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Annual Energy Outlook 2003

With Projections to 2025

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Energy Information Administration
Office of Integrated Analysis and Forecasting
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For Further Information . . .

The *Annual Energy Outlook 2003* (*AEO2003*) was prepared by the Energy Information Administration (EIA), under the direction of Mary J. Hutzler (mhutzler@ eia.doe.gov, 202/586-6351), Director, Integrated Analysis and Forecasting; Scott Sitzer (ssitzer@ eia.doe.gov, 202/586-2308), Director, Coal and Electric Power Division; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-4838), Director, Demand and Integration Division; John Conti (john.conti@eia.doe.gov, 202-586-4430), Director, International, Economic and Greenhouse Gases Division; James M. Kendell (jkendell@eia.doe.gov, 202/586-9646), Director, Oil and Gas Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

For ordering information and questions on other energy statistics available from EIA, please contact EIA's National Energy Information Center. Addresses, telephone numbers, and hours are as follows:

National Energy Information Center, EI-30
Energy Information Administration
Forrestal Building
Washington, DC 20585

Telephone: 202/586-8800
FAX: 202/586-0727
TTY: 202/586-1181
9 a.m. to 5 p.m., eastern time, M-F

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

Specific questions about the information in this report may be directed to:

Overview and Emissions . . . . Paul Holtberg (paul.holtberg@eia.doe.gov, 202/586-4838)
Economic Activity . . . . Ronald Earley (rearley@eia.doe.gov, 202/586-1398)
International Oil Markets . . . . . . G. Daniel Butler (gbutler@eia.doe.gov, 202/586-9503)
Residential Demand . . . . John H. Cymbalsky (jcymbals@eia.doe.gov, 202/586-4815)
Commercial Demand . . . . Erin E. Boedecker (eboedeck@eia.doe.gov, 202/586-4791)
Industrial Demand . . . . T. Crawford Honeycutt (choneycu@eia.doe.gov, 202/586-1420)
Transportation Demand . . . . John Maples (jmaples@eia.doe.gov, 202/586-1757)
Electricity Generation, Capacity . . J. Alan Beamon (jbeamon@eia.doe.gov, 202/586-2025)
Electricity Prices . . . . Lori Aniti (laniti@eia.doe.gov, 202/586-2867)
Nuclear Energy. . . . . Laura Martin (laura.martin@eia.doe.gov, 202/586-1494)
Renewable Energy . . . . Thomas W. Petersik (tpetersi@eia.doe.gov, 202/586-6582)
Oil and Gas Production . . . . Ted McCallister (tmccalli@eia.doe.gov, 202/586-4820)
Natural Gas Markets. . . . . Philip Budzik (pbudzik@eia.doe.gov, 202/586-2847)
Oil Refining and Markets . . . . . . Anthony Radich (anthony.radich@eia.doe.gov, 202/586-0504)
Coal Supply and Prices. . . . . Michael Mellish (mmellish@eia.doe.gov, 202/586-2136)

AEO2003 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early January 2003. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early January 2003, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* will be available at web site www.eia.doe.gov/bookshelf/docs.html.

Other contributors to the report include Joseph Benneche, Bill Brown, Robert Eynon, Zia Haq, James Hewlett, Jeff Jones, Diane Kearney, Nasir Khilji, Paul Kondis, Matthew Lackey, Thomas Leckey, Han-Lin Lee, Amar Mann, Phyllis Martin, Chris Namovicz, Chetha Phang, Eugene Reiser, Esmeralda Sanchez, Laurence Sanders, Dan Skelly, Yvonne Taylor, Brian Unruh, Dana Van Wagener, Steven Wade, and Peggy Wells.

Preface

The *Annual Energy Outlook 2003* (*AEO2003*) presents midterm forecasts of energy supply, demand, and prices through 2025 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2003* reference case. The next section, "Legislation and Regulations," discusses evolving legislative and regulatory issues. "Issues in Focus" discusses recent EIA analyses of energy legislation provisions; MTBE phaseout and renewable fuels standard proposals in the Energy Policy Act of 2002; the Bush Administration's Clear Skies Initiative; recent revisions in EIA's electricity and natural gas data series; natural gas depletion and wellhead productive capacity; emerging options for U.S. natural gas supply; recent additions to U.S. electricity generating capacity; and U.S. greenhouse gas intensity. It is followed by an analysis of projected energy market trends.

The analysis in *AEO2003* focuses primarily on a reference case and four other cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. Forecast tables for those cases are provided in Appendixes A through C. Alternative cases explore the impacts of varying key assumptions in NEMS—e.g., technology penetration. The major results for the alternative cases are shown in Appendix F. Appendix G briefly describes NEMS, the *AEO2003* assumptions, and the alternative cases.

The *AEO2003* projections are based on Federal, State, and local laws and regulations in effect on September 1, 2002. Pending legislation and sections of existing legislation requiring funds that have not been appropriated are not reflected in the forecasts. In general, the historical data used for the *AEO2003* projections were based on EIA's *Annual Energy Review 2001*, published in November 2002; however, data were taken from multiple sources. In some cases, only partial or preliminary 2002 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2002 and 2003 incorporate the short-term projections from EIA's September 2002 *Short-Term Energy Outlook*.

The *AEO2003* projections are used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors. They are published in accordance with Section 205c of the Department of Energy Organization Act of 1977 (Public Law 95–91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

The projections in *AEO2003* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of certainty. Many key uncertainties in the *AEO2003* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, analytical processes in the examination of policy initiatives.

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Key Energy Issues to 2025

As has been typical over the past few years, energy prices were extremely volatile during 2002. Spot natural gas prices, about $2 per thousand cubic feet in January, rose to between $3 and $4 per thousand cubic feet by the fall. Average wellhead prices, which are moderated by the inclusion of natural gas bought under contract, also increased over the year. Crude oil prices also rose in 2002, mainly because of reduced production by the Organization of Petroleum Exporting Counties (OPEC) and, to a lesser degree, fears about the potential impact of military action in Iraq. Crude oil prices began 2002 at roughly $16 per barrel and were between $25 and $30 per barrel by the fall.

The impact of near-term price trends is reflected in the *Annual Energy Outlook 2003* (*AEO2003*), but long-term energy markets are less influenced by near-term trends, such as supply disruptions or political actions, and more by the long-term fundamentals of energy markets. *AEO2003* focuses on these long-term fundamentals, including the availability of energy resources, developments in U.S. electricity markets, technology improvement, and the impact of economic growth on projected energy demand and prices through 2025.

A major consideration for energy markets through 2025 will be the availability of adequate natural gas supplies at competitive prices to meet growth in demand. *AEO2003* projects growing dependence on major new, large-volume natural gas supply projects for both domestic and imported supplies to meet future demand levels, including deepwater offshore wells, new and expanded liquefied natural gas (LNG) facilities, the Mackenzie Delta pipeline in Canada, and an Alaskan pipeline that would allow delivery of natural gas to the lower 48 States.

Net imports accounted for 55 percent of total U.S. oil demand in 2001, up from 37 percent in 1980 and 42 percent in 1990. That trend is expected to continue. A growing portion of imports is projected to be refined petroleum products, such as gasoline, diesel fuel, and jet fuel, assuming the future availability of those products in world markets.

While no new nuclear plants have been built in recent years, existing facilities have substantially improved their performance and lowered operating costs. Further, it has become common practice to request extension of the operating licenses of nuclear plants from the U.S. Nuclear Regulatory Commission (NRC). As a result, the downturn in nuclear generating capacity and generation previously expected is now anticipated to be delayed or eliminated. A more recent phenomenon has been uprating of nuclear plant capacity. The *AEO2003* forecast, reflecting those trends, projects an increase in nuclear capacity and generation.

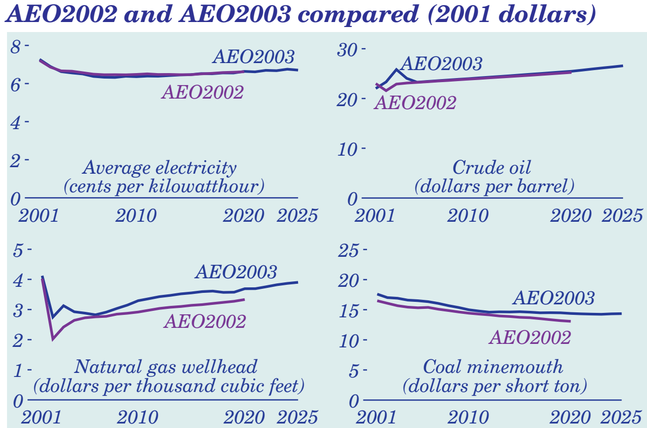
Economic Growth

The U.S. economy, as measured by gross domestic product (GDP), is projected to grow at an average annual rate of 3.0 percent from 2001 to 2025 in *AEO2003*, similar to the 3.1 percent rate projected in *AEO2002* for 2001 to 2020. Most of the determinants of economic growth are similar to those in *AEO2002*, but there are some important differences. For example, the projection of vehicle miles traveled, estimated using macroeconomic variables such as GDP growth, population, and income, is higher in this year's *AEO*. Light-duty vehicle miles traveled are projected to grow by 2.4 percent per year through 2020 in *AEO2003*, compared with 2.2 percent in *AEO2002*. This projection, which is more consistent with recent historical trends, increases the projected demand for transportation fuels.

Energy Prices

The average world oil price is projected to increase from $22.01 per barrel (2001 dollars) in 2001 to $25.83 per barrel in 2003, then to decline to $23.27 per barrel in 2005. Rising prices are projected for the longer term, to roughly $25.50 in 2020 (about the same as in *AEO2002*) and roughly $26.50 in 2025 (Figure 1), largely due to higher projected world oil demand. In nominal dollars, the average world oil price is expected to reach approximately $48 per barrel in 2025.

Figure 1. Energy price projections, 2001-2025: AEO2002 and AEO2003 compared (2001 dollars)



World oil demand is projected to increase from 76.0 million barrels per day in 2001 to 112.0 million barrels per day in 2020 (less than the *AEO2002* projection of 118.9 million barrels per day) due to lower projected demand in the former Soviet Union and in developing nations, including China, India, Africa, and South and Central America. World oil demand, including both conventional and unconventional oil supplies, grows to 123.2 million barrels per day by 2025 in *AEO2003*. Growth in oil production in both OPEC and non-OPEC nations leads to relatively slow growth in prices through 2025. OPEC conventional oil production is expected to reach 60.1 million barrels per day in 2025, more than double the 28.3 million barrels per day produced in 2001. The forecast assumes that sufficient capital will be available to expand production capacity.

Non-OPEC conventional oil production is expected to increase from 45.5 to 58.8 million barrels per day between 2001 and 2025. A 1.0 million barrel per day decline in production in the industrialized nations (United States, Canada, Mexico, Western Europe, Japan, Australia, and New Zealand) is more than offset by increased production from Russia, the Caspian Basin, Non-OPEC Africa, and South and Central America (in particular, Brazil). Russian oil production is expected to continue to recover from the lows of the 1990s and to reach 10.4 million barrels per day by 2025, 44 percent above 2001 levels. Production from the Caspian Basin is expected to exceed 5.0 million barrels per day by 2025, compared with 1.6 million barrels per day in 2001. By 2025, projected production from South and Central America reaches 6.3 million barrels per day, up from 3.7 million barrels per day in 2001. Non-OPEC African production is projected to grow from 2.7 million barrels per day in 2001 to 6.9 million barrels per day by 2025.

Average natural gas prices (including spot purchases and contracts) are projected to drop from $4.12 per thousand cubic feet in 2001 to $2.75 per thousand cubic feet in 2002. After 2002, natural gas prices are projected to move higher as technology improvements prove inadequate to offset the impacts of resource depletion and increased demand. Natural gas prices are projected to increase in an uneven fashion as higher prices allow the introduction of major new, large-volume natural gas projects that temporarily depress prices when initially brought on line. Prices are projected to reach about $3.70 per thousand cubic feet by 2020 and $3.90 per thousand cubic feet by 2025 (equivalent to more than $7.00 per thousand cubic feet in nominal dollars).

At roughly $3.70 per thousand cubic feet, the 2020 wellhead natural gas price in *AEO2003* is more than 35 cents higher than the *AEO2002* projection, due to a downward revision of the potential for inferred natural gas reserve appreciation and a reduced expectation for technology improvement over time. As demand for natural gas increases, expected technology improvements do not completely offset the effects of resource depletion.

In *AEO2003*, the average minemouth price of coal is projected to decline from $17.59 in 2001 to about $14.40 per short ton (2001 dollars) in 2020, remaining at about that level through 2025. Prices decline because of increased mine productivity, a shift to western production, and competitive pressures on labor costs. *AEO2003* is less optimistic about future productivity improvements in the Powder River Basin than was *AEO2002,* which projected average coal prices of roughly $13.10 per ton by 2020.

Average electricity prices are projected to decline from 7.3 cents per kilowatthour in 2001 to a low of 6.3 cents (2001 dollars) by 2007 as a result of cost reductions in an increasingly competitive market where excess generating capacity has resulted from the recent boom in construction and the continued decline in coal prices. Electricity industry restructuring contributes to declining projected prices through reductions in operating and maintenance costs, administrative costs, and other miscellaneous costs. After 2008, average real electricity prices are projected to increase by 0.4 percent per year as a result of rising natural gas prices and a growing need for new generating capacity to meet electricity demand growth. Real electricity prices reach 6.6 cents per kilowatthour in 2020 in *AEO2003*, identical to the price in *AEO2002*, and 6.7 cents per kilowatthour by 2025 as natural gas prices continue to increase.

Energy Consumption

Total energy consumption in *AEO2003* is projected to increase from 97.3 to 130.1 quadrillion British thermal units (Btu) between 2001 and 2020, an average annual increase of 1.5 percent. This projection is slightly below the 2020 projection of 130.9 quadrillion Btu for total consumption in *AEO2002*. By 2025, total energy consumption is projected to reach 139.1 quadrillion Btu in *AEO2003*. While total energy consumption levels in 2020 are similar in *AEO2002* and *AEO2003*, consumption by sector shifts; in particular, transportation consumption is higher and industrial consumption is lower by 2020 in *AEO2003*.

Residential energy consumption is projected to grow at an average rate of 1.0 percent per year between 2001 and 2025, with the most rapid growth expected for computers, electronic equipment, and appliances. By 2020, projected residential demand is 24.5

quadrillion Btu (slightly higher than the 24.3 quadrillion Btu projected in *AEO2002*). Slightly greater growth in the number of households explains the relatively higher level of energy demand in *AEO2003*. By 2025, total residential energy consumption is projected to reach 25.4 quadrillion Btu.

Commercial energy demand is projected to grow at an average annual rate of 1.6 percent between 2001 and 2025, reaching 23.5 quadrillion Btu in 2020 (slightly higher than the 23.2 quadrillion Btu in *AEO2002*) and 25.3 quadrillion Btu by 2025 in *AEO2003*. The most rapid increases in demand are projected for computers, office equipment, telecommunications, and miscellaneous small appliance uses. Commercial floorspace is projected to grow by an average of 1.6 percent per year between 2001 and 2020, identical to the rate of growth in *AEO2002* for the same time period.

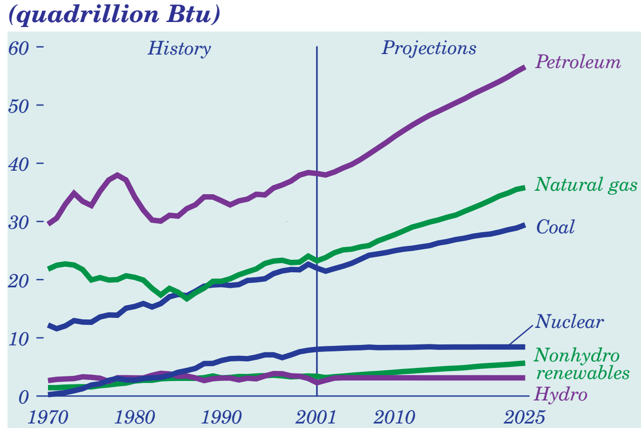
Industrial energy demand in *AEO2003* is projected to increase at an average rate of 1.3 percent per year between 2001 and 2025, reaching 41.7 quadrillion Btu in 2020 (significantly lower than the *AEO2002* projection of 43.8 quadrillion Btu) and 44.4 quadrillion Btu in 2025. The lower level of energy consumption in *AEO2003* in 2020 is partly the result of adopting an updated definition of what is included in industrial energy consumption. In earlier *AEO*s, industrial energy consumption included demand by combined heat and power (CHP) plants that were essentially independent power producers (IPPs), producing electricity but little steam. The energy demand of such "nontraditional" CHP plants is now included in the electric power sector.

Transportation energy demand in *AEO2003* is projected to grow at an average annual rate of 2.0 percent between 2001 and 2025, reaching 40.4 quadrillion Btu in 2020 (0.8 quadrillion Btu higher than in *AEO2002*) and 44.0 quadrillion Btu by 2025. The higher level of consumption in the transportation sector results from a higher forecast of vehicle miles traveled and a lower level of vehicle efficiency. Light-duty vehicle miles traveled are projected to grow by 2.4 percent per year through 2020 in *AEO2003* (compared with 2.2 percent per year in *AEO2002*) and by 2.3 percent per year through 2025. Consistent with recent trends, less improvement is projected for the average fuel efficiency of new light-duty vehicles than in *AEO2002*. New light-duty vehicle efficiency is projected to reach 25.6 miles per gallon by 2020 in *AEO2003* (down from 27.2 miles per gallon in *AEO2002*) and 26.1 miles per gallon by 2025.

Total electricity demand is projected to grow by 1.9 percent per year from 2001 through 2020 (the same as in *AEO2002*) and 1.8 percent per year from 2001 to 2025. Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the residential and commercial sectors is only partially offset by improved efficiency in these and other more traditional electrical applications; however, demand growth is expected to slow as regional and national market saturation is reached for air conditioning and some other applications.

Total demand for natural gas is projected to increase at an average annual rate of 1.8 percent between 2001 and 2025 (Figure 2), from 22.7 trillion cubic feet to 34.9 trillion cubic feet, primarily because of rapid growth in demand for electricity generation. With higher projected prices, total natural gas demand in 2020 (32.1 trillion cubic feet) is projected to be 1.6 trillion cubic feet lower in *AEO2003* than in *AEO2002*.

Figure 2. Energy consumption by fuel, 1970-2025 (quadrillion Btu)



In *AEO2003*, total coal consumption is projected to increase from 1,050 to 1,444 million short tons between 2001 and 2025, an average increase of 1.3 percent per year. Projected total coal demand in 2020 (based on short tons) is almost identical to that in *AEO2002* despite some shifts between sectors. Industrial coal demand is lower and electricity generation coal demand is higher in *AEO2003* as a result of the definitional changes in the data mentioned above and higher natural gas prices in *AEO2003* that lead to higher projected demand for coal in the electric power sector.

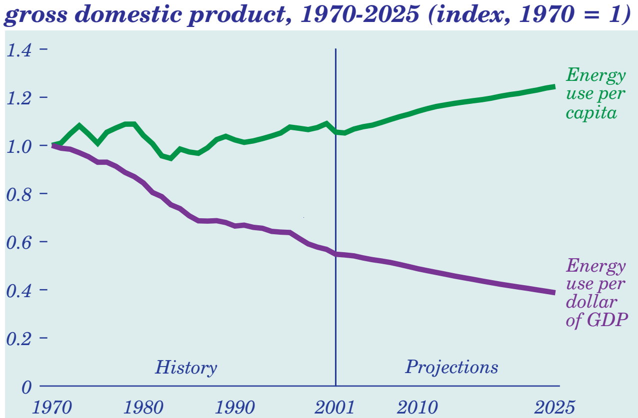
Total petroleum demand is projected to grow at an average annual rate of 1.7 percent through 2025 (reaching 29.17 million barrels per day), led by growth in the transportation sector, which is expected to account for about 74 percent of petroleum demand in 2025. Projected demand in 2020 (27.13 million barrels per day) is higher than in *AEO2002* by 470 thousand barrels per day due to higher transportation demand.

Total renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 2.2 percent per year through 2025, primarily due to State mandates for renewable electricity generation. About 55 percent of the projected demand for renewables in 2025 is for electricity generation and the rest for dispersed heating and cooling, industrial uses (including CHP), and fuel blending. The projected demand for renewables in 2020 in *AEO2003* is 0.6 quadrillion Btu lower than in *AEO2002*, reflecting an update in historical statistics primarily regarding electricity generation at pulp and paper plants that lowers the expectation for biomass use at industrial CHP plants.

Energy Intensity

As energy prices increased between 1970 and 1986, energy intensity, as measured by energy use per dollar of GDP, declined at an average annual rate of 2.3 percent as the economy shifted to less energy-intensive industries, product mix changed, and more efficient technologies were adopted (Figure 3). With slower price increases and growth in more energy-intensive industries, intensity declines moderated to an average of 1.4 percent per year between 1986 and 2001. Energy intensity is projected to continue to decline at an average annual rate of 1.5 percent through 2025, as continued efficiency gains and structural shifts in the economy offset growth in the demand for energy services.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)

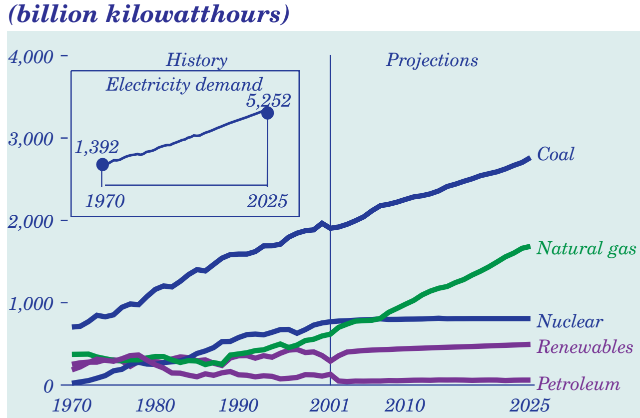


Energy use per person generally declined from 1970 through the mid-1980s but began to increase as energy prices declined in the late 1980s and 1990s. Per capita energy use is projected to increase in the forecast, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by 0.7 percent per year between 2001 and 2025 in *AEO2003*.

