements of the Clean Air Act Amendments of 1990 (CAA90) are phased in during the forecast period. CAA90 establishes a unique, market-based approach to reduction of sulfur dioxide

[17]For detailed information see Energy Information Administration, *U.S. Electricity Trade with Canada and Mexico*, DOE/EIA-0496(91) (Washington, DC, December 1991).

(SO_2) emissions,[18] whereby electric utilities receive a limited number of marketable emission permits or "allowances" each year.[19] Each marketable allowance permits the utility to emit 1 ton of SO_2 for that year or any year thereafter. As a result of CAA90, an estimated 600,000 allowances will be traded among companies in 2010—at an average price that will probably range from $610 to $705 (in 1990 dollars). In addition, between 11 and 16 gigawatts of coal-fired capacity are expected to be retrofitted with scrubbers.

Because of the addition of combined-cycle and combustion turbine generators, natural gas will continue to gain in importance, surpassing nuclear power once again (for the first time since the early 1980's) as the second largest source of U.S. electricity generation. The percentage of generation (both utility and nonutility) that is fueled by natural gas will increase from 12 percent in 1990 to between 17 and 19 percent in 2010, while nuclear power's share drops from 19 to around 15 percent. Residual fuel oil and renewable sources (including hydroelectric power) will maintain their 1990 shares of 4 and 12 percent, respectively.

Electricity suppliers are already large energy consumers. In 1990, electricity generators used all of the nuclear energy consumed in this country, more than 85 percent of the coal, over 55 percent of the renewable energy, nearly 45 percent of the residual fuel oil, and almost 20 percent of the natural gas.[20] Electric utilities will account for most of the growth in the consumption of each of these fuels by 2010.

Nuclear Power

Current Plant Status

On December 31, 1990, there were 111 operable U.S. nuclear power plant units, with a total net capacity of 100 gigawatts. No new nuclear units were licensed for operation in 1991. In early October 1991, the 167-megawatt Yankee Rowe unit, located in Massachusetts, was shut down indefinitely. Eight nuclear units, with a total net capacity of 10 gigawatts, were in the construction pipeline; but construction on six of these units has been deferred indefinitely—leaving only Comanche Peak 2 and Watts Bar 1 actively under construction.

Nuclear plants produced a record 577 net billion kilowatthours of electricity in 1990—a 9 percent increase over 1989. This was 21 percent of all the electricity generated by U.S. electric utilities during the year, and 19 percent of total U.S. electricity generation (including nonutility generation).

In 1990, U.S. nuclear units achieved an overall average capacity factor of 66.0 percent, which was 3.8 percentage points above the 1989 value and the highest in the history of the industry.[21] For the first 7 months of 1991, nuclear unit performance got even better, with an average capacity factor of about 70 percent. It was not expected that this level would be sustained for the entire year, but a new record high seems likely. This would be the fourth consecutive year that nuclear performance showed notable improvement over the average capacity factor of 57 percent experienced from 1979 (the year of the Three Mile Island accident) through 1987 (Figure 19). This general improvement in plant performance has a number of causes. Among them is greater utility emphasis on and expenditure for plant maintenance and other factors that improve performance—most notably, better training for operators. Also, relatively few units during this period have been in their first fuel cycle—when, historically, performance has been lower; so their effect on the average capacity factor was minimal. Finally, the nuclear industry has been shifting gradually to longer operating cycles between refueling, and instrumentation and control systems have been improved generally.

Current Industry Activity

In 1990 and 1991, the U.S. nuclear power industry continued efforts to revitalize itself, that is, to make the nuclear option attractive to utility decision makers. One such effort was the 1990 publication of the *Advanced Light Water Reactor Utility Requirements Document*.[22] This was a collaborative effort begun in the mid-1980's by DOE and the industry, as represented by the Electric Power Research Institute (EPRI) and the reactor manufacturers, to ascertain utility requirements for new nuclear plants. Also, in order to develop more unity in addressing nuclear power issues, the industry restructured and consolidated some of its existing organizations and formed new ones. The Nuclear Management and Resources Council (NUMARC) and the Nuclear Power Oversight Committee (NPOC) are

[18]The goal of Title IV of the CAA is to reduce both sulfur dioxide (SO_2) and nitrogen oxides (NO_x), which react with other chemicals in the atmosphere to form acids that fall onto the Earth as "acid deposition" or "acid rain."

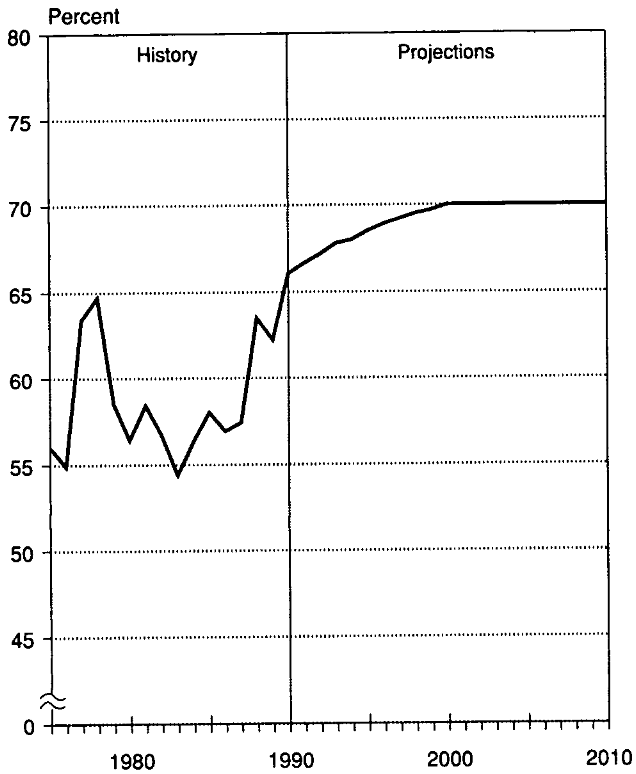
[19]No allowances are issued for NO_x emissions. Instead, the bill suggests maximum emission rates.

[20]These calculations were made using consumption in British thermal units, not physical units.

[21]Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(91/10) (Washington, DC, October 1991).

[22]Electric Power Research Institute, *Advanced Light Water Reactor Utility Requirements Document* (Palo Alto, CA, March 1990).

Figure 19. Nuclear Capacity Factor, 1975-2010



Sources: **History**: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(90/08). **Projections**: Energy Information Administration, AEO 1992 Forecasting System.

examples of this reorganization. In 1990, NPOC developed the *Strategic Plan for Building New Nuclear Power Plants*.[23] The goal of this plan is to have orders for new nuclear power plants by the mid-1990's. Also in 1991, the Department of Energy published the *National Energy Strategy*,[24] and many of the nuclear provisions of the Strategy are contained in major energy legislation that is currently being considered by Congress.

The Department of Energy has also embarked on a joint, multiyear program with industry to enhance the prospects for a nuclear plant order and to avoid the premature retirement of current units. Departmental activities supporting these goals include:

- Providing $20 million for engineering support for standardized Advanced Light Water Reactor (ALWR) designs;
- Participating in a project in which DOE funds are being matched by industry to assist in the certification by the Nuclear Regulatory Commission (NRC) of two evolutionary and two Advanced Light Water Reactor designs ("evolutionary" refers to large, improved versions of current technology; "advanced" refers to mid-sized plants that employ passive safety features);
- Demonstrating the NRC's early site certification process for nuclear plant construction by seeking and assisting an applicant for an early site permit. This is considered important, because it would provide a degree of certainty to a key step in obtaining a new nuclear order. Also, a newly initiated study by a DOE internal working group to identify ways to improve siting and permitting procedures for energy facilities in general will include nuclear power plants.
- Demonstrating the NRC license renewal process (which would permit a unit to continue operating for 20 years beyond its current license period) by obtaining two lead plant renewals by 1995.

Among the more important developments in the rapidly changing legal and regulatory framework of electric power production is the emergence of independent power producers (IPPs). Although no nuclear plants are yet owned by true IPPs, the concept of such ownership has been advocated by numerous parties, including the DOE, nuclear utilities, reactor manufacturers and architect-engineers. However, nuclear power faces economic uncertainties (high variability in cost and performance) and financial requirements that make this option problematic. Moreover, the mechanisms for allocating these risks are uncertain and subject to variability.[25]

Obstacles to New Orders

Before any utility or investor can be expected to order a new nuclear unit, several issues need to be resolved. A number of obstacles to nuclear orders were identified during public hearings on the National Energy Strategy.[26] Many of these issues have also been identified by representatives of the nuclear industry.

One issue is that tangible progress needs to be made on developing a permanent site for high-level waste disposal or—at least—the construction of a temporary

[23]Nuclear Power Oversight Committee, *Strategic Plan for Building New Nuclear Power Plants* (Washington, DC, November 1990).
[24]U.S. Department of Energy, *National Energy Strategy* (Washington, DC, February 1991).
[25]For a fuller treatment of this issue, see Energy Information Administration, *Commercial Nuclear Power 1991: Prospects for the United States and the World*, DOE/EIA-0438(91) (Washington, DC, August 1991), pp. 21-27.
[26]U.S. Department of Energy, *Interim Report, National Energy Strategy* (Washington, DC, April 1990).

storage facility (referred to as monitored retrievable storage) needs to be decoupled legislatively from the siting of the permanent repository, as is currently required by the Nuclear Waste Policy Act of 1982. The DOE is pursuing site characterization studies at Yucca Mountain, Nevada for eventual high-level waste disposal.

Another issue is that greater certainty in the reactor licensing process is needed. This could be provided by legislated one-step licensing (that is, provision of a combined construction permit and operating license), the availability of preapproved standardized designs, and advanced site certification.

Third, nuclear power must be deemed to be economically advantageous over alternative technologies for baseload generation in various regions of the country. This could be accomplished in large measure if licensing and construction times could be reduced to about 6 years from the average of about 14 years during the 1980's—a goal that industry spokesmen consider feasible.

Finally, interstate compacts (cooperative agreements) for the disposal of low-level nuclear waste must be established; the lack of such facilities will be an obstacle to any utility considering an order for a new nuclear power plant.

License Renewal and Life Extension

Whether or not new reactors are ordered, utilities are interested in being able to continue operating existing units beyond their current licensed lives. A few unit licenses will expire before 2010, but many will reach their 40-year limit in the 10 years that follow. The Atomic Energy Act of 1954 explicitly permits license renewal for commercial nuclear plants; but neither the regulatory requirements for the scope and content of license renewal applications nor the procedures for submitting and reviewing them have been defined. Currently, the NRC plans to put a license renewal program in place by 1994.

Although the two are related, life extension is an issue separate from license renewal. The latter is an administrative procedure to design a regulatory framework; the former is a more complex subject, relating to physical plant aging. The decision to "life extend" will depend on the economics of any needed restoration and subsequent performance, compared with the economics of providing alternative sources of power (which would include the cost of decommissioning the nuclear plant). Unlike license renewal, life extension does not have a prescribed procedure or timetable. It could become an issue before or after a license expires, and it will be very plant-specific.

Nuclear Capacity Assumptions

The three projections of nuclear capacity presented in *AEO92* are not produced explicitly by the modeling framework, but instead are based on sets of assumptions made in concert with the various macroeconomic cases. In all cases, it is assumed that regulatory procedures for license renewal would be implemented.[27] Other assumptions are specific to each case.

In the Low Economic Growth Case, low demand for electricity led to an assumption that none of the units whose construction has been deferred would be completed, no new orders would be placed, and only 30 percent of existing units would be life-extended. As a result, nuclear capacity rises to 103 gigawatts by the end of the century (as the two units currently under construction come on line), but then it declines to 99 gigawatts by 2010 because of retirements. In the Reference Case, because of relatively higher electricity demand, two of the six deferred units are assumed to be completed, and it is assumed that the lives of 50 percent of the existing units are extended. Consequently, operable nuclear capacity rises to 105 gigawatts in 2005 before declining to 102 gigawatts in 2010. In the High Economic Growth Case, all deferred units are assumed to be completed, 6 gigawatts of new nuclear orders are assumed to be built, and 70 percent of existing capacity is assumed to be life-extended. The result is a steady rise to 113 gigawatts of operable nuclear capacity in 2010. The High Economic Growth Case assumes changes in laws and regulations that establish an environment more conducive to new nuclear orders.

In summary, generation from nuclear power increases from the 1990 level of 577 billion kilowatthours to between 619 to 690 billion kilowatthours in 2010. The nuclear share of electricity generation (including nonutility generation) drops from around 19 percent in 1990 to approximately 15 percent in 2010.

Renewable Energy

Renewable energy resources are those that replenish themselves naturally. Generating systems which use these resources include hydropower, geothermal, solar

[27]Because fewer than a dozen units will reach their license expiration date by 2010, this assumption has a small effect on the projections.

thermal, ocean thermal, photovoltaic, wind, and biofuel plants. Biofuels include wood, municipal solid waste (MSW), landfill and sewer gas, and liquid fuels that can be produced from biomass (ethanol and methanol). Renewable energy sources are vastly different from one another in the stages of development they have reached. Hydropower is a mature technology, while others (such as MSW) are just becoming commercialized. Some (such as photovoltaics) are still at early stages of development, except for small-scale and specialized applications.

The current impetus to use renewable resources for the generation of electric power stems largely from the Public Utility Regulatory Policies Act of 1978 (PURPA), which was discussed earlier. Besides encouraging small-scale power production, PURPA was intended to promote renewable energy sources. Recent concerns regarding environmental pollution and possible global warming have provided additional impetus, via a comprehensive set of provisions in CAA90.

In 1990, 56 percent (3.6 quadrillion Btu) of all the renewable energy use accounted for in this country (6.4 quadrillion Btu) was directed to producing electricity. Hydroelectric sources accounted for 84 percent of this. Municipal solid waste and biomass contributed 11 percent, with all other sources (geothermal, solar thermal, and wind) supplying the small remainder (Table 7).

It is difficult to project how the ownership of renewable electricity generating facilities will be shared in the future among electric utilities, independent power producers (IPP's), PURPA "qualifying facilities," and industrial cogenerators. However, judging from the facilities added in recent years and reports of planned additions, nonutilities are expected to provide the majority of such new generating capacity. Renewable-based capacity in the nonutility sector is expected to grow at an average rate of 5 percent per year, much faster than the 0.3-percent rate in the utility sector. By 2010, it is estimated that 37 percent of nonutility capacity will be supplied by renewables. When comparing renewable fuels with fossil fuels, it would be better to examine output energy; but this is much more difficult to project. The sources of some renewable-based capacity are available only intermittently, so that capacity may not be proportional to actual electricity output.

Renewable-based net capability is expected to increase from 88 gigawatts in 1990 to between 110 and 117 gigawatts in 2010, an average annual increase of about 1.3 percent. MSW will fuel roughly 42 percent of the additions, followed by geothermal (24 percent), wind (13 percent), and hydropower (11 percent).

Economic considerations relating to cost and performance characteristics are only some of the factors that determine whether or not renewable power capability will be added. Certain environmental concerns, difficulties in obtaining and retaining licenses, and some operational inefficiencies may also constrain growth. These are the main reasons why only 79 gigawatts of hydroelectric capacity are projected by 2010 (representing only 3 gigawatts of additions since 1990), despite an estimated potential of 174

Table 7. U.S. Renewable Electric Generating Capability, Projections for 2010
(Gigawatts)

Type of Technology	1990	Alternative Projections for 2010		
		Reference	High Economic Growth	Low Economic Growth
Conventional Hydropower	76	79	79	79
Geothermal	3	8	11	6
Municipal Solid Waste	2	13	14	12
Biomass/Other Waste[a]	5	7	7	7
Solar Thermal	[b]0	2	2	2
Solar Photovoltaic	[b]0	[b]0	[b]0	[b]0
Wind	2	5	5	5
Total Renewable	**88**	**114**	**117**	**110**

[a]Includes wood, wood waste, and other biomass.
[b]Less than 0.5 gigawatts.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Tables A6, D6, and E6.

gigawatts.[28] Conversely, the rapid growth anticipated in power generation from MSW is due to improvements in combustion technologies and pollution controls, but also to problems associated with alternative methods of handling MSW—stringent and costly landfill regulations, plus difficulties in finding new sites for landfills.

The share of renewable generation from non-hydropower resources is expected to increase to 39 percent in 2010, up from 16 percent in 1990. Total electric power generation from renewables should displace between 5.0 (Low Economic Growth Case) and 5.5 quadrillion Btu (High Economic Growth Case) of conventionally-derived primary energy by 2010.[29] The range is relatively narrow because major sources of electric generation (hydropower, geothermal, and MSW) are generally insensitive to changes in world oil prices and macroeconomic conditions. Instead, their projected penetration is based on a number of non-economic factors—such as licensing policy, regulatory support, water availability, location of resources (relative to requirements and infrastructure), fiscal incentives, and technological improvements that reduce costs and improve performance characteristics.

Issues Generating Uncertainty

In recent years, a challenge has arisen to the notion that the electric power industry is a natural monopoly (an industry where the complex and pervasive infrastructure of distribution makes it far more efficient for a single supplier to provide service than for many small suppliers to duplicate facilities). Historically, the regulation of the electric power industry has been based on this premise. Now, the successful growth of the nonutility electricity supply market has led many industry analysts to believe that electricity *generation* is not a natural monopoly at all and should be deregulated. Wholesale electricity transactions are also beginning to take place within a less tightly regulated environment. The outcome of the debate on power industry structure—and the eventual effects of possible changes—are not clear. The trend toward deregulation and possible disaggregation of the electric utility industry could result in a more efficient use of resources and lower prices overall; on the other hand, it might undermine the reliability of service and subject customers to monopolistic abuses.

Electric utilities are developing integrated resource plans that consider the full costs of supplying electricity. As a result, new rules and regulations are emerging that attempt to create a level playing field for all supply and demand options when resource plans are developed. Not only are incentives being created (and disincentives removed) for demand-management programs; efforts are also underway to account for environmental and other external societal costs of supplying electricity. This evolving regulatory structure may result in a more energy-efficient country and a cleaner environment . . . *or* it may lead to inefficiencies greater than those the modifications attempt to solve.

Too much uncertainty surrounds these regulatory and deregulatory proposals to account for them effectively in the projections presented in this chapter; but—because they could have striking effects on the future of the electric power industry and the meaningfulness of the analysis put forth in *AEO92*—the major issues will be discussed here briefly.

Reform of PUHCA of 1935

The reform of the Public Utility Holding Company Act of 1935 (PUHCA, Public Law 74-333), which was enacted to prevent investor-owned utilities[30] from using complex corporate structures to avoid regulatory oversight, is being considered as a way to enhance the competition that has arisen among electricity generators since the passage of PURPA. Currently, because of PUHCA, an investor-owned utility that chooses to operate as a holding company in more than one State subjects itself to detailed regulation of its financial dealings by the Securities and Exchange Commission (SEC). Only if an investor-owned utility abandons the holding company structure or limits its operations primarily to a single State can it be exempted from PUHCA regulation. Some argue that PUHCA limits the growth of a more competitive generation market because a *nonutility* company that wishes to enter the independent power market must also limit its operations to a single State or risk regulation by the SEC, which ultimately could include divesting itself of its original nonutility operations.

It was in order to promote increased efficiency in the use of energy and better utilization of small-scale and renewable energy resources for electricity generation that Congress enacted PURPA in 1978. To maximize

[28]Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States—Developed and Undeveloped* (Washington, DC, January 1988), page vii.

[29]In the past, gross energy inputs from renewable sources were measured. Measuring net energy displacements (from fossil-based fuels), however, provides a better understanding of the impacts of renewable energy penetration over time.

[30]PUHCA defines an electric utility as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale." As a result, "independent power producers," as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), are considered "electric utilities" under PUHCA.

the effects of PURPA, Congress allowed "qualifying facilities" under PURPA to be exempted from PUHCA regulation. The success of PURPA, seen in the rapid growth of "nonutility" electricity generation since the law was enacted, has kindled the flame of competition among generators. Many now believe that PUHCA itself should be amended to allow *continued* growth in competition among generators of electricity, and numerous bills regarding PUHCA reform were introduced during the 102nd Congress.

By increasing competition, PUHCA reform could facilitate meeting the Nation's need for new electricity generating capacity. More competition might also lead to other benefits—including lower capital costs for new generating technologies, improved generating efficiencies, lower electricity prices, and reduced risks to consumers of cost overruns for new generating capacity. On the other hand, if PUHCA reform were to allow unregulated subsidiaries to engage in unsound financial practices with their regulated parent companies (such as self-dealing to inflate profits and using risky leverage schemes that involve large amounts of debt compared to equity), this would be detrimental to ratepayers and system reliability.

Market-Based Wholesale Rates

As the wholesale power market grows, some participants (both nonutilities and utilities) hope to move from cost-based to market-based rates[31] for wholesale electricity. Through a series of rulings in 1990, the Federal Energy Regulatory Commission (FERC), which regulates most wholesale power transactions, established precedents for approving market-based rates for independent power producers (IPPs), affiliated power producers (APPs), and traditional utilities. The FERC has approved market-based rates for an IPP if the IPP can show that it does not have "market power" in the region where it will operate (that is, if the producer does not furnish such a significant fraction of the region's power that it can singlehandedly have a marked effect on total supply and price). Among the factors considered by the FERC to determine if an IPP has market power are whether the utility purchasing its power considered other resource options before deciding to buy from the IPP, and whether the IPP owns or controls access (on its own or through affiliates) to transmission facilities in the region where it will operate.

Transmission Access

Although competition is developing in electricity generation, electricity transmission remains a monopoly service. Therefore, continued regulation of both price and "obligation to serve" is necessary. Large investor-owned utilities own much of the Nation's bulk power transmission system. Where they hold clear market power, access to transmission lines can be denied to wholesale power buyers and sellers . . . or the owners can charge such a high price for access that it is effectively denied. A dispute has arisen between transmission-owning utilities (who refute claims that they unjustifiably restrict access to transmission lines) and utilities and nonutilities that *lack* transmission capacity (who urge regulators to *require* more open access to transmission systems).

With relatively open access to transmission, wholesale power purchasers and sellers could usually trade with the lowest and highest priced bidders, respectively. In addition, generating units could be built where they are most economical—applying the country's resources more efficiently. On the other hand, power line owners have a valid point when they argue that any transmission system would be less reliable if more distinct enterprises used it. Furthermore, a public utility, which has an obligation to serve its assigned customer area, might invest in new generating capacity, only to find that it got no return on that investment because its customers decided to buy power from another supplier—who could use the first company's lines to deliver it. Forecasting the demand for electricity would become even more difficult if customers were allowed to come and go as competitive electricity prices changed. Despite such problems, recent rulings have leaned toward making U.S. systems more accessible to wholesale buyers and sellers.

The FERC, which regulates most wholesale power transactions, has used other issues as the means of broadening transmission access. For example, the agency approved the merger of Pacific Power and Light Company with Utah Power and Light Company on the condition that the new company provide access to its combined transmission system. In another ruling, the FERC granted the Public Service Company of Indiana (PSI) the right to sell 450 megawatts of power (from its excess capacity) at market-based rates—but only on the condition that PSI offer greater access to its transmission system.

Approaches to DSM

Historically, the regulatory ratemaking process has linked utility earnings directly to the level of electricity sales. Electricity rates were set in such a way as to allow a utility to recover its expenses and to make a reasonable return on its capital investment. However,

[31]Market-based rates are determined by competitive forces in the wholesale electricity market, usually through a bidding process.

advance rate-determination was based on *projections* of electricity sales. If actual sales turned out to be lower than projected, a utility's total earnings were reduced; and the difference might or might not be recognized in the next round of rate-setting decisions by regulators. Of course, sales that exceeded expectations would bring a higher return (at least in the short run); yet this relationship provided a disincentive for a utility to invest in and to run effective demand-side management programs. Anything that reduced electricity sales threatened the utility's earnings.

Recognition of the regulatory disincentives to DSM has led State public utility commissions (PUCs) to review and revise their resource planning processes. Many States have adopted a methodology of integrated resource planning (IRP), which tries to include all relevant costs and impacts (including environmental costs, effects on local employment, and so forth) when developing plans for both supply- and demand-side resources. Several States are also experimenting with various strategies to encourage utilities and others to invest in DSM programs. Among the approaches are revenue adjustment mechanisms, shared-savings programs, and resource bidding programs.

For instance, regulators in California have developed an electric revenue adjustment mechanism (ERAM) that decouples utility earnings from sales. Essentially, the ERAM program creates a balancing account to adjust utility revenues so that "allowed" fixed costs are covered even if actual sales prove different from the projections made when rates were set. If sales are higher than projected, a surplus is created; this is returned to ratepayers through future rate reductions. On the other hand, if sales are lower than projected, a shortage is created—which is recovered through future rate increases. As a result, utility earnings will not be reduced because of investments in DSM programs.

Commissions in the New England States, New York and California, are also using share-the-savings programs to spur increased utility investment in DSM. The utility is allowed to keep a portion of the difference between the cost of the DSM program it institutes and the costs that would have been incurred to produce the power the program saves. The level of incentive varies from State to State and from program to program, as Commissions continue to develop, evaluate and modify their individual approaches.

In the New England States many new utility resources (both supply-side and demand-side) are now acquired through a competitive bidding process. This puts DSM programs on equal footing with supply-side resources, by requiring utilities to define explicit criteria by which to evaluate proposals. In addition, the bidding process creates a vehicle for third-party energy service companies[32] (ESCOs) to participate in DSM when this proves efficient and desirable.

Environmental Externalities

Environmental concerns have led State Public Utility Commissions to establish regulatory measures for dealing with the adverse environmental effects associated with the production and consumption of electricity. According to a survey released by the National Association of Regulatory Utility Commissioners in 1990, at least 17 States now have mechanisms for incorporating environmental externalities (costs associated with environmental degradation that are not normally reflected in power pricing) into the processes utilities use for resource planning.[33]

The measures established include preferential treatment by PUCs for options the commissions consider more environmentally benign, simple additions of some percentage to the cost estimates for more harmful options, and attempts to directly quantify all the costs and benefits of each option.[34] Because the true costs of any option are difficult if not impossible to measure, there is always a risk that such mechanisms may inadvertently create incentives or disincentives which, in the long run, may be more undesirable than the original externalities. Nonetheless, these mechanisms are gaining favor because they attempt to deal with the environmental problems of generating electricity "proactively"—during the planning process, rather than after problems appear.

[32]Energy service companies "sell" reductions in the demand for electricity achieved via a conservation or demand-side management program.

[33]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).

[34]*Ibid.*

Coal Outlook

Coal Production

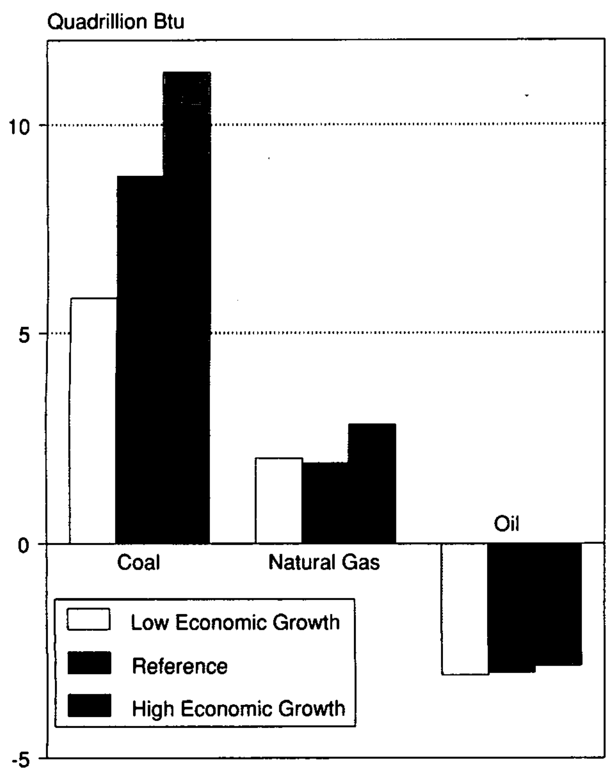
Coal accounts for a greater share of U.S. primary energy production than any other fuel, having surpassed petroleum in 1984. Its importance is projected to be even greater by 2010 (Figure 20). Depending on future world oil prices and the level of U.S. economic growth, coal's share of total U.S. energy production is estimated to rise from 31 percent in 1990 to a range between 35 and 38 percent by 2010.

From 1,029 million short tons in 1990, coal production is projected to grow by approximately 1 percent per year during the 1990's—rising to between 1,096 and 1,171 million short tons by 2000. During the second half of the forecast period, however, coal's growth is more rapid (between 1.8 and 2.9 percent per year). Its production reaches 1,311 million short tons in the Low Economic Growth Case and 1,555 million short tons in the High Economic Growth Case by 2010 (Table 8).

The development of large surface mines in Wyoming and lignite mines in Texas catapulted the share of coal that is produced west of the Mississippi River from 7 percent in 1970 to 39 percent in 1990. However, the East-West regional breakdown of future U.S. coal production should remain fairly stable through 2010 (Figure 21). Mines located west of the Mississippi River are projected to account for roughly 40 percent of total U.S. coal production in all three cases throughout the forecast period.

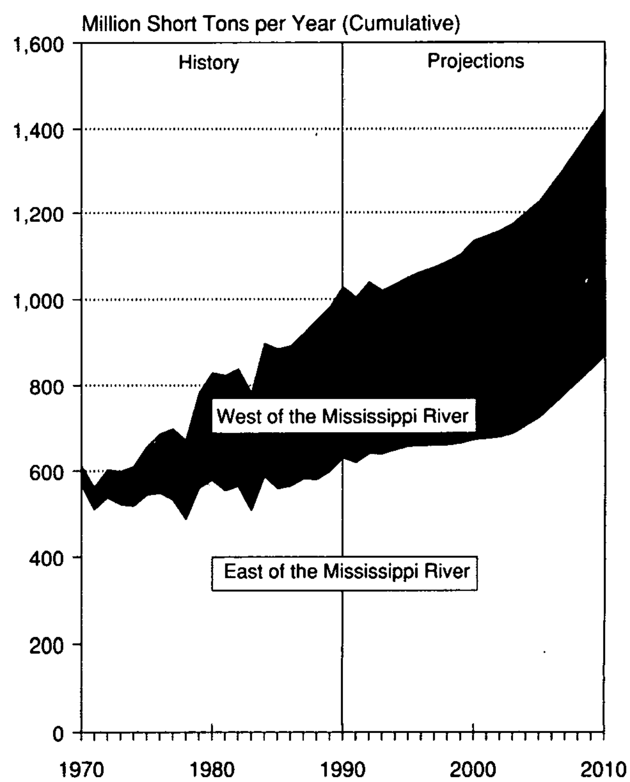
The expected stabilization in regional production shares is explained by two major factors: (1) a large increase in

Figure 20. Change in Annual U.S. Production of Fossil Fuels, 1990-2010



Sources: Tables A1, D1, and E1.

Figure 21. East-West Division of Coal Production, 1970-2010 (Reference Case)



Sources: **History:** Energy Information Administration, *Annual Energy Review 1990.* **Projections:** Table A10.

Table 8. Coal Supply, Disposition, and Prices, 1990 and 2010
(Million Short Tons)

	1990	Alternative Projections for 2010				
		Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price
Production	1,029	1,445	1,555	1,311	1,430	1,449
Exports	106	235	289	185	233	236
Imports	3	11	11	11	11	11
Stock Withdrawals[a]	-26	-8	-10	-6	-8	-8
Consumption						
Residential/Commercial	7	4	4	4	4	4
Industrial	76	85	86	84	85	84
Coke Plants	40	27	27	27	27	27
Electricity	772	1,097	1,151	1,016	1,200	1,216
Total	**895**	**1,213**	**1,269**	**1,131**	**1,200**	**1,216**
Discrepancy[b]	7	0	0	1	0	0
Prices (1990 dollars per short ton)						
Average at Minemouth	21.76	31.63	32.90	29.98	31.59	31.40
Average Delivered[c]	31.61	42.15	42.59	40.97	42.16	41.54

[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 due to independent rounding.
Sources: Tables A10, B10, C10, D10, and E10.

U.S. coal exports, most of which will originate from mines east of the Mississippi, and (2) less growth in the consumption of coal for electricity generation west of the Mississippi River as compared with the past 20 years. Despite a substantial increase in the demand for low-sulfur coal stemming from the Clean Air Act Amendments of 1990, low-sulfur western coal faces difficulties in penetrating eastern markets further because of the high transportation costs associated with the long haulage distances and the additional costs and problems posed in the conversion of existing bituminous coal-fired plants to burn subbituminous coal. Suppliers in central Appalachia are expected to meet most of the increased demand for low-sulfur coal east of the Mississippi River at a lower overall delivered cost than that of western low-sulfur coal.

Based on these coal production forecasts, and assuming that labor productivity will improve by 2 percent per year in underground U.S. coal mines and by 1 percent annually at U.S. surface mines, the number of U.S. miners is projected to decline from 131,000 in 1990 to between 114,000 and 124,000 in 2000—as gains in productivity outpace gains in coal production. After 2000, however, production growth picks up more rapidly; and this leads to employment increases—reaching a level of between 119,000 and 142,000 mining jobs by 2010.

Coal Consumption

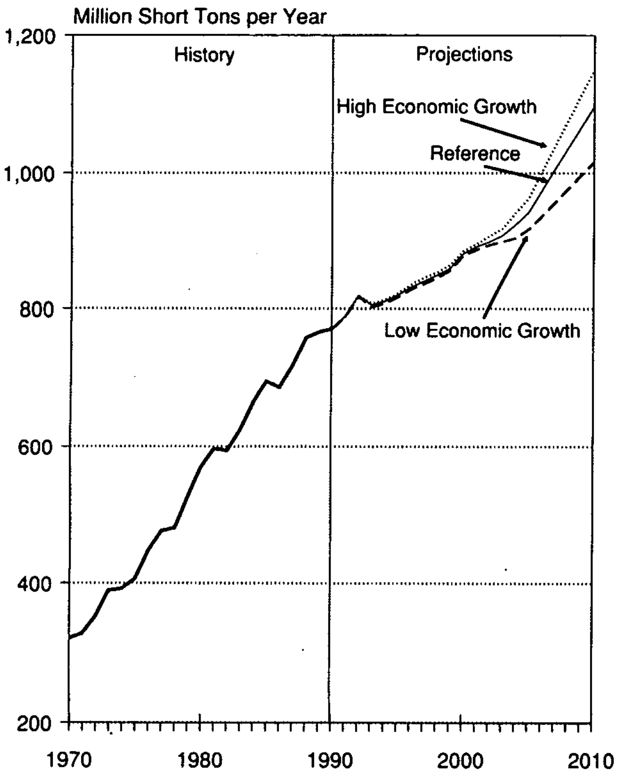
Coal accounted for 22 percent of U.S. energy consumption in 1990; and it is expected essentially to retain this share over the forecast period. Depending on economic growth assumptions, coal should comprise between 23 and 24 percent of total U.S. energy consumption in 2010.

Electricity production, the largest coal-using sector by far, accounts for virtually all of the projected growth in domestic coal consumption. From 772 million short tons in 1990, coal consumption for electricity generation increases to approximately 880 million short tons by 2000 in all cases (Figure 22). During this period, the growth in coal consumption for electricity generation will result mostly from fuller utilization of existing capacity, as only about 10 gigawatts of additional coal-fired capacity (net of retirements) will be added.

By 2010, the U.S. electricity sector is projected to be consuming between 1,016 and 1,151 million short tons of coal. Although plant utilization rates will continue to rise after 2000, it is the addition of between 47 and 101 gigawatts of new coal-fired capacity that will account for most of the additional coal consumption projected in the electricity sector. These coal-fired capacity additions include those by nonutility power producers, who should add somewhere between 7 and 26 gigawatts over the forecast period. With the exception of the Low Economic Growth Case, most of this expansion is projected to come after 2000.

During the 1990's, variations in electricity demand across the scenarios are expected to be met primarily by variations in gas-fired generation. Between 2000 and 2010, however, coal is expected to become the economical "first fuel choice" for new power generation. As noted in the preceding chapter, nuclear power (which played a large role in satisfying increased electricity demand during the preceding 20 years) will continue to contribute at approximately its current level of generation.

Figure 22. U.S. Coal Consumption for Electricity Generation, 1970-2010



Sources: **History:** Energy Information Administration, *Annual Energy Review 1990.* **Projections:** Tables A10, D10, and E10.

Industrial consumption of coal (other than for metallurgical purposes) is expected to stay near the 1990 level of about 76 million short tons through 2005. A steady decline in conventional industrial demand for steam coal is offset by growing use of coal for cogeneration (the simultaneous production of electricity and either process heat or process steam). However, by 2010, industrial steam coal consumption rises to approximately 85 million short tons in all cases. This increase is based on the expectation of a small increase in the production of coal-based synthetic gas and slightly greater use of coal in the industrial sector in general. The forecast for industrial coal consumption is virtually the same in all three cases, because most of the variation in industrial energy demand is handled by other fuels.

Domestic demand for metallurgical coal should decline gradually, from 40 million short tons in 1990 to 27 million short tons by 2010 in all cases, as existing coke plants are retired and no new facilities are built (due to environmental restrictions). This substantial reduction, however, does not reflect the same magnitude of decline in U.S. coke demand. Net imports of *finished* coke are expected to rise to approximately 8 million short tons by 2010—up from only about 200,000 short tons in 1990. These projected imports are equivalent to a displacement of about 11 million short tons of domestic metallurgical coal, almost exactly the decline expected over the next 20 years.

Growth in Exports

Exports are expected to be the fastest growing segment of the U.S. coal industry over the next two decades. This growth is driven by three major factors: declining coal production in Europe, as subsidies and trade restrictions are reduced; growing electricity demand in Asia; and the limited capability of other countries to increase their exports after the year 2000. Although environmental laws of the European Community favor the low-sulfur coals of South America, South Africa, and Indonesia, these exporters are expected to be near the upper limits of their capacity by 2000.

Worldwide, coal is used primarily to produce steam for the generation of electricity. Since electricity demand is strongly related to general economic conditions, the coal export projections vary considerably across the alternative economic growth rate cases. The projections for 2010 range from 185 million short tons in the Low Economic Growth Case to 289 million short tons in the High Economic Growth Case. Thus, exports represent between 14 and 19 percent of U.S. coal production in

2010, compared with 10 percent in 1990. The variation across the oil price cases is much less, because very little potential exists, or will exist, for substitution between oil and coal in either industrial applications or for electricity generation. Consequently, world coal trade should not be affected significantly by variations in oil prices.

Most of the projected growth in U.S. exports will occur after 2000, when the United States and Australia are the only countries still able to expand their export capabilities significantly. Furthermore, Australia's post-2000 capacity is expected to be limited by uncertain prospects for Australian coal in Europe, where U.S. coal should be highly competitive due to lower freight rates. Before 2000, new coal industry capacity in countries such as Colombia and Indonesia will supply much of the growing world coal demand.

Coal's Price Advantage

Projected minemouth coal prices rise in real terms over the forecast period, recovering from a steady decline that started in 1978. Strong demand for the low-sulfur coal of central Appalachia (stemming from the emission-reduction requirements of the new Clean Air Act Amendments and the large projected growth in U.S. coal exports) will raise minemouth prices in this region considerably, and many new mines will need to be opened to meet the expected demand. In general, increases in coal mining productivity are expected to level off, and the current surplus of production capacity should dissipate. This excess capacity resulted after many new mines opened during the late 1970's to meet large anticipated increases in coal demand. As other energy prices fell, the demand for coal—while increasing significantly—did not reach the level the industry had hoped for.

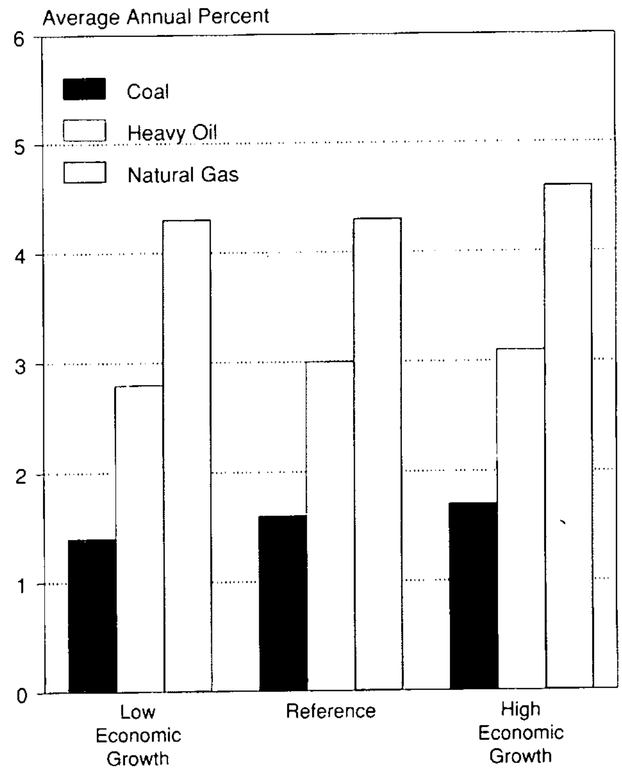
Minemouth prices rise in the *AEO92* forecasts at an average rate of between 1.6 and 2.1 percent per year—from about $22 per short ton in 1990 to between $30 and $33 per short ton (in 1990 dollars) by 2010. The higher the economic growth rate assumption, the higher is the demand for coal and the resulting average coal price. With only a moderate rise in coal transportation costs projected for the next two decades, the average delivered price of coal rises by only about 1.4 percent per year—going from about $31 per short ton in 1990 to $42 in 2010.

Coal prices rise less than other fuel prices in all cases, as illustrated by the projected price of fuels delivered to electricity suppliers (Figure 23). Projected coal prices also vary somewhat less than those for other fuels across scenarios. The Nation's abundant coal reserves can be mined at costs that should rise very gradually. This is the primary reason why coal is expected to remain the dominant energy source for electricity generation throughout the forecast period.

U.S. Coal Movements

U.S. coal is distributed from three major producing areas (Appalachia, Interior, and Western) to three broad domestic demand regions (East, Central, and West) and to export outlets. The distribution pattern should change to some extent over the forecast period. Developments in the world economy and international coal trade will be responsible for the greatest change, as U.S. coal exports rise substantially. By 2010, exports should account for between 14 and 19 percent of total coal movements within the United States, compared with their 10-percent share in 1990 (Table 9). While virtually all export coal originated in Appalachia in 1990, between 7 percent and 10 percent of exports are

Figure 23. Average Annual Growth Rates of Fossil Fuel Prices to Electricity Suppliers, 1990-2010



Sources: Tables A3, D3, and E3.

expected to come from the Interior Region by 2010, depending on the assumptions about economic growth, and about 6 percent should come from the Western Region by the end of the forecast period.

The changes in purely domestic coal distribution patterns are more subtle. The Central Region will remain the leading domestic coal-consuming region, receiving about 48 percent of the coal distributed domestically in 2010—nearly the same as in 1990. Primarily because of the early installation of scrubbers by Midwestern utilities and the growth of lignite-fired electricity generation in Texas, the Central Region is expected to receive an increasing share of its coal from mines in the Interior Region—rising from 34 percent in 1990 to about 36 percent in 2000 and roughly 39 percent in 2010 (with little variation among the alternative cases). Nearly all of the market share gained by Interior producers is lost by Appalachian producers, as shipments from Appalachia to the Central Region rise only slightly.

Consumers in the East are projected to receive a slightly smaller share of the coal distributed domestically in 2010 than the 37 percent they received in 1990. In 1990, about 83 percent of Eastern coal receipts came from Appalachian mines. As the Clean Air Act Amendments of 1990 increase the demand for low-sulfur coal from central Appalachia, this percentage will go even higher—until utilities install more scrubbers and other factors come into play after 2000. Between 2000 and 2010, more high-sulfur Interior coal

Table 9. U.S. Coal Distribution by Demand and Supply Regions, 1990, 2000, and 2010
(Million Short Tons)

Demand Region[a]	Supply Region[b]	1990	Alternative Projections for 2000			Alternative Projections for 2010		
			Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth
East		335	347	347	345	429	443	406
	Appalachia	279	302	295	302	345	347	331
	Interior	53	44	46	44	75	84	69
	Western	3	1	6	0	10	13	6
Central		447	493	498	491	577	602	533
	Appalachia	103	100	101	98	112	113	111
	Interior	151	180	177	182	223	240	199
	Western	194	214	220	210	242	248	223
West		132	149	148	148	204	221	187
	Appalachia	*	0	0	0	0	0	0
	Interior	*	0	0	0	0	0	0
	Western	132	149	148	148	204	221	187
Total Domestic Distribution		**914**	**989**	**993**	**984**	**1,210**	**1,266**	**1,127**
Exports		104	144	177	112	235	289	185
	Appalachia	99	130	160	100	201	244	159
	Interior	1	3	5	0	21	29	13
	Western	4	12	12	12	13	16	12
Total Distribution		**1,018**	**1,133**	**1,171**	**1,096**	**1,445**	**1,555**	**1,311**

[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.

*Less than 500,000 short tons.

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

Sources: **1990:** Energy Information Administration, *Coal Distribution January-December 1990*, DOE/EIA-0125(90/4Q) (Washington, DC, April 1991). **Projections:** AEO 1992 Forecasting System runs LMAC92.D0923913, AEO92B.D0923913, and HMAC92.D0923914.

will be burned in the East as additional scrubbers are installed on existing plants and new plants are equipped with scrubbers or advanced clean coal technologies. Combined with an increase in receipts of low-sulfur coal from the West, this leads to a slight decline in the share of the East's coal coming from Appalachia (to approximately 80 percent).

Because coal-fired electric power generation in the West grows rather rapidly, that region will experience a higher rate of growth in coal receipts than either the East or the Central Region. As a result, the West is projected to account for about 17 percent of total domestic coal distribution in 2010—up from 14 percent in 1990. Western Region producers will continue to supply virtually all of the coal distributed to consumers in the West throughout the forecast period.

Variables in Coal's Future

To a large extent, the uncertainties of the coal production and price forecasts are quantified through the development of projections for the five alternative cases, each with different assumptions for the principal factors influencing the energy sector: economic growth rates and future world oil prices. However, other factors may also have important effects on the future of the U.S. coal industry. These include the implementation of the Clean Air Act Amendments and other environmental protection laws, the development of clean coal technologies and coal-based synthetic fuels, the evolution of world coal trade, and the possible effects on coal mining employment from technological and productivity changes.

New Clean Air Rules

The impacts of the Clean Air Act Amendments of 1990 on the coal industry are included in the forecast. However, the extent of these effects is uncertain, largely because of the choices facing the electric utility industry as to how it will comply with sulfur dioxide emissions limitations: utilities may install flue gas scrubbers, switch to low-sulfur coal, or use other options, such as buying emissions allowances. For some utilities, the optimal compliance strategy will depend partly on the future price of Eastern low-sulfur coal; and this in turn will be affected by the demand for this high-quality coal by both utilities and exporters.

Various State and Federal factors can influence the fuel choice decision, or even determine the decision absolutely. For example, in an effort to protect their high-sulfur coal industries from the impacts of the Clean Air Act Amendments, Ohio, Illinois, and Indiana have passed legislation providing various incentives for utilities to install scrubbers. These include the partial funding of scrubber installations and the provision of tax credits for burning local coal. The Illinois law goes so far as to mandate specifically the installation of two scrubbers at each of two Illinois power plants. The ultimate impact of these incentives and the extent to which they will be adopted by other States are matters of conjecture.

Adding to the uncertainty is a Supreme Court case challenging an Oklahoma law that gives preference to coal mined within the State. Wyoming contends that the law violates the U.S. Constitution by restricting interstate commerce. Conceivably, the case could be extended to challenge the constitutionality of the laws already passed by other Midwestern States. The impacts of the Clean Air Act Amendments will also be affected by future regulatory decisions of the U.S. Environmental Protection Agency and State public utility commissions.

Clean Coal and Synthetic Fuels

An even more uncertain factor that is relevant to projections of long-term coal production 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 DOE's Clean Coal Technology Demonstration Program, as well as on other Federal and State initiatives.

The level of Government support will also affect the future extent of coal-based synthetic fuels production. Particularly for coal liquefaction, however, the primary factor is the perception of future oil prices. The price of commercially acceptable synthetics must be competitive with the prevailing world oil price at any given time. At the oil prices projected in this report, commercial coal liquids production by the year 2010 seems dubious without substantial subsidies.

World Coal Trade

The projections for rapid growth in U.S. coal exports are based on three major supply expectations: (1) declining coal production in Europe as trade barriers fall, (2) limited availability of Russian natural gas for export, and (3) limited capability of other coal-exporting countries to increase their shipments after 2000. On the demand side, electricity demand will continue to rise in Asia, which uses imported coal to generate a substantial portion of its electricity. Because they depend on political decisions, the extent and timing of European economic and international trade reforms (and thus the growth in world coal trade) are subject to uncertainty. Also, the ability of the United States to capture a growing share of the increasing world coal trade will depend to some extent on the degree of competition from Australian coal. This hinges on future ocean freight rates and developing suppliers, whose competitive strength can only be conjectured.

Another uncertainty concerning world coal trade involves the potential effects from future national and international policies based on apprehensions about global climate change. For instance, the European Community (EC) has considered a number of plans aimed at reducing its emissions of carbon dioxide (CO_2). One idea is to institute a carbon tax, based on the carbon content of fuels consumed. Another is to tax both carbon *and* energy consumption. Since coal has the highest percentage of carbon among the fossil fuels, it would be affected most by the adoption of such proposals. Furthermore, to achieve any meaningful CO_2 reduction, a pure carbon tax would have to represent a significant percentage of the total cost of coal. First, however, both the energy and the environmental ministers within EC would have to agree on any proposal of this type; and all plans submitted to date have drawn substantial opposition.

Although the *AEO92* forecasts do not incorporate any possible effects from this issue, it could conceivably bring about wide variations in EC coal consumption—and hence in U.S. coal exports. European demand for natural gas, renewable fuels, and nuclear power would be affected in various ways by the wide range of possible proposals. In addition, the effects of either carbon or energy taxes on the EC economy are highly uncertain, and evaluating them with any promise of accuracy would require extensive and careful analysis. (For example, while many of the proposals claim to have "revenue neutralizing" features, it is far from clear that there would be no net increase in the effective total tax burden.)

Productivity and Mine Employment

The overall employment level in U.S. coal mines is determined by two basic factors: the level of coal production and the average output per worker, or productivity. Changes in coal mining productivity are particularly difficult to forecast.

Coal mining productivity grew by a rapid 7.5 percent per year, on average, during the 1980's. Mechanization increased, more efficient mine sizes prevailed, and there were fewer mine strikes. In the *AEO92* forecasts, productivity gains are assumed to level off in the future—to about 1 percent per year for surface mining and 2 percent for underground mining. However, productivity could be affected by unforeseen changes in technology, the pace of mechanization, and the spread of longwall mining. Productivity could also be affected by future coal prices, since higher prices would allow less efficient mines to operate profitably. Any unanticipated changes in productivity would affect the coal mining employment projections.

Comparison With Other Forecasts

This section of the *Annual Energy Outlook 1992* compares the five EIA scenarios with outside forecasts. Projections by DRI/McGraw-Hill (DRI) and the WEFA Group (WEFA) are compared with *AEO92* projections for all fuels. Comparisons with several other forecasts are more limited. For example, the comparison to the 1992 Gas Research Institute (GRI) forecast is limited because only the GRI's overview is available at present, and several other forecasts do not cover the same fuels or forecast period as *AEO92*. The Canadian National Energy Board (NEB) offers comparable forecasts only for the world oil price and Canada's natural gas exports through 2010. The North American Electric Reliability Council (NERC) projects electricity supply and demand to the year 2000. The Enron Corp (Enron) projects natural gas supply and demand through the year 2005. The Independent Petroleum Association of America (IPAA) estimates petroleum and natural gas supplies and demands to the year 2000.

All of these forecasts extend through the end of the century, however; and most go to 2010 in at least some categories. Over this 20-year period, many changes are expected with regard to public and corporate planning, legislation, and new technologies. In longer term forecasting, projections depend on assumptions that are made about future events such as these as well as about the paths of the driver variables. The following discussion compares the *AEO92* with other forecasts and—where applicable—relates the differences to underlying differences in assumptions.

Macroeconomic Assumptions

The *AEO92* assumes GNP growth rates between 1990 and 2010 that range from 1.8 percent per year in the Low Economic Growth Case to 2.7 percent per year in the High Economic Growth Case (Table 10). The non-EIA forecasts use macroeconomic growth rates that fall in the middle or upper half of this range, depending on expectations about the pace and strength of the current economic recovery. WEFA uses the highest average growth rate (2.4 percent per year), partly because this forecast uses the Census Bureau's assumptions about high net immigration to arrive at a higher population estimate in 2010 than do the other forecasts. WEFA also uses an inflation rate that is higher than all *AEO92* cases except the Low Economic Growth Case. WEFA based this estimate on the assumption that non-farm labor costs rise at a rate of 5.6 percent from 1990 to 2010 (compared with the 4.9 percent assumed by DRI and by the *AEO92* Reference Case).

Table 10. Comparison of Macroeconomic Forecasts
(Average Annual Percentage Change, 1990-2010)

Category of Projection	*AEO92*					Other Forecasts		
	Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price	DRI	WEFA	GRI
Real GNP	2.2	2.7	1.8	2.2	2.2	2.3	2.4	2.2
Industrial Index	2.5	3.0	2.2	2.5	2.6	2.8	2.8	NA
Inflation[a]	3.9	3.1	4.9	3.9	3.8	3.8	4.1	4.4
Personal Income	1.8	2.2	1.5	1.8	1.8	1.8	2.1	1.8

[a]Inflation is the annual rate of increase of the GNP implicit price deflator.
NA = not available.
Sources: **EIA:** Energy Information Administration, *Annual Energy Outlook 1992.* **DRI:** DRI/McGraw-Hill, *Energy Review* (Fourth Quarter 1991). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Spring 1991). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991).

Petroleum Projections

The outside forecasts assume that world crude oil prices in 2010 will be between the $23 and $40 set by the Low and High Oil Price Cases of *AEO92* (Table 11). Because the price of crude oil is subject to periodic shocks, the forecasts assume price levels that each deems most likely to be sustainable in light of the amount of crude oil available worldwide. The NEB sees a price of $27 for West Texas Intermediate (WTI) in 2010, with a range from $20 to $35 representing the points at which this price becomes less sustainable.[35] The NEB prices should probably be recognized as a high approximation for the world oil price as defined in *AEO92*—because the WTI price has been more than $1.50 higher than the average cost of imported crude oil for the past 3 years. Adjusting the NEB projections for this differential leaves the NEB base case price lower than the WEFA projection of $26 in 2010, and its high boundary just slightly above the *AEO92* mid-price case but lower than either the DRI or the GRI forecasts. Enron assumed a $30 world oil price in 2005; this is comparable to the *AEO92* assumption for that year.

The outside forecasts for U.S. crude oil production (including natural gas plant liquids) lie between the 5.7 million barrels per day in the *AEO92* Low Oil Price Case and the 7.8 million barrels per day in its High Oil Price Case. The GRI forecast is the highest of all the base case projections, at 7.5 million barrels per day. The GRI forecast assumes that the increases in demand will create upward pressure on the world oil price, pushing it to $38 by 2010. In keeping with WEFA's lower oil price expectations, its forecast projects slightly lower crude oil production than does *AEO92*. The WEFA forecast anticipates a greater decline in oil production from known fields than does *AEO92*; but WEFA goes beyond *AEO92* in assuming that production from the Arctic National Wildlife Refuge will begin around the turn of the century and that production from a large field discovered in the Gulf of Mexico will begin by the end of the forecast period. WEFA also includes some increased production from oil shale, as well as production of coal-liquid fuels beginning by 2010. The DRI forecast is more pessimistic about the development of new sources for domestic crude oil at the turn of the century. That forecast is for a slightly higher level of production in 2000; but by 2010 its projection falls to a point about midway between the *AEO92* Reference and Low Oil Price Cases.

With regard to U.S. petroleum consumption, WEFA's projection for 2010 is not quite as close as DRI's and GRI's to the *AEO92* forecasts. WEFA (at 18.5 million barrels per day) predicts that total petroleum consumption will stay below the range set in the *AEO92*—which is 19.3 million barrels per day for both the High Oil Price and the Low Economic Growth Cases. The major difference is in the projections of motor gasoline consumption. *AEO92* projects a *rise* in consumption, from 7.2 million barrels of gasoline per day in 1990 to more than 8 million barrels per day in 2010; but WEFA projects higher vehicle efficiency and slightly fewer vehicle miles traveled than EIA does—resulting in a slight *decline* in consumption by 2010, to 6.8 million barrels per day. The DRI forecast, while within the *AEO92* range for total petroleum, is outside the range for motor gasoline. DRI expects reformulated gasoline to lower the consumption of conventional gasoline significantly, with all gasoline consumed in 2010 being of the reformulated type.

WEFA expects the demands for jet fuel and residual fuel oil to be slightly higher than those in *AEO92*'s Reference Case (but within the *AEO92* range). In the case of residual fuel oil, WEFA predicts stronger demand in the industrial sector—consistent with higher WEFA estimates for the future level of GNP and the industrial manufacturing index.

Natural Gas Projections

The forecasts are unanimous in predicting that natural gas will be competitive with other fuels in the future—particularly oil and coal—and that the largest source of future growth for natural gas lies in generation of electricity, both by utilities and cogenerators.

Because the natural gas picture is fairly tight across the *AEO92* cases, a number of comparison forecasts fall outside its range (Table 12). Enron's projection of the price for natural gas at the wellhead is farthest from that of *AEO92*, rising $1.40 above the highest EIA forecast by 2000. Enron expects more stringent environmental legislation to be enacted and projects that excess gas deliverability will vanish for this and other reasons—so that natural gas and oil become price competitive after 1995. GRI's wellhead price in 2000 is also above the highest *AEO92* projection for that year, although the GRI forecast shows less price growth after 2000 and its 2010 gas price projection falls within the *AEO92* range. The final wellhead price for WEFA is 44 cents below the lowest EIA forecast; this is attributable to optimism that technological advances, extended tax credits for production, competition from other fuels, and conservation gains will keep the price in check.

[35]The National Energy Board, *Canadian Energy Supply and Demand 1990-2010* (June 1991).

Table 11. Comparison of Petroleum Forecasts
(Million Barrels per Day, Except Where Noted)

Parameter	*AEO92* Reference	*AEO92* High Economic Growth	*AEO92* Low Economic Growth	*AEO92* High Oil Price	*AEO92* Low Oil Price	Other Forecasts DRI	Other Forecasts WEFA	Other Forecasts IPAA	Other Forecasts GRI
2000									
World Oil Price (1990 dollars per barrel)	26.40	26.40	26.40	31.80	17.90	27.11	22.23	NA	24.74
Crude Oil[a] and NGL Production	7.5	7.6	7.5	8.4	6.3	7.8	7.6	7.3	7.7
Crude Oil	5.9	5.9	5.9	6.7	4.7	6.1	6.0	5.7	6.3
Natural Gas Liquids	1.6	1.7	1.6	1.7	1.6	1.6	1.6	1.6	1.4
Total Net Imports[b]	9.8	10.6	9.3	8.5	12.1	9.3	8.2	10.3	10.0
Petroleum Demand[c]	18.4	19.2	17.9	17.9	19.5	18.1	18.0	18.6	18.6
Motor Gasoline	7.7	8.0	7.5	7.4	8.1	7.1	7.0	NA	7.3
Jet Fuel	1.7	1.9	1.6	1.7	1.8	1.7	1.8	NA	1.8
Distillate Fuel	3.4	3.6	3.3	3.3	3.6	3.4	3.5	NA	3.4
Residual Fuel	1.4	1.4	1.3	1.3	1.5	1.4	1.4	NA	1.6
2010									
World Oil Price (1990 dollars per barrel)	33.40	33.40	33.40	40.20	22.60	35.69	26.09	NA	38.38
Crude Oil[a] and NGL Production	7.2	7.3	7.2	7.8	5.7	6.4	6.9	NA	7.5
Crude Oil	5.5	5.6	5.5	6.1	4.2	4.7	5.3	NA	6.1
Natural Gas Liquids	1.6	1.7	1.7	1.7	1.5	1.7	1.6	NA	1.3
Total Net Imports[b]	11.6	12.9	10.8	10.2	15.4	12.2	9.6	NA	11.1
Petroleum Demand[c]	20.1	21.5	19.3	19.3	22.4	19.7	18.5	NA	19.5
Motor Gasoline	8.3	8.9	8.0	7.9	9.1	7.3	6.8	NA	7.3
Jet Fuel	2.1	2.4	1.8	2.0	2.2	2.0	2.3	NA	2.0
Distillate Fuel	3.7	3.9	3.5	3.6	4.5	4.0	3.7	NA	3.8
Residual Fuel	1.4	1.4	1.4	1.4	1.7	1.5	1.6	NA	1.4

[a]Includes lease condensate.
[b]Includes refined products.
[c]Includes feedstocks.
NA = Not available.
Sources: **EIA:** Energy Information Administration, *Annual Energy Outlook 1992.* **DRI:** DRI/McGraw-Hill, *Energy Review* (Fourth Quarter 1991). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Spring 1991). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991). **IPAA:** Independent Petroleum Association of America, Supply and Demand Committee, *Long-Run Forecast of U.S. Oil and Gas Trends* (May 1, 1991).