Electricity Generation

Generation from natural gas, coal, nuclear, and renewable fuels is projected to increase through 2025 to meet growing demand for electricity and offset the projected retirement of existing generating capacity, mostly fossil steam capacity being displaced by more efficient natural-gas-fired combined-cycle capacity brought online in the past few years and still being constructed (Figure 4). The projected levels of generation from power plants using coal, nuclear, and renewable fuels are higher than in *AEO2002* due to higher projected natural gas prices and uprates and life extensions of nuclear plants.

Figure 4. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



The natural gas share of electricity generation is projected to increase from 17 percent in 2001 to 29 percent in 2025, including generation by electric utilities, IPPs, and CHP generators. The share from coal is projected to decline from 52 percent in 2001 to 48 percent in 2025 as a more competitive electricity industry invests in less capital-intensive and more efficient natural gas generation technologies. Nonetheless, coal remains the primary fuel for electricity generation through 2025, and *AEO2003* projects that 74 gigawatts of new coal-fired generating capacity will be constructed between 2001 and 2025.

Nuclear generating capacity is projected to increase slightly from 2001 to 2025 in *AEO2003*. Primarily because of the relatively favorable economics of competing technologies, no new nuclear facilities are expected to be built through 2025; however, fewer expected nuclear retirements (as a result of life extensions), uprating of existing capacity, and an expectation of higher natural gas prices lead to a projection of more nuclear capacity than in *AEO2002*. No new nuclear power plants have been built in the United States for many years, however, and the economics of new plants are highly uncertain. Total nuclear capacity is projected to increase from 98.2 gigawatts in 2001 to a peak of 100.4 gigawatts by 2006 as a result of uprates before declining to 99.6 gigawatts by 2025. Uprates of 4.2 gigawatts offset retirements of 2.8 gigawatts between 2001 and 2025.

Renewable technologies are projected to grow slowly because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive natural gas technologies over coal and baseload renewables in the competition for new capacity. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are considered in the forecast. Federal subsidies for renewables (in particular, wind) are also included in the forecast.

Total renewable generation, including CHP, is projected to increase from 298 billion kilowatthours in 2001 to 476 billion kilowatthours by 2020 in *AEO2003*, an increase of 2.5 percent per year. Growth in renewable generation was projected to grow at a slower 2.1 percent per year between 2001 and 2020 in *AEO2002*. Total renewable generation reaches 495 billion kilowatthours by 2025 in *AEO2003*.

Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy production through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand (Figure 5). Projected U.S. crude oil production declines to 5.3 million barrels per day by 2025 in *AEO2003*, an average annual rate of 0.4 percent between 2001 and 2025. Production is 0.2 million barrels per day lower in 2020 than in *AEO2002* due to projected reduced production from the lower-48 onshore by 2020, particularly from enhanced oil recovery (EOR) operations. The lower level of lower 48 production in *AEO2003* relative to *AEO2002* is partially offset by projected increased production from Alaska and higher levels of production from the lower 48 offshore. Total domestic petroleum production (crude oil plus natural gas plant liquids) increases from 7.7 million barrels per day in 2001 to 8.0 million by 2025 due to an increase in the production of natural gas plant liquids (Figure 6).

Figure 5. Total energy production and consumption, 1970-2025 (quadrillion Btu)

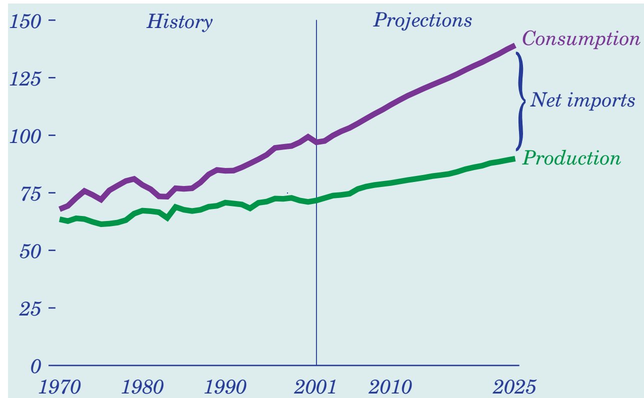
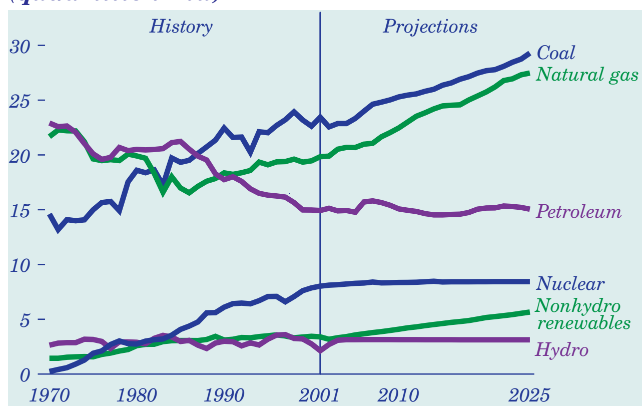


Figure 6. Energy production by fuel, 1970-2025 (quadrillion Btu)



By 2025, net petroleum imports, including both crude oil and refined products on the basis of barrels per day, are expected to account for 68 percent of demand, up from 55 percent in 2001. Despite an expected increase in domestic refinery distillation capacity of 3 million barrels per day, net refined petroleum product imports, on the basis of barrels per day, account for a growing portion of total net imports, increasing from 15 percent in 2001 to 34 percent by 2025.

Driven by growth in natural gas demand, domestic natural gas production is projected to increase from 19.5 to 25.1 trillion cubic feet between 2001 and 2020, an average rate of 1.3 percent per year. Domestic production is increasingly dependent on unconventional and more costly conventional resources in both the onshore and offshore. Projected production in 2020 is 3.4 trillion cubic feet lower than in *AEO2002* because of a reduction in the assumed potential of inferred natural gas reserves, updates to the economics of production, and reduced expectations for technology improvement for unconventional gas. After 2020, domestic production in *AEO2003* increases noticeably with the projected completion of an Alaskan pipeline. Total domestic natural gas production reaches 26.8 trillion cubic feet by 2025 in *AEO2003*.

Despite the projected increase in domestic natural gas production, an increasing share of U.S. gas demand is met by imports, including pipeline imports from Canada and Mexico (including some from an expected facility in Baja California, Mexico), and LNG. Three of the four existing U.S. LNG import facilities are open, and the fourth has announced plans to reopen in spring 2003; and three of the four have announced capacity expansion plans. Net imports of natural gas are projected to increase from 3.7 trillion cubic feet (16 percent of total demand) in 2001 to 7.8 trillion cubic feet (22 percent of total demand) in 2025.

As domestic coal demand grows in *AEO2003*, U.S. coal production is projected to increase from 1,138 million short tons in 2001 to 1,359 million short tons by 2020, an average rate of 0.9 percent per year. Projected production in 2020 is 38 million short tons lower than in *AEO2002*. By 2025, U.S. coal production is projected to reach 1,440 million short tons in *AEO2003*. Net coal exports are expected to fall throughout the *AEO2003* forecast, reflecting declining coal demand in some countries and intense competition from other international producers.

Renewable energy production, including hydroelectric generation, is projected to increase from 5.5 to 8.7 quadrillion Btu between 2001 and 2020, with growth in industrial biomass, ethanol, and all sources of renewable electricity generation. Renewable energy production in 2020 is 0.6 quadrillion Btu lower than projected in *AEO2002*, due to lower expected levels of industrial biomass use and generation from geothermal energy, offsetting higher levels of wind energy. By 2025, renewable energy production reaches 9.2 quadrillion Btu in *AEO2003*.

Carbon Dioxide Emissions

The *AEO* projections do not include future policy actions that might be taken to reduce carbon dioxide emissions. Carbon dioxide emissions from energy use are projected to increase from 1,559 to 2,082 million metric tons carbon equivalent between 2001 and 2020 in *AEO2003*, an average annual increase of 1.5 percent. This forecast is consistent with the 2,088 million metric tons carbon equivalent in 2020 projected in *AEO2002*. By 2025, total carbon dioxide emissions are projected to reach 2,237 million metric tons carbon equivalent in *AEO2003* (Figure 7). While total emissions in 2020 are virtually the same as in *AEO2002*, the amounts vary by sector. Projected industrial carbon dioxide emissions were 5 percent higher in 2020 in *AEO2002* due to differences in the definition of what is included in the industrial sector. As a result of the definitional change, carbon dioxide emissions in the electric power sector are higher in *AEO2003* in 2020 by 6.7 million metric tons carbon equivalent (1 percent). Carbon dioxide emissions are higher by 14.6 million metric tons carbon equivalent in 2020 in the transportation sector in *AEO2003* due to projections of less improvement in vehicle efficiency and more vehicle miles traveled.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons carbon equivalent)

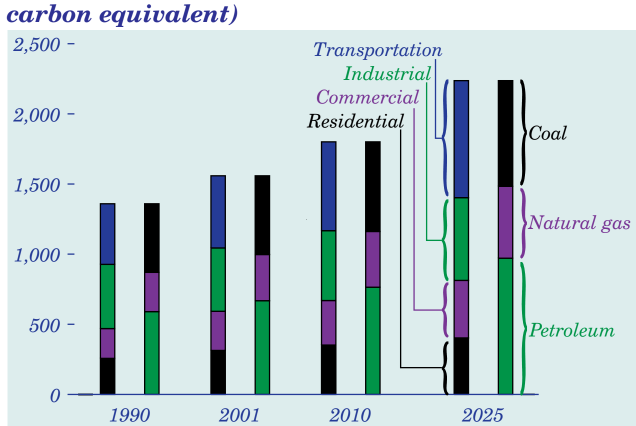


Table 1. Summary of results

Energy/Economic Factors	2000	2001	2025 Reference	2025 Low Economic Growth	2025 High Economic Growth	2025 Low World Oil Price	2025 High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	15.14	14.94	15.05	14.38	15.45	14.12	15.92
Natural Gas	19.50	19.97	27.47	25.24	28.72	26.99	27.99
Coal	22.58	23.97	29.29	27.81	31.08	29.18	29.74
Nuclear Power	7.87	8.03	8.43	8.43	8.43	8.43	8.43
Renewable Energy	5.96	5.33	8.78	8.26	9.38	8.82	8.76
Other	1.09	0.57	0.80	0.80	0.83	0.81	0.82
Total Primary Production	**72.15**	**72.81**	**89.83**	**84.93**	**93.90**	**88.36**	**91.66**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	22.28	23.29	41.23	37.63	45.82	44.06	37.97
Natural Gas	3.62	3.73	7.93	6.93	9.29	7.63	8.01
Coal/Other (- indicates export)	-0.84	-0.54	0.27	0.22	0.38	0.26	0.27
Total Net Imports	**25.06**	**26.48**	**49.43**	**44.78**	**55.49**	**51.96**	**46.25**
Discrepancy	-2.18	1.99	0.19	0.31	0.14	0.07	0.34
Consumption (quadrillion Btu)							
Petroleum Products	38.53	38.46	56.56	52.16	61.61	58.57	54.65
Natural Gas	24.07	23.26	35.81	32.58	38.42	35.03	35.98
Coal	22.64	22.02	29.42	27.89	31.32	29.32	29.67
Nuclear Power	7.87	8.03	8.43	8.43	8.43	8.43	8.43
Renewable Energy	5.96	5.33	8.78	8.26	9.39	8.82	8.76
Other	0.31	0.21	0.07	0.07	0.08	0.07	0.07
Total Consumption	**99.38**	**97.30**	**139.07**	**129.39**	**149.25**	**140.24**	**137.57**
Prices (2001 dollars)							
World Oil Price (dollars per barrel)	28.35	22.01	26.57	24.85	28.09	19.04	33.05
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	3.83	4.12	3.90	3.83	4.50	3.87	3.92
Domestic Coal at Minemouth (dollars per short ton)	17.18	17.59	14.36	13.99	14.93	14.17	14.59
Average Electricity Price (cents per kilowatthour)	6.9	7.3	6.7	6.5	7.1	6.6	6.7
Economic Indicators							
Real Gross Domestic Product							
(billion 1996 dollars)	9,191	9,215	18,917	16,589	21,155	18,972	18,875
(annual change, 2001-2025)	—	—	3.0%	2.5%	3.5%	3.1%	3.0%
GDP Chain-Type Price Index							
(index, 1996=1.000)	1.069	1.094	1.981	2.291	1.692	1.957	2.018
(annual change, 2001-2025)	—	—	2.5%	3.1%	1.8%	2.5%	2.6%
Real Disposable Personal Income							
(billion 1996 dollars)	6,630	6,748	13,435	12,246	14,587	13,451	13,480
(annual change, 2001-2025)	—	—	2.9%	2.5%	3.3%	2.9%	2.9%
Value of Manufacturing Shipments							
(billion 1996 dollars)	4,378	4,079	8,257	7,411	9,714	8,297	8,222
(annual change, 2001-2025)	—	—	3.0%	2.5%	3.7%	3.0%	3.0%
Energy Intensity							
(thousand Btu per 1996 dollar of GDP)	10.82	10.57	7.36	7.81	7.06	7.40	7.29
(annual change, 2001-2025)	—	—	-1.5%	-1.3%	-1.7%	-1.5%	-1.5%
Carbon Dioxide Emissions							
(million metric tons carbon equivalent)	1,578	1,559	2,237	2,083	2,401	2,261	2,211
(annual change, 2001-2025)	—	—	1.5%	1.2%	1.8%	1.6%	1.5%

Notes: Specific assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections beginning on page 50. Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Sources: Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2003* (*AEO2003*) are based on Federal, State, and local laws and regulations in effect on September 1, 2002. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation requiring funds that have not been appropriated) are not reflected in the projections.

Examples of Federal legislation incorporated in the projections includes the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis; the Tax Payer Relief Act of 1997; the Federal Highway Bill of 1998, which included an extension of the ethanol tax incentive; new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions; the new standards for energy-consuming equipment that were announced in 2001; and the Job Creation and Worker Assistance Act of 2002, which extended the production tax credit to certain renewable energy sources.

AEO2003 assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 will increase with inflation and that Federal taxes on those fuels will continue at 2001 levels in nominal terms. *AEO2003* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2003* assumes their continuation throughout the forecast.

AEO2003 also recognizes the regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of November 2002, 17 States and the District of Columbia still had active electric restructuring programs based on legislation previously passed or regulations promulgated. Five states have delayed restructuring activities, and one, California, has suspended restructuring.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, there is a phased reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. The *AEO2003* incorporates nitrogen oxide (NO_x) boiler standards issued by the U.S. Environmental Protection Agency (EPA) under CAAA90. In addition, the 19-state NO_x cap and trade program in the Northeast and Midwest is also represented. CAAA90 also required the EPA to study the effects of mercury emissions from power plants and determine whether they should be regulated. The EPA has so determined and is now in the process of deciding what the limits on mercury emissions from power plants will be. Those limits will be announced by the end of 2004. Because they have not been promulgated, they are not incorporated in *AEO2003*.

AEO2003 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The Tier 2 standards for reformulated gasoline (RFG) will be required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2003* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of 80 percent ULSD and 20 percent 500 part per million (ppm) highway diesel between June 2006 and June 2010, with a 100-percent requirement for ULSD thereafter. The *AEO2003* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

Energy combustion is the primary source of anthropogenic (human-caused) carbon dioxide emissions. *AEO2003* estimates of emissions do not include emissions from activities other than fuel combustion, such as landfills and agriculture, nor do they take into account "sinks" that absorb carbon dioxide, such as forests.

The *AEO2003* reference case projections include analysis of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis.

The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto Protocol, which was agreed to on December 11, 1997, but has not been ratified, or other international agreements. The Bush Administration has announced that it does not intend to seek ratification by the United States Senate of the Kyoto agreement, effectively removing the United States from further participation in its provisions.

Comparison of Proposed House Energy Bill and Senate Amendments

The U.S. House of Representatives passed H.R. 4, The Securing America's Future Energy (SAFE) Act of 2001, on August 2, 2001. In addition to addressing energy conservation, efficiency, and research and development, H.R. 4 encourages the development of domestic oil and gas resources, provides tax credits for alternative energy products, and requires an increase in average automobile fuel efficiency. The Senate amended the SAFE Act and on April 25, 2002, passed the Energy Policy Act of 2002.

Over the past year, EIA has analyzed several of the provisions included in the SAFE Act of 2001 at the request of members of Congress. The analysis reports can be found on the EIA web site at www.eia.doe.gov/bookshelf/services.html. The *Issues in Focus* section of this report also details the results of some of the analyses.

By extending the use of tax credits, deductions, and tax recovery periods and by liberalizing many of the definitions of current applicable laws, the Energy Policy Act of 2002 and corresponding Senate amendments attempt to amend the Internal Revenue Code of 1986 and, specifically, to address energy conservation, energy reliability, and energy production. The following summary is a comparison of the House energy bill and Senate amendments. Some of the provisions discussed below have been changed since they were modeled for EIA's analyses.

Conservation

Residential energy-efficient property credit

Section 3101 of the House energy bill proposes a 15-percent tax credit for the purchase of a qualified photovoltaic (PV) property and qualified solar water heating property that is used exclusively for purposes other than heating swimming pools and hot tubs. The credit would allow a maximum of $2,000 per PV property or solar water heating property, with an effective date of December 31, 2001, for solar property purchased before January 1, 2007, and PV property purchased before January 1, 2009.

Section 2103 of the Senate energy bill proposes a 15-percent tax credit for qualified solar water heaters purchased by the taxpayer during the applicable year. It proposes a 30-percent credit for the purchase of a fuel cell property or a wind energy property; a maximum credit of $2,000 is proposed for the latter purchase. The maximum credits for other purchases meeting specific efficiency targets in the bill are $75 for a heat pump water heater or a natural gas water heater and $250 for an electric heat pump, an advanced natural gas furnace, a qualifying central air conditioner, or a geothermal heat pump. The tax credit would be applicable for equipment purchased by the taxpayer during the tax year.

Credits for the installation of fuel cells

Section 3103 of the House bill proposes giving commercial and residential power generators a maximum tax credit of $1,000 per kilowatt of capacity for stationary fuel cell power-producing equipment with an efficiency of at least 30 percent. The property would have to be placed in service between January 1, 2002, and December 31, 2006.

Section 2104 of the Senate amendment proposes providing taxpayers with tax credits worth 30 percent of basis (maximum $500 per 0.5 kilowatt of capacity) for stationary fuel cell power plants that generate at least 0.5 kilowatts of electricity and have an efficiency of at least 30 percent. The property would have to be placed in service between December 31, 2002, and December 31, 2007. Alternatively, a taxpayer could receive tax credits worth either $200 or 10 percent of the purchase cost of a stationary microturbine unit with an electricity-only generating efficiency of at least 26 percent, based on International Standards Organization guidelines.

Alternative motor vehicle credit

Present law provides a maximum deduction for alternative motor vehicles of $50,000 for a truck or van weighing over 26,000 pounds and $2,000 for vehicles weighing 10,000 pounds or less. In addition, currently there is a 10-percent tax credit proposed for the cost of a qualified electric-run vehicle. The maximum amount of the credit is $4,000. The deduction and credit would be phased out from January 1, 2004, until December 31, 2006, after which the incentives would no longer be valid.

Section 3104 of the House bill would extend the existing alternative motor vehicle deduction through December 31, 2007, and would begin phasing out this provision in 2005. The provision also would repeal an existing credit for electric fuel cell vehicles and provide credits for the purchase of fuel cell powered motor vehicles, hybrid motor vehicles, mixed-fuel motor vehicles, and advanced lean burn technology motor vehicles. Unused credits could be carried forward 20 years and would apply to non-fuel-cell powered equipment placed in service before 2008 and to fuel cell powered vehicles placed in service before 2012. Property placed in service after December 31, 2001, could receive the tax credit. Specifically, the following credits are proposed in the House bill:

- **Alternative fuel motor vehicle** credits would be valued at 50 percent of the incremental cost, represented by the difference between the actual and suggested retail price, of a dedicated alternative fuel motor vehicle. An additional 30-percent credit would be available if the vehicle met specified emissions standards. The limits on incremental cost would begin at $5,000 for small vehicles and light trucks and continue up to $40,000 for vehicles weighing over 26,000 pounds. Alternative fuels would include compressed natural gas, liquefied petroleum gas, hydrogen, and fuel consisting of at least 80 percent methanol.

- **Fuel cell motor vehicles** weighing between 8,500 and 26,000 pounds would receive credits of between $4,000 and $40,000.

- **Hybrid motor vehicle** credits would vary not only by vehicle weight but also by power available from the battery system. Auto and light truck purchases would qualify for a credit for battery power ranging from $250 for 2.5 percent to $1,000 for 30 percent. For vehicles weighing over 26,000 pounds, the credit would range from $6,000 for a battery power of 20 percent to $10,000 for a battery power of 60 percent. Additional credits would apply to vehicles and light trucks that meet the 2000 fuel economy performance standards (as opposed to 2000 model year standards).

- **Mixed fuel vehicles** are vehicles weighing more than 14,000 pounds that use either 75:25 or 95:5 mixtures of alternative fuel and petroleum-based fuel. Those using the mixture with a lower percentage of alternative fuel would receive 70 percent of the otherwise allowable alternative fuel motor vehicle credit. Those using the 95:5 ratio would receive 95 percent of the allowable alternative fuel motor vehicle credit.

- **Advanced lean burn technology motor vehicles** would have to exceed 2000 model year fuel economy performance standards to receive a credit that ranges from $1,000 for fuel economy that is 125 percent of the year 2000 standard to $3,500 for 250 percent. In addition, $250 or $500 credits for estimated lifetime fuel savings would be available. Property placed in service beginning January 1, 2002, would be eligible for the credits.