The only forecast of dry gas production outside the *AEO92* range is that by GRI. Its forecast for the year 2000 is slightly below the *AEO92* lower bound; but post-2000 production rises, so that by 2010 the projection is at the *AEO92*'s upper boundary. GRI cites the current low rate of new well development and soft prices as restraints on future production.

In all forecasts, imports from Canada show a projected increase to the capacity of all known projects, with GRI assuming additional capacity; and liquefied natural gas (LNG) imports are uniformly projected to increase to about 1.2 trillion cubic feet in 2010, suggesting that all existing terminals will be fully utilized. Consistent with the *AEO92* forecast, the NEB foresees 2 trillion cubic feet of natural gas being exported from Canada to the United States in 2000, and 2.3 trillion cubic feet in 2010.

On the consumption side, the outlook for natural gas powered vehicles varies. GRI estimates that in the year 2010 approximately 380 billion cubic feet of natural gas will be used in such vehicles. Enron projects demand

Table 12. Comparison of Natural Gas Forecasts
(Trillion Cubic Feet, Except Where Noted)

Parameter	*AEO92*					Other Forecasts				
	Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price	DRI	WEFA	GRI[a]	Enron[b]	IPAA
2000										
Wellhead Price (1990 dollars per trillion cubic feet)	2.72	3.02	2.46	2.53	2.79	2.71	2.56	3.15	4.42	NA
Dry Gas Production	19.2	19.8	18.6	19.3	18.9	18.6	19.2	18.5	19.1	19.1
Net Imports	2.7	2.7	2.7	2.7	2.7	2.8	2.8	3.0	[b]2.8	2.8
Consumption[c]	21.9	22.5	21.3	22.0	21.6	21.3	22.8	21.4	21.7	22.0
Residential	4.8	4.8	4.8	4.7	4.8	4.5	4.8	4.5	4.5	4.8
Commercial	3.1	3.1	3.0	3.1	3.0	3.0	3.1	3.2	[b]3.6	3.0
Industrial[d]	7.8	8.0	7.7	8.0	7.5	7.8	7.7	7.5	[e]6.0	7.8
Electric Utility	4.4	4.7	4.0	4.4	4.4	4.1	5.1	4.2	[e]5.3	4.6
2010										
Wellhead Price (1990 dollars per trillion cubic feet)	4.65	4.80	4.62	4.46	4.00	4.69	3.56	4.77	NA	NA
Dry Gas Production	19.3	20.2	19.4	19.4	18.0	18.4	20.0	20.2	NA	NA
Net Imports	3.3	3.3	3.3	3.3	3.3	3.5	3.2	3.6	NA	NA
Consumption[c]	22.7	23.5	22.7	22.7	21.4	21.8	24.0	23.6	NA	NA
Residential	4.6	4.6	4.5	4.5	4.7	4.3	4.9	4.3	NA	NA
Commercial	3.2	3.2	3.2	3.2	3.2	3.2	3.5	3.7	NA	NA
Industrial[d]	7.4	7.9	7.0	7.6	7.5	7.8	7.3	8.5	NA	NA
Electric Utility	5.5	5.7	6.0	5.4	4.2	4.6	5.8	4.6	NA	NA

[a]GRI publishes natural gas projections in trillion Btu. The quantities shown here represent the GRI projections divided by the *AEO92* natural gas conversion factor of 1,031 Btu per cubic foot.

[b]The Enron forecast excludes 0.3 trillion cubic feet of Alaskan production and consumption. The Enron projection for net imports includes supplemental gas. The Enron projection for commercial consumption includes approximately 0.5 trillion cubic feet consumed in natural gas vehicles.

[c]Includes lease and plant fuel and pipeline fuel.

[d]Excludes lease and plant fuel. Includes natural gas used as a feedstock.

[e]The electric utility projection shown for Enron represents natural gas used by all generators, including cogenerators. Thus, some of this consumption occurs in the industrial sector.

NA = Not available.

Sources: **EIA:** Energy Information Administration, *Annual Energy Outlook 1992.* **DRI:** DRI/McGraw-Hill, *Energy Review* (Fourth Quarter 1991). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Spring 1991). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991). **IPAA:** Independent Petroleum Association of America, Supply and Demand Committee, *Long-Run Forecast of U.S. Oil and Gas Trends* (May 1, 1991). **Enron:** Enron Corp, *Enron Corp's Outlook for Natural Gas* (Summer 1991).

from natural gas vehicles to reach 730 billion cubic feet by 2005, as State and Federal efforts to enlarge the "clean" vehicle market intensify. The corresponding WEFA forecast (469 billion cubic feet) and the DRI projection (409 billion cubic feet) are between those made by GRI and Enron, but the *AEO92* estimate is conservative by comparison. Its estimates range from less than 10 billion cubic feet in the Low Oil Price Case to 70 billion cubic feet in the High Oil Price Case.

The GRI, DRI, and Enron forecasts for residential consumption of natural gas in 2000 are below the range set in the *AEO92*. Greater efficiency in both heating equipment and thermal integrity combine to offset an increase in the number of gas-heated homes in the GRI forecast.

In the commercial sector, the forecasts for the year 2000 (with the exception of Enron's) are very close, but WEFA and GRI predict higher post-2000 consumption than does *AEO92* or DRI. In the GRI forecast, this is based on the success of advanced commercial cogeneration and space cooling techniques.

The industrial and electric utility projections are farther apart. In the case of Enron, this is because its utility forecast is actually a power plant forecast, representing the gas consumed for all generation purposes, utility and nonutility. Its industrial gas forecast excludes gas consumed for cogeneration, as well as lease and plant fuel. Combining these elements brings Enron's forecasts closer to those in *AEO92*. The high GRI growth rate for industrial use between 2000 and 2010 is attributable to increased use for process heat and steam, and for cogeneration. All of the forecasts cite increased competition between oil and gas in the future.

Electricity Projections

As Table 13 shows, WEFA and NERC projections of total electricity sales for the year 2000 are within the range of *AEO92* projections (after the NERC sales forecast is adjusted to account for transmission and distribution losses), although WEFA projects higher residential sales and lower commercial sales than does EIA. DRI projects lower electricity sales in the commercial and industrial sectors. These patterns are true also for 2010. The lower DRI projections can be attributed to its assumption of greater efficiency gains, particularly in the industrial sector. *AEO92* forecasts a greater rate of growth in the commercial sector than does either DRI or WEFA. As existing equipment is replaced, life-cycle costs favor electrical equipment as the replacement, backing out commercial natural gas. The WEFA forecast assumes the lowest residential efficiency gains.

The major differences in the electricity generation forecasts are in the amount of electricity generated from oil and gas. The GRI projection for coal-fired generation in 2010 also differs substantially from the other forecasts, falling below the low end of the *AEO92* projection range. The forecasters all agree that combustion turbines and combined cycle units will play a larger role in generation, particularly following the start of Phase Two of the Clean Air Act Amendments in the late 1990's. The extent and timing of this contribution varies, however. Compared with DRI, WEFA, and NERC, the *AEO92* is conservative in its estimate of increased oil- and gas-fueled generating capability at the end of the century; but it adds more of this type of capacity between 2000 and 2010 than the DRI forecast does. Since gas can be an economically and environmentally efficient fuel, WEFA expects increased use of these plants by electric utilities—so that larger amounts of generation will come from oil and gas by the year 2010.

The *AEO92* alone forecasts that total U.S. electricity *sales* (which count only the energy actually delivered to customers, after some has been lost in transmission and distribution) will rise above *electric utility generation* by the end of the forecast period. What makes this possible is a greater rate of expansion for nonutility generation capability, with cogenerators and other "outside" suppliers contributing more electricity to the grid.

Coal Projections

With electric utilities being the major consumers of coal (representing more than 85 percent of total domestic consumption in 1990), higher expectations for the use of coal in electricity generation drive the *AEO92* coal consumption forecast above the corresponding forecasts of DRI, WEFA, and GRI (Table 14). Apart from utility use, *AEO92* is low with respect to the other forecasts. A lower economic growth rate (compared with WEFA and DRI), and *AEO92* expectations about the increasing electrification of the industrial sector combined to give it a lower forecast for the industrial use of steam coal. The *AEO92* forecast for metallurgical coal is also lower, due to a lower expected demand for steel and pig iron (and, as a result, for coke). Also, as indicated in this report, EIA does not expect any new coke plants to be built in the United States—due to the high cost of meeting current environmental protection regulations.

Three assumptions about foreign activity drive the *AEO92* forecast for coal exports far above those of DRI and WEFA. The impact of eliminating coal production subsidies in Western Europe, the limited ability of other coal exporters to expand, and higher electricity demand growth in Asia lead to higher demand for U.S. coal. Without these considerations, DRI and WEFA keep the United States as the world's swing coal supplier and leave its coal exports closer to historical levels.

As a result of its higher forecasts in these two disposition areas, the *AEO92* forecast for domestic coal production is also higher than the others'.

Table 13. Comparison of Electric Utility Forecasts
(Billion Kilowatthours, Except Where Noted)

Parameter	AEO92					Other Forecasts			
	Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price	DRI	WEFA	GRI	NERC
2000									
Average End-Use Price (1990 cents per kilowatthour)	6.70	6.79	6.51	6.72	6.60	6.39	6.91	6.83	NA
Electric Generation[a]	3,253	3,304	3,200	3,233	3,272	3,242	3,374	3,253	3,213
Coal	1,740	1,741	1,736	1,739	1,742	1,734	1,737	1,747	1,839
Petroleum	152	170	142	140	177	152	164	194	88
Natural Gas	403	427	374	402	395	338	504	346	341
Nuclear	639	645	633	633	639	675	618	637	670
Electricity Sales	3,276	3,353	3,207	3,253	3,300	3,124	3,295	3,194	[b]3,513
Residential	1,084	1,100	1,067	1,073	1,093	1,100	1,121	1,076	NA
Commercial	1,050	1,057	1,045	1,048	1,051	973	930	955	NA
Industrial	1,142	1,197	1,095	1,132	1,155	1,039	1,133	1,152	NA
Capability (gigawatts)									
Coal Steam	306.1	305.5	306.1	306.1	306.1	[c]343.3	316.7	[c]337.0	308.9
Oil and Gas	209.6	212.8	206.5	208.7	210.1	[c]260.9	252.3	[c]263.9	226.5
Nuclear	104.2	105.6	102.9	102.9	104.2	[c]112.8	102.6	[c]103.7	105.0
2010									
Average End-Use Price (1990 cents per kilowatthour)	6.99	7.13	6.96	7.02	6.74	6.94	7.63	7.30	NA
Electric Generation[a]	3,832	3,961	3,747	3,790	3,852	3,744	3,961	3,595	NA
Coal	2,184	2,256	2,059	2,167	2,182	2,102	2,144	1,973	NA
Petroleum	152	143	162	150	329	182	234	204	NA
Natural Gas	532	535	586	524	377	404	602	451	NA
Nuclear	634	690	619	619	634	700	620	631	NA
Electricity Sales	3,996	4,218	3,834	3,937	4,043	3,578	3,918	3,667	NA
Residential	1,225	1,279	1,181	1,189	1,250	1,216	1,344	1,230	NA
Commercial	1,313	1,343	1,293	1,305	1,311	1,096	1,128	1,143	NA
Industrial	1,458	1,597	1,361	1,444	1,481	1,252	1,314	1,279	NA
Capability (gigawatts)									
Coal Steam	371.0	384.4	349.9	367.7	371.0	[c]396.7	381.2	[c]356.0	NA
Oil and Gas	248.7	254.8	250.8	244.3	253.5	[c]277.0	330.3	[c]275.2	NA
Nuclear	101.7	112.8	99.1	99.1	101.7	[c]112.8	102.3	[c]100.7	NA

[a]These projections represent generation from electric utility power plants. Other sources of supply, such as power generated by nonutilities or foreign utilities, are not included. In some cases, this leads to total sales estimates which exceed the generation values shown.

[b]The NERC projection in the Sales row is actually net energy for load. Technically, sales equal net energy for load *minus* transmission and distribution losses.

[c]For DRI and GRI, capability represents nameplate capacity; for the others, capability represents net summer capability. Nameplate capacity is generally accepted to be approximately 5 percent greater than net summer capability.

NA = Not available.

Sources: **EIA:** Energy Information Administration, *Annual Energy Outlook 1992*. **DRI:** DRI/McGraw-Hill, *Energy Review* (Fourth Quarter 1991). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Spring 1991). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991). **NERC:** The North American Electric Reliability Council, *Electricity Supply and Demand 1991-2000* (July 1991).

Table 14. Comparison of Coal Forecasts for 2010
(Million Short Tons, Except Where Noted)

Parameter	AEO92					Other Forecasts		
	Reference	High Economic Growth	Low Economic Growth	High Oil Price	Low Oil Price	DRI	WEFA	GRI
Minemouth Price (1990 dollars per short ton)	31.63	32.90	29.98	31.59	31.40	NA	[a]31.59	NA
Production	1,445	1,555	1,311	1,430	1,449	1,226	1,307	1,169
Net Coal Exports	224	277	173	221	224	127	98	127
Consumption	1,213	1,269	1,131	1,200	1,216	1,093	1,209	1,036
Electric Utility	1,097	1,151	1,016	1,084	1,101	955	1,042	918
Metallurgical Coal	27	27	27	27	27	35	33	35

[a]The minemouth price for WEFA was deflated from 70.60 nominal dollars using the WEFA GNP deflators of 2.939 in 2010 and 1.315 in 1990.

NA = Not available.

Sources: **EIA:** Energy Information Administration, *Annual Energy Outlook 1992.* **DRI:** DRI/McGraw-Hill, *Energy Review* (Fourth Quarter 1991). **WEFA:** The WEFA Group, *Energy Analysis Quarterly* (Spring 1991). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Supply and Demand, 1992 Edition* (August 1991).

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	14.54	13.13	12.64	12.56	-1.1
Natural Gas Plant Liquids	2.16	2.16	2.27	2.36	2.28	.3
Dry Natural Gas [2]	18.27	18.96	19.89	20.74	20.06	.5
Coal	22.46	22.95	24.33	26.49	31.23	1.7
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy [3]	6.62	7.52	8.51	9.51	10.36	2.3
Total	71.45	72.67	75.10	78.81	83.40	.8
Imports						
Crude Oil [4]	12.70	13.77	16.59	18.51	18.76	2.0
Petroleum Products	4.29	5.91	5.89	6.22	7.67	2.9
Natural Gas [5]	1.45	2.31	2.80	3.20	3.42	4.4
Other Imports [6]	.09	.61	.75	.98	1.18	13.6
Total	18.53	22.61	26.02	28.91	31.03	2.6
Exports						
Coal	2.77	3.15	3.72	4.64	6.09	4.0
Petroleum	1.80	1.63	1.66	1.73	1.82	.0
Total	4.57	4.79	5.38	6.37	7.90	2.8
Net Stock Withdrawals	-1.32	-.22	-.23	-.17	-.21	-8.7
Discrepancy [7]	.93	.22	.10	-.03	-.20	-
Consumption						
Petroleum Products [8]	33.79	35.01	36.39	38.23	39.59	.8
Natural Gas	19.38	21.17	22.57	23.82	23.37	.9
Coal	19.09	19.86	20.70	21.97	25.21	1.4
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [9]	6.57	7.91	8.98	10.08	11.02	2.6
Total	85.02	90.49	95.61	101.20	106.10	1.1
Net Imports - Petroleum	15.18	18.05	20.81	23.01	24.61	2.4
Prices (1990 dollars per unit)						
World Oil Price ($ per barrel) [10]	21.78	20.80	26.40	30.50	33.40	2.2
Natural Gas Wellhead Price ($ per Mcf)	1.72	2.02	2.72	3.70	4.65	5.1
Coal Minemouth Price ($ per ton)	21.76	24.01	26.64	28.71	31.63	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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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

Sector and Source	Reference Case 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Residential						
Distillate Fuel	1.00	0.91	0.70	0.57	0.48	-3.6
Kerosene	.09	.07	.05	.03	.02	-7.5
Liquefied Petroleum Gas	.46	.44	.38	.34	.32	-1.9
Natural Gas	4.50	5.01	4.94	4.85	4.71	.2
Coal	.06	.04	.04	.04	.04	-1.8
Renewable Energy [1]	.96	1.12	1.51	1.91	2.31	4.5
Electricity	3.14	3.51	3.70	3.94	4.18	1.4
Total	10.22	11.10	11.33	11.68	12.06	.8
Commercial						
Distillate Fuel	.51	.53	.49	.43	.40	-1.3
Kerosene	.05	.04	.03	.03	.02	-3.9
Motor Gasoline [2]	.10	.12	.12	.13	.14	1.5
Residual Fuel	.21	.17	.15	.13	.11	-3.2
Natural Gas	2.70	3.03	3.14	3.22	3.29	1.0
Other [3]	.18	.14	.12	.10	.09	-3.5
Renewable Energy [1]	.05	.10	.21	.27	.34	9.8
Electricity	2.87	3.20	3.56	3.98	4.44	2.2
Total	6.68	7.34	7.83	8.30	8.82	1.4
Industrial [4]						
Distillate Fuel	1.08	1.28	1.31	1.34	1.39	1.2
Liquefied Petroleum Gas	1.49	1.87	1.97	2.14	2.33	2.2
Motor Gasoline [2]	.20	.22	.24	.25	.27	1.6
Petrochemical Feedstocks	1.09	1.15	1.26	1.40	1.55	1.8
Residual Fuel	.58	.73	.68	.68	.70	1.0
Other Petroleum [5]	4.11	3.66	3.65	3.69	3.71	-.5
Natural Gas [6]	8.71	9.08	9.30	9.13	8.90	.1
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	1.71	1.70	1.70	1.72	1.86	.4
Net Coal Coke Imports	.00	.07	.12	.17	.20	20.6
Renewable Energy [1]	2.01	2.25	2.32	2.40	2.50	1.1
Purchased Electricity	3.20	3.43	3.90	4.43	4.97	2.2
Total	25.25	26.36	27.29	28.12	29.11	.7
Transportation						
Distillate Fuel	3.74	4.21	4.54	4.97	5.39	1.8
Jet Fuel	3.13	3.33	3.58	3.94	4.20	1.5
Motor Gasoline [2]	13.58	13.98	14.41	15.02	15.55	.7
Residual Fuel	.77	.76	.85	.93	1.02	1.4
Other Petroleum [7]	.26	.28	.30	.33	.35	1.5
Pipeline Fuel Natural Gas	.59	.65	.70	.74	.73	1.1
Compressed Natural Gas	.00	.00	.00	.01	.03	-
Alcohol Fuels	.00	.00	.01	.03	.05	-
Electricity	.01	.01	.02	.03	.04	5.8
Total	22.07	23.22	24.40	26.01	27.37	1.1
Electric Utilities [8]						
Distillate Fuel	.09	.12	.21	.18	.17	3.3
Residual Fuel	1.16	1.08	1.42	1.66	1.44	1.1
Natural Gas	2.88	3.39	4.49	5.86	5.71	3.5
Steam Coal [9]	16.16	17.12	18.04	19.37	22.54	1.7
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [10]	3.54	4.37	4.81	5.29	5.62	2.3
Total	30.02	32.63	35.94	39.41	42.39	1.7
Primary Energy Consumption						
Distillate Fuel	6.42	7.04	7.25	7.49	7.82	1.0
Kerosene	.14	.11	.08	.06	.04	-5.9
Jet Fuel	3.13	3.33	3.58	3.94	4.20	1.5
Liquefied Petroleum Gas	2.06	2.40	2.43	2.56	2.73	1.4
Motor Gasoline	13.87	14.32	14.77	15.41	15.96	.7
Petrochemical Feedstocks	1.09	1.15	1.26	1.40	1.55	1.8
Residual Fuel	2.72	2.75	3.10	3.39	3.27	.9

- 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 [11]	4.35	3.91	3.93	3.98	4.03	-0.4
Natural Gas	19.38	21.17	22.57	23.82	23.37	.9
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	18.03	18.94	19.85	21.18	24.49	1.5
Net Coal Coke Imports	.00	.07	.12	.17	.20	20.6
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [12]	6.57	7.84	8.85	9.88	10.77	2.5
Alcohols	.00	.00	.01	.03	.05	-
Total	85.02	90.49	95.61	101.20	106.10	1.1
Electricity Consumption (all Sectors)	9.23	10.15	11.18	12.37	13.63	2.0
Industrial Electricity						
Gross Consumption	3.58	3.91	4.42	4.98	5.56	2.2
Self-generation - Own Use	.39	.49	.52	.55	.59	2.1
Purchased Electricity	3.20	3.43	3.90	4.43	4.97	2.2

[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 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 consumption by independent power producers.
[10] 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.
[11] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[12] 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(91/07) (Washington, DC, July 1991), 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 1992 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

Table A3. Energy Prices by End-Use Sector and Source (1990 Dollars per Million Btu)

Sector and Source	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	11.94	12.26	13.19	14.44	15.58	1.3
Primary Energy	6.28	6.39	7.11	8.02	8.90	1.8
Petroleum Products	8.43	7.81	9.01	9.91	10.58	1.1
Distillate Fuel	7.66	7.11	8.18	8.95	9.48	1.1
Kerosene	8.77	8.51	9.29	9.85	10.22	.8
Liquefied Petroleum Gas	10.02	9.13	10.51	11.52	12.27	1.0
Natural Gas	5.60	6.02	6.72	7.71	8.66	2.2
Steam Coal	2.16	2.27	2.47	2.66	2.90	1.5
Electricity	22.96	23.10	23.24	23.94	24.49	.3
Commercial	12.23	12.36	13.06	14.08	15.09	1.1
Primary Energy	5.01	5.22	6.02	6.97	7.87	2.3
Petroleum Products	5.72	5.61	6.81	7.75	8.43	2.0
Distillate Fuel	5.67	5.09	6.17	6.96	7.50	1.4
Residual Fuel	2.99	3.43	4.41	5.12	5.62	3.2
Kerosene	5.75	6.03	6.83	7.42	7.83	1.6
Other Petroleum [1]	9.08	9.04	10.46	11.55	12.30	1.5
Natural Gas	4.86	5.17	5.87	6.85	7.81	2.4
Steam Coal	2.13	2.20	2.40	2.58	2.82	1.4
Electricity	21.67	21.35	21.09	21.32	21.65	.0
Industrial	5.41	5.63	6.54	7.51	8.30	2.2
Primary Energy	3.88	4.08	4.89	5.70	6.38	2.5
Petroleum Products	5.43	5.47	6.51	7.27	7.81	1.8
Distillate Fuel	5.63	5.02	6.09	6.86	7.39	1.4
Liquefied Petroleum Gas	5.71	5.36	6.73	7.72	8.45	2.0
Motor Gasoline [2]	9.36	9.48	10.85	11.90	12.59	1.5
Residual Fuel	2.69	3.24	4.22	4.93	5.42	3.6
Other Petroleum [3]	5.46	5.78	6.64	7.27	7.71	1.7
Natural Gas [4]	2.94	3.28	3.98	4.96	5.91	3.5
Metallurgical Coal	1.78	1.96	2.17	2.33	2.56	1.8
Steam Coal	1.50	1.70	1.83	1.97	2.16	1.9
Electricity	14.41	14.40	14.88	15.63	16.08	.6
Transportation	8.47	8.50	9.71	10.61	11.20	1.4
Primary Energy	8.46	8.49	9.70	10.59	11.18	1.4
Petroleum Products	8.46	8.49	9.70	10.59	11.18	1.4
Distillate Fuel [5]	8.51	8.70	9.77	10.53	11.06	1.3
Jet Fuel [6]	5.69	4.82	5.92	6.71	7.26	1.2
Motor Gasoline [2]	9.34	9.50	10.87	11.92	12.61	1.5
Residual Fuel	3.03	3.22	4.04	4.62	4.99	2.5
Other Petroleum [7]	10.60	12.94	13.78	14.40	14.83	1.7
Natural Gas	.00	5.44	6.13	7.12	8.08	–
Electricity	23.54	23.37	23.28	23.79	24.49	.2
Total End-Use Energy	8.30	8.50	9.48	10.46	11.24	1.5
Primary Energy	6.22	6.35	7.36	8.28	9.00	1.9
Electricity	19.60	19.61	19.64	20.12	20.50	.2
Electric Utilities						
Fossil Fuel Average	1.70	1.86	2.22	2.65	2.88	2.7
Petroleum Products	3.42	3.84	4.76	5.43	6.17	3.0
Distillate Fuel	5.28	4.63	5.73	6.48	6.99	1.4
Residual Fuel	3.28	3.76	4.62	5.32	6.07	3.1
Natural Gas	2.33	2.51	3.27	4.39	5.44	4.3
Steam Coal	1.45	1.59	1.74	1.86	2.00	1.6

– See footnotes at end of table.

Table A3. Energy Prices by End-Use Sector and Source (Continued)
(1990 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	7.42	7.46	8.59	9.45	10.07	1.5
Distillate Fuel [5]	7.62	7.48	8.59	9.45	10.05	1.4
Jet Fuel [6]	5.69	4.82	5.92	6.71	7.26	1.2
Kerosene	7.68	7.65	8.29	8.69	8.92	.8
Liquefied Petroleum Gas	6.83	6.17	7.43	8.32	8.97	1.4
Motor Gasoline [2]	9.34	9.50	10.87	11.92	12.61	1.5
Residual Fuel	3.06	3.45	4.36	5.04	5.58	3.0
Other Petroleum Products [9]	5.70	6.15	7.03	7.68	8.14	1.8
Natural Gas	3.82	4.15	4.77	5.70	6.69	2.8
Coal	1.47	1.62	1.77	1.89	2.03	1.6
Electricity	19.60	19.61	19.64	20.12	20.50	.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: Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. 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: 1988*, DOE/EIA-0376(88) (Washington, DC, September 1990), 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1992 Forecasting System run AEO92B.D0923913. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	1,558	1,651	1,740	1,867	2,184	1.7
Petroleum	117	112	152	173	152	1.3
Natural Gas	264	314	403	529	532	3.6
Nuclear Power	577	600	639	647	634	.5
Pumped Storage Hydroelectric	-9	-10	-11	-13	-13	2.0
Renewable Sources/Other [1]	300	318	330	340	344	.7
Total	2,807	2,985	3,253	3,542	3,832	1.6
Net Imports	2	40	44	53	62	18.8
Nonutilities [2]						
Generation by Fuel Type						
Coal	35	51	53	58	133	6.9
Petroleum	4	5	6	6	7	2.7
Natural Gas	115	153	181	226	233	3.6
Renewable Sources/Other [1]	76	113	143	177	199	4.9
Total	230	322	384	468	572	4.7
Sales to Utilities	115	180	230	305	400	6.4
Generation for Own Use	115	142	154	162	172	2.0
Electricity Sales by Sector						
Residential	922	1,028	1,084	1,153	1,225	1.4
Commercial/Other [3]	846	942	1,050	1,174	1,313	2.2
Industrial	938	1,005	1,142	1,297	1,458	2.2
Total	2,705	2,975	3,276	3,625	3,996	2.0
End-Use Prices [4] **(1990 cents per kilowatthour)**						
Residential	7.83	7.88	7.93	8.17	8.36	.3
Commercial/Other [3]	7.40	7.29	7.20	7.28	7.40	.0
Industrial [5]	4.92	4.91	5.08	5.33	5.49	.6
Average	6.69	6.69	6.70	6.87	6.99	.2
Price Components [4] **(1990 cents per kilowatthour)**						
Capital Component	2.92	2.83	2.48	2.24	2.18	-1.5
Fuel Component	1.68	1.84	2.19	2.59	2.82	2.6
O&M Component	2.08	2.03	2.03	2.03	2.00	-.2
Total	6.69	6.69	6.70	6.87	6.99	.2

[1] 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.

[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.

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

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

[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 Monthly, September 1991*, DOE/EIA-0226(91/09) (Washington, DC, September 1991). 1990 nonutilities, prices, and all projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

Table A5. Electricity Generating Capability (Thousand Megawatts)

Summer Capability [1]	Reference Case 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Electric Utilities						
Capability						
Coal Steam	300.0	300.6	306.1	320.1	371.0	1.1
Other Fossil Steam [2]	144.4	138.3	131.8	124.7	120.9	-.9
Combined Cycle	6.0	8.4	12.1	35.1	47.3	10.9
Combustion Turbine/Diesel	46.2	53.4	65.7	72.7	80.5	2.8
Nuclear Power	99.6	101.9	104.2	105.4	101.7	.1
Pumped Storage Hydroelectric	17.3	18.6	21.8	21.8	21.8	1.2
Renewable Sources/Other [3]	77.4	79.6	82.2	83.8	84.5	.4
Total	690.9	700.8	723.7	763.6	827.8	.9
Cumulative Planned Additions [4]						
Coal Steam	3.0	7.9	18.6	21.4	21.7	10.4
Other Fossil Steam	.0	.0	.8	.8	.8	-
Combined Cycle	.1	2.5	5.4	6.0	6.0	21.2
Combustion Turbine/Diesel	.6	6.6	13.9	14.4	14.4	16.8
Nuclear Power	2.3	4.6	7.0	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	1.3	4.5	4.5	4.5	-
Renewable Sources/Other [3]	.2	2.0	3.6	3.9	3.9	16.5
Total	6.3	24.9	53.9	59.2	59.6	11.9
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	15.0	68.3	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.8	23.3	35.6	-
Combustion Turbine/Diesel	.0	1.6	6.7	14.6	22.6	-
Nuclear Power	.0	.0	.0	.0	.0	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.1	.5	1.4	2.9	3.6	21.2
Total	.1	2.1	9.6	55.8	130.1	45.1
Cumulative Total Additions	6.3	27.1	63.4	115.0	189.7	18.5
Cumulative Retirements	1.5	12.4	25.9	37.5	48.1	18.8
Nonutilities [5]						
Capability						
Coal	6.3	10.0	10.4	11.4	24.0	6.9
Petroleum	1.2	1.7	1.9	2.2	2.4	3.8
Natural Gas	11.5	20.0	25.3	34.4	35.9	5.9
Renewable Sources/Other [3]	15.1	23.1	27.9	33.1	36.9	4.6
Total	34.1	54.8	65.5	81.1	99.3	5.5
Cumulative Additions	5.9	26.7	37.4	53.0	71.2	13.2

[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: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and all projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	75.76	78.33	78.46	78.46	78.52	0.2
Geothermal	2.54	3.14	5.32	7.69	8.40	6.2
Municipal Solid Waste	2.36	5.21	7.76	10.78	12.91	8.9
Biomass/Other Waste	5.25	6.03	6.31	6.57	6.91	1.4
Solar Thermal	.43	1.15	1.16	1.31	1.69	7.1
Solar Photovoltaic	.00	.01	.01	.01	.01	5.8
Wind	1.95	2.62	3.46	4.31	5.16	5.0
Total	88.30	96.48	102.50	109.10	113.60	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	290.60	312.40	311.20	310.20	309.80	.3
Geothermal	14.13	18.03	33.95	53.83	59.27	7.4
Municipal Solid Waste	13.53	31.48	46.60	65.73	79.26	9.2
Biomass/Other Waste	26.08	31.51	36.23	39.36	43.46	2.6
Solar Thermal	.79	2.30	2.81	3.18	4.18	8.7
Solar Photovoltaic	.00	.01	.01	.01	.01	6.4
Wind	2.84	3.87	7.06	9.26	11.34	7.2
Total	347.90	399.60	437.90	481.50	507.30	1.9
Consumption/Displacement						
Conventional Hydropower	3.02	3.25	3.24	3.23	3.22	.3
Geothermal	.14	.19	.35	.56	.62	7.5
Municipal Solid Waste	.14	.33	.48	.68	.82	9.3
Biomass/Other Waste	.27	.32	.37	.40	.45	2.6
Solar Thermal	.01	.02	.03	.03	.04	8.8
Solar Photovoltaic	.00	.00	.00	.00	.00	–
Wind	.03	.04	.07	.10	.12	7.4
Total	3.61	4.15	4.55	5.00	5.27	1.9
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.16	.29	.41	–
Biofuels	2.70	3.03	3.29	3.56	3.84	1.8
Solar Thermal	.05	.08	.23	.34	.46	11.2
Transportation						
Ethanol	.08	.10	.12	.18	.24	5.6
Total	2.84	3.24	3.80	4.37	4.95	2.8
Total Renewable Energy	6.44	7.38	8.35	9.37	10.22	2.3

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 1992 Forecasting System run AEO92B.D0923913.

Table A7. Macroeconomic Indicators
(Billion 1982 Dollars, Unless Otherwise Noted)

Indicator	Reference Case					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GNP Implicit Price Deflator (Index, 1982=1.000)	1.315	1.530	1.841	2.265	2.812	3.9
Real Gross National Product	4,156	4,650	5,200	5,804	6,404	2.2
Real Disposable Personal Income	2,894	3,147	3,430	3,785	4,128	1.8
Index of Manufacturing Gross Output (Index, 1982=1.000)	1.218	1.381	1.585	1.800	2.008	2.5
AA Utility Bond Rate (percent)	9.66	8.83	8.78	8.73	8.64	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	5.56	5.61	5.46	5.38	-
Energy Intensity (thousand Btu per 1982 $ of GNP)	20.46	19.46	18.39	17.43	16.57	-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 1992 Forecasting System run AEO92B.D0923913.

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 (1990 dollars per barrel) [1]	21.78	20.80	26.40	30.50	33.40	2.2
Production						
Crude Oil [2]	7.35	6.68	5.91	5.62	5.51	-1.4
Alaska	1.77	1.33	.93	.69	.78	-4.0
Lower 48	5.58	5.34	4.98	4.93	4.73	-.8
Natural Gas Plant Liquids	1.56	1.56	1.63	1.70	1.64	.3
Other Domestic [3]	.08	.19	.27	.35	.42	8.7
Processing Gain [4]	.68	.71	.69	.72	.74	.4
Total	9.68	9.14	8.51	8.39	8.31	-.8
Imports (including SPR) [5]						
Crude Oil	5.89	6.39	7.68	8.59	8.71	2.0
Refined Products[6]	2.12	2.93	2.90	3.08	3.79	2.9
Total	8.02	9.32	10.58	11.67	12.50	2.2
Exports						
Crude Oil	.11	.10	.08	.07	.08	-1.4
Refined Products	.75	.68	.70	.75	.78	.2
Total	.85	.77	.78	.82	.86	.0
Net Imports (including SPR)	7.16	8.55	9.80	10.85	11.64	2.5
Primary Stock Changes						
Net Withdrawals [7]	-.09	-.03	-.03	-.04	-.02	-8.2
SPR Fill Rate Additions (-) [5]	-.02	-.05	-.05	.00	.00	-
Total Primary Supply [8]	16.73	17.60	18.23	19.20	19.94	.9
Unaccounted for Crude	.26	.20	.20	.20	.20	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.47	7.68	8.04	9.32	.7
Jet Fuel [10]	1.52	1.62	1.74	1.92	2.05	1.5
Distillate Fuel	3.02	3.31	3.40	3.52	3.68	1.0
Residual Fuel	1.23	1.20	1.35	1.48	1.42	.7
Other [11]	3.98	4.20	4.26	4.45	4.66	.8
Total	16.99	17.80	18.43	19.40	20.13	.9
Refined Petroleum Products Supplied						
Residential and Commercial	1.34	1.25	1.06	.92	.82	-2.4
Industrial [12]	4.25	4.67	4.78	5.02	5.30	1.1
Transportation	10.81	11.35	11.87	12.66	13.31	1.0
Electric Utilities [13]	.55	.53	.71	.80	.71	1.3
Total	16.95	17.80	18.43	19.40	20.13	.9
Net Disposition	16.99	17.80	18.43	19.40	20.14	.9

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols.
[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.
[13] The 1990 figure includes both sales and stock changes. All years data include consumption by independent power producers.

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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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]	17.61	18.29	19.19	19.99	19.30	0.5
Supplemental Gas [2]	.11	.10	.10	.13	.15	1.6
Net Imports	1.41	2.25	2.72	3.10	3.31	4.4
Net Storage Withdrawals [3]	-.52	.00	.00	.00	.00	-
Total Supply	18.61	20.63	22.01	23.22	22.77	1.0
Consumption by Sector						
Residential	4.37	4.86	4.79	4.70	4.57	.2
Commercial	2.62	2.94	3.05	3.13	3.19	1.0
Industrial [4]	7.24	7.66	7.81	7.60	7.40	.1
Electric Utilities [5]	2.79	3.29	4.36	5.69	5.54	3.5
Lease and Plant Fuel [6]	1.21	1.15	1.21	1.26	1.23	.1
Pipeline Fuel	.57	.63	.68	.72	.71	1.1
Transportation [7]	.00	.00	.00	.01	.03	-
Total	18.80	20.53	21.89	23.10	22.67	.9
Unaccounted for [8]	-.19	.10	.11	.12	.10	-
Average Wellhead Price (1990 dollars per thousand cubic feet)	1.72	2.02	2.72	3.70	4.65	5.1
Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	6.21	6.93	7.94	8.93	2.2
Commercial	5.01	5.33	6.05	7.07	8.06	2.4
Industrial	3.03	3.38	4.11	5.11	6.09	3.5
Electric Utilities	2.40	2.59	3.37	4.53	5.61	4.3
Transportation	.00	5.61	6.32	7.34	8.33	-
Average [9]	3.94	4.28	4.92	5.88	6.89	2.8

[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 anincrease 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered prices for 1990 and projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	656	671	723	869	1.6
West of the Mississippi	399	395	462	505	576	1.9
Total	1,029	1,052	1,133	1,229	1,445	1.7
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	121	144	179	235	4.1
Total	-103	-116	-138	-170	-224	4.0
Net Stock Withdrawals [2]	-26	-2	-3	-4	-8	-5.5
Total Supply [3]	901	933	992	1,054	1,213	1.5
Consumption by Sector						
Residential and Commercial	7	5	4	4	4	-3.1
Industrial [4]	76	76	76	77	85	.6
Coking Plants	40	35	32	30	27	-1.9
Electricity [5]	772	819	880	944	1,097	1.8
Total	895	934	993	1,055	1,213	1.5
Discrepancy [6]	6	0	0	-1	0	-
Average Minemouth Price [7] **(1990 dollars per short ton)**	21.76	24.01	26.64	28.71	31.63	1.9
Delivered Prices (1990 dollars per short ton)						
Residential and Commercial	48.39	53.70	57.85	63.01	67.83	1.7
Industrial	33.59	38.20	40.89	43.88	47.39	1.7
Coking Plants	47.79	52.00	57.67	61.86	67.90	1.8
Electricity	30.43	33.19	35.60	38.09	41.01	1.5
Average [8]	31.61	34.39	36.82	39.28	42.15	1.4

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(91/1Q) (Washington, DC, August 1991); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	98.3	103.2	107.8	111.7	0.9
Energy Consumption per Household (million Btu)	109.4	112.8	109.7	108.4	107.9	-.1
End-Use Consumption						
Distillate						
Space Heating	.86	.82	.65	.54	.46	-3.1
Other Uses [1]	.14	.09	.05	.03	.02	-9.4
Total	1.00	.91	.70	.57	.48	-3.6
Natural Gas						
Space Heating	3.14	3.45	3.37	3.29	3.19	.1
Water Heating	1.06	1.26	1.30	1.29	1.26	.9
Other Uses [1]	.31	.30	.28	.27	.27	-.7
Total	4.50	5.01	4.94	4.85	4.71	.2
Other Fuels [2]	.61	.53	.44	.39	.35	-2.7
Renewables [3]	.96	1.12	1.51	1.91	2.31	4.5
Electricity						
Space Heating	.32	.33	.32	.33	.34	.2
Cooling	.51	.56	.57	.58	.59	.7
Water Heating	.39	.51	.58	.67	.76	3.4
Other Uses [1]	1.92	2.11	2.23	2.36	2.50	1.3
Total	3.14	3.51	3.70	3.94	4.18	1.4
Total Consumption	10.22	11.10	11.33	11.68	12.06	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate), 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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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)	110.3	117.7	124.3	130.5	135.7	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)	106.3	106.3	103.6	100.5	98.4	-.4
End-Use Consumption						
Distillate						
Space Heating	.47	.49	.46	.41	.38	-1.1
Other Uses [1]	.04	.04	.03	.02	.02	-4.3
Total	.51	.53	.49	.43	.40	-1.3
Natural Gas						
Space Heating	1.76	1.96	2.00	2.00	1.97	.6
Cooling	.21	.22	.24	.25	.28	1.5
Other Uses [1]	.73	.85	.91	.97	1.03	1.8
Total	2.70	3.03	3.14	3.22	3.29	1.0
Other Fuels [2]	.54	.47	.42	.39	.36	-2.1
Renewables [3]	.05	.10	.21	.27	.34	9.8
Electricity						
Space Heating	.53	.60	.70	.83	1.00	3.3
Cooling	.74	.83	.92	1.01	1.10	2.0
Lighting	1.13	1.23	1.35	1.47	1.59	1.7
Other Uses [1]	.47	.53	.60	.67	.75	2.3
Total	2.87	3.20	3.56	3.98	4.44	2.2
Total Consumption	6.68	7.34	7.83	8.30	8.82	1.4

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	2401	2721	3124	3548	3957	2.5
Non-manufacturing	830	926	989	1065	1140	1.6
Total	3231	3647	4114	4613	5096	2.3
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.34	.35	.32	.29	.27	-1.0
Liquefied Petroleum Gas	.46	.51	.48	.46	.46	-.1
Petrochemical Feedstocks	.34	.31	.31	.30	.30	-.5
Residual Fuel	.18	.20	.16	.15	.14	-1.3
Other Petroleum [1]	1.27	1.00	.89	.80	.73	-2.7
Natural Gas [2]	2.69	2.49	2.26	1.98	1.75	-2.1
Metallurgical Coal and Coke [3]	.33	.27	.24	.21	.18	-3.0
Steam Coal [4]	.53	.47	.41	.37	.37	-1.8
Renewables [5]	.06	.06	.06	.05	.05	-1.2
Electricity	.99	.94	.95	.96	.98	-.1
Total	7.81	7.23	6.63	6.10	5.71	-1.6
Consumption (quadrillion Btu per year)						
Distillate	1.08	1.28	1.31	1.34	1.39	1.2
Liquefied Petroleum Gas	1.49	1.87	1.97	2.14	2.33	2.2
Motor Gasoline [6]	.20	.22	.24	.25	.27	1.6
Petrochemical Feedstocks	1.09	1.15	1.26	1.40	1.55	1.8
Residual Fuel	.58	.73	.68	.68	.70	1.0
Other Petroleum [1]	4.11	3.66	3.65	3.69	3.71	-.5
Natural Gas [2]	8.71	9.08	9.30	9.13	8.90	.1
Metallurgical Coal and Coke [3]	1.07	.99	.97	.96	.93	-.7
Steam Coal [4]	1.71	1.70	1.70	1.72	1.86	.4
Renewables [5]	2.01	2.25	2.32	2.40	2.50	1.1
Electricity	3.20	3.43	3.90	4.43	4.97	2.2
Total	25.25	26.36	27.29	28.12	29.11	.7

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	1.08	1.17	1.29	1.40	1.7
Freight Trucks	1.00	1.11	1.22	1.34	1.46	1.9
Air	.99	1.24	1.51	1.81	2.13	3.9
Rail	1.00	1.05	1.12	1.21	1.30	1.3
Marine	.99	1.03	1.10	1.19	1.25	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.10	29.19	31.80	34.44	36.68	1.3
New Light Truck MPG [1]	20.80	21.59	23.45	25.08	26.45	1.2
Light Duty Fleet MPG [2]	18.58	19.29	20.11	21.12	22.13	.9
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.02	1.05	1.10	1.11	1.13	.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	11.55	11.99	12.42	12.99	13.49	.8
Freight Trucks	4.93	5.31	5.60	6.05	6.49	1.4
Air	3.21	3.41	3.68	4.05	4.32	1.5
Rail	.48	.51	.53	.56	.59	1.0
Marine	1.13	1.15	1.27	1.39	1.51	1.5
Pipeline Fuel	.59	.65	.70	.74	.73	1.1
Other	.18	.19	.20	.22	.23	1.2
Total	22.07	23.22	24.40	26.01	27.37	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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1992 Forecasting System run AEO92B.D0923913.

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	14.41	13.08	12.67	12.72	-1.1
Natural Gas Plant Liquids	2.16	2.18	2.34	2.43	2.37	.4
Dry Natural Gas [2]	18.27	19.16	20.51	21.44	20.99	.7
Coal	22.46	23.33	25.23	28.55	33.70	2.0
Nuclear Power	6.19	6.54	7.03	7.24	7.53	1.0
Renewable Energy [3]	6.62	7.56	8.70	9.89	10.86	2.5
Total	71.45	73.18	76.89	82.22	88.19	1.1
Imports						
Crude Oil [4]	12.70	14.23	18.02	18.49	18.63	1.9
Petroleum Products	4.29	5.98	6.13	8.52	10.33	4.5
Natural Gas [5]	1.45	2.31	2.82	3.33	3.42	4.4
Other Imports [6]	.09	.61	.76	.99	1.20	13.7
Total	18.53	23.14	27.73	31.33	33.58	3.0
Exports						
Coal	2.77	3.49	4.60	6.29	7.48	5.1
Petroleum	1.80	1.65	1.73	1.84	1.86	.2
Total	4.57	5.14	6.33	8.12	9.34	3.6
Net Stock Withdrawals	-1.32	-.26	-.27	-.19	-.26	-7.8
Discrepancy [7]	.93	.19	.11	.00	-.25	-
Consumption						
Petroleum Products [8]	33.79	35.37	37.98	40.51	42.30	1.1
Natural Gas	19.38	21.35	23.22	24.65	24.27	1.1
Coal	19.09	19.90	20.72	22.37	26.28	1.6
Nuclear Power	6.19	6.54	7.03	7.24	7.53	1.0
Renewable Energy/Other [9]	6.57	7.95	9.18	10.46	11.55	2.9
Total	85.02	91.11	98.13	105.20	111.90	1.4
Net Imports - Petroleum	15.18	18.57	22.42	25.17	27.10	2.9
Prices (1990 dollars per unit)						
World Oil Price ($ per barrel) [10]	21.78	20.80	26.40	30.50	33.40	2.2
Natural Gas Wellhead Price ($ per Mcf)	1.72	2.11	3.02	4.22	4.80	5.3
Coal Minemouth Price ($ per ton)	21.76	24.46	27.34	30.15	32.90	2.1

[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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	1.00	0.90	0.69	0.56	0.47	-3.7
Kerosene	.09	.07	.05	.03	.02	-7.5
Liquefied Petroleum Gas	.46	.44	.38	.34	.32	-1.9
Natural Gas	4.50	5.02	4.96	4.87	4.75	.3
Coal	.06	.04	.04	.04	.04	-1.8
Renewable Energy [1]	.96	1.13	1.58	2.02	2.47	4.9
Electricity	3.14	3.52	3.75	4.05	4.36	1.7
Total	10.22	11.13	11.46	11.92	12.43	1.0
Commercial						
Distillate Fuel	.51	.53	.49	.43	.39	-1.3
Kerosene	.05	.04	.03	.03	.02	-3.9
Motor Gasoline [2]	.10	.12	.13	.14	.14	1.8
Residual Fuel	.21	.17	.15	.13	.11	-3.2
Natural Gas	2.70	3.03	3.15	3.23	3.29	1.0
Other [3]	.18	.14	.12	.10	.09	-3.5
Renewable Energy [1]	.05	.10	.22	.29	.36	10.0
Electricity	2.87	3.21	3.59	4.03	4.54	2.3
Total	6.68	7.34	7.87	8.37	8.94	1.5
Industrial [4]						
Distillate Fuel	1.08	1.29	1.37	1.42	1.50	1.6
Liquefied Petroleum Gas	1.49	1.82	1.99	2.23	2.43	2.5
Motor Gasoline [2]	.20	.23	.25	.27	.30	2.1
Petrochemical Feedstocks	1.09	1.15	1.30	1.49	1.69	2.2
Residual Fuel	.58	.71	.69	.71	.73	1.2
Other Petroleum [5]	4.11	3.68	3.73	3.75	3.78	-.4
Natural Gas [6]	8.71	9.16	9.53	9.41	9.51	.4
Metallurgical Coal	1.06	.92	.85	.78	.72	-1.9
Steam Coal	1.71	1.70	1.72	1.75	1.89	.5
Net Coal Coke Imports	.00	.07	.13	.18	.22	21.1
Renewable Energy [1]	2.01	2.25	2.34	2.44	2.58	1.2
Purchased Electricity	3.20	3.48	4.08	4.76	5.45	2.7
Total	25.25	26.47	27.98	29.20	30.78	1.0
Transportation						
Distillate Fuel	3.74	4.30	4.80	5.35	5.87	2.3
Jet Fuel	3.13	3.44	3.93	4.50	4.94	2.3
Motor Gasoline [2]	13.58	14.07	14.94	15.89	16.59	1.0
Residual Fuel	.77	.77	.87	.97	1.06	1.6
Other Petroleum [7]	.26	.28	.31	.35	.38	1.9
Pipeline Fuel Natural Gas	.59	.66	.71	.76	.82	1.7
Compressed Natural Gas	.00	.00	.00	.02	.03	-
Alcohol Fuels	.00	.00	.01	.03	.06	-
Electricity	.01	.01	.02	.03	.05	6.2
Total	22.07	23.52	25.59	27.90	29.79	1.5
Electric Utilities [8]						
Distillate Fuel	.09	.12	.25	.22	.15	2.9
Residual Fuel	1.16	1.17	1.57	1.65	1.36	.8
Natural Gas	2.88	3.48	4.87	6.36	5.88	3.6
Steam Coal [9]	16.16	17.17	18.06	19.74	23.58	1.9
Nuclear Power	6.19	6.54	7.03	7.24	7.53	1.0
Renewable Energy/Other [10]	3.54	4.38	4.90	5.50	5.87	2.6
Total	30.02	32.87	36.68	40.71	44.37	2.0
Primary Energy Consumption						
Distillate Fuel	6.42	7.14	7.60	7.98	8.38	1.3
Kerosene	.14	.11	.08	.06	.04	-5.9
Jet Fuel	3.13	3.44	3.93	4.50	4.94	2.3
Liquefied Petroleum Gas	2.06	2.36	2.46	2.66	2.83	1.6
Motor Gasoline	13.87	14.42	15.32	16.30	17.03	1.0
Petrochemical Feedstocks	1.09	1.15	1.30	1.49	1.69	2.2
Residual Fuel	2.72	2.83	3.28	3.46	3.27	.9

- 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 [11]	4.35	3.93	4.01	4.07	4.12	-0.3
Natural Gas	19.38	21.35	23.22	24.65	24.27	1.1
Metallurgical Coal	1.06	.92	.85	.78	.72	-1.9
Steam Coal	18.03	18.98	19.88	21.59	25.55	1.8
Net Coal Coke Imports	.00	.07	.13	.18	.22	21.1
Nuclear Power	6.19	6.54	7.03	7.24	7.53	1.0
Renewable Energy/Other [12]	6.57	7.87	9.03	10.25	11.27	2.7
Alcohols	.00	.00	.01	.03	.06	-
Total	85.02	91.11	98.13	105.20	111.90	1.4
Electricity Consumption (all Sectors)	9.23	10.22	11.44	12.88	14.39	2.2
Industrial Electricity						
Gross Consumption	3.58	3.97	4.66	5.37	6.10	2.7
Self-generation - Own Use	.39	.49	.57	.61	.65	2.6
Purchased Electricity	3.20	3.48	4.08	4.76	5.45	2.7

[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 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 consumption by independent power producers.
[10] 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.
[11] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[12] 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(91/07) (Washington, DC, July 1991), 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 1992 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

Table B3. Energy Prices by End-Use Sector and Source (1990 Dollars per Million Btu)

Sector and Source	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	11.94	12.37	13.55	15.11	16.04	1.5
Primary Energy	6.28	6.53	7.42	8.51	9.07	1.9
Petroleum Products	8.43	8.12	9.33	10.23	10.90	1.3
Distillate Fuel	7.66	7.37	8.45	9.21	9.75	1.2
Kerosene	8.77	8.80	9.58	10.14	10.50	.9
Liquefied Petroleum Gas	10.02	9.54	10.91	11.92	12.64	1.2
Natural Gas	5.60	6.11	7.03	8.24	8.81	2.3
Steam Coal	2.16	2.29	2.54	2.72	2.99	1.6
Electricity	22.96	23.12	23.54	24.64	24.98	.4
Commercial	12.23	12.45	13.40	14.75	15.55	1.2
Primary Energy	5.01	5.36	6.32	7.45	8.05	2.4
Petroleum Products	5.72	5.90	7.11	8.06	8.75	2.1
Distillate Fuel	5.67	5.42	6.51	7.28	7.83	1.6
Residual Fuel	2.99	3.64	4.62	5.34	5.81	3.4
Kerosene	5.75	6.31	7.12	7.71	8.12	1.7
Other Petroleum [1]	9.08	9.25	10.65	11.71	12.45	1.6
Natural Gas	4.86	5.26	6.18	7.38	7.96	2.5
Steam Coal	2.13	2.23	2.48	2.66	2.91	1.6
Electricity	21.67	21.39	21.42	22.07	22.24	.1
Industrial	5.41	5.78	6.83	7.96	8.60	2.3
Primary Energy	3.88	4.22	5.13	6.04	6.57	2.7
Petroleum Products	5.43	5.70	6.74	7.49	8.03	2.0
Distillate Fuel	5.63	5.05	6.13	6.88	7.42	1.4
Liquefied Petroleum Gas	5.71	5.96	7.31	8.29	8.99	2.3
Motor Gasoline [2]	9.36	9.54	10.91	11.94	12.65	1.5
Residual Fuel	2.69	3.40	4.37	5.09	5.56	3.7
Other Petroleum [3]	5.46	5.94	6.79	7.41	7.85	1.8
Natural Gas [4]	2.94	3.37	4.29	5.49	6.06	3.7
Metallurgical Coal	1.78	1.99	2.22	2.43	2.65	2.0
Steam Coal	1.50	1.71	1.85	2.01	2.22	2.0
Electricity	14.41	14.47	15.21	16.24	16.48	.7
Transportation	8.46	8.57	9.77	10.63	11.23	1.4
Primary Energy	8.46	8.56	9.76	10.62	11.21	1.4
Petroleum Products	8.46	8.56	9.76	10.62	11.21	1.4
Distillate Fuel [5]	8.51	8.79	9.87	10.62	11.15	1.4
Jet Fuel [6]	5.69	4.94	6.05	6.83	7.38	1.3
Motor Gasoline [2]	9.34	9.56	10.93	11.96	12.66	1.5
Residual Fuel	3.03	3.40	4.22	4.77	5.17	2.7
Other Petroleum [7]	10.60	13.20	14.03	14.65	15.08	1.8
Natural Gas	.00	5.53	6.44	7.65	8.23	-
Electricity	23.54	23.46	23.64	24.56	24.50	.2
Total End-Use Energy	8.30	8.60	9.68	10.78	11.43	1.6
Primary Energy	6.22	6.47	7.56	8.55	9.15	2.0
Electricity	19.59	19.63	19.90	20.73	20.90	.3
Electric Utilities						
Fossil Fuel Average	1.70	1.90	2.35	2.83	2.92	2.8
Petroleum Products	3.42	4.04	4.96	5.87	6.34	3.1
Distillate Fuel	5.28	4.85	5.93	6.67	7.20	1.6
Residual Fuel	3.28	3.96	4.80	5.76	6.24	3.3
Natural Gas	2.33	2.60	3.59	4.94	5.65	4.5
Steam Coal	1.45	1.60	1.76	1.87	2.02	1.7

- See footnotes at end of table.

Table B3. Energy Prices by End-Use Sector and Source (Continued) (1990 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	7.42	7.59	8.71	9.58	10.20	1.6
Distillate Fuel [5]	7.62	7.62	8.72	9.57	10.18	1.5
Jet Fuel [6]	5.69	4.94	6.05	6.83	7.38	1.3
Kerosene	7.68	7.94	8.58	8.98	9.21	.9
Liquefied Petroleum Gas	6.83	6.74	7.96	8.84	9.47	1.6
Motor Gasoline [2]	9.34	9.56	10.93	11.96	12.66	1.5
Residual Fuel	3.06	3.65	4.55	5.33	5.73	3.2
Other Petroleum Products [9]	5.70	6.32	7.20	7.84	8.30	1.9
Natural Gas	3.82	4.23	5.05	6.20	6.83	3.0
Coal	1.47	1.63	1.79	1.90	2.06	1.7
Electricity	19.59	19.63	19.90	20.73	20.90	.3

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: Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. 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: 1988*, DOE/EIA-0376(88) (Washington, DC, September 1990), 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1992 Forecasting System run HMAC92.D0923914. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	1,558	1,655	1,741	1,888	2,256	1.9
Petroleum	117	120	170	176	143	1.0
Natural Gas	264	322	427	567	535	3.6
Nuclear Power	577	600	645	664	690	.9
Pumped Storage Hydroelectric	-9	-10	-11	-13	-14	2.1
Renewable Sources/Other [1]	300	319	332	345	350	.8
Total	2,807	3,006	3,304	3,628	3,961	1.7
Net Imports	2	40	44	53	62	18.8
Nonutilities [2]						
Generation by Fuel Type						
Coal	35	51	54	76	184	8.6
Petroleum	4	5	6	6	7	2.8
Natural Gas	115	153	219	280	284	4.6
Renewable Sources/Other [1]	76	114	150	193	219	5.4
Total	230	323	428	554	694	5.7
Sales to Utilities	115	181	260	376	504	7.7
Generation for Own Use	115	142	168	179	190	2.5
Electricity Sales by Sector						
Residential	922	1,031	1,100	1,188	1,279	1.6
Commercial/Other [3]	846	944	1,057	1,191	1,343	2.3
Industrial	938	1,021	1,197	1,395	1,597	2.7
Total	2,705	2,996	3,353	3,773	4,218	2.2
End-Use Prices [4] (1990 cents per kilowatthour)						
Residential	7.83	7.89	8.03	8.41	8.52	.4
Commercial/Other [3]	7.40	7.30	7.31	7.54	7.60	.1
Industrial [5]	4.92	4.94	5.19	5.54	5.62	.7
Average	6.69	6.70	6.79	7.07	7.13	.3
Price Components [4] (1990 cents per kilowatthour)						
Capital Component	2.92	2.80	2.46	2.30	2.28	-1.2
Fuel Component	1.69	1.88	2.33	2.79	2.89	2.7
O&M Component	2.08	2.02	2.00	1.98	1.96	-.3
Total	6.69	6.70	6.79	7.07	7.13	.3

[1] 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.

[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.