The provisions of the Senate amendments (Sections 2001 and 2010) are similar to those of the House bill. The Senate amendments would repeal the existing electric fuel vehicle purchase credit and extend the present-law deduction through 2007, or through 2011 for hydrogen-related property. Phaseout of a 25-percent non-hydrogen-related property credit would begin in 2004 and end in 2005, and a hydrogen-related property credit would be phased out from 2004 to 2009. Unused credits could be carried forward for 20 years and carried back for 3 years. The equipment would have to be placed in service before 2007 (2012 for fuel cell motor vehicles). Like the House provision, the Senate amendments would repeal the present-law credit for electric fuel cell vehicles.

- **Fuel cell motor vehicles** would receive the same treatment as under the proposed House provision.

- **Hybrid motor vehicle** credits would vary not only by vehicle but also by power available from the battery system. Auto and light truck purchases would qualify for a credit for battery power from $250 for 4 percent to $1,000 for 30 percent. For vehicles weighing between 10,000 and 14,000 pounds, the credit would range from $1,000 for a battery power of 20 percent to $2,500 for a battery power of 60 percent. Additional credits would be available for vehicles and light trucks that exceed the 2000 fuel economy performance standards.

- **Alternative fuel motor vehicles** would be treated differently in the Senate version, in that the percentage allowed as the incremental cost of alternative fuel motor vehicles would be limited to 40 percent rather than 50 percent. Although the Senate supported a mixed fuel vehicle credit similar to that in the House bill, the Senate version does not include a provision that would allow a credit for Advanced Clean Coal Technology. It would also delay the effective date of implementation of the provision until September 30, 2002.
- **Mixed fuel vehicles** would receive the same treatment proposed in the House provision.

Extension of deduction for refueling property

Both the House bill (Section 3105) and the Senate bill (Section 2010) would extend the deduction for refueling property; however, the Senate would provide a 50-percent credit for costs associated with the installation of a clean-fuel vehicle refueling property. The credit would be limited to $30,000 if the property were a retail clean-fuel vehicle refueling property. The credit limit on residential property would be $1,000. In both cases, the property could not be placed in service after January 1, 2007, unless the refueling energy source were hydrogen, in which case the deadline would be January 1, 2012.

Modification of credit for electric vehicles

The proposed House bill (Section 3106) redefines eligibility for the credit for battery vehicles. The provision modifies the credit to vary by vehicle weight. Certain small vehicles would receive a credit of 10 percent of the manufacturer's retail price or $4,000, whichever is less. Other small vehicles of 8,500 pounds or less might be eligible to receive $4,000 or $5,000 if certain performance and capacity criteria were met. Vehicles weighing over 8,500 but not over 14,000 pounds would be eligible to receive $10,000. Owners of vehicles weighing more than 26,000 pounds could obtain a credit of $40,000. This provision would become effective on January 1, 2002.

While the Senate provision (Section 2002) has many similarities to that of the House bill, the eligible maximum credits for certain small vehicles would be $1,500 or 10 percent of the retail value of the vehicle. For vehicles weighing less than 8,500 pounds, the credit would range from $3,500 to $6,000. Unused credits could be carried forward 20 years and carried back 3 years. Property placed in service after September 30, 2002, would be eligible for the credit.

Energy-efficient appliances credit

Section 3107 of the House bill proposes a $50 production credit on clothes washers with minimum efficiency standards of at least 1.26 Modified Energy Factor (MEF) (as determined by the Secretary of Energy) or a refrigerator that consumes 10 percent less energy per year than the standards created by the U.S. Department of Energy (DOE). A clothes washer with an efficiency of at least 1.42 MEF effective on July 1, 2001, or a washer produced after January 1, 2004 with at least a 1.5 MEF would be eligible to receive a $100 credit. A refrigerator that consumes 15 percent less than the DOE standards could also receive the $100 credit. Section 2102 of the Senate amendments is similar to the Section 3107 provision of the House bill.

Credit for energy efficiency improvements to existing homes

Section 3108 of the House bill proposes a 20-percent tax credit, with a maximum of $2,000, for homeowners with certain energy-efficient building envelope components meeting the 1998 International Energy Conservation Code (IECC) code. Improvements would have to be made between January 1, 2002, and December 31, 2007.

Section 2109 of the Senate amendments proposes a credit to qualified energy efficiency improvements up to a maximum credit of $300 per household. Improvements would have to achieve a 30-percent reduction in energy consumption and be consistent with the 2000 IECC or, in the case of windows, would have to meet the Energy Star criteria or be certified as achieving a 30-percent reduction in energy use. Qualified improvements, which include insulation, exterior windows and doors, and skylights, would have to be installed after the date of the bill's enactment and before January 1, 2007.

Efficient new home credit

Section 3109 of the House bill would offer builders a maximum $2,000 tax credit for any home that achieves 30-percent energy savings for heating and cooling relative to a home that meets the 1998 IECC. The Efficient New Home Credit would apply to homes substantially completed between January 1, 2002, and December 31, 2006. Section 2101 of the Senate amendments would offer builders a tax credit of $1,250 tax credit for any home that achieves 30-percent energy savings for heating and cooling relative to a home that meets the 2000 IECC and a $1,250 tax credit for any home that achieves 50-percent energy savings for heating and cooling relative to a home that meets the 2000 IECC. Compliance for the credit could be component based or performance based. Homes available for the credit would have to be substantially completed after the date of enactment of the bill and before December 31, 2007.

Energy-efficient commercial buildings deduction

Section 3110 of the House bill would grant commercial building owners a maximum deduction of $2.25 per square foot for expenditures on the building envelope, water heating, lighting, ventilation, or heating and cooling of the building. Credits would be effective from the date of enactment until January 2, 2007. Section 2105 of the Senate amendments is similar, with effective dates from September 30, 2002, through December 31, 2009.

Deduction for qualified new or retrofitted energy management devices

Section 3111 of the House bill would allow a maximum deduction of $30 for each qualified energy management device, including a meter or metering device, used for managing a customer's daily use and purchase of electricity or natural gas. The provision would become effective on the date of its enactment. Section 2106 of the Senate amendments is similar to the House version.

Energy credit for combined heat and power system property

Section 3113 of the House bill would extend the current 10-percent business credit for solar power generation equipment. Qualifying equipment must have electrical capacity greater than 50 kilowatts or a mechanical energy capacity greater than 67 horsepower. The credit would be effective from December 31, 2002, through December 31, 2006. Section 2108 of the Senate amendments is similar to the House version.

Small ethanol producer credit

There is no provision in the House bill for changes to current laws. Section 2005 of the Senate bill would liberalize the definition of an eligible small producer to include a producer that does not exceed 60 million gallons and would permit a pass-through of the producer credit to a cooperative's patrons. The amendment would also liberalize the ordering and carry-forward/carry-back rules for small ethanol producers and would allow them to claim the credit against the alternative minimum tax.

Three-year applicable recovery period for depreciation of qualified water sub-metering devices

Section 3112 of the House bill would establish a 3-year recovery period for energy management devices put in service after the date of enactment of bill. Section 2111 of the Senate bill resembles the House version. It would add water sub-metering devices to applicable equipment devices.

Transfer of excise tax to the Highway Trust Fund

Section 2006 of the Senate bill would transfer 2.5 cents per gallon of the excise tax on gasohol from the General Fund to the Highway Trust Fund. The transfer would take effect on October 1, 2003.

Changes to income tax and excise tax rules governing the treatment of ETBE

Section 2007 of the Senate amendments would allow refiners blending gas and ethanol to accrue a credit equal to the amount of the alcohol fuels credit or excise tax rate reduction that would otherwise be available for fuel blended with ethyl tertiary butyl ether (ETBE). In addition, a refiner would be able to claim the credit against its excise liability rather than its income tax liability for motor fuels under Section 4081 of the Tax Code. Alternatively, the credit could be transferred to a registered position holder to offset that holder's excise tax liability. The provision would become effective on the date of enactment.

Income tax credit and excise tax rate reduction for biodiesel fuel mixtures

Section 2008 of the Senate amendments would allow taxpayers engaging in fuel production from biodiesel fuels from January 1, 2002, through December 31, 2006, to receive an income tax credit or an excise tax reduction. Those using recycled sources could receive a reduced income tax credit.

Tax credit for certain "power takeoff" vehicles

Section 2009 of the Senate amendments proposes a $250 income tax credit to business owners of a highway vehicle operated for either transportation or nontransportation purposes using a single motor. The provision requires the Treasury to provide a method for exempting from the fuel excise tax the fuel used for non-transportation use. The provision would take effect on the date of enactment and expire on December 31, 2004.

Credit for production from a clean coal technology unit

Sections 2201 and 2221 of the Senate amendments propose a credit of 0.34 cent per kilowatthour for electricity produced from units that have been retrofitted, repowered, and/or replaced with a clean coal technology within 10 years of the date of enactment. The effective date for the credit would be the date of the enactment of the provision.

Investment credit for advanced clean coal technologies

Section 3117 of the House bill includes a provision granting a 10-percent tax credit for qualified expenses for the construction of a power plant using advanced clean coal technologies, or the retrofitting or repowering of an existing conventional power plant with new advanced clean coal technologies. A total of no more than 6,500 megawatts could be placed in service before 2009, with additional limits by type of technology and an additional 1,000 megawatts before 2012. All investments would have to be made between January 1, 2002, and December 31, 2011.

Sections 2212 and 2221 of the Senate amendments have similar provisions. Not more than 2,000 megawatts of capacity may be placed in service before 2009 and an additional 2,000 megawatts before 2017. The credit would take effect on the date of enactment of the provision for capacity placed in service before January 1, 2017, or, in the case of advanced pulverized coal or atmospheric fluidized-bed combustion, before January 1, 2013.

Credit for production from advanced clean coal facilities

Section 3118 of the House bill proposes a production credit to power producers using qualified advanced clean coal technology facilities. The qualifying facility would be able to take the credit for a 10-year period that begins with the date that the qualifying facility is placed in service, with the amount for the first 5 years exceeding the amount for the second 5 years. Section 2212 of the Senate amendments is similar to the House version but uses different heat rate thresholds to qualify for the credit.

Energy Reliability

Treatment of natural gas gathering lines as 7-year property

Section 3201 of the House bill proposes a 7-year recovery period for natural gas gathering lines, as opposed to the current 15-year recovery period. It also would allow for alternative minimum tax relief by not adjusting the allowable amount of depreciation. The treatment would apply to property placed in service after the date of enactment. Section 2302 of the Senate bill does not allow for alternative minimum tax relief.

Recovery period for natural gas distribution

Section 3202 of the House bill proposes a 10-year recovery period for natural gas distribution lines, as opposed to the current 20-year recovery life available for taxpayers. The provision would allow alternative minimum tax relief by not adjusting the allowable amount of depreciation and would be effective for property placed in service after the date of enactment. Section 2311 of the Senate amendments proposes a 15-year tax life and does not allow for alternative minimum tax relief.

Treatment of petroleum refining property as 7-year property

Section 3203 of the House bill would change the current 10-year recovery period for refining property to 7 years. It would also provide no adjustment to the allowable amount of depreciation for purposes of computing income subject to the alternative minimum tax. Changes would apply to property placed in service after the date of enactment.

Expensing of capital costs incurred for production in complying with EPA sulfur regulations for small refiners

Section 3204 of the House bill would allow small refiners to deduct 75 percent of capital expenditure costs on the year of the expense for costs related to complying with the EPA's highway diesel fuel sulfur control requirements. The provision would apply to expenses paid or incurred after the date of enactment. Section 2303 of the Senate amendments is similar to the House version, except that it defines a small refiner somewhat differently.

Credit for small refiners for production of diesel fuel in compliance with the EPA sulfur regulations for small refiners

Section 3205 of the House bill proposes a 5-cent-per-gallon credit to small refiners of low-sulfur fuel for expenses incurred after the date of enactment. The total amount of the credit is limited to 25 percent of the capital costs incurred to reach compliance with the EPA diesel fuel regulations. Failure to reach compliance, change of ownership, or cessation of operations would cause the refiner to return the credit. Section 2304 of the Senate amendments is similar to the House version but reduces the credit amount, *pro rata*, for refiners producing in excess of 155,000 (but less than 205,000) barrels per day. In addition, the credit would have no recapture features and, in the case of cooperative organizations, could be apportioned to members.

Independent producer test change from daily runs to average daily runs

Section 3206 of the House bill would change the current definition of independent producer from 50,000 barrels per day to an average of 75,000 barrels per day, effective for production in taxable year 2002 and after. Section 2305 of the Senate amendments is similar to the House provision but would lower the production requirement to an average daily run of 60,000 barrels and would apply to production in taxable years after 2002.

Tax-exempt bonds for public power facilities

Section 3207 of the House bill would liberalize current rules on the ability of public power companies to use tax-exempt bonds to finance electric output property when participants engage in qualifying electric restructuring arrangements. This provision would allow power entities that engage in activities beyond those allowed under the liberalized private business use rules to elect to forgo certain future issuances of tax-exempt bonds for new generating capacity while preserving their tax-exempt status for other bonds. The provision would also alter existing rules concerning the issuance of tax-exempt bonds for the purchase of existing electric output facilities. The bill would be effective on the date of enactment. Sections 2401 and 2405 of the Senate amendments propose changes to current tax laws to conform with the new industry structure. On the date of enactment, the provision would allow modification to the amounts sold by qualified facilities without losing their "grandfathered" exception benefits.

Dispositions of transmission property to implement FERC restructuring policy

Section 3208 of the House bill would allow taxpayers greater flexibility in the treatment of the disposition of transmission property as an involuntary conversion by expanding the range of replacement property that qualifies as a related property (or similar in use) to converted electric transmission property. Section 2404 of the Senate amendments would allow the recognition of a gain from the disposition of electric transmission property over an 8-year period. As in the House provision, transactions occurring after the date of enactment would qualify for consideration.

Distribution of stock to implement FERC or State electric restructuring policy

Section 3209 of the House bill proposes an exception to Section 355(e) of the Tax Code for the acquisition of stock or assets of any controlled corporation during an electric transmission transaction.

Ongoing study and reports with regard to tax issues resulting from future restructuring decisions

Section 2401 of the Senate amendments would require that the Treasury Department study and analyze tax consequences resulting from the restructuring of the electric service industry. The series of reports would be presented to the Senate Committee on Finance and the House Ways and Means Committee. The first report would be due on December 31, 2002.

Special rules for nuclear decommissioning cost

Section 3210 of the House bill would repeal the cost-of-service requirement for deductible contributions to a qualified nuclear decommissioning fund. It would also allow qualified funds to accumulate an amount sufficient to pay for all decommissioning costs. The provision would permit contributions to qualified funds after the useful life of the nuclear power plant. In addition, there would be no recognition of gain or loss as a result of the transfer of a qualified fund in connection with the transfer of the power plant. The provision treats all nuclear decommissioning costs as deductible when paid and applies in taxable years after December 31, 2002. Section 2402 of the Senate amendments would not allow funds to accumulate an amount sufficient to pay for all decommissioning. The provision, which would apply in taxable years after December 31, 2002, would not permit funding after the useful life of the power plant.

Treatment of certain electric cooperatives

Section 3211 of the House bill would require that any income received or accrued from an "open access transaction" would not be included in determining whether or not a rural electric cooperative satisfies the 85-percent test for tax exemption under 501(c)(12) of the Tax Code. In addition, any income received or accrued by a rural electric cooperative from any nuclear decommissioning transaction would also be excluded from the 85-percent test. The provision specifies that income received or accrued from a "load loss transaction" be treated under 501(c)(12) as income collected by members for the sole purpose of covering losses and expenses related to providing service to its members. It would also provide that similar rules apply to the receipt or accrual of income from load loss transactions of taxable electric utilities. Its effective date would be the first taxable year after the date of enactment.

Sections 2403 and 2406 of the Senate amendments are similar to the House provision. Income from some asset exchange or conversion transactions would be excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under 501(c)(12). In addition, cancellation from indebtedness income from discounted prepayments of loans, debts, or obligations made, insured, or guaranteed by the Federal Government under the Rural Electrification Act of 1936 would be excluded in determining whether a rural electric cooperative satisfies the 85-percent test. Income received or accrued indirectly from a member by a rural electric cooperative from any "open access transaction" would be treated as member income in determining whether the cooperative satisfies the 85-percent test. Income received before 2007 for the construction of line extensions to facilitate the development of Section 29 qualified nonconventional fuel sources would be excluded in determining whether a rural electric cooperative satisfies the 85-percent test. The provision would take effect in the first taxable year after the date of enactment.

Energy Production

Marginal wells credit

Section 3301 of the House bill proposes a tax credit of $3 per barrel for the production of crude oil and $0.50 per thousand cubic feet for the production of qualified natural gas from marginal wells. The credit, which would be unavailable if the reference price of oil or natural gas exceeded $18 or $2, respectively, would become effective in taxable years after 2001 and would be reduced proportionately given the following cases: (1) the price of oil falls between $15 and $18, or (2) the price of gas falls between $1.67 and $2. Section 2301 of the Senate bill is the same as Section 3301 of the House bill but begins in the first taxable year after the date of enactment.

Net income limitation on percentage depletion for oil and gas property and suspension of limitation based on 65 percent of taxable years

Section 3302 of the House bill would suspend the 65-percent taxable income limitation for taxable years between January 1, 2002, and January 1, 2007, and extend the suspension of the 100-percent net income limitation for marginal wells for an additional 5 years. Section 2306 of the Senate amendments would also suspend the 100-percent net income limitation for marginal wells. Both the House and Senate provisions would be effective for taxable years after 2001.

Delay rental payments

Section 3303 of the House bill proposes a deduction for rental payments in lieu of royalty payments in the year paid or incurred, beginning in taxable years after 2001. Section 2308 of the Senate amendments would allow for a prospective 2-year amortization on the rental payments, starting in the first taxable year after 2002.

Geological and geographical costs

Section 3304 of the House bill would allow geological and geophysical costs incurred in domestic oil and gas exploration in taxable years after 2001 to be deducted in the year paid or incurred. Section 2307 of the Senate amendments includes a prospective 2-year amortization period for costs paid or incurred in taxable years after 2002.

Five-year carryback for net operating losses from oil and gas properties

Section 3305 of the House bill proposes a 5-year carry-back period for eligible oil and gas losses incurred in taxable years after 2001.

Extension and expansion of credit for producing fuel from an unconventional source

Section 3306 of H.R. 4 proposes a credit for the production of certain unconventional fuels produced at wells placed in service after the date of enactment and before January 1, 2007. The credit would be worth $3 per barrel for production from 2001 through 2002 and would be indexed for inflation beginning with the credit amount for 2003. Any production occurring after December 31, 2009, or exceeding 200,000 barrels (or cubic equivalent) would be excluded from the credit. The bill would also allow producers to claim a credit equal to the newly re-indexed value of $3 per barrel for production from certain existing wells between 2003 and 2006. The provision would allow landfill gas to be sold to a third party from facilities placed in service after June 30, 1998, and before January 1, 2007. The taxpayer could claim 5 years of credit beginning with the later of (1) the date of enactment or (2) the first day of operation of facility.

Section 2309 of the Senate amendments would permit an un-indexed credit of $3 per barrel of oil equivalent for the production of certain nonconventional fuels produced at wells placed in service after the date of enactment and before January 1, 2005 (3 years). This provision would also extend the present-law credit through December 31, 2004, for production from existing facilities producing coke, coke gas, or natural gas and byproducts produced by coal gasification from lignite. In addition, it would permit credit for the production of "refined coal" from facilities placed in service after the date of enactment and before January 1, 2007. This type of coal, which would be required to meet emissions reduction targets, would have a market value 50 percent higher than feedstock coal.

The Senate amendments would also extend the credit for the production of "viscous oil" from facilities placed in service after the date of enactment and before January 1, 2005, as well as for coal mine methane gas captured or extracted from a coal mine and sold after the date of enactment and before January 1, 2005. Credits for the production of liquid, gaseous, or solid fuels produced from agricultural and animal wastes would be available for facilities placed in service after the date of enactment and before January 1, 2005. The credit is valued at $3 per barrel of oil equivalent, un-indexed, for 5 years of production commencing when the facility is placed in service. The Senate would direct the Treasury to study the effect of the credit on coalbed methane.

Business credits against the alternative minimum tax

Section 3307 of the House bill proposes relief from the alternative minimum tax to some businesses. The credits would include energy-efficient appliance credits, new energy-efficient home construction credits, environmental tax credits, marginal well oil and gas production credits, and credits for production from qualifying advanced clean coal technology. Sections 2005(b)(3) and 2503(c) of the Senate amendments would permit the Alaska natural gas credit and the small ethanol producer credit to be claimed against the entire regular tax and the alternative minimum tax.

Intangible drilling costs

Section 3308 of the House bill would remove the existing alternative minimum tax preference for intangible drilling costs of independent producers for taxable years 2002 through 2004.

Enhanced oil recovery credit

Section 3309 of the House bill would allow the enhanced oil recovery credit to be taken against the alternative minimum tax.

Accelerated depreciation and wage credit benefits for businesses on Indian reservations

Section 3310 of the House bill would extend the current accelerated depreciation incentive until December 31, 2006. This extension would apply to property whose purpose is the transmission or refining of oil or natural gas, including operations related to the generation or transmission of electricity, belonging to a gas or oil well, or used for the production of any qualified fuel. The provision would also extend the Indian employment credit incentive through December 31, 2006, as long as the credit is used for wages paid for energy-related services performed at a facility for any of the activities listed above. Section 2501 of the Senate amendments would extend the wage credit and accelerated depreciation incentives through December 31, 2005, for all types of businesses.

Arbitrage rules not to apply to prepayments for natural gas

Section 3213 of the House bill states that the arbitrage rules would not apply when at least 85 percent of a natural gas purchase is used by Governmental utilities in the State where the issuer of the bonds is located. In addition, the provision would be less restrictive on the limits it places on customers and on the use of swap transactions. The 85-percent limit would apply to bonds issued after the date of enactment.

GAO study of effectiveness of alternative motor vehicles and fuel incentives

Section 2502 of the Senate amendments would require the U.S. General Accounting Office (GAO) to study the effectiveness of alternative motor vehicle and fuel incentives and conservation and energy efficiency incentives. The provision calls for a comparison of revenue cost to energy conserved and environmental benefits received. The study, which would encompass an examination of the distribution of incentive beneficiaries, is to provide an annual report beginning no later than December 31, 2002.

Credit for production of Alaskan natural gas

Section 2503 of the Senate amendments would provide a tax credit for Alaskan natural gas when the average monthly price exceeds $3.25 per million Btu at the Alberta, Canada, pipeline hub. If the price at the hub exceeds $4.875 (indexed for inflation), any prior credits can be recaptured. The credit could be claimed on the later of (1) January 1, 2010, or (2) the initial date of the interstate transportation of the Alaskan natural gas. The credit, which would take effect upon enactment, could be claimed against regular and minimum tax.

Sale of gasoline and diesel fuel at duty-free sales enterprises

The Senate amendments would change Title 19, Section 1555(b), of the U.S. Tax Code to treat gasoline sold from a duty-free enterprise as goods not for export.

Expanded exemption from aviation fuels excise taxes for aerial applicators

Section 2506 of the Senate amendments would expand the exception from aviation fuels excise taxes for crop dusters to include fuel used between farms and airfields and would grant the aerial applicator the exclusive right to the refund. The amendment would affect aerial applicators from 2001 through 2003.

Regional Transmission Organizations and Market Design

The FERC has taken 3 measures over the past 6 years to address discriminatory transmission practices. Such practices include the potential of a utility to use the transmission system it owns to prevent the transmission of energy from competing generation or unfairly charging for the transmission service. The latest FERC measure, moreover, addresses the problem of inconsistent market design and administration through transmission service contracts, wholesale markets (such as day-ahead and real-time markets), congestion pricing methodology, capacity requirement, transmission ownership, price hedging tools, and interconnection charges.

The first measure was implemented in FERC Orders 888 and 889, issued in 1996. The FERC mandated that utilities open their transmission systems to competing power providers on a nondiscriminatory basis and provide an Open Access Same-Time Information System (OASIS). The purpose of an OASIS is to level the playing field by making the same transmission information, such as available transmission capacity, available at the same time for all market participants. Nevertheless, the FERC felt that transmission-owning utilities still found ways to discriminate against competing generators.

The FERC also decided that engineering and economic inefficiencies were inherent in current operation systems because of a lack of regional coordination of an interconnected grid. The Commission called for the formation of Regional Transmission Organizations (RTOs), which were to improve grid reliability and market performance, remove opportunities for discriminatory practices, and provide for less regulation. Improved market performance would include regional transmission pricing, improved congestion management, more accurate calculations for total transmission capability and available transmission capability, better management of parallel path flows (i.e., when electricity flows along multiple paths to its destination), lower transactions costs, and State retail access programs [*1*].

In the second measure, the FERC declared in Order 2000 that, in order to accomplish its goals, an RTO must satisfy four characteristics: independence, scope and regional configuration, operational authority, and short-term reliability. Furthermore, the RTO must perform eight functions: tariff design and administration, congestion management, parallel path flow, ancillary services, OASIS management and calculation of total and available transmission capability, market monitoring, planning and expansion, and interregional coordination. Utilities were to join and have operational RTOs by December 2001.

The implementation of Order 2000 has been slow, however, and only one functioning RTO, the Midwest Independent System Operator (MISO), has been formed to date. This has been due in part to unclear rules concerning the formation, structure, and operation of an RTO and unclear rules regarding market design. Market participants have been reluctant to commit to something they feel is ill defined, and those willing to commit have struggled to reconcile their business interests with the ideal proposed by the FERC. Consequently, the FERC began a series of discussions, conferences, and working groups to gather feedback and input from the industry. Those efforts resulted in the third measure, the Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) issued on July 31, 2002. The RTO remains the cornerstone of the FERC plan to eliminate transmission discrimination and market inefficiencies in the SMD and puts forth the design as a "cookbook" for a well-functioning wholesale market.

The FERC has listed the following as objectives of its SMD proposal [*2*]:

- Establish a single flexible transmission network access service, with a single open-access transmission tariff that applies to all wholesale and retail transmission customers
- Require that transmission be operated by an independent entity and that public utilities operating imbalance energy markets and transmission systems be independent of market participants
- Adopt location marginal pricing (LMP)—a market-based method for congestion management—and provide tradable financial rights (congestion revenue rights) as a means to lock in a fixed price for transmission

- Facilitate real-time and day-ahead markets
- Establish procedures to monitor and mitigate market power
- Facilitate competitive markets by establishing procedures to assure, on a long-term regional basis, that markets will develop adequate transmission, generation, and demand-side resources
- Establish an access charge to recover embedded transmission costs that would be a demand charge billed on a customer's load ratio share of the transmission provider's costs and would be paid by any entity taking power off the grid
- Require that customers receive the same level and quality of service under the SMD that they receive under their current contracts, to the greatest extent feasible
- Adopt a new transmission pricing policy
- Provide for fair treatment of transmission capacity reserved for reliability
- Create a formal role for State representatives to participate in the decisionmaking processes of RTOs or other regional security and reliability entities
- More explicitly state in the *pro forma* tariff the obligations of transmission providers to comply with all appropriate standards for ensuring system security and reliability.

The SMD would be implemented in two stages. The first stage would require all public utilities that own, operate, or control interstate transmission facilities to place all customers, including bundled retail customers, under their open-access transmission tariffs. The second stage would implement the new market design and revised open access transmission tariff (the SMD Tariff). The Commission takes the approach of providing incentives through the market design for industry entities to join an RTO. The SMD also proposes penalties, such as a loss of market-based rates, for those that do not join an RTO. Furthermore, those that do not join an RTO must contract with an independent entity to operate their transmission facilities. The Commission proposes that the Interim Tariff must be filed by July 31, 2003, to become effective by September 30, 2004. The SMD Tariff would be filed by December 1, 2003, to become effective no later than September 30, 2004.

The SMD proposal has been controversial. Although 23 States have endorsed the FERC's effort to eliminate transmission system discrimination in order to create a truly competitive bulk power market [*3*], other States are decidedly against the plan and the perceived usurpation of their authority by the Federal Government. Many western and southeastern States with relatively cheap power are worried that being forced to participate in a large competitive electricity market will raise the price of power for their consumers. They are concerned that sales to States with more expensive power will deplete their cheap power resources, and that their customers will be forced to pay for new transmission lines to benefit the residents of other States. It is unclear to them how the market would work in regions with large Federal Power Authorities and other public power utilities if those utilities were not required to participate in the RTO.

Because this is only a proposed ruling, no measures were taken to account for it in *AEO2003*. The States that oppose the FERC's SMD proposal are calling for more regional cost-benefit analyses and asking the FERC to address their regional issues before any market design regulations are implemented. Furthermore, members of the U.S. House of Representatives have submitted draft legislation that could strip the FERC of its authority to require utilities to join an RTO. In addition, the FERC has recently issued two new NOPRs for the implementation of interconnection standards for large and small generators, designed to work in tandem with the SMD rulemaking to improve the operation of competitive bulk wholesale electricity markets.

Extension of Wind and Biomass Production Tax Credits

The Renewable Energy Production Tax Credit (PTC) was first established by the 1992 EPACT. The PTC is an inflation-indexed tax credit given to qualifying wind and biomass energy facilities for the first 10 years after the facility is commissioned. The tax credit was originally set at 1.5 cents for every kilowatthour sold from a qualifying facility and has gradually been adjusted for inflation, to the current level of 1.8 cents per kilowatthour sold. A qualifying facility must have been commissioned after the law's enactment in 1992 and before the law's current expiration date. The law was allowed to expire briefly in 1999 but was extended retroactively to December 31, 2001, when it was allowed to expire again. In March 2002, the PTC was, once again, retroactively extended (to December 31, 2003) by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147).

The tax credit applies to all wind power facilities owned by a tax-paying entity and to all tax-paying biomass power facilities that use either a closed-loop or poultry waste fuel source. (A biomass fuel source is considered "closed loop" if it is planted specifically for use in energy production and is not a waste or surplus product from some other activity.) For non-tax-paying entities, such as municipal electric utilities, a separate provision, the Renewable Energy Production Incentive (REPI), provides a direct payment based on annual energy production. Although designed to be comparable with the PTC, the exact level of the REPI is contingent on annual appropriations from Congress, and it is considered a less certain subsidy than the PTC.

The value of the PTC is reduced if the facility owner also receives certain types of State or local financial incentives, such as initial-cost buydowns or investment tax credits. Wind and biomass facilities, as well as other renewable energy facilities, also benefit from an accelerated capital cost depreciation schedule of 5 years. *AEO2003* incorporates the original PTC and all extensions by providing the tax credit, as well as the 5-year depreciation allowance, to all new wind capacity construction through 2003. Because all new capacity additions are assumed to be owned by tax-paying entities, the REPI is not explicitly represented.

Further extension of the PTC to 2007 is included in both the House and Senate versions of the Energy Policy Act of 2002. The House version would expand eligibility for the credit to facilities using landfill gas and certain "open-loop" biomass fuels, including agricultural residue and landscaping trimmings. The Senate version would include those facilities and would also expand eligibility to additional agricultural animal wastes and to geothermal and solar facilities. The Senate version would further allow assignment of the credit by non-tax-paying entities to certain tax-paying entities. Because they have not been signed into law, none of the provisions in the House or Senate bills is considered in the *AEO2003* reference case.

Energy Provisions in 2002 Farm Bill

Several sections of the Farm Security and Rural Investment Act of 2002 (P.L. 107-171), signed by President Bush on May 13, 2002, have energy market implications. Under the Rural Development title, loans and loan guarantees for rural purchases of solar energy systems are extended to purchases of other renewable energy systems, such as wind generators and anaerobic digesters [*4*]. The Research and Related Matters title authorizes the Agriculture Secretary to grant up to $20 million to colleges, universities, and Federal laboratories for research on production of alcohol, diesel fuel, and other industrial hydrocarbons from agricultural and forest products. The grants are authorized through 2007, and at least half the money must go to alcohol research. Funding for carbon cycle research, which originated under the Agricultural Risk Protection Act of 2000 (P.L. 106-224), is also extended through 2007 [*5*].

The Forest Land Enhancement Program is established in a section of the Forestry title. One of its goals is to increase and enhance carbon sequestration in forests. Funding for the Office of International Forestry, which was originated by the Global Climate Change Prevention Act of 1990 (P.L. 101-624, Title XXIV), is extended through 2007 [*6*].

Title IX of the Farm Security and Rural Investment Act deals directly with energy issues. Development grants are available to cover up to 30 percent of the cost of a biorefinery. Biorefinery products can include fuels, chemicals, and/or electricity. Grants are offered for biodiesel fuel education. Several sections are intended to help rural businesses become more energy efficient and to use alternative sources of energy. Audits of rural businesses to provide recommendations to improve energy efficiency and to use renewable energy are eligible for grants for up to 75 percent of cost. If a rural business wishes to upgrade its energy systems, the Department of Agriculture may offer loans, loan guarantees, and/or grants. A grant cannot be more than 25 percent of project cost, and the total of grants and loans cannot be more than 50 percent of project cost. Interest on a loan is to equal the prevailing Treasury security rate. The Agriculture and Energy Secretaries are to cooperate on developing and promoting rural applications of hydrogen and fuel cell technology. In addition to the biorefinery grants, another section of Title IX makes more funding available for biomass research and development. The EPA is directed to coordinate research on carbon flux in soil and plants and exchange of other greenhouse gases due to agriculture [*7*].

Section 9002 requires Federal agencies to give purchasing preference to biobased products. Biobased products must be available in reasonable time and at a reasonable price and must meet applicable performance requirements. The rules apply to purchases of products with a total value of $10,000 or more per fiscal year. It does not apply to motor vehicle fuel or electricity.

Section 9010 extends the Commodity Credit Corporation (CCC) bioenergy program through 2006. This program, established in 2000, awards subsidies based on feedstock prices for new or expanded ethanol or biodiesel production. In 2001, the CCC paid out $32.7 million for 141.7 million gallons of ethanol production and $7.9 million for 6.4 million gallons of biodiesel production. Through the third quarter of 2002, the CCC had paid $40 million for 146.5 million gallons of ethanol and $7.5 million for 5.7 million gallons of biodiesel [*8*]. The total subsidy is limited to $150 million per year.

The extension of the CCC bioenergy program is likely to have the largest impact because of its funding level and structure. The program rewards expanded production of ethanol from grain and biodiesel from vegetable oil or animal fats. All of these are known commercial technologies. The grants and loan programs for biomass fuels research and for biorefineries are likely to aid the development of cellulose ethanol technology, which is still a pilot technology. It is expected that cellulose ethanol will not be marketed in large quantities until after 2010. The carbon cycle research and forestry programs do not have a direct effect on energy production, but the results of those initiatives may help to shape the Nation's climate change policy.

Emissions Standards for Non-road Engines

In October 1998, the EPA finalized new emissions standards for mobile non-road diesel compression-ignition (CI) engines used in a wide range of non-road construction, agricultural, and industrial equipment and some marine applications, including bulldozers, tractors, forklifts, and sailboat auxiliary propulsion units [*9*]. The Tier 2 engine standards are based on horsepower rating and are to be phased in from 2001 to 2006. The standards are applicable to all engine sizes and require on average a 30-percent reduction in emissions of nitrogen oxides (NO_x) and nonmethane hydrocarbons (NMHCs) from the existing Tier 1 standards. Yet more stringent Tier 3 standards for engines rated over 50 horsepower take effect from 2006 to 2008, requiring on average a 40-percent reduction in emissions of NO_x and NMHCs from Tier 2 standards. The Tier 3 standards are expected to lead to implementation of control technologies similar to those that will be used by manufacturers of heavy-duty engines to comply with the 2004 heavy vehicle engine standards. The final rule applies to all new equipment built after the start date for an engine category (1999 to 2008, depending on the category) and does not apply to existing non-road equipment.

In addition to standards for land-based non-road engines, the EPA adopted similar emissions standards for marine diesel engines in December 1999 [*10*]. These standards take effect between 2004 and 2007, depending on the size of the engine. The final rule will reduce emissions of NO_x and particulate matter (PM) from new marine diesel engines rated over 50 horsepower, which are used for propulsion and auxiliary power on commercial vessels in a variety of marine applications, including fishing boats, tug and towboats, dredgers, coastal and Great Lakes cargo vessels, and oceangoing vessels. Standards for marine engines under 50 horsepower were established in the October 1998 ruling.

In April 1998, the EPA finalized emissions standards for NO_x, hydrocarbons (HC), carbon monoxide (CO), PM, and smoke for newly manufactured and remanufactured locomotive engines [*11*]. Under the final ruling, three separate sets of emission standards have been adopted. The first set of standards applies to remanufactured locomotives originally manufactured between 1973 and 2001; the second set applies to locomotives manufactured from 2002 to 2004; and the final set applies to locomotives manufactured in 2005 and beyond. The new standards are expected to achieve approximately a two-thirds reduction in NO_x emissions and a 50-percent reduction in emissions of HC and PM.

In September 2002, the EPA established emissions standards for several types of previously unregulated non-road engines and vehicles [*12*]. The standards apply to large industrial spark-ignition (SI) engines rated over 25 horsepower, non-road recreational vehicles such as snowmobiles and all-terrain vehicles (ATVs), and recreational marine diesel engines over 50 horsepower used in yachts and cruisers. The new standards, to be phased in from 2004 to 2009, will limit emissions of NO_x, HC, and CO from the affected engines. Manufacturers will be required to apply existing engine technologies, such as modified two-stroke engine technology, changing from two-stroke to four-stroke engine technology, or improved diesel combustion and aftercooling. When the standards are fully implemented, reductions of 72 percent in HC emissions, 80 percent in NO_x emissions, and 56 percent in CO emissions from the affected engines are expected by 2020.

The effects of the EPA's new non-road vehicle emissions standards are not represented in *AEO2003* because of uncertainties about the types of pollution control technologies to be implemented and their associated impacts on new vehicle efficiency. Several pollution control technologies are currently used to manage emissions in heavy-duty highway vehicles, including exhaust gas recirculation, ignition timing, and injection timing retard. These technologies are expected to be adopted by diesel engine manufacturers to meet non-road emission standards. It is unclear at this time which technologies will be implemented and what the overall impact will be on energy use by non-road vehicles.

California Renewable Portfolio Standard

On September 12, 2002, Governor Gray Davis signed California Senate Bill (S.B.) 1078, establishing a State renewable portfolio standard (RPS) effective January 1, 2003. California's RPS requires its three investor-owned electric utilities (IOUs) to increase their share of renewables from approximately 10 percent today by at least 1 percent a year, until renewables equal 20 percent of retail sales, to be achieved no later than 2017. Overall, the baseline is composed of renewables under contract to IOUs in 2001, including small hydropower (30 megawatts or less) and nonthermal uses of municipal solid waste. Eligible renewables for the RPS increases are biomass, digester gas, and nonthermal municipal solid waste conversion; fuel cells using renewable energy sources; geothermal; landfill gas; ocean thermal; ocean tidal and ocean wave; photovoltaics; solar thermal electric; small hydropower that does not require increased water diversion; and wind power. There is a clear preference for renewable energy sources obtained in the State. The cost difference between the more expensive renewables and least-cost alternatives will be paid by ratepayers from public goods charges included in retail electricity rates.

It is unclear at this time which and how many additional renewable generating facilities will result from California's newly enacted RPS, and when the facilities will be built. California has not yet estimated the expected renewable energy additions under its RPS. Moreover, the IOUs are excused from meeting the RPS until the California Public Utility Commission declares them creditworthy—an important qualification given the bankruptcy and financial challenges facing the utilities today. Further, the RPS is effective only to the extent that public goods charges can meet the higher cost of renewables. Finally, S.B. 1078 is a supplement to California's already existing renewables mandate, A.B. 1890, which remains in force. The *AEO2003* projections considered both S.B. 1078 and A.B. 1890.

California Carbon Standard for Light-Duty Vehicles

In July 2002, California Assembly Bill (A.B.) 1493 was signed into law. The bill requires that the California Air Resources Board (CARB) develop and adopt, by January 1, 2005, a maximum feasible carbon pollution standard for light-duty vehicles. In estimating the feasibility of the standard, the CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the requirement. The standard will apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The bill does not mandate the sale of any specific technology and, in addition, prohibits the use of the following as options for carbon reduction: mandatory trip reduction; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; a reduction in vehicle weight; or a limitation or reduction on the speed limit on any street or highway in the State. Consequently, A.B. 1493 will rely heavily on vehicle efficiency improvement or a switch to low-carbon fuels to achieve the carbon emission standard.

If it is determined that low-carbon alternative fuels are not a feasible solution, A.B. 1493 will become in effect a fuel economy standard, which is facing considerable opposition from the auto industry. Current suits filed against California's Low Emission Vehicle Program (LEVP) state that the program attempts to preempt the Federal Government's authority to set fuel economy standards. The Bush Administration endorses the auto industry's argument and has filed a brief in the United States Court of Appeals stating that the Federal Government holds exclusive jurisdiction in the regulation of fuel economy standards. If the fuel economy stipulations outlined in the LEVP are overturned, it is likely that those proposed for A.B. 1493 will also be overturned. Given the opposition in the courts, the A.B. 1493 carbon pollution standard is not represented in *AEO2003*.

Issues in Focus

EIA Analyses of Energy Legislation Provisions

The U.S. House of Representatives passed H.R. 4, The Securing America's Future Energy (SAFE) Act of 2001, on August 2, 2001. In addition to addressing energy conservation, efficiency, and research and development, H.R. 4 encourages the development of domestic oil and gas resources, provides tax credits for alternative energy products, and requires an increase in average automobile fuel efficiency. In December 2001, the U.S. Senate Committee on Energy and Natural Resources made a request to the Energy Information Administration (EIA) for analyses of various proposals contained in provisions of H.R. 4 and Senate Bill 1766 (S. 1766), the Energy Policy Act of 2002 [*13*].

The National Energy Modeling System (NEMS) was used as the primary tool for the analyses, based on the reference case prepared for the *Annual Energy Outlook 2002* (*AEO2002*). EIA was asked to analyze the "potential costs and benefits of proposed legislation to update and revise our national energy strategy," specifically with regard to potential impacts on gross domestic product (GDP), energy consumption and production, energy prices, dependence on foreign imports, energy infrastructure, and emissions of greenhouse gases and air pollutants such as sulfur dioxide and nitrogen oxides.

In response to the Committee's request, EIA prepared six reports describing the results of its analyses [*14*]:

- *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R. 4 Section 124, 142, and 143)*, SR/OIAF/2002-01 (February 2002)
- *The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S. 1766 on U.S. Energy Markets*, SR/OIAF/2002-02 (February 2002)
- *Impacts of a 10-Percent Renewable Portfolio Standard*, SR/OIAF/2002-03 (February 2002)
- *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*, SR/OIAF/2002-06 (March 2002)
- *Analysis of Corporate Average Fuel Economy (CAFE) Standards for Light Trucks and Increased Alternative Fuel Use*, SR/OIAF/2002-05 (March 2002)
- *Impacts of Energy Research and Development (S. 1766 Sections 1211-1245, and Corresponding Sections of H.R. 4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing*, SR/OIAF/2002-04 (March 2002).

The six analyses are summarized below.

Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products

EIA's analysis addressed the provisions of H.R. 4 and S. 1766 that pertain to efficiency in the residential, commercial, and industrial sectors. S. 1766 sets specific standards for residential-sized central air conditioners and heat pumps, torchiere lighting, illuminated exit signs, and low-voltage dry-type transformers. H.R. 4 sets specific requirements for Federal purchases of residential-sized central air conditioners and heat pumps. S. 1766 also allows the U.S. Department of Energy (DOE) to enter into voluntary agreements with industrial entities to reduce industrial-sector energy intensity by 2.5 percent per year over the next 10 years. The estimated effects of the provisions were presented where quantitative analysis was feasible. Because EIA does not currently have comprehensive data sources for estimating the quantities or efficiency levels of equipment in use for illuminated exit signs and transformers, quantitative analysis of those provisions was precluded, and a qualitative discussion was presented.