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

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

[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 Monthly, September 1991*, DOE/EIA-0226(91/09) (Washington, DC, September 1991). 1990 nonutilities, prices, and all projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

Table B5. Electricity Generating Capability
(Thousand Megawatts)

Summer Capability [1]	High Economic Growth 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Electric Utilities						
Capability						
Coal Steam	300.0	300.6	305.5	323.5	384.4	1.2
Other Fossil Steam [2]	144.4	138.3	131.8	124.7	120.9	-.9
Combined Cycle	6.0	8.4	12.3	44.5	51.8	11.4
Combustion Turbine/Diesel	46.2	53.7	68.7	75.0	82.1	2.9
Nuclear Power	99.6	103.1	105.6	109.2	112.8	.6
Pumped Storage Hydroelectric	17.3	18.6	21.8	21.8	21.8	1.2
Renewable Sources/Other [3]	77.4	79.6	82.5	84.6	85.4	.5
Total	690.9	702.3	728.3	783.3	859.2	1.1
Cumulative Planned Additions [4]						
Coal Steam	3.0	7.9	18.6	21.4	21.7	10.4
Other Fossil Steam	.0	.0	.8	.8	.8	-
Combined Cycle	.1	2.5	5.4	6.0	6.0	21.2
Combustion Turbine/Diesel	.6	6.6	13.9	14.4	14.4	16.8
Nuclear Power	2.3	5.8	8.3	11.9	11.9	8.6
Pumped Storage Hydroelectric	.0	1.3	4.5	4.5	4.5	-
Renewable Sources/Other [3]	.2	2.0	3.6	3.9	3.9	16.5
Total	6.3	26.1	55.1	62.8	63.2	12.3
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.0	18.3	81.7	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	1.1	32.8	40.0	-
Combustion Turbine/Diesel	.0	1.9	9.7	16.9	24.2	-
Nuclear Power	.0	.0	.0	.0	6.0	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.1	.6	1.8	3.6	4.4	22.6
Total	.1	2.5	12.7	71.6	156.3	46.5
Cumulative Total Additions	6.3	28.6	67.8	134.5	219.6	19.4
Cumulative Retirements	1.5	12.4	25.7	37.4	46.6	18.6
Nonutilities [5]						
Capability						
Coal	6.3	10.0	10.5	14.3	32.6	8.5
Petroleum	1.2	1.7	1.9	2.2	2.5	4.0
Natural Gas	11.5	20.0	32.0	44.6	45.4	7.1
Renewable Sources/Other [3]	15.1	23.2	28.9	35.1	39.6	4.9
Total	34.1	54.9	73.3	96.3	120.2	6.5
Cumulative Additions	5.9	26.8	45.2	68.2	92.1	14.7

[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: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and all projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	75.76	78.33	78.46	78.46	78.52	0.2
Geothermal	2.54	3.30	6.32	9.63	10.61	7.4
Municipal Solid Waste	2.36	5.21	8.09	11.44	13.97	9.3
Biomass/Other Waste	5.25	6.06	6.35	6.71	7.18	1.6
Solar Thermal	.43	1.15	1.16	1.31	1.69	7.1
Solar Photovoltaic	.00	.01	.01	.01	.01	5.8
Wind	1.95	2.62	3.46	4.31	5.16	5.0
Total	88.30	96.68	103.80	111.90	117.10	1.4
Generation (billion kilowatthours)						
Conventional Hydropower	290.60	312.40	311.20	310.20	309.80	.3
Geothermal	14.13	19.22	41.36	69.09	76.68	8.8
Municipal Solid Waste	13.53	31.48	48.76	70.10	86.33	9.7
Biomass/Other Waste	26.08	31.65	36.43	40.72	44.68	2.7
Solar Thermal	.79	2.30	2.81	3.18	4.18	8.7
Solar Photovoltaic	.00	.01	.01	.01	.01	6.4
Wind	2.84	3.87	7.06	9.26	11.34	7.2
Total	347.90	400.90	447.70	502.50	533.00	2.2
Consumption/Displacement						
Conventional Hydropower	3.02	3.25	3.24	3.23	3.22	.3
Geothermal	.14	.20	.43	.72	.80	8.9
Municipal Solid Waste	.14	.33	.51	.73	.90	9.8
Biomass/Other Waste	.27	.32	.37	.42	.46	2.8
Solar Thermal	.01	.02	.03	.03	.04	8.8
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.03	.04	.07	.10	.12	7.4
Total	3.61	4.16	4.65	5.22	5.54	2.2
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.16	.29	.41	-
Biofuels	2.70	3.05	3.37	3.71	4.08	2.1
Solar Thermal	.05	.08	.23	.34	.46	11.2
Transportation						
Ethanol	.08	.10	.12	.18	.24	5.6
Total	2.84	3.26	3.89	4.52	5.19	3.1
Total Renewable Energy	6.44	7.42	8.53	9.74	10.73	2.6

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 1992 Forecasting System run HMAC92.D0923914.

Table B7. Macroeconomic Indicators
(Billion 1982 Dollars, Unless Otherwise Noted)

Indicator	High Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GNP Implicit Price Deflator (Index, 1982=1.000)	1.315	1.536	1.771	2.073	2.432	3.1
Real Gross National Product	4,156	4,748	5,504	6,290	7,050	2.7
Real Disposable Personal Income	2,894	3,169	3,589	4,069	4,477	2.2
Index of Manufacturing Gross Output (Index, 1982=1.000)	1.218	1.418	1.691	1.955	2.208	3.0
AA Utility Bond Rate (percent)	9.66	7.94	7.80	7.83	7.75	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	4.71	4.77	4.82	4.73	-
Energy Intensity (thousand Btu per 1982 $ of GNP)	20.46	19.19	17.83	16.73	15.87	-1.3

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 1992 Forecasting System run HMAC92.D0923914.

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 (1990 dollars per barrel) [1]	21.78	20.80	26.40	30.50	33.40	2.2
Production						
Crude Oil [2]	7.35	6.61	5.88	5.62	5.57	-1.4
Alaska	1.77	1.33	.93	.69	.78	-4.0
Lower 48	5.58	5.28	4.95	4.93	4.79	-.8
Natural Gas Plant Liquids	1.56	1.57	1.68	1.75	1.71	.4
Other Domestic [3]	.08	.19	.28	.36	.44	8.9
Processing Gain [4]	.68	.70	.72	.74	.74	.4
Total	9.68	9.08	8.56	8.47	8.45	-.7
Imports (including SPR) [5]						
Crude Oil	5.89	6.61	8.35	8.59	8.65	1.9
Refined Products[6]	2.12	2.96	3.02	4.21	5.11	4.5
Total	8.02	9.56	11.37	12.80	13.76	2.7
Exports						
Crude Oil	.11	.10	.08	.07	.08	-1.4
Refined Products	.75	.68	.74	.80	.80	.3
Total	.85	.78	.82	.87	.88	.2
Net Imports (including SPR)	7.16	8.79	10.55	11.93	12.88	3.0
Primary Stock Changes						
Net Withdrawals [7]	-.09	-.05	-.05	-.04	-.03	-5.7
SPR Fill Rate Additions (-) [5]	-.02	-.05	-.05	.00	.00	-
Total Primary Supply [8]	16.73	17.76	19.01	20.36	21.30	1.2
Unaccounted for Crude	.26	.20	.20	.20	.20	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.52	7.97	8.50	8.88	1.0
Jet Fuel [10]	1.52	1.67	1.91	2.19	2.40	2.3
Distillate Fuel	3.02	3.36	3.56	3.75	3.94	1.3
Residual Fuel	1.23	1.23	1.42	1.51	1.42	.7
Other [11]	3.98	4.18	4.34	4.61	4.85	1.0
Total	16.99	17.96	19.21	20.56	21.50	1.2
Refined Petroleum Products Supplied						
Residential and Commercial	1.34	1.25	1.06	.92	.82	-2.4
Industrial [12]	4.25	4.64	4.90	5.23	5.55	1.3
Transportation	10.81	11.50	12.46	13.59	14.46	1.5
Electric Utilities [13]	.55	.57	.80	.82	.66	1.0
Total	16.95	17.96	19.21	20.56	21.50	1.2
Net Disposition	16.99	17.96	19.21	20.56	21.50	1.2

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols.
[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.
[13] The 1990 figure includes both sales and stock changes. All years data include consumption by independent power producers.

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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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]	17.61	18.48	19.79	20.67	20.21	0.7
Supplemental Gas [2]	.11	.10	.11	.13	.15	1.6
Net Imports	1.41	2.25	2.73	3.23	3.31	4.4
Net Storage Withdrawals [3]	-.52	.00	.00	.00	.00	-
Total Supply	18.61	20.83	22.63	24.03	23.68	1.2
Consumption by Sector						
Residential	4.37	4.87	4.81	4.72	4.60	.3
Commercial	2.62	2.94	3.05	3.13	3.19	1.0
Industrial [4]	7.24	7.72	8.00	7.83	7.91	.4
Electric Utilities [5]	2.79	3.38	4.72	6.17	5.70	3.6
Lease and Plant Fuel [6]	1.21	1.16	1.24	1.30	1.31	.4
Pipeline Fuel	.57	.64	.69	.74	.79	1.7
Transportation [7]	.00	.00	.00	.01	.03	-
Total	18.80	20.71	22.52	23.91	23.54	1.1
Unaccounted for [8]	-.19	.12	.11	.12	.14	-
Average Wellhead Price (1990 dollars per thousand cubic feet)	1.72	2.11	3.02	4.22	4.80	5.3
Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	6.30	7.25	8.49	9.09	2.3
Commercial	5.01	5.42	6.37	7.61	8.21	2.5
Industrial	3.03	3.48	4.43	5.66	6.25	3.7
Electric Utilities	2.40	2.68	3.70	5.10	5.83	4.5
Transportation	.00	5.70	6.64	7.89	8.49	-
Average [9]	3.94	4.37	5.21	6.39	7.04	3.0

[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 anincrease 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered prices for 1990 and projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	669	697	796	941	2.0
West of the Mississippi	399	399	474	518	614	2.2
Total	1,029	1,067	1,171	1,313	1,555	2.1
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	134	177	242	289	5.1
Total	-103	-129	-171	-232	-277	5.1
Net Stock Withdrawals [2]	-26	-2	-3	-5	-10	-4.9
Total Supply [3]	901	936	997	1,075	1,268	1.7
Consumption by Sector						
Residential and Commercial	7	5	4	4	4	-3.2
Industrial [4]	76	76	77	79	86	.6
Coking Plants	40	35	32	30	27	-1.9
Electricity [5]	772	821	884	964	1,151	2.0
Total	895	936	997	1,076	1,269	1.8
Discrepancy [6]	6	0	-1	-1	0	-
Average Minemouth Price [7] **(1990 dollars per short ton)**	21.76	24.46	27.34	30.15	32.90	2.1
Delivered Prices (1990 dollars per short ton)						
Residential and Commercial	48.39	54.30	59.57	64.00	70.00	1.9
Industrial	33.59	38.32	41.31	44.77	48.55	1.9
Coking Plants	47.79	52.88	58.93	64.49	70.28	1.9
Electricity	30.43	33.45	35.87	38.20	41.40	1.6
Average [8]	31.61	34.67	37.13	39.50	42.59	1.5

[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(91/1Q) (Washington, DC, August 1991); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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

Key Indicators and Consumption	High Economic Growth 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Key Indicators						
Total Housing (millions)	93.4	98.7	104.7	110.5	115.9	1.1
Energy Consumption per Household (million Btu)	109.4	112.7	109.4	107.9	107.2	-.1
End-Use Consumption						
Distillate						
Space Heating	.86	.81	.64	.53	.45	-3.2
Other Uses [1]	.14	.09	.05	.03	.02	-9.4
Total	1.00	.90	.69	.56	.47	-3.7
Natural Gas						
Space Heating	3.14	3.46	3.37	3.29	3.19	.1
Water Heating	1.06	1.26	1.30	1.30	1.28	.9
Other Uses [1]	.31	.30	.28	.27	.28	-.5
Total	4.50	5.02	4.96	4.87	4.75	.3
Other Fuels [2]	.61	.53	.45	.39	.36	-2.7
Renewables [3]	.96	1.13	1.58	2.02	2.47	4.9
Electricity						
Space Heating	.32	.33	.32	.33	.34	.3
Cooling	.51	.56	.58	.60	.62	1.0
Water Heating	.39	.51	.60	.70	.81	3.7
Other Uses [1]	1.92	2.12	2.26	2.42	2.59	1.5
Total	3.14	3.52	3.75	4.05	4.36	1.7
Total Consumption	10.22	11.13	11.46	11.92	12.43	1.0

[1] Includes cooking, cooling (natural gas), water heating (distillate), 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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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)	110.3	119.3	129.4	138.2	144.7	1.4
Total Floorspace (billion square feet)	62.9	69.1	76.0	83.3	91.0	1.9
Energy Consumption per Square Foot (thousand Btu)	106.3	106.3	103.5	100.5	98.2	-.4
End-Use Consumption						
Distillate						
Space Heating	.47	.49	.46	.41	.37	-1.1
Other Uses [1]	.04	.04	.03	.02	.02	-4.3
Total	.51	.53	.49	.43	.39	-1.3
Natural Gas						
Space Heating	1.76	1.96	2.00	2.00	1.96	.5
Cooling	.21	.22	.24	.25	.28	1.6
Other Uses [1]	.73	.85	.91	.97	1.04	1.8
Total	2.70	3.03	3.15	3.23	3.29	1.0
Other Fuels [2]	.54	.47	.43	.40	.37	-2.0
Renewables [3]	.05	.10	.22	.29	.36	10.0
Electricity						
Space Heating	.53	.61	.71	.85	1.05	3.5
Cooling	.74	.83	.92	1.02	1.11	2.0
Lighting	1.13	1.23	1.35	1.48	1.61	1.8
Other Uses [1]	.47	.54	.61	.69	.76	2.4
Total	2.87	3.21	3.59	4.03	4.54	2.3
Total Consumption	6.68	7.34	7.87	8.37	8.94	1.5

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

Table B13. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	High Economic Growth 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Key Indicators						
Value of Gross Output (billion 1982 dollars)						
Manufacturing	2401	2795	3333	3853	4352	3.0
Non-manufacturing	830	961	1069	1168	1262	2.1
Total	3231	3756	4403	5021	5614	2.8
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.34	.34	.31	.28	.27	-1.1
Liquefied Petroleum Gas	.46	.48	.45	.44	.43	-.3
Petrochemical Feedstocks	.34	.31	.30	.30	.30	-.6
Residual Fuel	.18	.19	.16	.14	.13	-1.5
Other Petroleum [1]	1.27	.98	.85	.75	.67	-3.1
Natural Gas [2]	2.69	2.44	2.16	1.87	1.69	-2.3
Metallurgical Coal and Coke [3]	.33	.27	.22	.19	.17	-3.4
Steam Coal [4]	.53	.45	.39	.35	.34	-2.2
Renewables [5]	.06	.06	.05	.05	.05	-1.5
Electricity	.99	.93	.93	.95	.97	-.1
Total	7.81	7.05	6.36	5.82	5.48	-1.8
Consumption (quadrillion Btu per year)						
Distillate	1.08	1.29	1.37	1.42	1.50	1.6
Liquefied Petroleum Gas	1.49	1.82	1.99	2.23	2.43	2.5
Motor Gasoline [6]	.20	.23	.25	.27	.30	2.1
Petrochemical Feedstocks	1.09	1.15	1.30	1.49	1.69	2.2
Residual Fuel	.58	.71	.69	.71	.73	1.2
Other Petroleum [1]	4.11	3.68	3.73	3.75	3.78	-.4
Natural Gas [2]	8.71	9.16	9.53	9.41	9.51	.4
Metallurgical Coal and Coke [3]	1.07	.99	.98	.96	.94	-.6
Steam Coal [4]	1.71	1.70	1.72	1.75	1.89	.5
Renewables [5]	2.01	2.25	2.34	2.44	2.58	1.2
Electricity	3.20	3.48	4.08	4.76	5.45	2.7
Total	25.25	26.47	27.98	29.20	30.78	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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	1.08	1.21	1.36	1.49	2.0
Freight Trucks	1.00	1.14	1.30	1.46	1.61	2.4
Air	.99	1.29	1.67	2.10	2.54	4.8
Rail	1.00	1.07	1.17	1.28	1.39	1.7
Marine	.99	1.04	1.14	1.22	1.29	1.3
Energy Efficiency Indicators						
New Car MPG [1]	28.10	29.28	31.92	34.54	36.77	1.4
New Light Truck MPG [1]	20.80	21.66	23.53	25.15	26.51	1.2
Light Duty Fleet MPG [2]	18.58	19.31	20.17	21.18	22.14	.9
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.02	1.05	1.10	1.11	1.13	.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	11.55	12.02	12.81	13.67	14.32	1.1
Freight Trucks	4.93	5.45	5.97	6.57	7.13	1.9
Air	3.21	3.52	4.03	4.62	5.07	2.3
Rail	.48	.52	.55	.60	.64	1.4
Marine	1.13	1.16	1.31	1.44	1.57	1.7
Pipeline Fuel	.59	.66	.71	.76	.82	1.7
Other	.18	.19	.21	.23	.25	1.5
Total	22.07	23.52	25.59	27.90	29.79	1.5

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1992 Forecasting System run HMAC92.D0923914.

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	14.53	13.11	12.60	12.50	-1.1
Natural Gas Plant Liquids	2.16	2.13	2.21	2.31	2.30	.3
Dry Natural Gas [2]	18.27	18.77	19.30	20.31	20.19	.5
Coal	22.46	22.71	23.40	24.56	28.30	1.2
Nuclear Power	6.19	6.53	6.90	6.89	6.75	.4
Renewable Energy [3]	6.62	7.46	8.32	9.13	9.82	2.0
Total	71.45	72.14	73.23	75.81	79.85	.6
Imports						
Crude Oil [4]	12.70	13.63	15.64	17.15	18.66	1.9
Petroleum Products	4.29	5.88	5.72	5.82	5.97	1.7
Natural Gas [5]	1.45	2.31	2.80	3.01	3.38	4.3
Other Imports [6]	.09	.61	.75	.97	1.19	13.6
Total	18.53	22.44	24.91	26.95	29.19	2.3
Exports						
Coal	2.77	2.96	2.86	3.26	4.77	2.8
Petroleum	1.80	1.62	1.61	1.65	1.74	-.2
Total	4.57	4.58	4.47	4.91	6.51	1.8
Net Stock Withdrawals	-1.32	-.21	-.17	-.15	-.20	-9.1
Discrepancy [7]	.93	.19	.10	-.02	-.20	-
Consumption						
Petroleum Products [8]	33.79	34.83	35.29	36.45	37.84	.6
Natural Gas	19.38	20.96	21.99	23.21	23.45	1.0
Coal	19.09	19.81	20.63	21.45	23.63	1.1
Nuclear Power	6.19	6.53	6.90	6.89	6.75	.4
Renewable Energy/Other [9]	6.57	7.85	8.78	9.68	10.48	2.4
Total	85.02	89.98	93.59	97.68	102.10	.9
Net Imports - Petroleum	15.18	17.89	19.75	21.32	22.89	2.1
Prices (1990 dollars per unit)						
World Oil Price ($ per barrel) [10]	21.78	20.80	26.40	30.50	33.40	2.2
Natural Gas Wellhead Price ($ per Mcf)	1.72	1.96	2.46	3.24	4.62	5.1
Coal Minemouth Price ($ per ton)	21.76	23.81	25.77	27.03	29.98	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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	1.00	0.92	0.72	0.58	0.48	-3.6
Kerosene	.09	.07	.05	.03	.02	-7.5
Liquefied Petroleum Gas	.46	.44	.38	.34	.31	-1.9
Natural Gas	4.50	4.98	4.91	4.81	4.68	.2
Coal	.06	.04	.04	.04	.04	-1.8
Renewable Energy [1]	.96	1.10	1.45	1.79	2.14	4.1
Electricity	3.14	3.48	3.64	3.83	4.03	1.3
Total	10.22	11.04	11.19	11.43	11.71	.7
Commercial						
Distillate Fuel	.51	.54	.50	.44	.40	-1.2
Kerosene	.05	.04	.03	.03	.02	-3.9
Motor Gasoline [2]	.10	.12	.12	.12	.13	1.3
Residual Fuel	.21	.17	.15	.13	.11	-3.2
Natural Gas	2.70	3.03	3.14	3.22	3.28	1.0
Other [3]	.18	.14	.12	.10	.09	-3.5
Renewable Energy [1]	.05	.10	.20	.26	.32	9.3
Electricity	2.87	3.20	3.55	3.94	4.37	2.1
Total	6.68	7.33	7.81	8.24	8.72	1.3
Industrial [4]						
Distillate Fuel	1.08	1.26	1.27	1.26	1.30	.9
Liquefied Petroleum Gas	1.49	1.93	1.96	2.06	2.28	2.1
Motor Gasoline [2]	.20	.22	.22	.23	.25	1.2
Petrochemical Feedstocks	1.09	1.15	1.22	1.31	1.45	1.4
Residual Fuel	.58	.76	.67	.65	.68	.9
Other Petroleum [5]	4.11	3.64	3.59	3.59	3.62	-.6
Natural Gas [6]	8.71	9.01	9.14	8.90	8.52	-.1
Metallurgical Coal	1.06	.91	.84	.78	.72	-1.9
Steam Coal	1.71	1.70	1.68	1.70	1.86	.4
Net Coal Coke Imports	.00	.07	.12	.16	.21	20.8
Renewable Energy [1]	2.01	2.23	2.30	2.35	2.41	.9
Purchased Electricity	3.20	3.38	3.73	4.12	4.64	1.9
Total	25.25	26.25	26.75	27.13	27.95	.5
Transportation						
Distillate Fuel	3.74	4.15	4.34	4.66	5.06	1.5
Jet Fuel	3.13	3.23	3.26	3.44	3.69	.8
Motor Gasoline [2]	13.58	13.98	14.11	14.47	14.92	.5
Residual Fuel	.77	.76	.83	.90	.98	1.2
Other Petroleum [7]	.26	.27	.29	.31	.34	1.2
Pipeline Fuel Natural Gas	.59	.64	.68	.72	.73	1.1
Compressed Natural Gas	.00	.00	.00	.01	.03	-
Alcohol Fuels	.00	.00	.01	.03	.05	-
Electricity	.01	.01	.02	.03	.04	5.5
Total	22.07	23.05	23.54	24.57	25.83	.8
Electric Utilities [8]						
Distillate Fuel	.09	.10	.22	.24	.23	5.1
Residual Fuel	1.16	1.01	1.31	1.60	1.50	1.3
Natural Gas	2.88	3.30	4.12	5.54	6.20	3.9
Steam Coal [9]	16.16	17.08	18.00	18.87	20.97	1.3
Nuclear Power	6.19	6.53	6.90	6.89	6.75	.4
Renewable Energy/Other [10]	3.54	4.35	4.71	5.08	5.36	2.1
Total	30.02	32.37	35.26	38.23	41.01	1.6
Primary Energy Consumption						
Distillate Fuel	6.42	6.96	7.05	7.18	7.48	.8
Kerosene	.14	.11	.08	.06	.04	-5.9
Jet Fuel	3.13	3.23	3.26	3.44	3.69	.8
Liquefied Petroleum Gas	2.06	2.47	2.42	2.48	2.67	1.3
Motor Gasoline	13.87	14.31	14.46	14.83	15.30	.5
Petrochemical Feedstocks	1.09	1.15	1.22	1.31	1.45	1.4
Residual Fuel	2.72	2.70	2.95	3.28	3.28	.9

- 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 [11]	4.35	3.89	3.86	3.88	3.93	-0.5
Natural Gas	19.38	20.96	21.99	23.21	23.45	1.0
Metallurgical Coal	1.06	.91	.84	.78	.72	-1.9
Steam Coal	18.03	18.89	19.78	20.67	22.91	1.2
Net Coal Coke Imports	.00	.07	.12	.16	.21	20.8
Nuclear Power	6.19	6.53	6.90	6.89	6.75	.4
Renewable Energy/Other [12]	6.57	7.78	8.66	9.49	10.22	2.2
Alcohols	.00	.00	.01	.03	.05	-
Total	85.02	89.98	93.59	97.68	102.10	.9
Electricity Consumption (all Sectors)	9.23	10.07	10.94	11.92	13.08	1.8
Industrial Electricity						
Gross Consumption	3.58	3.86	4.25	4.66	5.21	1.9
Self-generation - Own Use	.39	.48	.51	.54	.56	1.9
Purchased Electricity	3.20	3.38	3.73	4.12	4.64	1.9

[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 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 consumption by independent power producers.

[10] 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.

[11] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.

[12] 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(91/07) (Washington, DC, July 1991), 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 1992 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

Table C3. Energy Prices by End-Use Sector and Source (1990 Dollars per Million Btu)

Sector and Source	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	11.94	12.13	12.71	13.79	15.40	1.3
Primary Energy	6.28	6.27	6.85	7.59	8.82	1.7
Petroleum Products	8.43	7.50	8.69	9.58	10.26	1.0
Distillate Fuel	7.66	6.84	7.91	8.68	9.21	.9
Kerosene	8.77	8.22	9.00	9.56	9.93	.6
Liquefied Petroleum Gas	10.02	8.73	10.11	11.11	11.89	.9
Natural Gas	5.60	5.96	6.46	7.25	8.62	2.2
Steam Coal	2.16	2.26	2.43	2.55	2.79	1.3
Electricity	22.96	23.00	22.52	23.18	24.45	.3
Commercial	12.23	12.24	12.58	13.41	14.86	1.0
Primary Energy	5.01	5.11	5.75	6.55	7.78	2.2
Petroleum Products	5.72	5.32	6.51	7.43	8.13	1.8
Distillate Fuel	5.67	4.76	5.84	6.63	7.17	1.2
Residual Fuel	2.99	3.22	4.20	4.91	5.43	3.0
Kerosene	5.75	5.74	6.54	7.13	7.55	1.4
Other Petroleum [1]	9.08	8.84	10.27	11.36	12.14	1.5
Natural Gas	4.86	5.11	5.61	6.40	7.77	2.4
Steam Coal	2.13	2.20	2.37	2.48	2.70	1.2
Electricity	21.67	21.24	20.39	20.45	21.39	-.1
Industrial	5.41	5.49	6.24	7.08	8.10	2.0
Primary Energy	3.88	3.95	4.66	5.38	6.22	2.4
Petroleum Products	5.43	5.22	6.28	7.03	7.58	1.7
Distillate Fuel	5.63	4.99	6.06	6.82	7.36	1.3
Liquefied Petroleum Gas	5.71	4.77	6.15	7.14	7.89	1.6
Motor Gasoline [2]	9.36	9.42	10.78	11.83	12.53	1.5
Residual Fuel	2.69	3.08	4.05	4.77	5.28	3.4
Other Petroleum [3]	5.46	5.61	6.48	7.11	7.56	1.6
Natural Gas [4]	2.94	3.22	3.72	4.50	5.86	3.5
Metallurgical Coal	1.78	1.95	2.13	2.23	2.44	1.6
Steam Coal	1.50	1.70	1.81	1.92	2.08	1.7
Electricity	14.41	14.32	14.43	15.03	15.96	.5
Transportation	8.46	8.43	9.67	10.57	11.16	1.4
Primary Energy	8.46	8.42	9.66	10.56	11.14	1.4
Petroleum Products	8.46	8.42	9.66	10.56	11.15	1.4
Distillate Fuel [5]	8.51	8.60	9.67	10.43	10.96	1.3
Jet Fuel [6]	5.69	4.70	5.80	6.58	7.13	1.1
Motor Gasoline [2]	9.34	9.44	10.81	11.85	12.55	1.5
Residual Fuel	3.03	3.03	3.85	4.44	4.81	2.3
Other Petroleum [7]	10.60	12.68	13.53	14.14	14.58	1.6
Natural Gas	.00	5.38	5.87	6.66	8.04	-
Electricity	23.54	23.25	22.65	22.96	24.36	.2
Total End-Use Energy	8.30	8.39	9.23	10.14	11.13	1.5
Primary Energy	6.22	6.24	7.18	8.04	8.88	1.8
Electricity	19.59	19.53	19.07	19.46	20.41	.2
Electric Utilities						
Fossil Fuel Average	1.70	1.82	2.12	2.50	2.92	2.8
Petroleum Products	3.42	3.64	4.60	5.26	6.01	2.9
Distillate Fuel	5.28	4.40	5.49	6.24	6.78	1.3
Residual Fuel	3.28	3.56	4.44	5.12	5.89	3.0
Natural Gas	2.33	2.45	2.98	3.90	5.40	4.3
Steam Coal	1.45	1.58	1.72	1.81	1.93	1.4

- See footnotes at end of table.