The analysis found that, while the higher efficiency standards for air conditioners and heat pumps would reduce energy consumption and carbon dioxide emissions, the costs to consumers of the more efficient equipment would be higher than the energy savings realized. For example, over the life of existing and new equipment installed between 2002 and 2020 (and that continues to operate through 2036), consumers would reduce electricity consumption by 799 billion kilowatthours under the S. 1766 standard (a seasonal energy efficiency ratio [SEER] of 13) relative to the current standard (SEER of 10). *AEO2002* assumed a 12 SEER standard. Carbon dioxide emission savings over the 2002-2020 period were estimated at 105 million metric tons carbon equivalent. The net present cost to consumers (projected expenditures exceeded savings) was estimated at $0.6 billion, assuming a real 7-percent discount rate. In the case of the torchiere standard proposed in S. 1766, 138 billion kilowatthours of cumulative electricity savings was estimated through 2020 relative to the reference case.

The Senate has amended S. 1766 to include an air conditioning SEER of 12, as proposed by DOE. In EIA's analysis report, comparison of a 12 SEER standard with the current 10 SEER reduced the estimated energy savings by about 26 percent relative to the savings estimated with a 13 SEER but provided a positive net present value to consumers (projected savings exceeded expenditures).

Alaskan Oil and Natural Gas

EIA's analysis addressed the Alaskan oil and natural gas provisions of H.R. 4 and S. 1766. The Arctic National Wildlife Refuge (ANWR) provision in H.R. 4 called for the establishment of a leasing program that would open ANWR to oil and gas production. The Alaskan natural gas pipeline provision in S. 1766 would authorize the Secretary of Energy to guarantee up to 80 percent of the principal of any loan made to finance construction of a pipeline. The size of the loan guarantee would be capped at $10 billion. This provision also called for expedited approval and environmental review of an Alaskan pipeline.

The ANWR analysis assumed that: (1) technically recoverable crude oil resources would be equal to United States Geological Survey (USGS) estimates; (2) first oil production from ANWR would occur no earlier than 2011; and (3) ANWR natural gas resources would not be developed before 2020 because of a lack of infrastructure. The Alaskan natural gas pipeline analysis assumed that the expedited approval process would shorten the pipeline planning and construction period by 2 years, and that the loan guarantee would reduce the pipeline construction trigger price from $3.50 per thousand cubic feet to $3.05 per thousand cubic feet.

Using the USGS mean ANWR resource estimate, the analysis found that opening up ANWR would reduce U.S. petroleum import dependence from 62 percent of total 2020 oil consumption to 60 percent, as a result of the projected ANWR production of 1.92 million barrels per day in 2020. High and low ANWR resource cases projected 2020 oil production levels of 2.58 and 1.62 million barrels per day, respectively, and U.S. petroleum import dependence levels of 57 and 61 percent.

Under *AEO2002* reference case assumptions, expedited approval and loan guarantees for an Alaskan natural gas pipeline were projected to bring the pipeline into full operation by the end of 2020 at 4 billion cubic feet per day (1.46 trillion cubic feet per year), and lower 48 wellhead gas prices were projected to be lower by 6 cents per thousand cubic feet. Under *AEO2002* slow oil and gas technology case assumptions—which result in natural gas price projections that are 25 percent higher than the reference case projections in 2020—expedited approval and loan guarantees were estimated to bring the pipeline into full operation by 2015, reducing lower 48 wellhead gas prices in 2020 by 32 cents per thousand cubic feet.

10-Percent Renewable Portfolio Standard

EIA's analysis addressed the Renewable Portfolio Standard (RPS) provision of S. 1766 and also studied the impacts of an RPS patterned after the one called for in S. 1766, but with the required share of renewable fuels in the Nation's total use of energy for retail electricity generation based on a 20-percent RPS by 2020 rather than the 10-percent RPS called for in S. 1766. The following assumptions were made in the 10-percent RPS case:

- The program begins in 2003, and the required renewable share grows from 2.5 percent of retail electricity sales in 2005 to 10 percent in 2020 in annual increments of 0.5 percentage point. The shares required for 2003 and 2004 are to be set by the Secretary of Energy at a value under the 2.5 percent required in 2005. The 2003 share was assumed to be set at 0.5 percent, and the 2004 share at 1.5 percent. The program would expire (sunset) on December 31, 2020.
- All power sellers with retail sales of 500 million kilowatthours per year are required to hold credits. Small utilities with retail sales below 500 million kilowatthours per year are exempt.
- Qualifying renewable facilities include all new renewable generation facilities (including upgrades, repowerings, and co-firing changes) placed in service on or after January 1, 2002. Qualifying fuels include hydroelectric, geothermal, biomass, solar, wind, ocean, and landfill gas. Renewable facilities in service before January 1, 2002, do not receive credits.
- A civil penalty of up to 3 cents per credit may be applied for each required renewable credit not submitted by a covered retail electricity supplier.

The analysis indicated that the sunset and civil penalty provisions would have a significant impact on the amount of renewables stimulated by the RPS, combining to limit the amount of renewables developed. Under the *AEO2002* reference case assumptions, the 10-percent RPS called for would not be achieved. The projections suggested that, as the end of the program approached (December 31, 2020), electricity suppliers would choose to pay the penalty rather than invest in additional renewables that would be eligible for credits only for a few years. The level achieved by 2020 was projected to be 8.4 percent.

The 10-percent RPS requirement was projected to lead to greater generation from wind, biomass, and to a lesser extent geothermal resources. By 2020, wind generation was projected to reach 162 billion kilowatthours, up from 24 billion kilowatthours in the reference case. In the reference case, 9 gigawatts of wind capacity would be on line in 2020, compared with 52 gigawatts in the RPS case. Conversely, the imposition of the RPS would lead to lower generation from natural gas and coal facilities. By 2020 both coal- and natural-gas-fired generation were projected to be 6 percent below the levels expected in the reference case.

The RPS was projected to have fairly small impacts on electricity prices and producer costs. The retail electricity price impacts of the RPS were projected to be small because the price impact of buying renewable credits and building the required renewables was projected to be relatively small when compared with total electricity costs and to be mostly offset by lower natural gas prices when gas consumption was reduced. The average retail price of electricity in 2020 was projected to be 6.6 cents per kilowatthour in the RPS case, compared with 6.5 cents in the reference case. The net increase in cumulative resource costs to the industry from 2000 to 2020 in the RPS case relative to the reference case was estimated at 1 percent, or $7 billion.

Renewable Fuels and MTBE

EIA's analysis addressed the provisions of S. 1766 related to a renewable fuels standard (RFS) and the gasoline additive methyl tertiary butyl ether (MTBE). The RFS provision of S. 1766 sets a requirement for production of 5 billion gallons of renewables-based transportation fuel a year by 2012. The MTBE provision requires a complete phaseout within 4 years and gives the option to States to waive the oxygen requirement for reformulated gasoline (RFG). The analysis showed that, between 2006 and 2009, the market demand for ethanol as a gasoline blending component exceeded the RFS requirement when a full Federal ban on MTBE was assumed. When only the RFS was assumed, the requirement was not projected to be met until 2010. After 2005, the provisions of S. 1766 were projected to add about 4 cents per gallon (real 2000 dollars) to the average price of gasoline through 2020 and between 9 and 10.5 cents per gallon to the price of reformulated gasoline (RFG), relative to the reference case projections. A more detailed discussion of the analysis is presented in the next section of "Issues in Focus."

Fuel Economy Standards for Light Trucks

EIA's analysis addressed the provisions in H.R. 4 mandating a 5-billion-gallon reduction in gasoline consumption by light trucks (including sport utility vehicles) between 2004 and 2010 and in S. 804 (the Automobile Fuel Economy Act of 2001, analyzed as a placeholder for yet-to-be-drafted CAFE provisions of S. 1766) raising the CAFE standard for light trucks to 27.5 miles per gallon by 2008. With those assumptions, the analysis indicated that smaller light trucks (less than 8,500 pounds gross vehicle weight) would meet the proposed CAFE standard by 2014, but the expected physical capacity and engine characteristics of larger light trucks (over 8,500 pounds) through 2020 would preclude the possibility of meeting the standard overall. Light truck prices would be nearly $1,300 above the reference case by 2020. The reduction in light vehicle fuel demand would reduce net petroleum imports by 5 percent (830,000 barrels per day) by 2020 relative to the reference case. Because they could not meet the standards, light truck manufacturers would pay almost $10 billion in CAFE fines over the projection period.

Energy Research and Development

EIA's analysis addressed the provisions of S. 1766 and H.R. 4 that pertain to research, development, and deployment goals for a range of energy technologies. No clear quantitative relationship was found between spending for research and development (R&D) and the development and market penetration of more efficient energy-consuming or energy-producing technologies. Some technologies have benefited from government R&D in the past, but others have not. It is not possible, based on proposed levels of funding only, to determine the future success or failure of a particular program.

The analysis found that the S. 1766 R&D goals are not uniform. For some programs, the goals are ambitious, promoting the competitiveness of new technologies (such as solar thermal generation) with cheaper existing technologies. In other instances, the goals are not nearly as stringent, seeking continued good performance, as with nuclear generation, or pursuing promising research, as with superconductivity applications. In the discussion of these programs, EIA assumed that R&D has the implicit goal of commercial penetration, or at least some commercial benefit. The progress of the programs described in the report was assessed with this goal in mind. Two separate topics—the Price-Anderson Act authorizing limits on liability of operators of Federal nuclear facilities and relicensing of hydroelectric plants—were also analyzed.

Analysis of MTBE Phaseout and Renewable Fuels Standard Proposals in the Energy Policy Act of 2002

Two proposals contained in provisions of the Energy Policy Act of 2002 could affect U.S. markets for petroleum products in ways that would vary from the *AEO2003* projections. The first is a proposed Federal ban on the fuel additive MTBE. The second is a proposed RFS that would set a requirement for production of renewables-based transportation fuel.

MTBE is widely used as a blending component in motor gasoline, accounting for about 3 percent of the total volume of gasoline sold in the United States in 2001. Initially, MTBE was added to gasoline to boost octane, which helps prevent engine knock. Then, in the 1990s, it began to be used to meet the 2-percent oxygen requirement for reformulated gasoline (RFG). The Clean Air Act Amendments of 1990 (CAAA90) require RFG to be used year-round in cities with the worst smog problems. In the past few years, however, the use of MTBE has become a subject of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels.

MTBE is the oxygenate used in almost all RFG outside of the Midwest. Ethanol, which is currently used in the Midwest as an oxygenate in RFG and as an octane booster and volume extender in conventional gasoline, would be the leading candidate to replace MTBE. Even without the Federal oxygen requirement on RFG, refiners would need to make up for the loss of volume and octane resulting from a ban on MTBE. Reliance on other oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), is assumed to be limited because of concerns that they may share the characteristics of MTBE that lead to water problems.

The RFS proposal in the Energy Policy Act of 2002 would require that specific quantities of renewable fuels be produced by refiners. The RFS schedule proposed would require 2.3 billion gallons of renewable fuel by 2004, increasing to 5.0 billion gallons by 2012. Ethanol is the product most likely to be used to satisfy the mandate. In addition to ethanol derived from corn, new technologies are being developed to produce "biomass ethanol" from plant fiber (cellulose). The proposed legislation includes a provision that would encourage biomass ethanol production by giving credit for 1.5 gallons toward the RFS for every gallon of biomass ethanol produced. The credit would be likely to reduce renewable fuels production under the RFS schedule by about 10 million gallons in 2003, 130 million gallons in 2012, and 370 million gallons in 2020. Biodiesel, a fuel produced from vegetable oil or animal fat, could also contribute to meeting the RFS requirements, but even with the most optimistic assumptions of market penetration, it would be unlikely to make up more than 10 percent of the mandated total.

In response to requests from the Senate Committee on Energy and Natural Resources, EIA analyzed the effects on energy supply, demand, and price projections of (1) simultaneous implementation of the proposed RFS and a full Federal ban on MTBE and (2) the proposed RFS without an MTBE ban. The two analysis cases were compared against a policy-neutral reference case based on the *AEO2002* midterm forecasts of energy supply, demand, and prices through 2020.

The analysis cases assumed that certain States would choose to opt out of the CAAA90 2-percent oxygen requirement for RFG. For the combined RFS/MTBE ban case it was assumed that States on the East and West Coasts would exercise the Energy Policy Act's provision to grant governors the authority to waive the oxygen requirement. For the RFS only case it was assumed that the oxygen requirement on RFG would be repealed nationally.

In this analysis the reference case differed from the reference case in *AEO2002* in one important respect. In order to evaluate the impact of the RFS alone, no State-level restrictions on MTBE were included. At the time of the study, legislation had been passed in 14 States (Arizona, California, Colorado, Connecticut, Indiana, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington) that would restrict the use of MTBE in gasoline beginning in 2004 (currently 17 States have banned it). *AEO2002* noted that, although State MTBE legislation or executive orders had been passed, there was considerable uncertainty as to when the requirements would be implemented. In California, for example, officials have postponed the ban on MTBE by 1 year, in part because the U.S. Environmental Protection Agency (EPA) denied the State's request for an oxygen waiver.

RFS and Full MTBE Ban

In general, net petroleum imports in the RFS/MTBE ban case were projected to be about 1 percent lower than in the reference case. Net petroleum imports were 156,000 barrels per day below reference case levels in 2006 (a reduction of 1.2 percent) and 227,000 barrels per day lower in 2020 (a reduction of 1.4 percent). The lower import projections translate into a reduction in the import share of petroleum consumption of between 0.4 and 0.7 percent.

Before 2006, the projected average national prices of all gasoline and of RFG were not significantly different from those in the reference case. After the Federal MTBE ban was assumed to become effective in 2006, the national average price of all gasoline was projected to be about 4 cents per gallon higher and the national average RFG price between 9.0 and 10.5 cents per gallon higher than in the reference case.

RFS Only

In the RFS only case, with no increase in ethanol blending requirements due to a complete ban on MTBE, the projected level of renewables was effectively set by the RFS schedule. After 2012, the renewable fuels production target was determined as the percentage of total highway demand expected to be met by renewables in 2012. By 2020, total renewables consumption in this case was projected to be 40 million gallons per year higher than in the RFS/MTBE ban case, because the relatively high gasoline prices associated with that case had a slight dampening effect on gasoline demand, which in turn reduced blending.

The projected reduction in net petroleum imports (relative to the reference case) was smaller than in the RFS/MTBE ban case: 61,000 barrels per day in 2006 and 189,000 barrels per day in 2020, as compared with 156,000 barrels per day in 2006 and 227,000 barrels per day in 2020 in the RFS/MTBE ban case. MTBE imports, allowed in the RFS only case but not in the RFS/MTBE ban case, accounted for most of the difference.

Projected prices in the RFS only case were well below those in the RFS/MTBE ban case. In the absence of an MTBE ban, more ethanol was available to be blended into conventional gasoline instead of being pulled into RFG blending to help replace MTBE. Beginning in 2006, projected RFG prices in the RFS only case rose gradually to about 1 cent per gallon higher than the reference case by 2012, where they remained through 2020. The impact on the price of all gasoline remained below 0.5 cent per gallon through 2020.

RFS and Partial MTBE Bans

After the initial study was conducted, a followup study was requested to address concerns about input assumptions in the initial reference and analysis cases. In response, EIA conducted further analyses using the *AEO2002* reference case assumption that current MTBE restrictions or bans would become effective in the 14 States that had since passed legislation. The RFS/MTBE ban case was also modified by assuming that the provision for governors to waive the ban would be exercised to the extent that only 87 percent of all MTBE use would be banned. In another case requested by the Committee, it was assumed that all the New England States would ban MTBE, bringing the total to 19 States.

The analysis found that market demand for ethanol in the revised reference case would be 260 million gallons greater than the amount specified by the RFS schedule in 2004, due to the implementation of State-level MTBE restrictions in 14 States. In the 19-State MTBE ban case, assuming that the oxygen requirement would be maintained and that other Northeastern States with RFG markets would follow suit and ban MTBE in the same year, an additional 540 million gallons of ethanol would be required in 2004.

In the analysis case assuming both the proposed RFS and an 87-percent MTBE ban, ethanol use for gasoline blending in 2006 was projected to be 390 million gallons per year higher than in the 19-State MTBE ban case and 880 million gallons per year higher than in the modified reference case (with a 14-State MTBE ban). The projected level of ethanol blending in the RFS/87-percent MTBE ban case was 3.62 billion gallons, 720 million gallons above the specified RFS target for 2006.

The inclusion of State-level restrictions in the modified reference case resulted in projection of average annual prices for all gasoline that were roughly 2 cents per gallon higher than projected in the original reference case (without the restrictions) and RFG prices 3.5 to 4 cents per gallon higher. The price impact of implementing the 14 State-level restrictions was reduced slightly over time, with incremental changes at refineries expected to minimize the impact of the lost MTBE volumes. In the 19-State MTBE ban case, the average annual price of all gasoline was projected to be about 0.5 cent per gallon higher and the RFG price 2 cents per gallon higher than in the modified reference case. In the RFS/87-percent MTBE ban case, the projected average gasoline price in 2006 was about 0.5 cent per gallon higher than in the 19-State MTBE ban case, and the RFG price was about 2 cents per gallon higher. The projected price increases in the RFS/87-percent

MTBE ban case translate into higher annual fuel costs for consumers between 2006 and 2020: $2.06 billion per year on average relative to the projections in the modified reference case and $980 million per year relative to the 19-State MTBE ban case.

When the RFS provision was added to the modified reference case (including the 14 State-level MTBE restrictions occurring in 2004 but with no Federal ban on MTBE), the projections for renewable fuel consumption before 2006 were above the RFS targets and identical to those in the modified reference case. After 2006, renewable fuel consumption for transportation was essentially determined by the RFS targets adjusted for the biomass ethanol credit: 60 million gallons below the RFS target for 2006 and 130 million gallons below the 2012 target (but still in technical compliance because of the biomass credits). The 2006 projections in this case were about 100 million gallons above the market demand for ethanol projected in the modified reference case. With incremental growth in the RFS schedule, the difference between the RFS amount (adjusted for the biomass credit) and the market demand projected in the reference case widened to 1.9 billion gallons per year by 2012. The RFS provision without a Federal MTBE ban was projected to raise prices by up to 0.5 cent per gallon for all gasoline and by up to 1 cent per gallon for RFG, implying an annual average cost to consumers between 2006 and 2020 that would be $260 million higher than projected in the reference case.

Ethanol Production Capacity

After the above studies, an additional request was received for an analysis of the industry's ability to increase ethanol production in response to the proposed RFS and how the level of production capacity would influence price. EIA's analysis found that the ethanol industry has more than enough capacity to meet the immediate needs that would result from the RFS and/or a Federal MTBE ban, because 461 million gallons of capacity is under construction and only 2 years is needed to build a new plant. With no fundamental supply constraints expected, the price impacts were similar to those in the previous studies; however, new information gathered on production costs did lead to slightly lower estimates of the price impacts.

Clear Skies Initiative

In February 2002, President George W. Bush proposed a "Clear Skies Initiative" to cut harmful emissions from U.S. electric power plants. At the end of the summer, the Clear Skies Act of 2002 was submitted to Congress to implement the President's strategy as an amendment to the Clean Air Act. The legislation would establish new "cap and trade" programs requiring further reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and new reductions in emissions of mercury from electricity generating facilities.

The proposal would cut SO_2 emissions by 73 percent from current levels by 2018, to an annual cap of 3 million tons, with an intermediate cap of 4.5 million tons in 2010. NO_x emissions would be reduced by 67 percent, to caps of 2.1 million tons in 2008 and 1.7 million tons in 2018. Separate caps are proposed for NO_x emissions in eastern and western States, to address regional haze concerns. Mercury emissions would be reduced by 69 percent, to annual caps of 26 tons in 2010 and 15 tons in 2018. The *AEO2003* reference case projects slight reductions in SO_2 and NO_x emissions over the forecast period as a result of current programs, but the reductions proposed in the Clear Skies Act are much greater. Emissions of mercury have never been restricted, and the reference case projects increases over the forecast period in the absence of any reduction targets.

EIA has previously published a number of multi-pollutant analyses. On the basis of those analyses, EIA expects that implementation of the Clear Skies Act would result in significant additions of emissions control equipment as the dominant compliance option. In an October 2001 analysis of multi-emission reduction strategies [*15*], a case was analyzed assuming 65-percent reductions in emissions of each of the three pollutants, to target levels similar to those in the Clear Skies proposal. In that analysis it was projected that SO_2 scrubbers would be added to 127 gigawatts of coal-fired generating capacity, some form of post-combustion NO_x control would be added to more than 200 gigawatts of coal-fired capacity, and some form of mercury control would be added to nearly 100 gigawatts of capacity. To a smaller extent, the projections showed a decrease in coal use and an increase in natural gas use in the electricity sector. Natural-gas-fired generation was projected to be 9 percent above and coal-fired generation 7 percent below reference case values in 2020. Electricity prices were projected to be slightly higher over the long term as a result of higher expenditures for emission allowances and higher natural gas use.

A number of uncertainties would have to be considered in any comprehensive analysis of the Clear Skies Act. The evolution of new technologies is particularly unpredictable, and mercury emissions control technologies are relatively new and untested on a commercial scale. In addition, while a substantial amount of data about mercury emissions from coal-fired power plants has been collected in recent years, there is still considerable uncertainty in the measurement of mercury emissions and the extent to which control technologies designed primarily to remove SO_2 or NO_x might contribute to reducing emissions of mercury. It is possible that new, innovative technologies could be developed that would lower the costs of mercury removal, but it is also possible that reducing mercury emissions substantially at some facilities may be more difficult than is currently expected on the basis of the limited data available. Another key uncertainty is the future price of natural gas. If natural gas prices turn out to be higher than expected, new coal-fired plants could become economically attractive, and their higher emissions rates could increase the cost of meeting emission caps and lead to higher electricity prices.