Table C3. Energy Prices by End-Use Sector and Source (Continued)
(1990 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	7.42	7.32	8.47	9.32	9.93	1.5
Distillate Fuel [5]	7.62	7.36	8.44	9.28	9.88	1.3
Jet Fuel [6]	5.69	4.70	5.80	6.58	7.13	1.1
Kerosene	7.68	7.36	8.00	8.40	8.63	.6
Liquefied Petroleum Gas	6.83	5.60	6.89	7.79	8.45	1.1
Motor Gasoline [2]	9.34	9.44	10.81	11.85	12.55	1.5
Residual Fuel	3.06	3.25	4.18	4.85	5.43	2.9
Other Petroleum Products [9]	5.70	5.98	6.86	7.51	7.97	1.7
Natural Gas	3.82	4.10	4.53	5.26	6.63	2.8
Coal	1.47	1.61	1.74	1.84	1.96	1.4
Electricity	19.59	19.53	19.07	19.46	20.41	.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: Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. 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: 1988*, DOE/EIA-0376(88) (Washington, DC, September 1990), 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1992 Forecasting System run LMAC92.D0923913. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	1,558	1,647	1,736	1,821	2,059	1.4
Petroleum	117	104	142	173	162	1.7
Natural Gas	264	305	374	508	586	4.1
Nuclear Power	577	599	633	632	619	.3
Pumped Storage Hydroelectric	-9	-10	-11	-13	-13	2.0
Renewable Sources/Other [1]	300	318	326	332	335	.6
Total	2,807	2,964	3,200	3,453	3,747	1.5
Net Imports	2	40	44	53	62	18.8
Nonutilities [2]						
Generation by Fuel Type						
Coal	35	51	53	54	73	3.7
Petroleum	4	5	6	6	7	2.6
Natural Gas	115	153	165	191	225	3.4
Renewable Sources/Other [1]	76	111	136	163	180	4.4
Total	230	320	360	414	484	3.8
Sales to Utilities	115	179	210	257	319	5.2
Generation for Own Use	115	142	150	158	165	1.8
Electricity Sales by Sector						
Residential	922	1,020	1,067	1,124	1,181	1.2
Commercial/Other [3]	846	941	1,045	1,162	1,293	2.1
Industrial	938	990	1,095	1,207	1,361	1.9
Total	2,705	2,951	3,207	3,493	3,834	1.8
End-Use Prices [4] (1990 cents per kilowatthour)						
Residential	7.83	7.85	7.68	7.91	8.34	.3
Commercial/Other [3]	7.40	7.25	6.96	6.98	7.31	-.1
Industrial [5]	4.92	4.89	4.92	5.13	5.44	.5
Average	6.69	6.66	6.51	6.64	6.96	.2
Price Components [4] (1990 cents per kilowatthour)						
Capital Component	2.92	2.82	2.36	2.14	2.14	-1.6
Fuel Component	1.68	1.80	2.09	2.44	2.79	2.6
O&M Component	2.08	2.04	2.05	2.06	2.03	-.1
Total	6.69	6.66	6.51	6.64	6.96	.2

[1] 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.
[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.
[3] Other includes sales of electricity to Government, railways, and street lighting authorities.
[4] Prices represent average revenue per kilowatthour of sales over all customer classes.
[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 Monthly, September 1991*, DOE/EIA-0226(91/09) (Washington, DC, September 1991). 1990 nonutilities, prices, and all projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	300.0	300.6	306.1	313.5	349.9	0.8
Other Fossil Steam [2]	144.4	138.3	131.8	124.7	120.9	-.9
Combined Cycle	6.0	8.4	11.5	28.7	52.0	11.4
Combustion Turbine/Diesel	46.2	53.1	63.2	70.9	77.9	2.6
Nuclear Power	99.6	101.9	102.9	102.9	99.1	.0
Pumped Storage Hydroelectric	17.3	18.6	21.8	21.8	21.8	1.2
Renewable Sources/Other [3]	77.4	79.5	81.6	82.8	83.3	.4
Total	690.9	700.4	718.9	745.2	805.0	.8
Cumulative Planned Additions [4]						
Coal Steam	3.0	7.9	18.6	21.4	21.7	10.4
Other Fossil Steam	.0	.0	.8	.8	.8	-
Combined Cycle	.1	2.5	5.4	6.0	6.0	21.2
Combustion Turbine/Diesel	.6	6.6	13.9	14.4	14.4	16.8
Nuclear Power	2.3	4.6	5.8	5.8	5.8	4.7
Pumped Storage Hydroelectric	.0	1.3	4.5	4.5	4.5	-
Renewable Sources/Other [3]	.2	2.0	3.6	3.9	3.9	16.5
Total	6.3	24.9	52.7	56.7	57.1	11.7
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	8.3	47.2	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.3	16.9	40.3	-
Combustion Turbine/Diesel	.0	1.3	4.2	12.8	19.9	-
Nuclear Power	.0	.0	.0	.0	.0	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.1	.4	.9	1.9	2.3	18.8
Total	.1	1.7	6.0	39.9	109.8	43.9
Cumulative Total Additions	6.3	26.7	58.6	96.6	166.9	17.8
Cumulative Retirements	1.5	12.4	25.9	37.6	48.1	18.8
Nonutilities [5]						
Capability						
Coal	6.3	10.0	10.4	10.6	13.8	4.0
Petroleum	1.2	1.7	1.9	2.1	2.4	3.6
Natural Gas	11.5	20.0	22.3	27.5	34.5	5.7
Renewable Sources/Other [3]	15.1	22.8	26.9	31.3	34.5	4.2
Total	34.1	54.5	61.5	71.5	85.2	4.7
Cumulative Additions	5.9	26.4	33.4	43.4	57.1	12.0

[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: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report.* 1990 nonutility capability and all projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	75.76	78.33	78.46	78.46	78.52	0.2
Geothermal	2.54	2.96	4.28	5.66	6.07	4.5
Municipal Solid Waste	2.36	5.05	7.35	10.05	11.85	8.4
Biomass/Other Waste	5.25	5.97	6.26	6.41	6.60	1.2
Solar Thermal	.43	1.15	1.16	1.31	1.69	7.1
Solar Photovoltaic	.00	.01	.01	.01	.01	5.8
Wind	1.95	2.62	3.46	4.31	5.16	5.0
Total	88.30	96.08	101.00	106.20	109.90	1.1
Generation (billion kilowatthours)						
Conventional Hydropower	290.60	312.40	311.20	310.20	309.80	.3
Geothermal	14.13	16.78	26.16	37.80	40.93	5.5
Municipal Solid Waste	13.53	30.39	43.87	60.83	72.17	8.7
Biomass/Other Waste	26.08	31.22	35.91	38.79	41.12	2.3
Solar Thermal	.79	2.30	2.81	3.18	4.18	8.7
Solar Photovoltaic	.00	.01	.01	.01	.01	6.4
Wind	2.84	3.87	7.06	9.26	11.34	7.2
Total	347.90	397.00	427.00	460.00	479.50	1.6
Consumption/Displacement						
Conventional Hydropower	3.02	3.25	3.24	3.23	3.22	.3
Geothermal	.14	.17	.27	.39	.43	5.5
Municipal Solid Waste	.14	.32	.46	.63	.75	8.8
Biomass/Other Waste	.27	.32	.37	.40	.42	2.3
Solar Thermal	.01	.02	.03	.03	.04	8.8
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.03	.04	.07	.10	.12	7.4
Total	3.61	4.12	4.43	4.78	4.98	1.6
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.16	.29	.41	-
Biofuels	2.70	2.99	3.20	3.39	3.59	1.4
Solar Thermal	.05	.08	.23	.34	.46	11.2
Transportation						
Ethanol	.08	.10	.12	.18	.24	5.6
Total	2.84	3.20	3.72	4.20	4.69	2.6
Total Renewable Energy	6.44	7.32	8.15	8.98	9.67	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 1992 Forecasting System run LMAC92.D0923913.

Table C7. Macroeconomic Indicators
(Billion 1982 Dollars, Unless Otherwise Noted)

Indicator	Low Economic Growth					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GNP Implicit Price Deflator (index, 1982=1.000)	1.315	1.543	2.070	2.696	3.402	4.9
Real Gross National Product	4,156	4,567	4,902	5,342	5,923	1.8
Real Disposable Personal Income	2,894	3,144	3,336	3,601	3,903	1.5
Index of Manufacturing Gross Output (index, 1982=1.000)	1.218	1.362	1.506	1.671	1.887	2.2
AA Utility Bond Rate (percent)	9.66	9.95	10.15	9.97	9.65	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	6.47	6.64	6.65	6.59	-
Energy Intensity (thousand Btu per 1982 $ of GNP)	20.46	19.70	19.09	18.29	17.24	-.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 1992 Forecasting System run LMAC92.D0923913.

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 (1990 dollars per barrel) [1]	21.78	20.80	26.40	30.50	33.40	2.2
Production						
Crude Oil [2]	7.35	6.67	5.90	5.61	5.49	-1.5
Alaska	1.77	1.33	.93	.69	.78	-4.0
Lower 48	5.58	5.34	4.97	4.92	4.71	-.8
Natural Gas Plant Liquids	1.56	1.54	1.58	1.67	1.65	.3
Other Domestic [3]	.08	.19	.27	.34	.41	8.6
Processing Gain [4]	.68	.74	.69	.67	.73	.3
Total	9.68	9.14	8.44	8.29	8.29	-.8
Imports (including SPR) [5]						
Crude Oil	5.89	6.33	7.24	7.96	8.66	1.9
Refined Products[6]	2.12	2.91	2.82	2.88	2.95	1.7
Total	8.02	9.24	10.06	10.84	11.61	1.9
Exports						
Crude Oil	.11	.10	.08	.07	.08	-1.4
Refined Products	.75	.67	.68	.71	.74	.0
Total	.85	.77	.76	.78	.82	-.2
Net Imports (including SPR)	7.16	8.47	9.30	10.06	10.79	2.1
Primary Stock Changes						
Net Withdrawals [7]	-.09	-.02	.00	-.03	-.03	-5.4
SPR Fill Rate Additions (-) [5]	-.02	-.05	-.05	.00	.00	-
Total Primary Supply [8]	16.73	17.54	17.69	18.31	19.05	.7
Unaccounted for Crude	.26	.20	.20	.20	.20	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.46	7.52	7.73	7.98	.5
Jet Fuel [10]	1.52	1.58	1.58	1.68	1.80	.8
Distillate Fuel	3.02	3.27	3.31	3.38	3:52	.8
Residual Fuel	1.23	1.18	1.28	1.43	1.43	.8
Other [11]	3.98	4.24	4.20	4.30	4.53	.6
Total	16.99	17.73	17.89	18.51	19.25	.6
Refined Petroleum Products Supplied						
Residential and Commercial	1.34	1.26	1.07	.92	.82	-2.4
Industrial [12]	4.25	4.71	4.70	4.83	5.12	.9
Transportation	10.81	11.28	11.46	11.95	12.55	.7
Electric Utilities [13]	.55	.49	.67	.81	.76	1.7
Total	16.95	17.73	17.89	18.51	19.25	.6
Net Disposition	16.99	17.74	17.89	18.51	19.25	.6

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols.
[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.
[13] The 1990 figure includes both sales and stock changes. All years data include consumption by independent power producers.

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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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]	17.61	18.11	18.62	19.58	19.43	0.5
Supplemental Gas [2]	.11	.10	.10	.12	.15	1.6
Net Imports	1.41	2.25	2.72	2.92	3.27	4.3
Net Storage Withdrawals [3]	-.52	.00	.00	.00	.00	-
Total Supply	18.61	20.45	21.44	22.62	22.85	1.0
Consumption by Sector						
Residential	4.37	4.83	4.76	4.67	4.54	.2
Commercial	2.62	2.94	3.04	3.12	3.18	1.0
Industrial [4]	7.24	7.60	7.69	7.39	7.03	-.1
Electric Utilities [5]	2.79	3.20	4.00	5.38	6.02	3.9
Lease and Plant Fuel [6]	1.21	1.14	1.18	1.24	1.24	.1
Pipeline Fuel	.57	.62	.66	.70	.71	1.1
Transportation [7]	.00	.00	.00	.01	.02	-
Total	18.80	20.33	21.33	22.51	22.74	1.0
Unaccounted for [8]	-.19	.12	.11	.11	.11	-
Average Wellhead Price (1990 dollars per thousand cubic feet)	1.72	1.96	2.46	3.24	4.62	5.1
Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	6.14	6.66	7.47	8.89	2.2
Commercial	5.01	5.27	5.78	6.60	8.02	2.4
Industrial	3.03	3.32	3.83	4.64	6.04	3.5
Electric Utilities	2.40	2.53	3.08	4.02	5.57	4.3
Transportation	.00	5.54	6.05	6.87	8.29	-
Average [9]	3.94	4.23	4.67	5.42	6.83	2.8

[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 anincrease 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered prices for 1990 and projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	647	639	662	790	1.1
West of the Mississippi	399	395	456	486	521	1.3
Total	1,029	1,042	1,096	1,148	1,311	1.2
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	114	112	127	185	2.8
Total	-103	-109	-105	-117	-173	2.6
Net Stock Withdrawals [2]	-26	-2	-3	-3	-6	-6.9
Total Supply [3]	901	931	988	1,028	1,132	1.1
Consumption by Sector						
Residential and Commercial	7	5	4	4	4	-3.2
Industrial [4]	76	75	75	76	84	.5
Coking Plants	40	34	32	29	27	-1.9
Electricity [5]	772	816	877	919	1,016	1.4
Total	895	931	988	1,028	1,131	1.2
Discrepancy [6]	6	0	0	-1	1	-
Average Minemouth Price [7] **(1990 dollars per short ton)**	21.76	23.81	25.77	27.03	29.98	1.6
Delivered Prices (1990 dollars per short ton)						
Residential and Commercial	48.39	53.65	57.08	60.16	65.56	1.5
Industrial	33.59	38.20	40.37	42.90	46.05	1.6
Coking Plants	47.79	51.79	56.54	59.28	64.61	1.5
Electricity	30.43	33.10	35.24	37.23	39.83	1.4
Average [8]	31.61	34.31	36.41	38.37	40.97	1.3

[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(91/1Q) (Washington, DC, August 1991); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	97.6	101.8	105.1	108.2	0.7
Energy Consumption per Household (million Btu)	109.4	113.1	109.9	108.7	108.3	-.1
End-Use Consumption						
Distillate						
Space Heating	.86	.83	.66	.55	.47	-3.0
Other Uses [1]	.14	.09	.05	.03	.02	-9.4
Total	1.00	.92	.72	.58	.48	-3.6
Natural Gas						
Space Heating	3.14	3.43	3.36	3.28	3.19	.1
Water Heating	1.06	1.25	1.28	1.27	1.23	.8
Other Uses [1]	.31	.30	.27	.26	.26	-.9
Total	4.50	4.98	4.91	4.81	4.68	.2
Other Fuels [2]	.61	.53	.44	.39	.35	-2.8
Renewables [3]	.96	1.10	1.45	1.79	2.14	4.1
Electricity						
Space Heating	.32	.33	.32	.32	.33	.2
Cooling	.51	.55	.56	.56	.57	.5
Water Heating	.39	.50	.57	.64	.72	3.1
Other Uses [1]	1.92	2.10	2.19	2.30	2.41	1.1
Total	3.14	3.48	3.64	3.83	4.03	1.3
Total Consumption	10.22	11.04	11.19	11.43	11.71	.7

[1] Includes cooking, cooling (natural gas), water heating (distillate), 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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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)	110.3	117.0	120.5	123.9	130.0	0.8
Total Floorspace (billion square feet)	62.9	69.0	75.4	81.9	88.5	1.7
Energy Consumption per Square Foot (thousand Btu)	106.3	106.2	103.5	100.6	98.5	-.4
End-Use Consumption						
Distillate						
Space Heating	.47	.50	.47	.42	.38	-1.0
Other Uses [1]	.04	.04	.03	.02	.02	-4.3
Total	.51	.54	.50	.44	.40	-1.2
Natural Gas						
Space Heating	1.76	1.96	2.00	2.00	1.98	.6
Cooling	.21	.22	.24	.25	.28	1.4
Other Uses [1]	.73	.85	.91	.97	1.02	1.7
Total	2.70	3.03	3.14	3.22	3.28	1.0
Other Fuels [2]	.54	.47	.42	.38	.35	-2.2
Renewables [3]	.05	.10	.20	.26	.32	9.3
Electricity						
Space Heating	.53	.60	.69	.81	.97	3.1
Cooling	.74	.83	.92	1.00	1.08	1.9
Lighting	1.13	1.23	1.34	1.46	1.57	1.7
Other Uses [1]	.47	.53	.60	.67	.75	2.3
Total	2.87	3.20	3.55	3.94	4.37	2.1
Total Consumption	6.68	7.33	7.81	8.24	8.72	1.3

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	2401	2685	2967	3294	3718	2.2
Non-manufacturing	830	896	929	979	1048	1.2
Total	3231	3580	3896	4272	4766	2.0
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.34	.35	.33	.30	.27	-1.0
Liquefied Petroleum Gas	.46	.54	.50	.48	.48	.2
Petrochemical Feedstocks	.34	.32	.31	.31	.30	-.5
Residual Fuel	.18	.21	.17	.15	.14	-1.1
Other Petroleum [1]	1.27	1.02	.92	.84	.76	-2.5
Natural Gas [2]	2.69	2.52	2.35	2.08	1.79	-2.0
Metallurgical Coal and Coke [3]	.33	.28	.25	.22	.19	-2.6
Steam Coal [4]	.53	.47	.43	.40	.39	-1.5
Renewables [5]	.06	.06	.06	.06	.05	-1.0
Electricity	.99	.94	.96	.96	.97	-.1
Total	7.81	7.33	6.87	6.35	5.86	-1.4
Consumption (quadrillion Btu per year)						
Distillate	1.08	1.26	1.27	1.26	1.30	.9
Liquefied Petroleum Gas	1.49	1.93	1.96	2.06	2.28	2.1
Motor Gasoline [6]	.20	.22	.22	.23	.25	1.2
Petrochemical Feedstocks	1.09	1.15	1.22	1.31	1.45	1.4
Residual Fuel	.58	.76	.67	.65	.68	.9
Other Petroleum [1]	4.11	3.64	3.59	3.59	3.62	-.6
Natural Gas [2]	8.71	9.01	9.14	8.90	8.52	-.1
Metallurgical Coal and Coke [3]	1.07	.99	.96	.94	.93	-.7
Steam Coal [4]	1.71	1.70	1.68	1.70	1.86	.4
Renewables [5]	2.01	2.23	2.30	2.35	2.41	.9
Electricity	3.20	3.38	3.73	4.12	4.64	1.9
Total	25.25	26.25	26.75	27.13	27.95	.5

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	1.08	1.15	1.24	1.35	1.5
Freight Trucks	1.00	1.09	1.16	1.24	1.36	1.5
Air	.99	1.20	1.35	1.55	1.84	3.2
Rail	1.00	1.04	1.08	1.14	1.23	1.1
Marine	.99	1.02	1.06	1.13	1.20	1.0
Energy Efficiency Indicators						
New Car MPG [1]	28.10	29.10	31.69	34.32	36.56	1.3
New Light Truck MPG [1]	20.80	21.53	23.36	25.00	26.37	1.2
Light Duty Fleet MPG [2]	18.58	19.26	20.08	21.07	22.07	.9
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.02	1.05	1.10	1.11	1.13	.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	11.55	12.03	12.23	12.59	13.00	.6
Freight Trucks	4.93	5.22	5.33	5.63	6.05	1.0
Air	3.21	3.32	3.35	3.54	3.80	.9
Rail	.48	.51	.51	.53	.56	.8
Marine	1.13	1.15	1.24	1.34	1.46	1.3
Pipeline Fuel	.59	.64	.68	.72	.73	1.1
Other	.18	.19	.20	.21	.23	1.0
Total	22.07	23.05	23.54	24.57	25.83	.8

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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1992 Forecasting System run LMAC92.D0923913.

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	15.64	14.84	14.21	13.86	-0.6
Natural Gas Plant Liquids	2.16	2.17	2.29	2.37	2.29	.3
Dry Natural Gas [2]	18.27	19.07	20.04	20.86	20.17	.5
Coal	22.46	23.11	24.32	26.69	30.94	1.6
Nuclear Power	6.19	6.54	6.90	6.89	6.75	.4
Renewable Energy [3]	6.62	7.54	8.63	9.70	10.63	2.4
Total	71.45	74.05	77.02	80.73	84.64	.9
Imports						
Crude Oil [4]	12.70	12.21	13.93	15.93	17.50	1.6
Petroleum Products	4.29	5.61	5.63	5.79	5.98	1.7
Natural Gas [5]	1.45	2.31	2.80	3.07	3.42	4.4
Other Imports [6]	.09	.61	.77	1.05	1.31	14.2
Total	18.53	20.75	23.12	25.84	28.21	2.1
Exports						
Coal	2.77	3.32	3.72	4.64	6.03	4.0
Petroleum	1.80	1.62	1.63	1.72	1.82	.0
Total	4.57	4.94	5.36	6.36	7.85	2.7
Net Stock Withdrawals	-1.32	-.19	-.22	-.18	-.21	-8.9
Discrepancy [7]	.93	.20	.14	.01	-.21	-
Consumption						
Petroleum Products [8]	33.79	34.32	35.28	36.83	38.00	.6
Natural Gas	19.38	21.23	22.73	23.82	23.43	1.0
Coal	19.09	19.85	20.68	22.17	25.00	1.4
Nuclear Power	6.19	6.54	6.90	6.89	6.75	.4
Renewable Energy/Other [9]	6.57	7.93	9.12	10.33	11.42	2.8
Total	85.02	89.87	94.71	100.00	104.60	1.0
Net Imports - Petroleum	15.18	16.21	17.92	20.00	21.66	1.8
Prices (1990 dollars per unit)						
World Oil Price ($ per barrel) [10]	21.78	25.30	31.80	36.90	40.20	3.1
Natural Gas Wellhead Price ($ per Mcf)	1.72	2.02	2.53	3.35	4.46	4.9
Coal Minemouth Price ($ per ton)	21.76	24.21	26.63	28.85	31.59	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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	1.00	0.90	0.68	0.53	0.42	-4.2
Kerosene	.09	.07	.05	.03	.02	-7.5
Liquefied Petroleum Gas	.46	.44	.38	.34	.32	-1.9
Natural Gas	4.50	4.99	4.88	4.76	4.59	.1
Coal	.06	.04	.04	.04	.04	-1.8
Renewable Energy [1]	.96	1.13	1.60	2.07	2.54	5.0
Electricity	3.14	3.50	3.66	3.86	4.06	1.3
Total	10.22	11.08	11.29	11.63	11.99	.8
Commercial						
Distillate Fuel	.51	.53	.49	.42	.38	-1.5
Kerosene	.05	.04	.03	.03	.02	-3.9
Motor Gasoline [2]	.10	.12	.12	.13	.14	1.5
Residual Fuel	.21	.17	.15	.13	.11	-3.2
Natural Gas	2.70	3.03	3.14	3.24	3.31	1.0
Other [3]	.18	.14	.12	.10	.09	-3.5
Renewable Energy [1]	.05	.10	.24	.31	.38	10.4
Electricity	2.87	3.20	3.56	3.96	4.41	2.2
Total	6.68	7.34	7.85	8.31	8.84	1.4
Industrial [4]						
Distillate Fuel	1.08	1.22	1.23	1.25	1.30	.9
Liquefied Petroleum Gas	1.49	1.79	1.86	2.00	2.19	1.9
Motor Gasoline [2]	.20	.22	.23	.25	.26	1.5
Petrochemical Feedstocks	1.09	1.11	1.21	1.34	1.49	1.6
Residual Fuel	.58	.65	.59	.59	.61	.3
Other Petroleum [5]	4.11	3.60	3.60	3.63	3.65	-.6
Natural Gas [6]	8.71	9.18	9.52	9.44	9.13	.2
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	1.71	1.70	1.70	1.72	1.86	.4
Net Coal Coke Imports	.00	.07	.12	.17	.20	20.6
Renewable Energy [1]	2.01	2.25	2.32	2.40	2.50	1.1
Purchased Electricity	3.20	3.41	3.86	4.39	4.93	2.2
Total	25.25	26.13	27.09	27.97	28.85	.7
Transportation						
Distillate Fuel	3.74	4.18	4.49	4.90	5.28	1.7
Jet Fuel	3.13	3.26	3.51	3.85	4.09	1.4
Motor Gasoline [2]	13.58	13.74	13.95	14.36	14.72	.4
Residual Fuel	.77	.76	.84	.93	1.01	1.4
Other Petroleum [7]	.26	.27	.30	.32	.35	1.5
Pipeline Fuel Natural Gas	.59	.65	.70	.74	.73	1.1
Compressed Natural Gas	.00	.00	.01	.04	.07	-
Alcohol Fuels	.00	.00	.03	.10	.18	-
Electricity	.01	.01	.02	.03	.04	5.6
Total	22.07	22.89	23.84	25.26	26.47	.9
Electric Utilities [8]						
Distillate Fuel	.09	.11	.22	.20	.17	3.4
Residual Fuel	1.16	1.05	1.29	1.55	1.42	1.0
Natural Gas	2.88	3.38	4.48	5.61	5.61	3.4
Steam Coal [9]	16.16	17.11	18.03	19.56	22.32	1.6
Nuclear Power	6.19	6.54	6.90	6.89	6.75	.4
Renewable Energy/Other [10]	3.54	4.37	4.81	5.29	5.62	2.3
Total	30.02	32.56	35.74	39.10	41.88	1.7
Primary Energy Consumption						
Distillate Fuel	6.42	6.95	7.11	7.30	7.55	.8
Kerosene	.14	.11	.08	.06	.04	-5.9
Jet Fuel	3.13	3.26	3.51	3.85	4.09	1.4
Liquefied Petroleum Gas	2.06	2.33	2.32	2.42	2.59	1.1
Motor Gasoline	13.87	14.08	14.30	14.74	15.12	.4
Petrochemical Feedstocks	1.09	1.11	1.21	1.34	1.49	1.6
Residual Fuel	2.72	2.63	2.88	3.19	3.15	.7

- 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 [11]	4.35	3.85	3.87	3.92	3.97	-0.5
Natural Gas	19.38	21.23	22.73	23.82	23.43	1.0
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	18.03	18.93	19.83	21.38	24.27	1.5
Net Coal Coke Imports	.00	.07	.12	.17	.20	20.6
Nuclear Power	6.19	6.54	6.90	6.89	6.75	.4
Renewable Energy/Other [12]	6.57	7.85	8.97	10.07	11.03	2.6
Alcohols	.00	.00	.03	.10	.18	-
Total	85.02	89.87	94.71	100.00	104.60	1.0
Electricity Consumption (all Sectors)	9.23	10.13	11.10	12.23	13.43	1.9
Industrial Electricity						
Gross Consumption	3.58	3.89	4.39	4.94	5.51	2.2
Self-generation - Own Use	.39	.48	.52	.55	.58	2.0
Purchased Electricity	3.20	3.41	3.86	4.39	4.93	2.2

[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 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 consumption by independent power producers.
[10] 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.
[11] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
[12] 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(91/07) (Washington, DC, July 1991), 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 1992 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

Table D3. Energy Prices by End-Use Sector and Source (1990 Dollars per Million Btu)

Sector and Source	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	11.94	12.38	13.24	14.40	15.69	1.4
Primary Energy	6.28	6.52	7.11	7.89	8.88	1.7
Petroleum Products	8.43	8.42	9.79	10.92	11.72	1.7
Distillate Fuel	7.66	7.70	8.92	9.86	10.45	1.6
Kerosene	8.77	8.87	9.78	10.48	10.90	1.1
Liquefied Petroleum Gas	10.02	9.79	11.36	12.60	13.46	1.5
Natural Gas	5.60	6.01	6.54	7.36	8.48	2.1
Steam Coal	2.16	2.29	2.48	2.68	2.89	1.5
Electricity	22.96	23.16	23.35	24.04	24.73	.4
Commercial	12.23	12.47	13.10	14.02	15.10	1.1
Primary Energy	5.01	5.35	6.03	6.87	7.88	2.3
Petroleum Products	5.72	6.19	7.55	8.69	9.46	2.5
Distillate Fuel	5.67	5.62	6.85	7.81	8.41	2.0
Residual Fuel	2.99	4.00	5.11	6.00	6.57	4.0
Kerosene	5.75	6.38	7.32	8.05	8.52	2.0
Other Petroleum [1]	9.08	9.85	11.45	12.74	13.57	2.0
Natural Gas	4.86	5.16	5.68	6.51	7.62	2.3
Steam Coal	2.13	2.22	2.41	2.60	2.82	1.4
Electricity	21.67	21.43	21.16	21.34	21.73	.0
Industrial	5.41	5.86	6.72	7.70	8.60	2.3
Primary Energy	3.88	4.33	5.10	5.94	6.75	2.8
Petroleum Products	5.43	6.08	7.27	8.21	8.82	2.5
Distillate Fuel	5.63	5.85	7.07	8.02	8.61	2.1
Liquefied Petroleum Gas	5.71	5.87	7.43	8.65	9.48	2.6
Motor Gasoline [2]	9.36	10.40	11.91	13.14	13.90	2.0
Residual Fuel	2.69	3.85	4.97	5.85	6.42	4.5
Other Petroleum [3]	5.46	6.32	7.32	8.11	8.62	2.3
Natural Gas [4]	2.94	3.27	3.79	4.61	5.71	3.4
Metallurgical Coal	1.78	1.97	2.18	2.35	2.58	1.9
Steam Coal	1.50	1.71	1.84	1.98	2.17	1.9
Electricity	14.41	14.47	14.89	15.58	16.11	.6
Transportation	8.46	9.34	10.69	11.74	12.38	1.9
Primary Energy	8.46	9.33	10.68	11.73	12.37	1.9
Petroleum Products	8.46	9.33	10.68	11.74	12.38	1.9
Distillate Fuel [5]	8.51	9.46	10.68	11.62	12.21	1.8
Jet Fuel [6]	5.69	5.58	6.84	7.81	8.41	2.0
Motor Gasoline [2]	9.34	10.42	11.93	13.16	13.92	2.0
Residual Fuel	3.03	3.68	4.61	5.34	5.75	3.3
Other Petroleum [7]	10.60	13.36	14.34	15.10	15.61	2.0
Natural Gas	.00	5.43	5.95	6.77	7.89	-
Electricity	23.54	23.63	23.58	24.07	24.96	.3
Total End-Use Energy	8.30	8.92	9.91	10.93	11.80	1.8
Primary Energy	6.22	6.82	7.85	8.84	9.65	2.2
Electricity	19.59	19.69	19.71	20.13	20.59	.2
Electric Utilities						
Fossil Fuel Average	1.70	1.89	2.23	2.61	2.89	2.7
Petroleum Products	3.42	4.41	5.50	6.30	7.14	3.7
Distillate Fuel	5.28	5.28	6.51	7.45	8.02	2.1
Residual Fuel	3.28	4.31	5.32	6.15	7.03	3.9
Natural Gas	2.33	2.51	3.07	4.03	5.24	4.1
Steam Coal	1.45	1.60	1.74	1.87	1.99	1.6

- See footnotes at end of table.