Fuel Use for Electricity Production: EIA Data Revisions in *AEO2003*

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications.

The goal of EIA's comprehensive review was to improve the quality and consistency of its electric power data throughout all data and analysis products. Because power facilities operate in all sectors of the economy (e.g., in commercial buildings, such as hospitals and college campuses, and industrial facilities, such as paper mills and refineries) and use many fuels, any change to electric power data affects data series in nearly all fuel areas and causes changes in a wide variety of EIA publications.

As a result of the comprehensive review, the following changes have been made:

- EIA has adjusted all presentations of data on electric power to a consistent format and defined the electric power sector to include electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public [*16*].
- EIA is providing detail on fuel used by CHP plants in the electric power, commercial, and industrial sectors.
- EIA has changed the source of data on fuel used by components of the electric power sector: all tabulations and publications will use data obtained from EIA's surveys of electric power generators. This change in data source affects the reporting of EIA's historical data for total fuel consumption of natural gas. The revisions contribute to changes in EIA's electricity series as well as the fuel-use series.

EIA's *Annual Energy Review 2001* (*AER2001*) was the first of its annual reports in which the revised electricity and fuel data were published.

Natural Gas Consumption

In addition to changes in data for the electric power sector, the review of EIA data resulted in changes to primary fossil fuel inputs that affect both the sectoral allocation of those fuels and total energy consumption. In past EIA data publications, natural gas consumption was presented for the residential, commercial, industrial, transportation, and electric utility sectors. Deliveries of natural gas to independent power producers (called "other nonutility power producers" on EIA survey forms) were included in the data reported for the industrial sector, and the measures were collected through natural gas survey forms submitted by gas delivery agents (local distribution companies and pipelines).

As with the other data, beginning with *AER2001*, the definition of industrial sector gas consumption for 1993-2001 no longer includes independent power producers. The definition of the electric power sector includes independent power producers, utilities, and other electricity generators whose primary business is selling electricity. The data reported for the electric power sector are derived entirely from data that were submitted on EIA's electricity data collection forms, including Forms EIA-759, "Monthly Power Plant Report," and EIA-860B, "Annual Electric Generator Report—Nonutility," through 2000 and Form EIA-906, "Power Plant Report," for 2001.

In comparison with past publications, the impact of the definitional change for the industrial sector is to reduce measured natural gas consumption by the industrial sector. For example, in *AER2000* EIA showed 9.39 trillion cubic feet delivered to industrial facilities in 2000. In *AER2001*, the comparable figure (under the "other industrial" heading) for 2000 is 8.25 trillion cubic feet. This change is a result of the change in the operational definition of deliveries to the industrial sector.

In comparison with past publications, the impact of the definitional change and the new data sources for the electric power sector is to increase measured natural gas consumption. As a result of the changes in data sources (predominantly new electric power data sources), total natural gas consumption is higher than previously published. Total natural gas consumption in the electric power sector for 1998, 1999, and 2000 has been revised upward by 5 percent, 3 percent, and 3 percent, respectively.

Also beginning with the publication of *AER2001* and following with the *Natural Gas Annual*, new detail is available about natural gas consumption in the commercial, industrial, and electric power sectors that distinguishes deliveries of natural gas to CHP plants from deliveries to other facilities. “Deliveries to industrial consumers” includes deliveries to industrial consumers that are CHP plants (such as paper mills) and to other industrial users. Included with the CHP plant data are a small number of industrial firms that report using natural gas only to generate electricity (most likely for their own use). “Deliveries to commercial consumers” also include deliveries to CHP plants, such as hospitals. Similarly, a small number of plants that report natural gas use only for electricity generation are included with the data on commercial CHP plants. The sources for total commercial and industrial sector data are natural gas survey forms, and the sources for the subcomponent CHP data series are electric power survey forms. The sources of all electric power data series, including the CHP subcomponent, are electric power survey forms.

Data Changes in AEO2003

The reallocation of EIA’s natural gas consumption data series, as described above, does not affect the values reported in *AEO2003*, although it does change the values reported in other EIA data publications. In previous *AEO*s, natural gas consumption by independent power producers already was excluded from the industrial sector and included in power sector consumption; however, use of the data reported on the EIA utility data forms rather than the data series reported by natural gas suppliers increases total historical natural gas consumption. Historical data have been updated back to 1993, and the changes are reflected in *AER2001*. The changes affect the level of total natural gas consumption reported in *AEO2003*. Total natural gas consumption for 2000 in *AEO2003* is 0.6 trillion cubic feet higher than it would have been without the data changes [*17*].

The inclusion of CHP fuel use in the electric power sector rather than the industrial sector has resulted in some changes in natural gas consumption data in *AEO2003* as compared with *AEO2002* (Figure 8). The impact on the projections for natural gas consumption is minimal, however, because other factors in the forecast, such as more rapid projected growth of the bulk chemicals industry and the expected construction of more than 100 gigawatts of natural-gas-fired generating capacity in 2001 and 2002, overwhelm the relatively small impact of the data revisions.

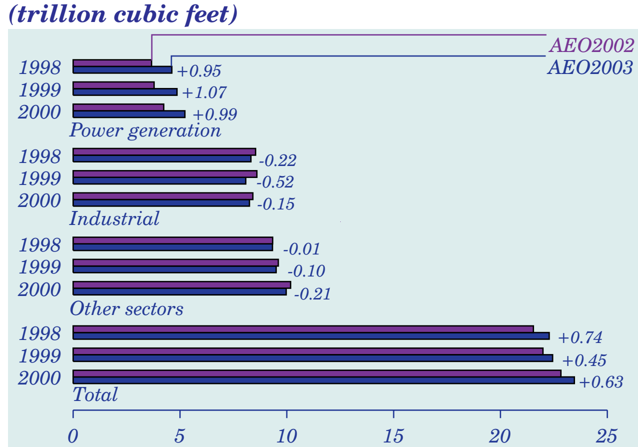
Data on renewable energy consumption were also revised in *AER2001*, primarily affecting reported renewable energy use in the industrial sector. Two factors contributed to the revisions:

- A methodological issue involved plants that generated electricity from noncombustible renewables and another fuel, such as natural gas. In the past, all the generation from such plants was attributed to the noncombustible renewable source. The revised methodology attributes the generation to each source. As a consequence, for example, reported industrial hydroelectric generation in 2000 was revised from 200 trillion Btu to 42 trillion Btu.
- Extensive reexamination of reported biomass consumption data resulted in decreases for several large facilities.

The net impact of the data revisions was to decrease reported renewable energy consumption in 2000 by 0.52 quadrillion Btu, or 8 percent (Figure 9). The data revisions do not directly affect the rate of growth in the *AEO2003* forecast, because growth in industrial biomass use is primarily a function of economic activity in the pulp and paper industry.

Data revisions that affect the allocation of other fuels to particular end-use sectors have also been

Figure 8. Changes in AEO data for 1998-2000 natural gas consumption by sector (trillion cubic feet)



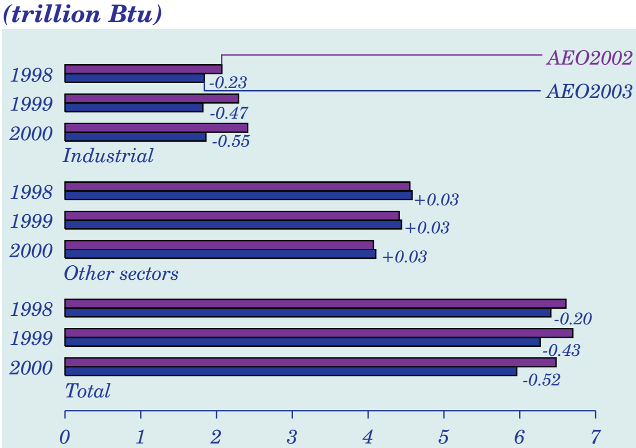
implemented in *AEO2003*. The changes affect distillate, residual fuel oil, and steam coal. In general, the portion of those fuels used in the power sector increased by less than 1 percent, and the portion allocated to the other sectors fell by the same amount.

Finally, the *AEO2003* presentation of electricity data and projections has been modified to reflect the data changes discussed above. Table A2, "Energy Consumption by Sector and Source," now includes all power sector energy consumption in the power sector, including fuel consumption by nontraditional CHPs. In *AEO2002*, Table A2 included fuel consumption only for electricity generators and independent power producers in this category. Table A8, "Electricity Supply, Disposition, Prices, and Emissions," now provides electricity production data separately for power-only generators and CHPs in the power sector. Parallel changes have been made to Table A9, "Electricity Generating Capability."

Natural Gas Depletion and Wellhead Productive Capacity

Natural gas fields vary in both size and cost of development. In general, the fields first developed in a given geographic area are the relatively large and inexpensive resources. Subsequent fields in the same area are on average smaller and more costly to develop, and they do not produce at the same high levels as the fields they are replacing. Thus, as time progresses, more exploration and development activity is needed just to maintain production levels. If drilling activity increases sufficiently, production can actually increase despite the finding of smaller and potentially less productive fields. A key question facing producers and policymakers today is whether natural gas resources in the mature onshore lower 48 States have been exploited to a point at which more rapid depletion rates eliminate the possibility of increasing—or even maintaining—current production levels at reasonable cost.

Figure 9. Changes in AEO data for 1998-2000 renewable fuels consumption by sector (trillion Btu)



Depletion is a natural phenomenon that accompanies the development of all nonrenewable resources. Resource depletion is both economic and physical. Physically, depletion is the progressive reduction of the overall volume of a resource over time as the resource is produced. In the petroleum industry, depletion may also more narrowly refer to the decline of production associated with a particular well, reservoir, or field. As existing wells, reservoirs, and fields are depleted, new resources must be developed to replace depleted reservoirs.

Depletion has been counterbalanced historically by improvements in technology that have allowed gas resources to be discovered more efficiently and developed less expensively, have extended the economic life of existing fields, and have allowed natural gas to be produced from resources that previously were too costly to develop. In *AEO2003*, technological progress for both conventional and unconventional recovery is expected to continue to enhance exploration, reduce costs, and improve production technology.

Resources

The estimate of total technically recoverable natural gas resources in the United States as of January 1, 2002, which was used in developing *AEO2003*, is 1,289 trillion cubic feet. This is the "technically recoverable" resource and not the total volume of gas in place, which is likely to be much larger because it includes known gas resources that are currently technologically unrecoverable. With technology improvements, some unrecoverable resources could become part of the technically recoverable resource in future years. This is one reason the estimated gas resource today is larger than the estimated resource in the early 1980s.

Proved natural gas reserves are located in known and developed reservoirs, for which wells have been drilled and production rates have been demonstrated. Proved natural gas reserves were 183 trillion cubic feet at the beginning of 2002 (Figure 10). Unproved technically recoverable resources include the following:

- *Undiscovered nonassociated conventional* natural gas resources are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir, that are estimated to exist in fields that have yet to be discovered, based on regional geologic formations and their propensity to hold economically producible natural gas. The estimated total of U.S. technically recoverable undiscovered nonassociated natural gas resources is 269 trillion cubic feet, less than half of which is in the lower 48 onshore.

- *Inferred nonassociated conventional* natural gas reserves are gas deposits in known reservoirs that are considered likely to exist on the basis of a field's geology and past production but have not yet been developed through developmental drilling. Because wells have not yet been drilled or production tests conducted, there is some uncertainty about the recovery of the inferred reserves. The estimated total of U.S. inferred nonassociated reserves is 222 trillion cubic feet, 81 percent of which is in onshore reservoirs.

- The largest category of unproved resource, estimated at 445 trillion cubic feet, is *unconventional* natural gas, 71 percent of which is tight gas (low-permeability deposits in sandstone). Other unconventional natural gas resources include gas shales (which are also low-permeability deposits) and coalbed methane.

- *Other unproved* natural gas resources include gas in Alaska (32 trillion cubic feet) and associated-dissolved natural gas in lower 48 crude oil reservoirs (137 trillion cubic feet).

Technological advances make it cheaper to discover and develop resources and reclassify them as proved reserves, but the volume of resources added to proved reserves each year is fundamentally determined by the level and success of drilling activity. Although the level of proved reserves might fluctuate because of the counterbalancing effects of depletion, technological advances, the amount of drilling, and reevaluation of economical reserves when prices shift, the total size of the ultimate in-place resource remains unchanged, other than reductions as a result of extraction.

Drilling

One necessary activity in finding and producing natural gas is gas well drilling. The slowdown in drilling that resulted from low natural gas wellhead prices in 1998 and 1999 was one of the factors contributing to the scarcity of gas supplies during the winter of 2000-2001, which in turn caused high gas prices, leading to the boom in gas well drilling in 2000 and 2001.

Lower natural gas wellhead prices are expected to reduce drilling levels over the next 5 years (2002-2006), bringing the total number of gas wells drilled back to the historical trend. Overall drilling generally increases in the AEO2003 reference case between 2007 and 2025, from 15,870 wells in 2007 to 20,130 in 2025 (Figure 11). Throughout the forecast, about 86 percent of total lower 48 gas drilling is expected to be developmental [*18*]. Unconventional gas drilling accounts for the vast majority of the projected growth in drilling, with its share of total lower 48 wells increasing from 39 percent in 2001 to 46 percent in 2025. Only 2 percent of the wells drilled in the lower 48 States are expected to be drilled offshore; however, the average offshore well tends to be much more productive than the average onshore well, and the impact of the small offshore share of total drilling can be important.

The increases in drilling in the AEO2003 reference case are fueled by growth in the demand for natural gas and sustained by rising gas prices. The projected drilling levels are supported by growing producer

Figure 10. Technically recoverable U.S. natural gas resources as of January 1, 2002 (trillion cubic feet)

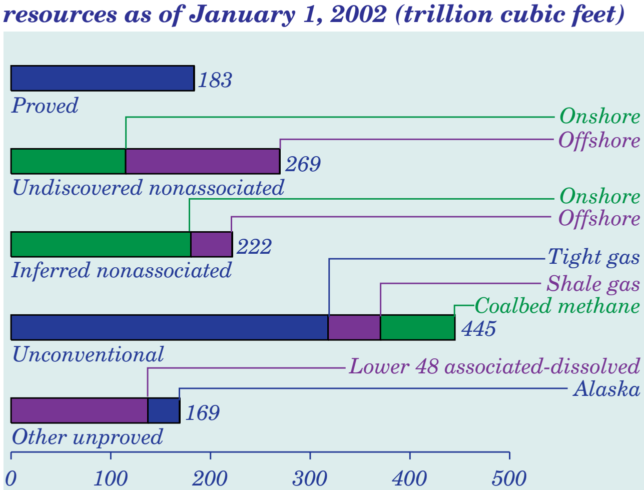
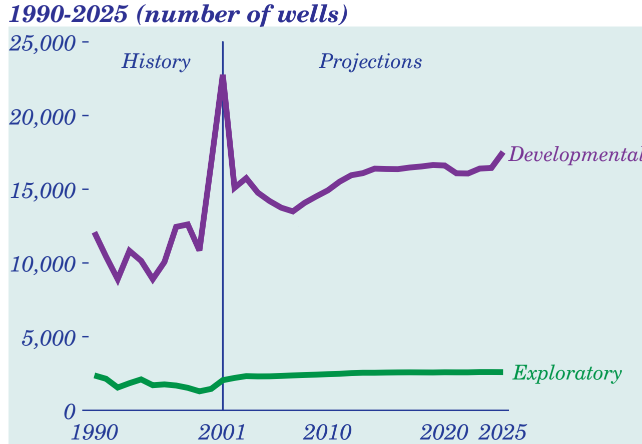


Figure 11. Lower 48 natural gas wells drilled, 1990-2025 (number of wells)



cash flows from domestic oil and gas production, which result from higher prices and higher production levels. Moreover, future improvements in technology—particularly in unconventional gas recovery—are assumed to make a larger portion of the in-place resource base technically recoverable.

Success Rates

Improvements in technology have significantly improved the ability to determine where gas is located before an expensive exploratory well is drilled (Figure 12). A well is classified as successful if the accumulation of natural gas found can be profitably developed and produced. Conversely, a "dry hole" may encounter hydrocarbon deposits with geologic characteristics that make them unprofitable to produce. The success rate is calculated by dividing the number of successful wells by the total number of wells drilled (successful wells plus dry holes).

The spike in both the developmental and exploratory success rate in 2000 and 2001 appears to be a result of high natural gas prices. High wellhead prices spurred drilling in areas known to contain resources that were not necessarily economical at lower prices. The projected success rate of developmental drilling remains fairly constant at about 85 percent for onshore wells and 75 percent for offshore wells. Exploration success rates are projected to increase from roughly 40 percent in the early years of the forecast to almost 48 percent by 2025 as improvements in technology continue.

The significant increase in the exploratory success rates for both onshore and offshore drilling in the past decade can be attributed largely to the use of advanced imaging technology. For example, three-dimensional (3-D) seismic technology provides data to create a multidimensional picture of the subsurface by bouncing acoustic or electrical vibrations off subsurface structures, so that oil and gas deposits can be better targeted. Although 3-D seismic technology has been commercially available since the late 1970s, major improvements in data acquisition, processing, interpretation, display, and computer hardware during the 1990s significantly reduced the cost of 3-D surveys and expanded their availability from only larger producers to small and medium-sized independent producers. Because 3-D seismic technology is now widely used, improvements in exploratory success rates are expected to slow.

Drilling Costs

The drilling cost for a representative gas well is estimated at the regional level, taking into account the separate impacts of drilling to greater depths, rig availability, level of drilling activity in a given year, and technological progress. These relationships are assumed to continue throughout the projection period.

Drilling costs per well have shown a generally declining trend since the mid-1980s. In the mid-1990s, the use of relatively new, more expensive techniques and a trend toward deeper wells increased the average cost to drill a well (Figure 13). Some of the relatively new technologies, such as directional and horizontal drilling, have a higher cost per well; but the gains in productivity generally outweigh the additional cost. For example, the cost of vertical drilling currently is roughly half the cost of horizontal drilling, but the production increase from horizontal drilling averages anywhere from 300 to 700 percent. In addition, the cost difference is expected to be reduced by gains in efficiency and experience. Continued improvement in unconventional gas recovery technologies is also expected to reduce the cost of drilling.

Figure 12. Average onshore natural gas success rates, 1990-2025 (percent)

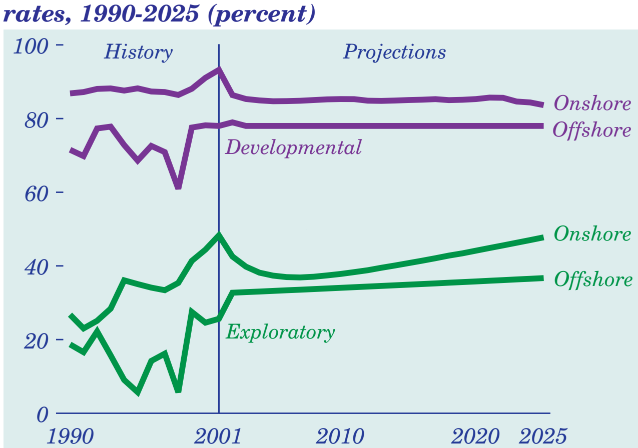
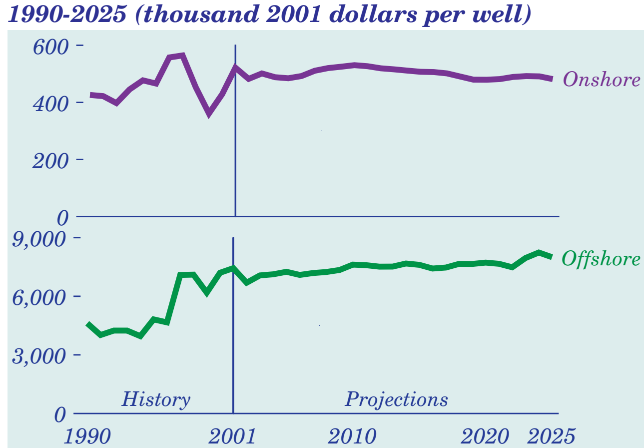


Figure 13. Average natural gas drilling costs, 1990-2025 (thousand 2001 dollars per well)



Drilling costs are estimated to have increased in 2000 and 2001, primarily because of the high level of drilling activity and rig demand. As technologies continue to reduce costs and growth in drilling activity stabilizes, drilling costs per onshore well on average are projected to decline slightly. By 2025, average onshore drilling costs per well are projected to be about 8 percent lower than in 2001, declining at an average annual rate of about 0.3 percent. In nominal dollars, however, average onshore drilling costs are expected to increase from $521,000 per well in 2001 to $872,000 per well by 2025. The average cost to drill a well offshore is projected to be roughly 8 percent higher in 2025 than in 2001, reaching $8,000,000 per well by 2025 in 2001 dollars ($14,000,000 in nominal dollars). Technological progress still is expected to reduce drilling costs in the offshore, making it possible to access resources in deeper waters, but the movement to deep (greater than 200 meters) and ultra-deep (greater than 1,600 meters) water drilling will increase the overall average per well cost. At least initially, such high costs will focus activity on larger deposits.

Finding Rates

Reserve additions per well (or finding rates) are projected through a set of equations that distinguish between new field discoveries, discoveries in known fields (also defined as extensions and new pools), and increases due to reevaluation of discovered areas during the developmental phase (also known as revisions and adjustments). The equations capture the impacts of technology, prices, and declining resources. In the absence of technological change, the yield from exploratory and developmental drilling declines as the resource base is depleted, reflecting primarily the natural progression of the discovery process from larger, more profitable fields to smaller, less economical ones. The more mature the region, the faster the decline. Technological advancement accelerates the discovery of the resource by improving the ability to target the more promising resources and by making currently uneconomical resources accessible and economical. Eventually, however, as new fields grow smaller and as large old fields are fully produced, the reserves added per well will decline.