Table D3. Energy Prices by End-Use Sector and Source (Continued)
(1990 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	7.42	8.23	9.51	10.53	11.20	2.1
Distillate Fuel [5]	7.62	8.24	9.50	10.54	11.21	1.9
Jet Fuel [6]	5.69	5.58	6.84	7.81	8.41	2.0
Kerosene	7.68	8.01	8.77	9.32	9.61	1.1
Liquefied Petroleum Gas	6.83	6.74	8.19	9.31	10.06	2.0
Motor Gasoline [2]	9.34	10.42	11.93	13.16	13.92	2.0
Residual Fuel	3.06	3.99	5.03	5.85	6.49	3.8
Other Petroleum Products [9]	5.70	6.69	7.71	8.52	9.04	2.3
Natural Gas	3.82	4.14	4.57	5.35	6.48	2.7
Coal	1.47	1.63	1.77	1.90	2.02	1.6
Electricity	19.59	19.69	19.71	20.13	20.59	.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: Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. 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: 1988*, DOE/EIA-0376(88) (Washington, DC, September 1990), 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1992 Forecasting System run HWOP92.D0923913. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	1,558	1,650	1,739	1,886	2,167	1.7
Petroleum	117	108	140	165	150	1.2
Natural Gas	264	313	402	505	524	3.5
Nuclear Power	577	600	633	632	619	.3
Pumped Storage Hydroelectric	-9	-10	-11	-13	-14	2.1
Renewable Sources/Other [1]	300	318	330	340	344	.7
Total	2,807	2,978	3,233	3,515	3,790	1.5
Net Imports	2	40	44	53	62	18.8
Nonutilities [2]						
Generation by Fuel Type						
Coal	35	51	53	58	117	6.2
Petroleum	4	5	6	6	7	2.6
Natural Gas	115	153	177	212	230	3.5
Renewable Sources/Other [1]	76	113	143	177	199	4.9
Total	230	322	379	453	552	4.5
Sales to Utilities	115	180	226	292	381	6.2
Generation for Own Use	115	142	153	162	171	2.0
Electricity Sales by Sector						
Residential	922	1,026	1,073	1,130	1,189	1.3
Commercial/Other [3]	846	942	1,048	1,169	1,305	2.2
Industrial	938	1,000	1,132	1,286	1,444	2.2
Total	2,705	2,968	3,253	3,586	3,937	1.9
End-Use Prices [4] (1990 cents per kilowatthour)						
Residential	7.83	7.90	7.97	8.20	8.44	.4
Commercial/Other [3]	7.40	7.32	7.23	7.29	7.42	.0
Industrial [5]	4.92	4.94	5.08	5.32	5.50	.6
Average	6.69	6.72	6.72	6.87	7.02	.2
Price Components [4] (1990 cents per kilowatthour)						
Capital Component	2.92	2.82	2.49	2.26	2.18	-1.4
Fuel Component	1.68	1.86	2.20	2.57	2.83	2.6
O&M Component	2.08	2.03	2.03	2.04	2.01	-.2
Total	6.69	6.72	6.72	6.87	7.02	.2

[1] 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.
[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.
[3] Other includes sales of electricity to Government, railways, and street lighting authorities.
[4] Prices represent average revenue per kilowatthour of sales over all customer classes.
[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 Monthly, September 1991*, DOE/EIA-0226(91/09) (Washington, DC, September 1991). 1990 nonutilities, prices, and all projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	300.0	300.6	306.1	323.5	367.7	1.0
Other Fossil Steam [2]	144.4	138.3	131.8	124.7	120.9	-.9
Combined Cycle	6.0	8.4	12.1	30.4	47.3	10.9
Combustion Turbine/Diesel	46.2	53.4	64.8	70.8	76.1	2.5
Nuclear Power	99.6	101.9	102.9	102.9	99.1	.0
Pumped Storage Hydroelectric	17.3	18.6	21.8	21.8	21.8	1.2
Renewable Sources/Other [3]	77.4	79.6	82.2	83.8	84.5	.4
Total	690.9	700.7	721.7	757.8	817.5	.8
Cumulative Planned Additions [4]						
Coal Steam	3.0	7.9	18.6	21.4	21.7	10.4
Other Fossil Steam	.0	.0	.8	.8	.8	-
Combined Cycle	.1	2.5	5.4	6.0	6.0	21.2
Combustion Turbine/Diesel	.6	6.6	13.9	14.4	14.4	16.8
Nuclear Power	2.3	4.6	5.8	5.8	5.8	4.7
Pumped Storage Hydroelectric	.0	1.3	4.5	4.5	4.5	-
Renewable Sources/Other [3]	.2	2.0	3.6	3.9	3.9	16.5
Total	6.3	24.9	52.7	56.7	57.1	11.7
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	18.3	65.0	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.8	18.6	35.6	-
Combustion Turbine/Diesel	.0	1.6	5.9	12.7	18.2	-
Nuclear Power	.0	.0	.0	.0	.0	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.1	.5	1.4	2.9	3.6	21.2
Total	.1	2.1	8.7	52.5	122.3	44.7
Cumulative Total Additions	6.3	27.0	61.4	109.2	179.5	18.2
Cumulative Retirements	1.5	12.4	25.9	37.6	48.1	18.8
Nonutilities [5]						
Capability						
Coal	6.3	10.0	10.4	11.3	21.2	6.2
Petroleum	1.2	1.7	1.9	2.1	2.4	3.7
Natural Gas	11.5	20.0	24.4	31.6	35.3	5.8
Renewable Sources/Other [3]	15.1	23.1	27.9	33.1	36.9	4.6
Total	34.1	54.8	64.5	78.2	95.8	5.3
Cumulative Additions	5.9	26.6	36.4	50.1	67.7	12.9

[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: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report.* 1990 nonutility capability and all projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	75.76	78.33	78.46	78.46	78.52	0.2
Geothermal	2.54	3.14	5.32	7.69	8.40	6.2
Municipal Solid Waste	2.36	5.21	7.76	10.78	12.91	8.9
Biomass/Other Waste	5.25	6.03	6.31	6.57	6.91	1.4
Solar Thermal	.43	1.15	1.16	1.31	1.69	7.1
Solar Photovoltaic	.00	.01	.01	.01	.01	5.8
Wind	1.95	2.62	3.46	4.31	5.16	5.0
Total	88.30	96.48	102.50	109.10	113.60	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	290.60	312.40	311.20	310.20	309.80	.3
Geothermal	14.13	18.03	33.95	53.83	59.27	7.4
Municipal Solid Waste	13.53	31.48	46.60	65.73	79.26	9.2
Biomass/Other Waste	26.08	31.51	36.23	39.36	43.46	2.6
Solar Thermal	.79	2.30	2.81	3.18	4.18	8.7
Solar Photovoltaic	.00	.01	.01	.01	.01	6.4
Wind	2.84	3.87	7.06	9.26	11.34	7.2
Total	347.90	399.60	437.90	481.50	507.30	1.9
Consumption/Displacement						
Conventional Hydropower	3.02	3.25	3.24	3.23	3.22	.3
Geothermal	.14	.19	.35	.56	.62	7.5
Municipal Solid Waste	.14	.33	.48	.68	.82	9.3
Biomass/Other Waste	.27	.32	.37	.40	.45	2.6
Solar Thermal	.01	.02	.03	.03	.04	8.8
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.03	.04	.07	.10	.12	7.4
Total	3.61	4.15	4.55	5.00	5.27	1.9
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.21	.37	.53	-
Biofuels	2.70	3.04	3.31	3.59	3.88	1.8
Solar Thermal	.05	.08	.28	.42	.58	12.5
Transportation						
Ethanol	.08	.10	.12	.18	.24	5.6
Total	2.84	3.25	3.92	4.56	5.22	3.1
Total Renewable Energy	6.44	7.40	8.47	9.56	10.49	2.5

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 1992 Forecasting System run HWOP92.D0923913.

Table D7. Macroeconomic Indicators
(Billion 1982 Dollars, Unless Otherwise Noted)

Indicator	High Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GNP Implicit Price Deflator (index, 1982=1.000)	1.315	1.538	1.849	2.271	2.816	3.9
Real Gross National Product	4,156	4,627	5,172	5,773	6,363	2.2
Real Disposable Personal Income	2,894	3,135	3,418	3,776	4,121	1.8
Index of Manufacturing Gross Output (index, 1982=1.000)	1.218	1.372	1.572	1.785	1.986	2.5
AA Utility Bond Rate (percent)	9.66	8.95	8.96	8.94	8.89	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	5.64	5.69	5.56	5.48	-
Energy Intensity (thousand Btu per 1982 $ of GNP)	20.46	19.42	18.31	17.33	16.44	-1.1

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 1992 Forecasting System run HWOP92.D0923913.

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 (1990 dollars per barrel) [1]	21.78	25.30	31.80	36.90	40.20	3.1
Production						
Crude Oil [2]	7.35	7.20	6.72	6.37	6.14	-.9
Alaska	1.77	1.39	1.02	.97	1.17	-2.0
Lower 48	5.58	5.81	5.70	5.40	4.96	-.6
Natural Gas Plant Liquids	1.56	1.56	1.65	1.71	1.65	.3
Other Domestic [3]	.08	.19	.27	.34	.41	8.5
Processing Gain [4]	.68	.69	.64	.65	.71	.2
Total	9.68	9.64	9.28	9.07	8.90	-.4
Imports (Including SPR) [5]						
Crude Oil	5.89	5.67	6.45	7.40	8.12	1.6
Refined Products[6]	2.12	2.78	2.77	2.86	2.96	1.7
Total	8.02	8.45	9.22	10.26	11.08	1.6
Exports						
Crude Oil	.11	.11	.09	.10	.12	.5
Refined Products	.75	.66	.68	.72	.74	.0
Total	.85	.77	.77	.82	.86	.0
Net Imports (Including SPR)	7.16	7.68	8.45	9.45	10.22	1.8
Primary Stock Changes						
Net Withdrawals [7]	-.09	-.02	-.03	-.04	-.02	-7.4
SPR Fill Rate Additions (-) [5]	-.02	-.05	-.05	.00	.00	-
Total Primary Supply [8]	16.73	17.25	17.66	18.48	19.11	.7
Unaccounted for Crude	.26	.20	.20	.20	.20	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.34	7.44	7.69	7.89	.4
Jet Fuel [10]	1.52	1.59	1.70	1.87	1.99	1.4
Distillate Fuel	3.02	3.27	3.34	3.43	3.55	.8
Residual Fuel	1.23	1.15	1.25	1.39	1.37	.6
Other [11]	3.98	4.10	4.12	4.29	4.50	.6
Total	16.99	17.45	17.85	18.68	19.30	.6
Refined Petroleum Products Supplied						
Residential and Commercial	1.34	1.25	1.05	.89	.79	-2.6
Industrial [12]	4.25	4.50	4.57	4.79	5.06	.9
Transportation	10.81	11.18	11.57	12.23	12.76	.8
Electric Utilities [13]	.55	.51	.67	.77	.70	1.2
Total	16.95	17.45	17.85	18.68	19.30	.7
Net Disposition	16.99	17.45	17.86	18.68	19.31	.6

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols.
[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.
[13] The 1990 figure includes both sales and stock changes. All years data include consumption by independent power producers.

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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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]	17.61	18.39	19.34	20.11	19.42	0.5
Supplemental Gas [2]	.11	.10	.10	.12	.15	1.5
Net Imports	1.41	2.25	2.72	2.98	3.31	4.4
Net Storage Withdrawals [3]	-.52	.00	.00	.00	.00	-
Total Supply	18.61	20.74	22.16	23.21	22.88	1.0
Consumption by Sector						
Residential	4.37	4.84	4.73	4.61	4.45	.1
Commercial	2.62	2.94	3.05	3.14	3.21	1.0
Industrial [4]	7.24	7.75	8.01	7.89	7.61	.3
Electric Utilities [5]	2.79	3.28	4.35	5.44	5.44	3.4
Lease and Plant Fuel [6]	1.21	1.15	1.22	1.27	1.24	.1
Pipeline Fuel	.57	.63	.68	.71	.70	1.1
Transportation [7]	.00	.00	.01	.03	.07	-
Total	18.80	20.60	22.04	23.10	22.73	1.0
Unaccounted for [8]	-.19	.14	.11	.11	.15	-
Average Wellhead Price (1990 dollars per thousand cubic feet)	1.72	2.02	2.53	3.35	4.46	4.9
Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	6.20	6.74	7.59	8.74	2.1
Commercial	5.01	5.32	5.86	6.71	7.86	2.3
Industrial	3.03	3.38	3.91	4.75	5.89	3.4
Electric Utilities	2.40	2.59	3.17	4.15	5.40	4.1
Transportation	.00	5.60	6.13	6.98	8.13	-
Average [9]	3.94	4.27	4.71	5.51	6.68	2.7

[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 anincrease 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered prices for 1990 and projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	662	670	730	864	1.6
West of the Mississippi	399	396	462	508	566	1.8
Total	1,029	1,058	1,132	1,238	1,430	1.7
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	128	144	179	233	4.0
Total	-103	-123	-138	-170	-221	3.9
Net Stock Withdrawals [2]	-26	-2	-3	-5	-8	-5.9
Total Supply [3]	901	933	991	1,063	1,201	1.4
Consumption by Sector						
Residential and Commercial	7	5	4	4	4	-3.2
Industrial [4]	76	76	76	77	85	.6
Coking Plants	40	35	32	30	27	-1.9
Electricity [5]	772	818	879	953	1,084	1.7
Total	895	933	992	1,064	1,200	1.5
Discrepancy [6]	6	0	0	-1	0	-
Average Minemouth Price [7] **(1990 dollars per short ton)**	21.76	24.21	26.63	28.85	31.59	1.9
Delivered Prices (1990 dollars per short ton)						
Residential and Commercial	48.39	54.58	58.10	63.44	67.83	1.7
Industrial	33.59	38.41	41.16	44.19	47.50	1.7
Coking Plants	47.79	52.45	57.91	62.49	68.40	1.8
Electricity	30.43	33.43	35.72	38.42	41.00	1.5
Average [8]	31.61	34.64	36.96	39.60	42.16	1.5

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(91/1Q) (Washington, DC, August 1991); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	98.2	103.1	107.6	111.6	0.9
Energy Consumption per Household (million Btu)	109.4	112.8	109.5	108.1	107.4	-.1
End-Use Consumption						
Distillate						
Space Heating	.86	.81	.63	.50	.40	-3.7
Other Uses [1]	.14	.09	.05	.03	.02	-9.5
Total	1.00	.90	.68	.53	.42	-4.2
Natural Gas						
Space Heating	3.14	3.43	3.31	3.20	3.07	-.1
Water Heating	1.06	1.25	1.29	1.29	1.26	.9
Other Uses [1]	.31	.30	.28	.27	.27	-.7
Total	4.50	4.99	4.88	4.76	4.59	.1
Other Fuels [2]	.61	.53	.44	.39	.35	-2.7
Renewables [3]	.96	1.13	1.60	2.07	2.54	5.0
Electricity						
Space Heating	.32	.33	.31	.31	.31	-.3
Cooling	.51	.56	.55	.55	.54	.3
Water Heating	.39	.51	.57	.64	.71	3.0
Other Uses [1]	1.92	2.11	2.23	2.36	2.49	1.3
Total	3.14	3.50	3.66	3.86	4.06	1.3
Total Consumption	10.22	11.08	11.29	11.63	11.99	.8

[1] Includes cooking, cooling (natural gas), water heating (distillate), 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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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)	110.3	117.4	124.0	130.3	135.5	1.0
Total Floorspace (billion square feet)	62.9	69.0	75.6	82.5	89.5	1.8
Energy Consumption per Square Foot (thousand Btu)	106.3	106.3	103.9	100.8	98.7	-.4
End-Use Consumption						
Distillate						
Space Heating	.47	.49	.45	.40	.36	-1.3
Other Uses [1]	.04	.04	.03	.02	.02	-4.3
Total	.51	.53	.49	.42	.38	-1.5
Natural Gas						
Space Heating	1.76	1.96	2.00	2.02	2.00	.6
Cooling	.21	.22	.24	.25	.28	1.5
Other Uses [1]	.73	.85	.91	.97	1.03	1.8
Total	2.70	3.03	3.14	3.24	3.31	1.0
Other Fuels [2]	.54	.47	.42	.39	.36	-2.1
Renewables [3]	.05	.10	.24	.31	.38	10.4
Electricity						
Space Heating	.53	.61	.69	.82	.98	3.1
Cooling	.74	.83	.92	1.01	1.09	2.0
Lighting	1.13	1.23	1.35	1.47	1.59	1.7
Other Uses [1]	.47	.53	.60	.67	.75	2.3
Total	2.87	3.20	3.56	3.96	4.41	2.2
Total Consumption	6.68	7.34	7.85	8.31	8.84	1.4

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	2401	2703	3098	3518	3914	2.5
Non-manufacturing	830	922	985	1061	1135	1.6
Total	3231	3625	4083	4579	5049	2.3
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.34	.34	.30	.27	.26	-1.3
Liquefied Petroleum Gas	.46	.49	.45	.44	.43	-.3
Petrochemical Feedstocks	.34	.31	.30	.29	.30	-.7
Residual Fuel	.18	.18	.15	.13	.12	-1.9
Other Petroleum [1]	1.27	.99	.88	.79	.72	-2.8
Natural Gas [2]	2.69	2.53	2.33	2.06	1.81	-2.0
Metallurgical Coal and Coke [3]	.33	.27	.24	.21	.18	-2.9
Steam Coal [4]	.53	.47	.42	.38	.37	-1.8
Renewables [5]	.06	.06	.06	.05	.05	-1.1
Electricity	.99	.94	.95	.96	.98	-.1
Total	7.81	7.21	6.63	6.11	5.71	-1.6
Consumption (quadrillion Btu per year)						
Distillate	1.08	1.22	1.23	1.25	1.30	.9
Liquefied Petroleum Gas	1.49	1.79	1.86	2.00	2.19	1.9
Motor Gasoline [6]	.20	.22	.23	.25	.26	1.5
Petrochemical Feedstocks	1.09	1.11	1.21	1.34	1.49	1.6
Residual Fuel	.58	.65	.59	.59	.61	.3
Other Petroleum [1]	4.11	3.60	3.60	3.63	3.65	-.6
Natural Gas [2]	8.71	9.18	9.52	9.44	9.13	.2
Metallurgical Coal and Coke [3]	1.07	.99	.97	.95	.92	-.7
Steam Coal [4]	1.71	1.70	1.70	1.72	1.86	.4
Renewables [5]	2.01	2.25	2.32	2.40	2.50	1.1
Electricity	3.20	3.41	3.86	4.39	4.93	2.2
Total	25.25	26.13	27.09	27.97	28.85	.7

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	1.07	1.16	1.28	1.39	1.7
Freight Trucks	1.00	1.10	1.21	1.33	1.45	1.9
Air	.99	1.21	1.47	1.76	2.07	3.8
Rail	1.00	1.05	1.12	1.21	1.29	1.3
Marine	.99	1.03	1.09	1.18	1.25	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.10	30.24	33.68	36.57	39.04	1.7
New Light Truck MPG [1]	20.80	22.37	24.83	26.64	28.15	1.5
Light Duty Fleet MPG [2]	18.58	19.41	20.63	21.95	23.21	1.1
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.02	1.05	1.10	1.11	1.13	.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	11.55	11.75	11.97	12.38	12.76	.5
Freight Trucks	4.93	5.29	5.57	6.02	6.45	1.4
Air	3.21	3.35	3.60	3.95	4.21	1.4
Rail	.48	.51	.53	.56	.59	1.0
Marine	1.13	1.15	1.27	1.39	1.50	1.4
Pipeline Fuel	.59	.65	.70	.74	.73	1.1
Other	.18	.19	.20	.22	.23	1.2
Total	22.07	22.89	23.84	25.26	26.47	.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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1992 Forecasting System run HWOP92.D0923913.

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	12.96	10.59	9.87	9.75	-2.4
Natural Gas Plant Liquids	2.16	2.15	2.24	2.20	2.13	-.1
Dry Natural Gas [2]	18.27	18.85	19.57	19.35	18.69	.1
Coal	22.46	22.94	24.33	26.32	31.25	1.7
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy [3]	6.62	7.50	8.39	9.31	10.07	2.1
Total	71.45	70.94	72.08	74.10	78.81	.5
Imports						
Crude Oil [4]	12.70	15.89	20.64	21.30	21.57	2.7
Petroleum Products	4.29	6.48	6.80	10.74	12.49	5.5
Natural Gas [5]	1.45	2.31	2.80	3.15	3.42	4.4
Other Imports [6]	.09	.61	.74	.95	1.13	13.3
Total	18.53	25.29	30.99	36.14	38.60	3.7
Exports						
Coal	2.77	3.14	3.73	4.65	6.11	4.0
Petroleum	1.80	1.65	1.72	1.79	1.78	-.1
Total	4.57	4.79	5.45	6.44	7.89	2.8
Net Stock Withdrawals	-1.32	-.26	-.27	-.22	-.23	-8.3
Discrepancy [7]	.93	.14	-.01	-.10	-.33	-
Consumption						
Petroleum Products [8]	33.79	36.00	38.55	42.40	44.15	1.3
Natural Gas	19.38	21.02	22.26	22.38	22.01	.6
Coal	19.09	19.87	20.70	21.80	25.22	1.4
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [9]	6.57	7.89	8.85	9.84	10.68	2.5
Total	85.02	91.32	97.33	103.50	109.00	1.2
Net Imports - Petroleum	15.18	20.72	25.72	30.25	32.28	3.8
Prices (1990 dollars per unit)						
World Oil Price ($ per barrel) [10]	21.78	16.00	17.90	20.10	22.60	.2
Natural Gas Wellhead Price ($ per Mcf)	1.72	1.98	2.79	3.52	4.00	4.3
Coal Minemouth Price ($ per ton)	21.76	24.03	26.62	28.38	31.40	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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	1.00	0.92	0.75	0.64	0.58	-2.7
Kerosene	.09	.07	.05	.03	.02	-7.5
Liquefied Petroleum Gas	.46	.44	.38	.34	.32	-1.9
Natural Gas	4.50	5.01	4.98	4.92	4.83	.3
Coal	.06	.04	.04	.04	.04	-1.8
Renewable Energy [1]	.96	1.10	1.42	1.74	2.07	3.9
Electricity	3.14	3.51	3.73	4.00	4.26	1.5
Total	10.22	11.11	11.35	11.72	12.12	.9
Commercial						
Distillate Fuel	.51	.54	.51	.46	.44	-.8
Kerosene	.05	.04	.03	.03	.02	-3.9
Motor Gasoline [2]	.10	.12	.12	.13	.14	1.5
Residual Fuel	.21	.17	.15	.13	.11	-3.2
Natural Gas	2.70	3.03	3.14	3.21	3.28	1.0
Other [3]	.18	.14	.12	.10	.09	-3.5
Renewable Energy [1]	.05	.10	.18	.24	.30	8.9
Electricity	2.87	3.20	3.57	3.98	4.43	2.2
Total	6.68	7.34	7.82	8.27	8.79	1.4
Industrial [4]						
Distillate Fuel	1.08	1.37	1.51	1.61	1.70	2.3
Liquefied Petroleum Gas	1.49	1.95	2.19	2.41	2.57	2.8
Motor Gasoline [2]	.20	.23	.25	.26	.28	1.8
Petrochemical Feedstocks	1.09	1.20	1.35	1.52	1.69	2.2
Residual Fuel	.58	.88	.92	.94	.94	2.5
Other Petroleum [5]	4.11	3.74	3.77	3.82	3.84	-.3
Natural Gas [6]	8.71	8.97	8.98	8.86	8.90	.1
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	1.71	1.69	1.69	1.71	1.84	.4
Net Coal Coke Imports	.00	.07	.13	.17	.20	20.6
Renewable Energy [1]	2.01	2.25	2.32	2.40	2.50	1.1
Purchased Electricity	3.20	3.45	3.94	4.49	5.05	2.3
Total	25.25	26.72	27.91	28.99	30.23	.9
Transportation						
Distillate Fuel	3.74	4.24	4.60	5.08	5.54	2.0
Jet Fuel	3.13	3.40	3.72	4.13	4.42	1.7
Motor Gasoline [2]	13.58	14.28	15.15	16.19	17.00	1.1
Residual Fuel	.77	.76	.85	.94	1.03	1.5
Other Petroleum [7]	.26	.28	.30	.33	.36	1.6
Pipeline Fuel Natural Gas	.59	.65	.69	.69	.68	.7
Compressed Natural Gas	.00	.00	.00	.00	.00	-
Alcohol Fuels	.00	.00	.00	.00	.00	-4.6
Electricity	.01	.01	.02	.03	.05	6.2
Total	22.07	23.63	25.33	27.39	29.06	1.4
Electric Utilities [8]						
Distillate Fuel	.09	.12	.26	1.13	1.21	14.1
Residual Fuel	1.16	1.18	1.62	2.23	1.92	2.5
Natural Gas	2.88	3.36	4.48	4.69	4.32	2.1
Steam Coal [9]	16.16	17.14	18.06	19.20	22.56	1.7
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [10]	3.54	4.37	4.81	5.30	5.62	2.3
Total	30.02	32.71	36.19	39.60	42.56	1.8
Primary Energy Consumption						
Distillate Fuel	6.42	7.19	7.63	8.92	9.46	2.0
Kerosene	.14	.11	.08	.06	.04	-5.9
Jet Fuel	3.13	3.40	3.72	4.13	4.42	1.7
Liquefied Petroleum Gas	2.06	2.49	2.66	2.83	2.97	1.8
Motor Gasoline	13.87	14.63	15.52	16.59	17.41	1.1
Petrochemical Feedstocks	1.09	1.20	1.35	1.52	1.69	2.2
Residual Fuel	2.72	3.00	3.54	4.23	4.00	1.9

- 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 [11]	4.35	3.99	4.05	4.12	4.16	-0.2
Natural Gas	19.38	21.02	22.26	22.38	22.01	.6
Metallurgical Coal	1.06	.92	.85	.79	.73	-1.9
Steam Coal	18.03	18.94	19.85	21.01	24.49	1.5
Net Coal Coke Imports	.00	.07	.13	.17	.20	20.6
Nuclear Power	6.19	6.54	6.97	7.06	6.92	.6
Renewable Energy/Other [12]	6.57	7.82	8.73	9.67	10.48	2.4
Alcohols	.00	.00	.00	.00	.00	-4.6
Total	85.02	91.32	97.33	103.50	109.00	1.2
Electricity Consumption (all Sectors)	9.23	10.17	11.26	12.50	13.79	2.0
Industrial Electricity						
Gross Consumption	3.58	3.93	4.47	5.05	5.64	2.3
Self-generation - Own Use	.39	.49	.52	.56	.59	2.1
Purchased Electricity	3.20	3.45	3.94	4.49	5.05	2.3

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 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 consumption by independent power producers.
10 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.
11 Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, asphalt, road oil, and miscellaneous petroleum products.
12 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(91/07) (Washington, DC, July 1991), 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 1992 Forecasting System. The 1990 values are not final and may be updated in subsequent EIA publications. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

Table E3. Energy Prices by End-Use Sector and Source (1990 Dollars per Million Btu)

Sector and Source	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
Residential	11.94	12.07	12.92	13.88	14.66	1.0
Primary Energy	6.28	6.20	6.91	7.57	8.05	1.2
Petroleum Products	8.43	7.12	7.57	8.06	8.59	.1
Distillate Fuel	7.66	6.44	6.83	7.29	7.77	.1
Kerosene	8.77	8.11	8.36	8.64	8.95	.1
Liquefied Petroleum Gas	10.02	8.38	8.91	9.46	10.07	.0
Natural Gas	5.60	5.98	6.79	7.52	7.99	1.8
Steam Coal	2.16	2.25	2.44	2.60	2.84	1.4
Electricity	22.96	22.93	22.91	23.31	23.63	.1
Commercial	12.23	12.17	12.79	13.54	14.23	.8
Primary Energy	5.01	5.03	5.79	6.50	7.01	1.7
Petroleum Products	5.72	4.95	5.44	6.03	6.62	.7
Distillate Fuel	5.67	4.48	4.89	5.37	5.85	.2
Residual Fuel	2.99	2.81	3.17	3.57	4.00	1.5
Kerosene	5.75	5.62	5.90	6.21	6.57	.7
Other Petroleum [1]	9.08	8.13	8.73	9.42	10.09	.5
Natural Gas	4.86	5.13	5.94	6.68	7.16	2.0
Steam Coal	2.13	2.18	2.37	2.54	2.78	1.4
Electricity	21.67	21.17	20.77	20.72	20.86	-.2
Industrial	5.41	5.33	6.01	6.70	7.24	1.5
Primary Energy	3.88	3.77	4.32	4.84	5.28	1.6
Petroleum Products	5.43	4.77	5.12	5.53	5.99	.5
Distillate Fuel	5.63	4.11	4.50	4.95	5.42	-.2
Liquefied Petroleum Gas	5.71	4.77	5.26	5.79	6.39	.6
Motor Gasoline [2]	9.36	8.46	9.04	9.72	10.37	.5
Residual Fuel	2.69	2.56	2.92	3.33	3.75	1.7
Other Petroleum [3]	5.46	5.17	5.45	5.77	6.14	.6
Natural Gas [4]	2.94	3.24	4.07	4.79	5.26	3.0
Metallurgical Coal	1.78	1.93	2.14	2.31	2.55	1.8
Steam Coal	1.50	1.69	1.82	1.94	2.15	1.8
Electricity	14.41	14.28	14.69	15.25	15.52	.4
Transportation	8.46	7.56	8.05	8.61	9.17	.4
Primary Energy	8.46	7.55	8.04	8.60	9.15	.4
Petroleum Products	8.46	7.55	8.04	8.60	9.15	.4
Distillate Fuel [5]	8.51	7.85	8.24	8.69	9.16	.4
Jet Fuel [6]	5.69	3.97	4.37	4.83	5.31	-.3
Motor Gasoline [2]	9.34	8.48	9.06	9.74	10.39	.5
Residual Fuel	3.03	2.71	3.01	3.34	3.66	1.0
Other Petroleum [7]	10.60	12.47	12.75	13.07	13.44	1.2
Natural Gas	.00	5.40	6.21	6.95	7.43	-
Electricity	23.54	23.04	22.59	22.49	22.91	-.1
Total End-Use Energy	8.30	7.98	8.58	9.24	9.82	.8
Primary Energy	6.22	5.79	6.38	6.99	7.51	1.0
Electricity	19.59	19.45	19.35	19.59	19.76	.0
Electric Utilities						
Fossil Fuel Average	1.70	1.80	2.15	2.51	2.65	2.3
Petroleum Products	3.42	3.21	3.54	4.15	4.75	1.7
Distillate Fuel	5.28	3.90	4.30	4.79	5.26	.0
Residual Fuel	3.28	3.14	3.42	3.82	4.43	1.5
Natural Gas	2.33	2.41	3.29	4.11	4.65	3.5
Steam Coal	1.45	1.58	1.72	1.83	1.97	1.5

- See footnotes at end of table.