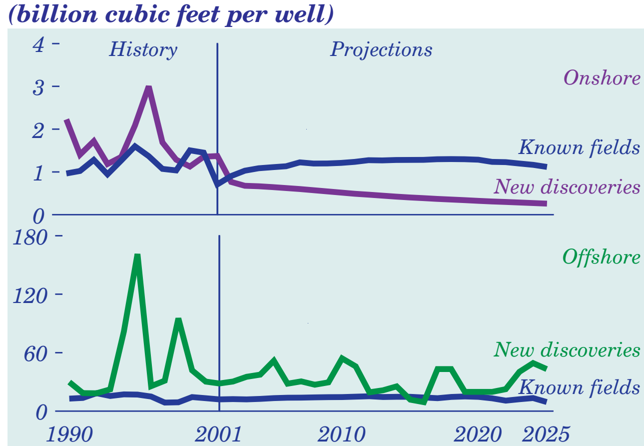
The most productive onshore wells, in terms of reserves added, are drilled in known fields. Finding rates for nonassociated natural gas in known onshore fields have varied over the historical period, with a slightly increasing trend (Figure 14). Over the projection period, onshore nonassociated natural gas finding rates in known fields are projected to increase from 0.7 billion cubic feet per well in 2001 to almost 1.3 billion cubic feet per well in 2018 and then decline to 1.1 billion cubic feet per well in 2025. The reserves added from drilling an onshore new field wildcat are expected to decline through the projection period, continuing the historical trend.

Finding rates for both onshore conventional and unconventional wells drilled in known fields are projected to rise initially, as technological gains lead to greater recovery, but then eventually to decline at different points in the projection period. Finding rates for conventional wells begin to decline early in the forecast as mature lower 48 conventional fields are developed and produced. Finding rates for unconventional wells begin to decline late in the forecast period, as producers are forced to enter less productive areas in search of viable prospects.

The projected reserves added per nonassociated gas well drilled in the offshore are significantly higher than in the onshore, averaging almost 15 billion cubic feet per well between 2001 and 2025, compared with an average of roughly 1 billion cubic feet per onshore well. The reserves added per well vary extensively by area in the offshore. New areas in deep waters are expected to produce reserve additions of 30 to 40 billion cubic feet or more per well, but some mature areas on the continental shelf already are producing reserve additions of as little as 1 or 2 billion cubic feet per well.

In contrast to onshore wells, the finding rate for new field wildcats drilled in the offshore Gulf of Mexico is greater than the reserves added per well drilled in known fields. More than 70 percent of the total unproved nonassociated natural gas resources offshore are estimated to be in currently undiscovered fields, most of which are in the deep waters of the Gulf

Figure 14. Average reserve addition per nonassociated gas well, 1990-2025 (billion cubic feet per well)



of Mexico. The average finding rate curve for offshore new field wildcats is not smooth, because the reserves added per offshore well are determined on the basis of discrete fields, in contrast to reserve additions per onshore conventional well, which are determined using econometrically estimated equations at an aggregate level.

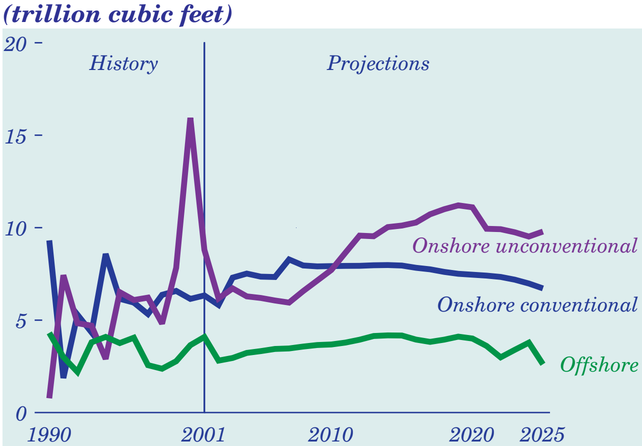
Reserve Additions

Each year, production is taken from proved reserves, reducing both proved reserves and the total resource base. As the proved reserves are being produced, exploration and development add to the inventory of proved reserves. Since 1994, natural gas reserve additions have exceeded production in every year except 1998. The drop in reserve additions in 1998 can be attributed to accounting adjustments as a result of extremely low gas prices, as well as the continuing economic restructuring of the industry, characterized by mergers, acquisitions, and spinoffs.

The majority of reserve additions historically have come from the continued development and expansion of known fields (also referred to as reserve appreciation). This trend is expected to continue throughout the projection period. With the expected growth in drilling for unconventional gas sources (tight gas, shale gas, and coalbed methane), reserve additions from unconventional gas are expected to increase significantly, from a low of 6 trillion cubic feet in 2007 to a high of 11 trillion cubic feet in 2019 (Figure 15). Reserve additions from unconventional gas are expected to decline after 2019 as supply from other sources (Alaska and Canada) increases.

Total offshore reserve additions from known fields are expected to decline after 2020, when reserve additions from deepwater fields no longer offset the

Figure 15. Nonassociated natural gas reserve additions in known fields, 1990-2025 (trillion cubic feet)



expected decline in reserves added from shallow fields. It is also expected that discoveries of large ultra-deep fields in the Gulf of Mexico may temporarily interrupt the declining trend. Between 2001 and 2025, additions of nonassociated natural gas reserves in known fields are projected to average 4 trillion cubic feet from offshore drilling, 7 trillion cubic feet from onshore conventional drilling, and 9 trillion cubic feet from onshore unconventional drilling per year.

For conventional gas, by far the largest contribution to reserves is made by other exploratory wells (wildcats in established fields), which increase the size of known fields either by extending field boundaries or by discovering new reservoirs. Reserve additions for unconventional gas, however, generally result from developmental wells. The existence and extent of unconventional fields are usually not at issue due to the nature of these deposits, which tend to occur in large continuous plays. However, because of the poor economics of unconventional gas production (due to the slower flow rates, stimulation requirements, etc.) reserves generally are not booked until wells are actually committed to production from the targeted deposits.

New field discoveries in the Gulf of Mexico, particularly in deep waters, are expected to continue to be larger than the onshore discoveries (Figure 16). Annual discoveries of nonassociated natural gas in offshore and onshore new fields are projected to average 770 billion cubic feet and 220 billion cubic feet, respectively.

Production-to-Reserve Ratios

The relationship between production and proved reserves, quantified as the PR ratio (production divided by reserves), is the basis for projecting future nonassociated natural gas production. Each year, the expected natural gas production is calculated as a fraction of the proved reserves of a given type (conventional or unconventional) in a given region.

The PR ratio for nonassociated natural gas has averaged about 11 percent per year for the past several years, with conventional onshore gas at about 11 percent per year, onshore unconventional at roughly 8 percent per year, and offshore at 18 percent per year (Figure 17). With expected increases in natural gas demand and improvements in exploration and production technologies, the average PR ratio for nonassociated gas is expected to increase from 11 percent in 2001 to almost 13 percent by 2025. (This is equivalent to a reserve-to-production ratio, RP, decreasing from 9.1 to 7.8.) The average offshore PR ratio is projected to increase in the last few years of the projection period as a result of the development of relatively large ultra-deepwater (greater than 1,600 meters) natural gas fields.

Production

The depletion of conventional and unconventional natural gas resources is expected to continue over the projection period as the demand for natural gas increases significantly, continuing the trend that began in the mid-1990s. With sustained wellhead prices generally over $3 per thousand cubic feet (in 2001 dollars) and continued technological improvements, lower 48 nonassociated gas production is expected to increase above current levels (Figure 18). Onshore conventional nonassociated gas production, which currently accounts for 40 percent of total lower 48 nonassociated gas production, is reduced to 35 percent by 2025. The continued growth in production from onshore unconventional and deepwater Gulf of Mexico conventional sources is necessary to meet rising demand levels but is, in general, more costly and pushes average wellhead prices up. Other supply is also needed to meet natural gas demand and to help mitigate further price increases by reducing the need for more costly unconventional gas. Additional supplies are expected to come from Alaska, Canada's MacKenzie Delta, imports of liquefied natural gas (LNG), and associated-dissolved gas in the lower 48 onshore and offshore.

Prices

Nonassociated natural gas production from conventional and unconventional resources is expected to increase over the projection period, supported by a relatively large resource base and expected advances in technology that will enhance exploration, reduce costs, and improve production rates. In order for that to happen, wellhead prices must remain high enough to spur drilling and additions to proved reserves. Wellhead prices are expected to remain relatively high—compared with prices over the past decade—throughout the projection period (Figure 19). Real wellhead prices (in 2001 dollars) are projected to increase from $2.75 per thousand cubic feet in 2002 to $3.90 per thousand cubic feet (equivalent to a nominal price of $7.07 per thousand cubic feet) in 2025. The depletion of natural gas resources at a rate faster than in the *AEO2003* reference case, which reflects historical trends, would put additional upward pressure on wellhead prices and could potentially result in some demand shifting to alternative fuels, more focus on access to resources both onshore and offshore, and more natural gas imports from other countries.

Figure 16. Nonassociated natural gas reserve additions from new field discoveries, 1990-2025 (trillion cubic feet)

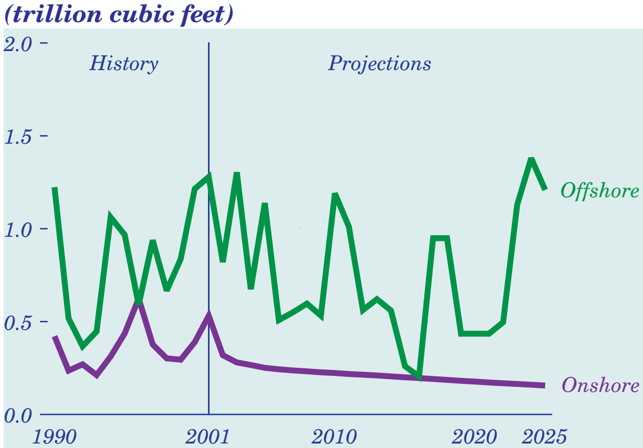


Figure 17. Lower 48 nonassociated production-to-reserves (PR) ratios, 1990-2025

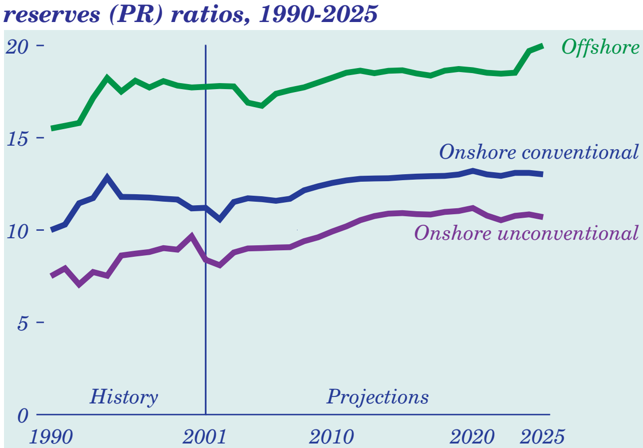


Figure 18. Lower 48 dry natural gas production, 1990-2025 (trillion cubic feet)

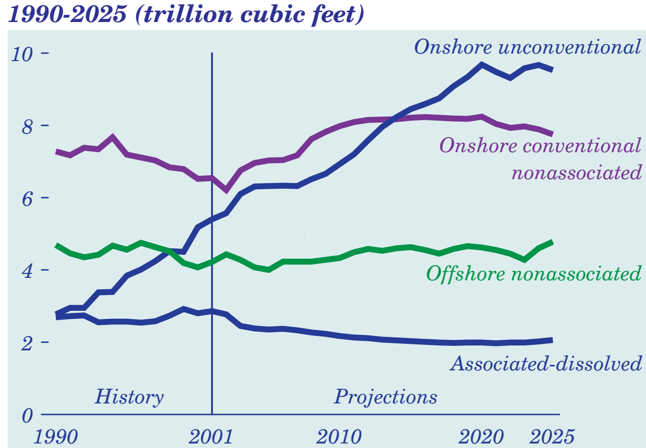
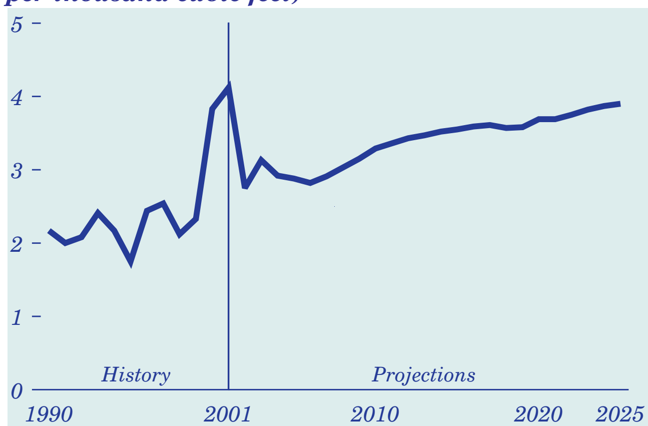


Figure 19. Average lower 48 natural gas wellhead price, 1990-2025 (2001 dollars per thousand cubic feet)



Natural Gas Supply Options: LNG, Canada's MacKenzie Delta, and Alaska

With natural gas prices on domestic spot markets climbing above $10 per thousand cubic feet in early 2001, the attention of the U.S. natural gas industry returned to construction of new import terminals for liquefied natural gas (LNG) and new pipelines for natural gas from Alaska and from the MacKenzie Delta on Canada's northern frontier. In the 1970s, when natural gas prices were rising rapidly, LNG import facilities were constructed at four sites (Everett, Massachusetts; Elba Island, Georgia; Cove Point, Maryland; and Lake Charles, Louisiana), and construction of an Alaska Natural Gas Transportation System (ANGTS) was proposed to deliver Alaskan gas to the lower 48 States. Some pipeline segments intended to bring Alaskan gas through Canada to the lower 48 States were constructed, but the system was not completed.

In the 1970s, investors in LNG and Alaskan pipeline projects were protected on the downside by minimum prices established by regulation, and they hoped to reap significant gains from record high prices. When gas wellhead price deregulation and the subsequent restructuring of the gas transmission industry caused gas prices to fall during the 1980s, however, all but one of the LNG facilities were mothballed, and construction of the Alaskan gas pipeline was deferred. Three of the four LNG terminals are now open, and the fourth, Cove Point, is scheduled to reopen in the spring of 2003. The general consensus is that current market conditions will support the construction of both an Alaskan gas pipeline and new LNG regasification capacity. This perception is based both on a decline in pipeline and LNG facility construction costs and on recently higher natural gas prices.

Contributing to the current optimism about new construction projects is the availability of low-cost natural gas supplies. A considerable volume of overseas gas is considered to be "stranded" [*19*], with no indigenous market. For example, in countries such as Nigeria, associated natural gas produced in conjunction with oil production is flared [*20*]. Similarly, the only indigenous market for North Slope Alaskan gas is for reinjection into oil wells to enhance future production.

North Slope gas reserves are estimated to total 35 trillion cubic feet, and another 16 trillion cubic feet is expected to be found and developed [*21*]. Thus, a total resource base of 51 trillion cubic feet could be available to support the Alaskan gas pipeline. Gas reserves in the MacKenzie Delta/Beaufort Sea area of Canada's northern frontier are estimated at 9 trillion cubic feet, with an additional 55 trillion cubic feet expected to be found and developed in the same area [*22*], providing a total resource base of 64 trillion cubic feet to support the MacKenzie Delta pipeline either independently or in conjunction with an Alaskan pipeline.

The two pipelines would bring gas to Alberta, from where it could be moved to both Canadian and U.S. markets. The MacKenzie Delta and Alaskan gas volumes transported into Alberta are expected to be 548 billion cubic feet and 1,642 billion cubic feet per year, respectively, with an additional 23 percent capacity that can be added to each pipeline through expansion [*23*]. Although some MacKenzie Delta gas is expected to be used in Canada to support oil sands production [*24*], some analysts contend that, in addition to the MacKenzie Delta/Beaufort Sea gas, other deposits will be discovered and developed along the MacKenzie Delta pipeline that can supplement the MacKenzie Delta supplies.

Overseas natural gas supplies appear to be sufficient for international LNG markets well beyond 2025. According to the *International Energy Outlook 2002*, as of January 1, 2002, world natural gas reserves totaled 5,451 trillion cubic feet, with world consumption projected to reach 162 trillion cubic feet by 2020 [*25*]. Of the total reserves, approximately 4,500 trillion cubic feet is considered to be stranded [*26*].

Although the four existing U.S. LNG facilities could be expanded, their current capacity limits the amount of LNG that can be received and regasified to 832 billion cubic feet per year. Capacity is expected to increase to 1.06 trillion cubic feet per year as the result of announced expansions; and subsequent expansions at existing terminals, beyond those already announced, are expected before the construction of new terminals. The potential for expansion beyond the 1.06 trillion cubic feet depends on a variety of site-specific factors, such as the availability of additional land and harbor constraints on the number of tankers that can be berthed simultaneously. It is estimated that the potential expansion beyond 1.06 trillion cubic feet is 410 billion cubic feet per year, which would give a total maximum sustainable capacity at the four existing U.S. terminals of 1.47 trillion cubic feet per year. Thus, although world supplies are plentiful, any significant increase in LNG imports would require investment in either expansion of existing facilities or construction of new facilities.

New LNG regasification facilities have been proposed to serve U.S. markets (Table 2), including traditional land-based U.S. terminals, facilities on offshore platforms, shipboard regasification systems such as El Paso Corporation's EP Energy Bridge™ [*27*], and terminals outside U.S. boundaries. LNG from proposed facilities in the Bahamas and Baja California, Mexico, would be regasified there and transported to the United States by pipeline. Construction of regasification terminals outside the United States is expected to be less expensive and take less time than construction inside U.S. borders. The design capacities of the proposed facilities range from 200 to 685 billion cubic feet per year.

None of the proposed facilities is specifically included in the *AEO2003* forecast. Instead, new generic facilities are constructed in regions where market conditions make them economical. Each new facility is assumed to have an initial design capacity of 125 to 254 billion cubic feet per year and expansion potential for an additional 317 to 764 billion cubic feet per year [*28*].

Significant investments would be required to construct new LNG facilities and new pipelines from Alaska and the MacKenzie Delta. The production costs of Alaskan gas and MacKenzie Delta gas are estimated to be $0.80 per thousand cubic feet and $1.00 per thousand cubic feet, respectively (costs and prices cited in this discussion are in 2001 dollars). LNG supply costs are expected to range from $0.25 to $0.60 per thousand cubic feet, depending on the source country. When the estimated capital and operating costs for pipelines from Alaska and the MacKenzie Delta are added to gas production costs, "trigger prices" for the projects—the minimum lower 48 wellhead prices needed to make them economical—can be estimated. For a pipeline from the MacKenzie Delta, the estimated trigger price is $3.37 per thousand cubic feet. The trigger price for an Alaskan pipeline is $3.48 per thousand cubic feet. The trigger prices are based solely on economics and do not include provisions for any type of Federal or State support.

Because LNG would be delivered to various locations along the U.S. coast, the economic viability of a new LNG facility is determined not by the domestic wellhead gas price but by the delivered price at or near the LNG terminal site. The delivered prices equal the wellhead price plus the cost of transporting the gas to locations near the LNG terminal. For example, in the *AEO2003* reference case, the projected average wellhead price in 2016 is $3.59 per thousand cubic feet, whereas the "tailgate" LNG price (including the cost of regasification) needed to trigger new construction

Table 2. Proposed LNG import terminals to serve U.S. markets as of August 2002

Location	Design capacity (billion cubic feet per year)	Company
Ocean Cay, Bahamas	200	AES
Freeport, Bahamas	200	El Paso
Freeport, Bahamas	250	Enron
Tampa, FL	200	BP
Gulf of Mexico Offshore, LA	365	ChevronTexaco
Brownsville, Texas	365	Cheniere
Freeport, Texas, TX	365	Cheniere
Sabine Pass, TX	365	Cheniere
Hackberry, LA	275	Dynergy
Mare Island, CA	475	Bechtel/Shell
Los Angeles, CA	685	Mitsubishi
Energy Bridge, Offshore USA	438	El Paso
Baja California, CA	200	ChevronTexaco
Tijuana, Baja California, Mexico	365	Marathon/Pertamina
Ensenada, Baja California, Mexico	365	Sempra/CMS
Rosarito, Baja California, Mexico	250	El Paso/Phillips
Total proposed capacity	**5,363**	

in the South Atlantic region is $3.67 per thousand cubic feet.

LNG facility trigger prices are estimated by adding liquefaction, transportation, and regasification costs to overseas production costs. The *AEO2003* regional trigger prices at which new U.S.-based LNG facilities are expected to become economical range from $3.79 to $4.64 per thousand cubic feet (Table 3). The costs for new LNG facilities include $0.45 to $0.87 per thousand cubic feet for regasification, with production, liquefaction, and shipping costs accounting for the remainder (Table 4). These estimates do not include any provision for technological progress, because it is assumed that increases in production costs would offset decreases in other areas resulting from technological progress.

Regasification costs at existing terminals are lower, at an estimated average of $0.16 per thousand cubic feet. The regional trigger prices for capacity expansions at existing LNG facilities are expected to be in the range of $3.31 to $3.51 per thousand cubic feet. Regasification costs for expansion beyond currently announced or proposed levels at existing terminals are estimated to range from $0.16 to $0.35 per thousand cubic feet.

In addition to cost, there are many other uncertainties for LNG projects. For example, there is the risk that a project would not be permitted and licensed in a timely fashion, increasing construction costs and delaying additions to lower 48 gas supplies. Local opposition to an LNG terminal could preclude and/or delay construction. Another risk includes the coordination of overseas LNG supplies, LNG tankers, and the construction of domestic terminals so that they are all ready for operation at the same time.