Table E3. Energy Prices by End-Use Sector and Source (Continued) (1990 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	7.42	6.59	6.99	7.42	8.00	0.4
Distillate Fuel [5]	7.62	6.64	7.00	7.25	7.75	.1
Jet Fuel [6]	5.69	3.97	4.37	4.83	5.31	-.3
Kerosene	7.68	7.25	7.36	7.49	7.66	.0
Liquefied Petroleum Gas	6.83	5.51	5.87	6.31	6.85	.0
Motor Gasoline [2]	9.34	8.48	9.06	9.74	10.39	.5
Residual Fuel	3.06	2.84	3.18	3.60	4.06	1.4
Other Petroleum Products [9]	5.70	5.56	5.85	6.19	6.58	.7
Natural Gas	3.82	4.11	4.85	5.59	6.09	2.4
Coal	1.47	1.61	1.75	1.86	2.00	1.6
Electricity	19.59	19.45	19.35	19.59	19.76	.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: Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. 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: 1988*, DOE/EIA-0376(88) (Washington, DC, September 1990), 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered natural gas prices for 1990 are from the AEO 1992 Forecasting System run LWOP92.D0923914. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	1,558	1,652	1,742	1,848	2,182	1.7
Petroleum	117	120	177	345	329	5.3
Natural Gas	264	312	395	397	377	1.8
Nuclear Power	577	600	639	647	634	.5
Pumped Storage Hydroelectric	-9	-10	-11	-13	-13	2.0
Renewable Sources/Other [1]	300	318	330	340	344	.7
Total	2,807	2,993	3,272	3,564	3,852	1.6
Net Imports	2	40	44	53	62	18.8
Nonutilities [2]						
Generation by Fuel Type						
Coal	35	51	53	62	143	7.3
Petroleum	4	5	9	22	29	10.4
Natural Gas	115	153	185	227	230	3.5
Renewable Sources/Other [1]	76	113	143	177	199	4.9
Total	230	323	391	487	602	4.9
Sales to Utilities	115	180	237	325	429	6.8
Generation for Own Use	115	142	154	163	173	2.1
Electricity Sales by Sector						
Residential	922	1,029	1,093	1,172	1,250	1.5
Commercial/Other [3]	846	942	1,051	1,176	1,311	2.2
Industrial	938	1,010	1,155	1,317	1,481	2.3
Total	2,705	2,982	3,300	3,664	4,043	2.0
End-Use Prices [4]						
(1990 cents per kilowatthour)						
Residential	7.83	7.83	7.82	7.95	8.06	.1
Commercial/Other [3]	7.40	7.23	7.09	7.08	7.12	-.2
Industrial [5]	4.92	4.87	5.01	5.20	5.30	.4
Average	6.69	6.64	6.60	6.68	6.74	.0
Price Components [4]						
(1990 cents per kilowatthour)						
Capital Component	2.92	2.81	2.44	2.19	2.12	-1.6
Fuel Component	1.68	1.80	2.14	2.48	2.65	2.3
O&M Component	2.08	2.03	2.02	2.01	1.98	-.2
Total	6.69	6.64	6.60	6.68	6.74	.0

[1] 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.
[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.
[3] Other includes sales of electricity to Government, railways, and street lighting authorities.
[4] Prices represent average revenue per kilowatthour of sales over all customer classes.
[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 Monthly, September 1991*, DOE/EIA-0226(91/09) (Washington, DC, September 1991). 1990 nonutilities, prices, and all projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	300.0	300.6	306.1	316.8	371.0	1.1
Other Fossil Steam [2]	144.4	138.3	131.8	124.7	120.9	-.9
Combined Cycle	6.0	8.4	11.2	39.8	50.6	11.3
Combustion Turbine/Diesel	46.2	53.5	67.1	76.0	82.0	2.9
Nuclear Power	99.6	101.9	104.2	105.4	101.7	.1
Pumped Storage Hydroelectric	17.3	18.6	21.8	21.8	21.8	1.2
Renewable Sources/Other [3]	77.4	79.6	82.2	83.8	84.5	.4
Total	690.9	700.9	724.3	768.3	832.6	.9
Cumulative Planned Additions [4]						
Coal Steam	3.0	7.9	18.6	21.4	21.7	10.4
Other Fossil Steam	.0	.0	.8	.8	.8	-
Combined Cycle	.1	2.5	5.4	6.0	6.0	21.2
Combustion Turbine/Diesel	.6	6.6	13.9	14.4	14.4	16.8
Nuclear Power	2.3	4.6	7.0	8.3	8.3	6.6
Pumped Storage Hydroelectric	.0	1.3	4.5	4.5	4.5	-
Renewable Sources/Other [3]	.2	2.0	3.6	3.9	3.9	16.5
Total	6.3	24.9	53.9	59.2	59.6	11.9
Cumulative Unplanned Additions [4]						
Coal Steam	.0	.0	.6	11.7	68.3	-
Other Fossil Steam	.0	.0	.0	.0	.0	-
Combined Cycle	.0	.0	.0	28.1	38.9	-
Combustion Turbine/Diesel	.0	1.7	8.1	17.9	24.1	-
Nuclear Power	.0	.0	.0	.0	.0	-
Pumped Storage Hydroelectric	.0	.0	.0	.0	.0	-
Renewable Sources/Other [3]	.1	.5	1.4	2.9	3.6	21.2
Total	.1	2.2	10.1	60.5	134.9	45.4
Cumulative Total Additions	6.3	27.2	64.0	119.7	194.5	18.7
Cumulative Retirements	1.5	12.4	25.9	37.5	48.1	18.8
Nonutilities [5]						
Capability						
Coal	6.3	10.0	10.4	11.9	25.7	7.2
Petroleum	1.2	1.8	2.7	5.4	7.1	9.5
Natural Gas	11.5	20.0	26.0	34.6	35.3	5.8
Renewable Sources/Other [3]	15.1	23.1	27.9	33.1	36.9	4.6
Total	34.1	54.8	67.0	85.2	105.1	5.8
Cumulative Additions	5.9	26.7	38.8	57.0	77.0	13.7

[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: Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*. 1990 nonutility capability and all projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	75.76	78.33	78.46	78.46	78.52	0.2
Geothermal	2.54	3.14	5.32	7.69	8.40	6.2
Municipal Solid Waste	2.36	5.21	7.76	10.78	12.91	8.9
Biomass/Other Waste	5.25	6.03	6.31	6.57	6.91	1.4
Solar Thermal	.43	1.15	1.16	1.31	1.69	7.1
Solar Photovoltaic	.00	.01	.01	.01	.01	5.8
Wind	1.95	2.62	3.46	4.31	5.16	5.0
Total	88.30	96.48	102.50	109.10	113.60	1.3
Generation (billion kilowatthours)						
Conventional Hydropower	290.60	312.40	311.20	310.20	309.80	.3
Geothermal	14.13	18.03	33.95	53.83	59.27	7.4
Municipal Solid Waste	13.53	31.48	46.60	65.73	79.26	9.2
Biomass/Other Waste	26.08	31.51	36.23	39.36	43.46	2.6
Solar Thermal	.79	2.30	2.81	3.18	4.18	8.7
Solar Photovoltaic	.00	.01	.01	.01	.01	6.4
Wind	2.84	3.87	7.06	9.26	11.34	7.2
Total	347.90	399.60	437.90	481.50	507.30	1.9
Consumption/Displacement						
Conventional Hydropower	3.02	3.25	3.24	3.23	3.22	.3
Geothermal	.14	.19	.35	.56	.62	7.5
Municipal Solid Waste	.14	.33	.48	.68	.82	9.3
Biomass/Other Waste	.27	.32	.37	.40	.45	2.6
Solar Thermal	.01	.02	.03	.03	.04	8.8
Solar Photovoltaic	.00	.00	.00	.00	.00	-
Wind	.03	.04	.07	.10	.12	7.4
Total	3.61	4.15	4.55	5.00	5.27	1.9
Non-Electric Renewable Energy						
Residential, Commercial, and Industrial						
Geothermal	.00	.02	.12	.20	.28	-
Biofuels	2.70	3.01	3.26	3.52	3.80	1.7
Solar Thermal	.05	.08	.18	.26	.34	9.6
Transportation						
Ethanol	.08	.10	.12	.18	.24	5.6
Total	2.84	3.22	3.68	4.16	4.66	2.5
Total Renewable Energy	6.44	7.37	8.23	9.16	9.93	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 1992 Forecasting System run LWOP92.D0923914.

Table E7. Macroeconomic Indicators
(Billion 1982 Dollars, Unless Otherwise Noted)

Indicator	Low Oil Price					Annual Growth 1990-2010 (percent)
	1990	1995	2000	2005	2010	
GNP Implicit Price Deflator (Index, 1982=1.000)	1.315	1.520	1.829	2.251	2.799	3.8
Real Gross National Product	4,156	4,675	5,242	5,863	6,481	2.2
Real Disposable Personal Income	2,894	3,162	3,449	3,807	4,147	1.8
Index of Manufacturing Gross Output (Index, 1982=1.000)	1.218	1.391	1.604	1.829	2.047	2.6
AA Utility Bond Rate (percent)	9.66	8.67	8.52	8.36	8.19	-
90-Day U.S. Government Treasury Bill Rate (percent)	7.49	5.47	5.46	5.29	5.19	-
Energy Intensity (thousand Btu per 1982 $ of GNP)	20.46	19.53	18.57	17.65	16.81	-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 1992 Forecasting System run LWOP92.D0923914.

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 (1990 dollars per barrel) [1]	21.78	16.00	17.90	20.10	22.60	0.2
Production						
Crude Oil [2]	7.35	5.93	4.71	4.30	4.16	-2.8
Alaska	1.77	1.25	.83	.55	.43	-6.9
Lower 48	5.58	4.68	3.87	3.75	3.74	-2.0
Natural Gas Plant Liquids	1.56	1.55	1.61	1.59	1.53	-.1
Other Domestic [3]	.08	.19	.28	.36	.44	8.9
Processing Gain [4]	.68	.74	.74	.74	.74	.4
Total	9.68	8.40	7.33	6.99	6.88	-1.7
Imports (including SPR) [5]						
Crude Oil	5.89	7.38	9.56	9.89	10.01	2.7
Refined Products[6]	2.12	3.21	3.35	5.31	6.18	5.5
Total	8.02	10.58	12.91	15.20	16.19	3.6
Exports						
Crude Oil	.11	.08	.06	.05	.04	-4.5
Refined Products	.75	.70	.75	.80	.80	.3
Total	.85	.78	.81	.85	.84	-.1
Net Imports (including SPR)	7.16	9.80	12.10	14.35	15.35	3.9
Primary Stock Changes						
Net Withdrawals [7]	-.09	-.05	-.05	-.06	-.03	-5.8
SPR Fill Rate Additions (-) [5]	-.02	-.05	-.05	.00	.00	-
Total Primary Supply [8]	16.73	18.10	19.33	21.28	22.20	1.4
Unaccounted for Crude	.26	.20	.20	.20	.20	-
Refined Petroleum Products Supplied						
Motor Gasoline [9]	7.23	7.63	8.07	8.65	9.08	1.1
Jet Fuel [10]	1.52	1.66	1.81	2.01	2.15	1.7
Distillate Fuel	3.02	3.38	3.58	4.19	4.45	2.0
Residual Fuel	1.23	1.31	1.54	1.84	1.74	1.8
Other [11]	3.98	4.33	4.53	4.78	4.97	1.1
Total	16.99	18.30	19.53	21.47	22.40	1.4
Refined Petroleum Products Supplied						
Residential and Commercial	1.34	1.26	1.09	.97	.89	-2.0
Industrial [12]	4.25	4.90	5.26	5.60	5.86	1.6
Transportation	10.81	11.57	12.36	13.41	14.24	1.4
Electric Utilities [13]	.55	.57	.82	1.49	1.41	4.8
Total	16.95	18.30	19.53	21.47	22.40	1.4
Net Disposition	16.99	18.30	19.53	21.48	22.40	1.4

[1] Average refiner acquisition cost for imported crude oil.
[2] Includes lease condensate.
[3] Includes other hydrocarbons and alcohols.
[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.
[13] The 1990 figure includes both sales and stock changes. All years data include consumption by independent power producers.

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(91/07) (Washington, DC, July 1991). Figures for 1990 may differ from published data due to internal conversion factors within the AEO 1992 Forecasting System. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

Table E9. Natural Gas Supply, Disposition, and Prices (Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Low Oil Price 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Production						
Dry Gas Production [1]	17.61	18.18	18.88	18.64	17.99	0.1
Supplemental Gas [2]	.11	.10	.10	.12	.14	1.3
Net Imports	1.41	2.25	2.72	3.05	3.31	4.4
Net Storage Withdrawals [3]	-.52	.00	.00	.00	.00	-
Total Supply	18.61	20.53	21.70	21.82	21.44	.7
Consumption by Sector						
Residential	4.37	4.86	4.83	4.77	4.68	.3
Commercial	2.62	2.94	3.04	3.12	3.18	1.0
Industrial [4]	7.24	7.56	7.52	7.41	7.47	.2
Electric Utilities [5]	2.79	3.26	4.35	4.55	4.19	2.1
Lease and Plant Fuel [6]	1.21	1.14	1.19	1.19	1.16	-.2
Pipeline Fuel	.57	.63	.67	.67	.66	.7
Transportation [7]	.00	.00	.00	.00	.00	-
Total	18.80	20.39	21.59	21.71	21.35	.6
Unaccounted for [8]	-.19	.14	.10	.11	.10	-
Average Wellhead Price (1990 dollars per thousand cubic feet)	1.72	1.98	2.79	3.52	4.00	4.3
Delivered Prices (1990 dollars per thousand cubic feet)						
Residential	5.77	6.16	7.00	7.75	8.24	1.8
Commercial	5.01	5.29	6.13	6.88	7.38	2.0
Industrial	3.03	3.34	4.19	4.94	5.43	3.0
Electric Utilities	2.40	2.48	3.39	4.24	4.79	3.5
Transportation	.00	5.56	6.41	7.16	7.66	-
Average [9]	3.94	4.24	5.00	5.76	6.28	2.4

[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 anincrease 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(91/3Q) (Washington, DC, August 1991). Commercial and industrial delivered prices for 1990 and projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	656	671	714	864	1.6
West of the Mississippi	399	396	462	508	584	1.9
Total	1,029	1,052	1,133	1,223	1,449	1.7
Net Imports						
Imports	3	5	6	9	11	6.9
Exports	106	121	145	179	236	4.1
Total	-103	-116	-138	-170	-224	4.0
Net Stock Withdrawals [2]	-26	-2	-3	-4	-8	-5.6
Total Supply [3]	901	934	992	1,048	1,216	1.5
Consumption by Sector						
Residential and Commercial	7	5	4	4	4	-3.2
Industrial [4]	76	75	76	77	84	.5
Coking Plants	40	35	32	30	27	-1.9
Electricity [5]	772	819	881	939	1,101	1.8
Total	895	934	993	1,049	1,216	1.5
Discrepancy [6]	6	0	0	-1	0	-
Average Minemouth Price [7] **(1990 dollars per short ton)**	21.76	24.03	26.62	28.38	31.40	1.9
Delivered Prices (1990 dollars per short ton)						
Residential and Commercial	48.39	53.57	57.31	61.48	66.80	1.6
Industrial	33.59	38.12	40.58	43.36	46.93	1.7
Coking Plants	47.79	51.42	56.94	61.37	67.69	1.8
Electricity	30.43	33.02	35.33	37.42	40.39	1.4
Average [8]	31.61	34.21	36.53	38.62	41.54	1.4

[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(91/1Q) (Washington, DC, August 1991); and *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991). Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

Table E11. Residential Sector Key Indicators and End-Use Consumption (Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Low Oil Price 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Key Indicators						
Total Housing (millions)	93.4	98.4	103.4	108.0	112.0	0.9
Energy Consumption per Household (million Btu)	109.4	112.8	109.7	108.5	108.2	–.1
End-Use Consumption						
Distillate						
Space Heating	.86	.83	.69	.61	.56	-2.2
Other Uses [1]	.14	.09	.05	.03	.02	-9.3
Total	1.00	.92	.75	.64	.58	-2.7
Natural Gas						
Space Heating	3.14	3.46	3.40	3.35	3.28	.2
Water Heating	1.06	1.26	1.30	1.30	1.28	1.0
Other Uses [1]	.31	.30	.28	.27	.27	–.7
Total	4.50	5.01	4.98	4.92	4.83	.3
Other Fuels [2]	.61	.53	.44	.39	.35	-2.7
Renewables [3]	.96	1.10	1.42	1.74	2.07	3.9
Electricity						
Space Heating	.32	.33	.33	.34	.35	.4
Cooling	.51	.56	.58	.61	.63	1.1
Water Heating	.39	.51	.59	.69	.78	3.5
Other Uses [1]	1.92	2.11	2.23	2.37	2.50	1.3
Total	3.14	3.51	3.73	4.00	4.26	1.5
Total Consumption	10.22	11.11	11.35	11.72	12.12	.9

[1] Includes cooking, cooling (natural gas), water heating (distillate), 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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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)	110.3	118.0	124.7	130.9	136.0	1.0
Total Floorspace (billion square feet)	62.9	69.1	75.7	82.6	89.7	1.8
Energy Consumption per Square Foot (thousand Btu)	106.3	106.3	103.3	100.2	98.1	-.4
End-Use Consumption						
Distillate						
Space Heating	.47	.50	.47	.44	.42	-.6
Other Uses [1]	.04	.04	.03	.02	.02	-4.4
Total	.51	.54	.51	.46	.44	-.8
Natural Gas						
Space Heating	1.76	1.96	2.00	1.99	1.96	.5
Cooling	.21	.22	.24	.25	.28	1.5
Other Uses [1]	.73	.85	.91	.97	1.03	1.8
Total	2.70	3.03	3.14	3.21	3.28	1.0
Other Fuels [2]	.54	.47	.42	.39	.36	-2.1
Renewables [3]	.05	.10	.18	.24	.30	8.9
Electricity						
Space Heating	.53	.60	.70	.82	.99	3.2
Cooling	.74	.83	.92	1.01	1.10	2.0
Lighting	1.13	1.23	1.35	1.47	1.59	1.7
Other Uses [1]	.47	.53	.60	.68	.75	2.3
Total	2.87	3.20	3.57	3.98	4.43	2.2
Total Consumption	6.68	7.34	7.82	8.27	8.79	1.4

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

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	2401	2742	3161	3605	4035	2.6
Non-manufacturing	830	930	996	1073	1148	1.6
Total	3231	3672	4157	4678	5183	2.4
Consumption						
Consumption per Unit Output (thousand Btu per 1982 dollars)						
Distillate	.34	.37	.36	.35	.33	-.1
Liquefied Petroleum Gas	.46	.53	.53	.52	.50	.4
Petrochemical Feedstocks	.34	.33	.33	.33	.33	-.2
Residual Fuel	.18	.24	.22	.20	.18	.1
Other Petroleum [1]	1.27	1.02	.91	.82	.74	-2.7
Natural Gas [2]	2.69	2.44	2.16	1.89	1.72	-2.2
Metallurgical Coal and Coke [3]	.33	.27	.24	.20	.18	-3.0
Steam Coal [4]	.53	.46	.41	.37	.36	-2.0
Renewables [5]	.06	.06	.06	.05	.05	-1.3
Electricity	.99	.94	.95	.96	.98	-.1
Total	7.81	7.28	6.71	6.20	5.83	-1.5
Consumption (quadrillion Btu per year)						
Distillate	1.08	1.37	1.51	1.61	1.70	2.3
Liquefied Petroleum Gas	1.49	1.95	2.19	2.41	2.57	2.8
Motor Gasoline [6]	.20	.23	.25	.26	.28	1.8
Petrochemical Feedstocks	1.09	1.20	1.35	1.52	1.69	2.2
Residual Fuel	.58	.88	.92	.94	.94	2.5
Other Petroleum [1]	4.11	3.74	3.77	3.82	3.84	-.3
Natural Gas [2]	8.71	8.97	8.98	8.86	8.90	.1
Metallurgical Coal and Coke [3]	1.07	1.00	.98	.96	.93	-.7
Steam Coal [4]	1.71	1.69	1.69	1.71	1.84	.4
Renewables [5]	2.01	2.25	2.32	2.40	2.50	1.1
Electricity	3.20	3.45	3.94	4.49	5.05	2.3
Total	25.25	26.72	27.91	28.99	30.23	.9

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991), and Office of Coal, Nuclear, Electric, and Alternate Fuels. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

Table E14. Transportation Sector Key Indicators and End-Use Consumption

Key Indicators and Consumption	Low Oil Price 1990	1995	2000	2005	2010	Annual Growth 1990-2010 (percent)
Key Indicators						
Level of Travel Index (1989 = 1.0)						
Light Duty Vehicles	1.00	1.10	1.19	1.31	1.43	1.8
Freight Trucks	1.00	1.12	1.23	1.35	1.47	2.0
Air	.99	1.27	1.57	1.90	2.25	4.2
Rail	1.00	1.06	1.13	1.22	1.31	1.4
Marine	.99	1.04	1.11	1.20	1.27	1.2
Energy Efficiency Indicators						
New Car MPG [1]	28.10	27.97	29.09	30.78	32.73	.8
New Light Truck MPG [1]	20.80	20.69	21.45	22.42	23.60	.6
Light Duty Fleet MPG [2]	18.58	19.11	19.41	19.80	20.34	.5
Aircraft Efficiency Index [3]	1.01	1.09	1.18	1.27	1.37	1.5
Freight Truck Efficiency Index [4]	1.02	1.05	1.10	1.11	1.13	.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	11.55	12.29	13.16	14.16	14.93	1.3
Freight Trucks	4.93	5.34	5.64	6.11	6.56	1.4
Air	3.21	3.49	3.82	4.23	4.54	1.7
Rail	.48	.51	.53	.57	.60	1.1
Marine	1.13	1.16	1.28	1.41	1.53	1.5
Pipeline Fuel	.59	.65	.69	.69	.68	.7
Other	.18	.19	.21	.22	.24	1.2
Total	22.07	23.63	25.33	27.39	29.06	1.4

[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, *Monthly Energy Review*, DOE/EIA-0035(91/07) (Washington, DC, July 1991). Energy use by mode based on model estimates. Projections: Energy Information Administration, AEO 1992 Forecasting System run LWOP92.D0923914.

Long-Term Effects of Price Volatility

Each of the various world oil price paths presented in the *Annual Energy Outlook* rises smoothly through 2010. How would the results of EIA's analyses differ if future price changes were erratic (as they have been in the past)? This appendix considers the sensitivity of the U.S. economy as a whole to a volatile oil price path, using the size and duration of the price shocks of the past two decades as a guide.

Energy markets affect economic growth in numerous ways. Energy, as a factor of production, is integral to the production process of all U.S. goods and services. Energy is also used by individual consumers as a final product. The path of energy prices affects decisions in both production and consumption. The real price of oil roughly doubled between 1970 and 1990—creating serious problems of economic adjustment. However, in retrospect, we realize that the abruptness and unpredictability of changes in petroleum prices (up *and* down) were themselves a major factor in the economic damage done (Figure F1-A). The events of the recent Persian Gulf War have heightened concern about this volatility effect.[36]

In the *AEO92* High Oil Price Case, the world oil price almost doubles again by 2010—from $21.78 in 1990 to $40.20 in 2010. Over this period the price averages $31.47. This is contrasted with the *AEO92* Reference Case, where the world oil price increases to $33.40 over the same time span and the average is lower. If these two world oil price paths diverge smoothly, the loss in real GNP relative to the Reference Case is gradual and minimal (Figure F1-B). Through 2010, the net present value of the real GNP loss, using a 10-percent discount rate, is calculated as $181 billion[37] (Figure F1-C).

By contrast, consider two volatile price paths. In the first, the world oil price path follows a path similar to that experienced in the 1970-1990 period and *ends at precisely $40.20 in the year 2010.* This case yields an average price of $44.09 over the forecast interval, $12.62 above the high world oil price average. In the other volatile case, the same pattern is followed, but with the *average price remaining the same as in* AEO92's *High Oil Price Case—$31.47.*

Volatile world oil prices cause price instability throughout the U.S. economy. This price instability in turn leads to cycles in the demand for and the production of goods and services—which can hobble the long-run growth potential of the economy. Fluctuations in price (and resultant fluctuations in interest rates) adversely affect investment decisions, and this yields a lower level of aggregate capital stock.

In the first volatile oil price case, the net present value of the real GNP loss triples to $548 billion. Thus the cyclical effect is roughly twice as large as the trend effect. In fact, even if the average price remains the *same* as in the non-volatile High Oil Price Case, the loss in real GNP is considerably greater than if a smooth high price path were followed ($230 billion vs. $181 billion).

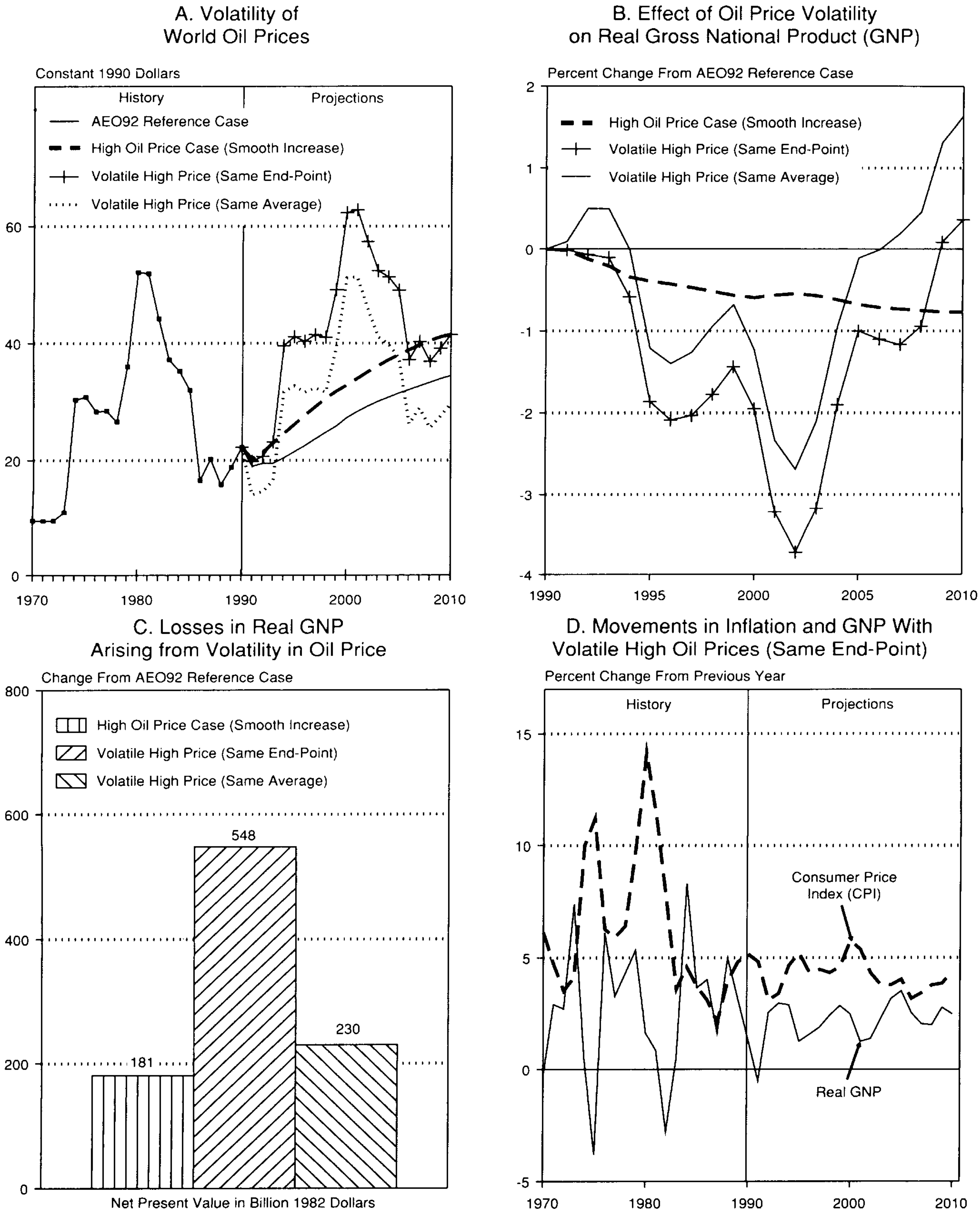
Figure F1-D shows historical oscillations in inflation and output and the oscillations considered in the first volatile price case. In looking at the last two decades, it is difficult to distinguish the effects of oil price shocks on the economy from the results of other events. The emphasis of monetary policy was altered, international exchange rate regimes switched from fixed to flexible, world commodity prices rose dramatically, and U.S. energy markets were directly influenced by such specific governmental policies as the imposition and then the removal of price controls.

The volatility simulation endeavors to isolate the cyclicality introduced *only* by changes in the world oil price. The experiment focused exclusively on the loss to real GNP from volatile oil prices, using a standalone run of the Data Resources, Inc. (DRI) Compact Model of the U.S. Economy; and this simulation suggests that the oscillations in inflation and output would be smaller than those felt during the 1970's and 1980's.

[36]Refer to the lead article by Dr. Calvin Kent and Dr. Mark Rodekohr in the January-February 1992 issue of *Government Information Quarterly*, entitled "The Role of Government Information During Periods of National Crisis: The Energy Information Administration and the Persian Gulf War." This appendix draws on material presented in that paper.

[37]In accordance with statistical convention for GNP calculations, this Appendix uses constant 1982 dollars for changes in Gross National Product, although projected oil prices are given (as elsewhere in *AEO92*) in 1990 dollars.

Figure F1. Economic Effects of Volatility in Oil Prices



The result flows in part from the *AEO92* projection that the energy intensity of the U.S. economy will continue to decline, relative to the levels of the 1970's and 1980's. More efficient use of energy should dampen the effects of future world oil price volatility.

Overall, EIA concluded that the volatility of oil prices *will* influence the economy—prices, real output, disposable income, and interest rates—although perhaps in a less severe fashion than was actually experienced during the past 20 years.

AEO92 Forecasting System

The projections presented in *AEO92* 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 *AEO92* 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 *AEO92* Forecasting System. The world oil price is derived from the Oil Market Simulation Model (OMS), which represents world oil demand and supply. OMS assumes that the Organization of Petroleum Exporting Countries (OPEC) remains the marginal supplier of crude oil, so 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 national product (GNP), the GNP 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 *AEO92* 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 *AEO92* Forecasting System utilize the most recently available data from EIA's supply and consumption surveys. A companion EIA report, *Assumptions for the Annual Energy Outlook 1992*, provides further information on the assumptions that underlie the *AEO92* forecasts, the models used to produce the forecasts, and changes made to these models specifically for *AEO92*. That volume also provides references to the model documentation reports, which are available from the National Energy Information Center.

Information on individual models and subject areas can be obtained from the following contact persons:

Intermediate Future Forecasting System (IFFS)	Susan Shaw	202/586-4838
World Oil Price (OMS)	Erik Kreil	202/586-6573
Macroeconomic	Ronald Earley/Kay Smith	202/586-1398
Oil Markets (OMM)	Stacy MacIntyre	202/586-9795
Coal (CSTM)	Richard Newcombe	202/586-2415
Natural Gas Markets (GAMS)	Barbara Mariner-Volpe	202/586-5878
Oil and Gas Production (PROLOG)	Ted McCallister	202/586-4820
Electricity (EMM)	Jeffrey Jones	202/586-2038
Residential	John Cymbalsky/Henry Clarius	202/586-4815
Commercial	Eugene Reiser	202/586-5840
Industrial	John Holte/Amelia Elson	202/586-1471
Transportation	Barry Cohen	202/586-5359
Forecast Comparisons	Paul Kondis	202/586-1469

Appendix H. Conversion Factors

Fuel	Units	Approximate Heat Content
Coal		
Production	million Btu/short ton	21.827
Consumption	million Btu/short ton	21.344
Coke Plants	million Btu/short ton	26.801
Industrial	million Btu/short ton	22.428
Residential and Commercial	million Btu/short ton	23.574
Electric Utilities	million Btu/short ton	20.945
Imports	million Btu/short ton	25.000
Exports	million Btu/short ton	26.197
Coal Coke	million Btu/short ton	24.800
Crude Oil		
Production	million Btu/barrel	5.800
Imports	million Btu/barrel	5.901
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	10,331
Nuclear Energy	Btu/kilowatthour	10,724
Geothermal	Btu/kilowatthour	21,096

Sources: Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(91/07) (Washington, DC, July 1991). Natural gas conversion factors are those used in the model.

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