Table 3. LNG facility trigger prices by facility and region (2001 dollars per thousand cubic feet)

Expansion at existing facilities	
Everett, MA	3.51
Cove Point, MD	3.41
Elba Island, GA	3.31
Lake Charles, LA	3.50
Initial Construction at New Facilities	
New England	4.12
Middle Atlantic	3.93
South Atlantic	3.79
Florida	4.06
East South Central	3.81
West South Central	3.84
Washington/Oregon	4.64
California	4.37
Baja California/Mexico	3.40

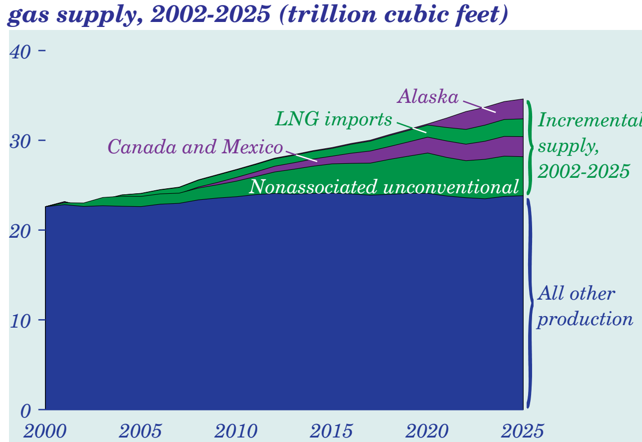
Table 4. Components of LNG trigger prices for new facilities (2001 dollars per thousand cubic feet)

Component	Low	High
Production	0.25	0.60
Liquefaction	1.32	1.72
Shipping	0.89	3.72
Regasification	0.45	0.87

Finally, there is uncertainty about the interaction of various potential projects. The total volumes represented by all the proposed projects would be a significant portion of total U.S. gas supply and therefore could affect market prices. A decline in wellhead natural gas prices resulting from the introduction of additional supplies from one of the sources, such as an Alaskan pipeline, could make other choices uneconomical. This uncertainty applies not only to competition between pipeline and LNG projects but also to competition among individual pipelines or LNG terminals.

In the *AEO2003* reference case, future natural gas prices are projected to be sufficient to make the construction of both the Alaskan and MacKenzie Delta pipelines economical, as well as expanded and new LNG facilities (Figure 20). The high and low economic growth cases illustrate the degree of variability in the results given varying assumptions. The two alternate cases show the impacts of higher and lower levels of demand on natural gas prices and, in turn, the viability of new supply projects (Table 5). In the low economic growth case, total projected consumption of natural gas in 2025 is 31.8 trillion cubic feet, and only one new LNG facility is expected, coming into service in 2025. In the high economic growth case, with consumption projected at 37.5 trillion cubic feet in 2025, all three new supply sources come into play, with MacKenzie Delta gas beginning to flow in 2014, gas from new LNG facilities becoming available

Figure 20. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)



in 2013, and gas from an Alaskan pipeline first reaching the lower 48 States in 2018.

In both the reference and high economic growth cases, domestic supplies and Canadian imports are expected to be sufficient to meet demands through the first half of the forecast period. By 2010, prices are expected to reach levels that begin to trigger the introduction of new supply sources. Beginning in 2016 in the reference case, the MacKenzie Delta pipeline and new LNG terminals begin to play a role in meeting growing demands for natural gas, with gas from an Alaskan pipeline beginning to contribute in 2021. In the high economic growth case, gas from the MacKenzie Delta and new LNG terminals becomes available in 2014, 2 years earlier than in the reference case, and the Alaskan pipeline begins to deliver gas in 2018.

Although the general pattern is for prices to recede with the introduction of supplies from any one of these new sources, demand growth is strong enough that prices fall back slightly for only a short period before beginning to increase again and trigger either expansion at the new source or the activation of an additional source of supply. For example, in the high economic growth case, natural gas wellhead prices generally grow steadily from $2.97 in 2005 to $3.77 in 2013 and 2014. In 2013 supplies from a Baja LNG facility begin to flow, and in 2014 supplies from both the MacKenzie Delta and from new domestic LNG facilities come on line in the same year. The new supply contributes to price declines, to $3.58 in 2019, but they are short-lived. Subsequent price increases are projected to bring the average price to $4.50 per thousand cubic feet by 2025, with the Alaskan pipeline coming on line in 2021.

The projections for net LNG imports (gross imports minus 65 billion cubic feet per year of Alaskan LNG exported to Japan) in 2025 range from 1.45 trillion cubic feet in the low economic growth case to 2.84 trillion cubic feet in the high economic growth case, compared with 2.14 trillion cubic feet in the reference case. In the high economic growth case, five new LNG facilities, including one in Baja California, Mexico, are expected to be constructed, four of which are later expanded as demand increases; and both the Alaska and MacKenzie Delta pipelines are also projected to be constructed and later expanded. The additional sources of supply temper price increases, allowing demands to be met at prices competitive with other supply sources. The reference case does not project the same levels of penetration for alternate supply sources as does the high economic growth case, but construction of four new LNG facilities, in addition to

Table 5. AEO2003 projections for lower 48 wellhead natural gas prices and consumption, Alaskan production, and Canadian, Mexican, and LNG imports in three cases

Projection	2010	2015	2020	2025
Lower 48 average wellhead price (2001 dollars per thousand cubic feet)				
Low economic growth case	3.17	3.26	3.58	3.83
Reference case	3.29	3.55	3.69	3.90
High economic growth case	3.59	3.71	3.63	4.50
Total U.S. consumption (trillion cubic feet)				
Low economic growth case	26.29	28.38	30.30	31.78
Reference case	27.06	29.50	32.14	34.93
High economic growth case	28.13	30.90	34.59	37.48
Net Canadian imports (trillion cubic feet)				
Low economic growth case	3.83	4.12	4.45	5.23
Reference case	4.05	4.42	5.08	5.31
High economic growth case	4.38	5.00	5.03	5.46
Alaskan production (trillion cubic feet)				
Low economic growth case	0.48	0.51	0.54	0.57
Reference case	0.48	0.51	0.55	2.64
High economic growth case	0.48	0.51	2.39	2.85
Net LNG imports (trillion cubic feet)				
Low economic growth case	0.99	1.01	1.11	1.45
Reference case	0.99	1.03	1.51	2.14
High economic growth case	0.99	1.27	2.08	2.84
Net Mexican imports (trillion cubic feet)				
Low economic growth case	-0.27	-0.24	-0.16	0.09
Reference case	-0.26	-0.19	0.07	0.30
High economic growth case	-0.23	0.07	0.47	0.78

both the MacKenzie Delta and Alaskan pipelines, is projected.

In the low economic growth case, the three alternate supply sources are not expected to be economical until late in the forecast. Supplies from new LNG facilities and from the MacKenzie Delta do not make a contribution until 2024. Although prices do reach a level sufficient to trigger construction of the Alaskan pipeline, construction does not begin until 2024, and supplies do not begin to flow during the forecast period.

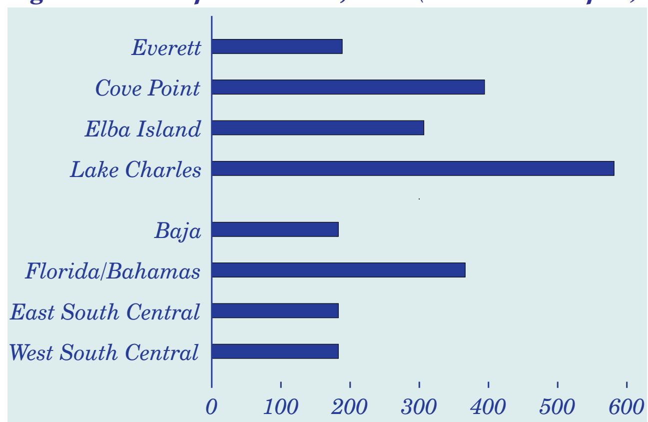
The projections for LNG imports from existing and proposed LNG facilities are shown in Figure 21. The facilities in Baja California are expected to serve both Mexico and the United States; the amount of gas available for U.S. markets is expected to be 183 billion cubic feet per year, with an additional 275 billion cubic feet per year available through expansion.

In summary, the *AEO2003* projections indicate that, given the expected increases in U.S. natural gas consumption and prices and the expected construction costs for the projects, both the Alaskan and MacKenzie Delta pipelines will be needed in addition to new and expanded LNG facilities. The three cases discussed here differ only in regard to when the facilities would be needed, ranging from 2010 to 2025.

Generating Capacity Additions Revisited

Ensuring that there is enough—and just enough—generating capacity to meet consumer needs at all times has always been difficult for the U.S. electric power industry. Many factors make balancing electricity supply and demand a challenge. In the short run, demand variations brought about by unexpected weather or economic growth can ruin the careful planning of power suppliers. In the longer term,

Figure 21. Projected LNG imports by terminal and region in the reference case, 2025 (billion cubic feet)



unexpected changes in demographic trends, consumers' uses of electricity, or shifts in energy-intensive industries can make planning even more difficult. When still other complicating factors are considered—the inability to store electricity, the large capital requirements and long development lead times for new capacity, and the long service lives of generating assets—the challenge of balancing electricity demand and supply is clear. Power plant developers are constantly looking into the future and trying to predict consumer needs, fuel prices, and the costs of generating technologies, in order to determine how much and what types of capacity they should begin developing today.

Historically, both electricity sales and electric generating capacity have grown nearly continuously since 1950 (Figures 22 and 23). Except for a few recession years, they have nearly always increased from year to year; however, they have not always been in balance (Figure 24). From 1950 through early 1970s, growth in electricity sales and growth in generating capacity

Figure 22. Electricity sales, 1950-2005 (billion kilowatthours)

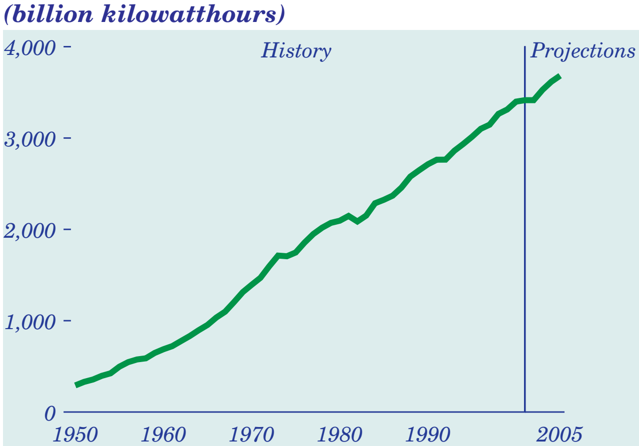
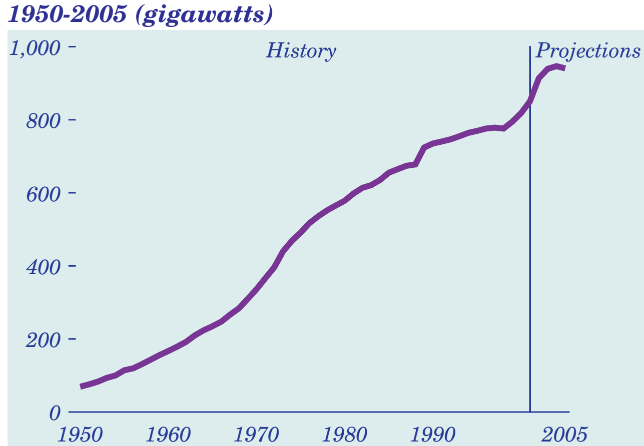


Figure 23. Electricity generating capacity, 1950-2005 (gigawatts)



were roughly in balance. Except for a brief period in the early 1960s, when capacity growth exceeded demand growth for a few years, the index lines hardly separate until the early 1970s.

The main reason for the imbalance that developed in the early 1970s was a rapid slowdown in growth of electricity sales. Before 1960, 5-year average annual growth rates for electricity sales exceeded 8 percent; between 1960 and 1973 they were generally between 6 and 8 percent (Figure 25) [*29*].They declined rapidly after 1973, however, and have generally hovered between 2 and 4 percent annually. (The only years since 1950 in which annual electricity sales have actually declined are 1974, 1982, and 2001.) Many factors, including the energy crises and the associated economic slowdowns of the early and late 1970s, contributed to the slowdown.

The slowdown in electricity sales growth caught power suppliers in the midst of a building boom (Figure 26). From 1960 to 1969, power suppliers brought 180 gigawatts of new generating capacity on line—an average of 18 gigawatts per year—and over the next 5 years, from 1970 to 1974, the pace doubled to an average of 36 gigawatts per year. Power suppliers appear to have been assuming that electricity sales would continue to grow as they had before 1973. Power plant developers did respond, however, delaying and canceling many plants. After peaking at 41 gigawatts of new capacity in 1974, annual additions had slowed to 19 gigawatts by 1979. Still, nearly 314 gigawatts of new capacity was brought on between 1970 and 1979, nearly 75 percent more than in the previous 10 years.

New capacity additions slowed to 172 gigawatts in the 1980s and 84 gigawatts in the 1990s, but the gap between generating capacity and electricity sales persisted for many years (Figure 24). By the mid- to late 1990s, however, many regions of the country needed or were close to needing new capacity in order to meet consumer requirements reliably. The need for new capacity can be seen in the declining capacity margins of the 1990s (Figure 27). The national average reserve margin began the 1990s at just under 25 percent, and by 1998 it had declined to just over 15 percent.

Tightening electricity supplies contributed to the increase in wholesale electricity prices that was seen in some areas of the country in 2001 and 2002. In some areas, wholesale electricity prices at times exceeded $1,000 per megawatthour. Higher prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000 and 43 gigawatts in 2001 and are on pace to build 62 gigawatts in 2002. Counting capacity that is already under construction and expected to be completed, together with a small amount of capacity that is

Figure 24. Electricity sales and generating capacity, 1950-2005 (index, 1950 =1)

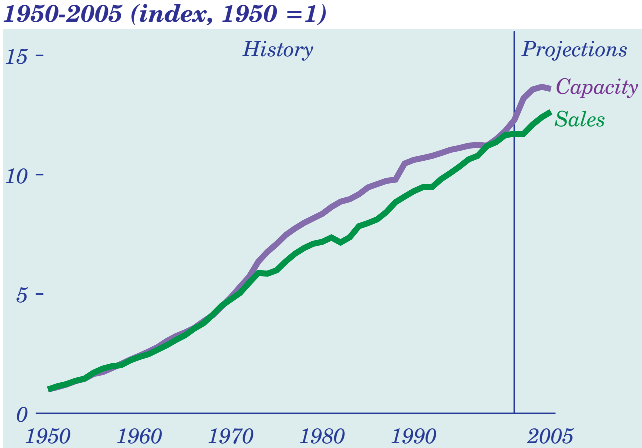


Figure 25. Electricity sales growth, 1955-1999 (5-year moving average annual percent growth)

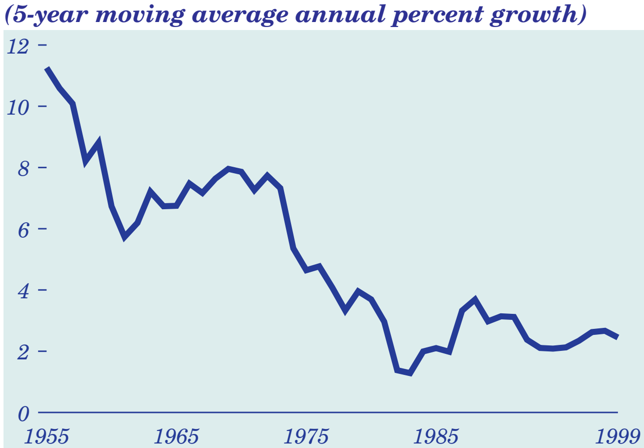


Figure 26. Generating capacity added by year, 1900-2004 (gigawatts)

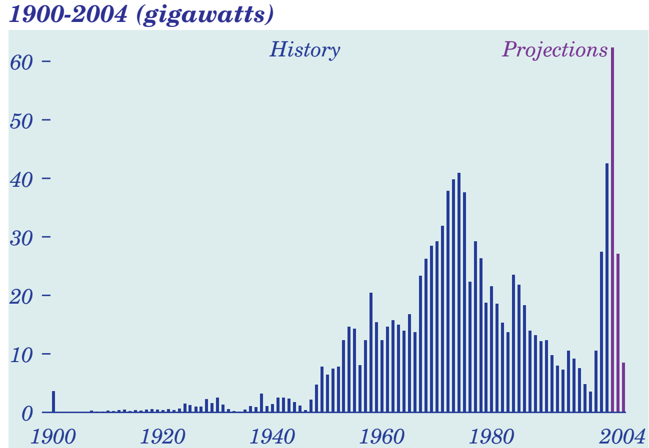
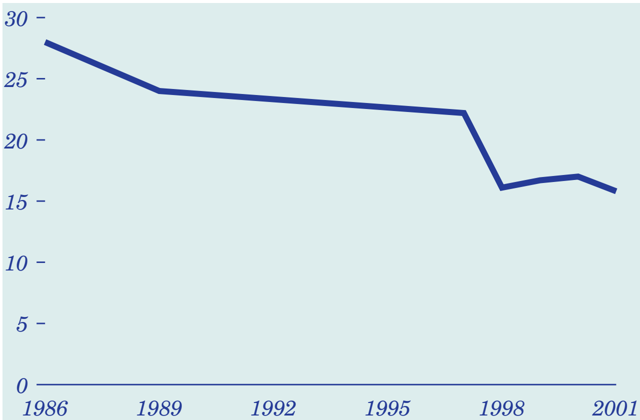


Figure 27. Average U.S. summer capacity margin, 1986-2001 (percent)



expected to be needed in a few regions, suppliers are projected to build another 27 gigawatts in 2003 and 9 gigawatts in 2004.

The 62 gigawatts of new generating capacity expected in 2002 is by far the most ever built in a single year in the United States, and the total amount of new capacity expected to be built between 2000 and 2004 (168 gigawatts) approaches the most ever constructed over a 5-year period (188 gigawatts between 1971 and 1975). In total it amounts to a 21-percent increase in generating capacity in 5 years. It is possible that even more could be built, because the values reported above exclude plants that have been announced but are not under construction. If all the planned capacity reported to EIA comes on line, more than 288 gigawatts of new capacity will be added between 2000 and 2004 (27 gigawatts in 2000, 48 gigawatts in 2001, 90 gigawatts in 2002, 83 gigawatts in 2003, and 41 gigawatts in 2004).

Power plant developers already are responding to the developing imbalance. Over the next few years, many of the planned units that are not already under construction are likely to be canceled or deferred. Most regions of the country will not need additional capacity beyond what is now under construction for several years. It is unclear how long the expected slowdown in new capacity construction might persist. The *AEO2003* reference case projects less than 10 gigawatts of new capacity that is not currently under construction by 2005 and less than 70 gigawatts by 2010. Thus, through 2010, approximately 9 gigawatts of currently unplanned capacity is expected to be needed each year—just over one-quarter of the total capacity (34 gigawatts per year) that is projected to come on line in the 2000-2004 period.

U.S. Greenhouse Gas Intensity

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*30*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output. *AEO2003* projects energy-related carbon dioxide emissions, which represent approximately 82 percent of total U.S. greenhouse gas emissions. Projections for other greenhouse gases are included in the U.S. Department of State's *Climate Action Report 2002* [*31*]. Table 6 combines the *AEO2003* reference case projections for energy-related carbon dioxide emissions with the business-as-usual projections for other greenhouse gases from the *Climate Action Report*.

According to the combined emissions projections in Table 6, the greenhouse gas intensity of the U.S. economy is expected to be reduced by nearly 14 percent between 2002 and 2012. The Administration's

Table 6. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2012

Projection	2002	2012	Percent change, 2002-2012
Greenhouse gas emissions (million metric tons carbon equivalent)			
Energy-related carbon dioxide	1,536	1,862	21.2
Non-energy-related carbon dioxide	37	40	10.3
Methane	171	171	0.2
Nitrous oxide	120	129	7.5
Gases with high global warming potential	39	66	69.1
Adjustments for bunker fuel and military use	-16	-16	-0.7
Total	**1,886**	**2,252**	**19.4**
Gross domestic product (billion 1996 dollars)	9,440	13,082	38.6
Greenhouse gas intensity (grams carbon equivalent per 1996 dollar)	**200**	**172**	**-13.8**

goal of reducing greenhouse gas intensity by 18 percent would require additional emissions reductions of about 109 million metric tons carbon equivalent by 2012. Although *AEO2003* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, carbon dioxide emissions in 2012 are projected to be 55 million metric tons less than the reference case projection. As a result, U.S. greenhouse gas intensity would fall by 15 percent over the 2002-2012 period, still somewhat short of the Administration's goal of 18 percent.

Market Trends

The projections in *AEO2003* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

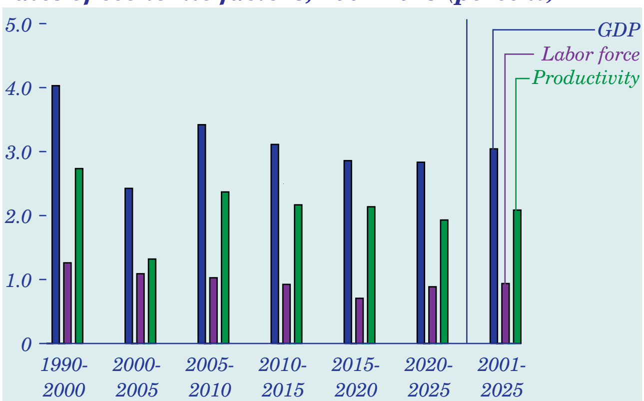
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of certainty. Many key uncertainties in the *AEO2003* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, analytical processes in the examination of policy initiatives.

Strong Economic Growth Is Expected To Continue

Figure 28. Projected average annual real growth rates of economic factors, 2001-2025 (percent)

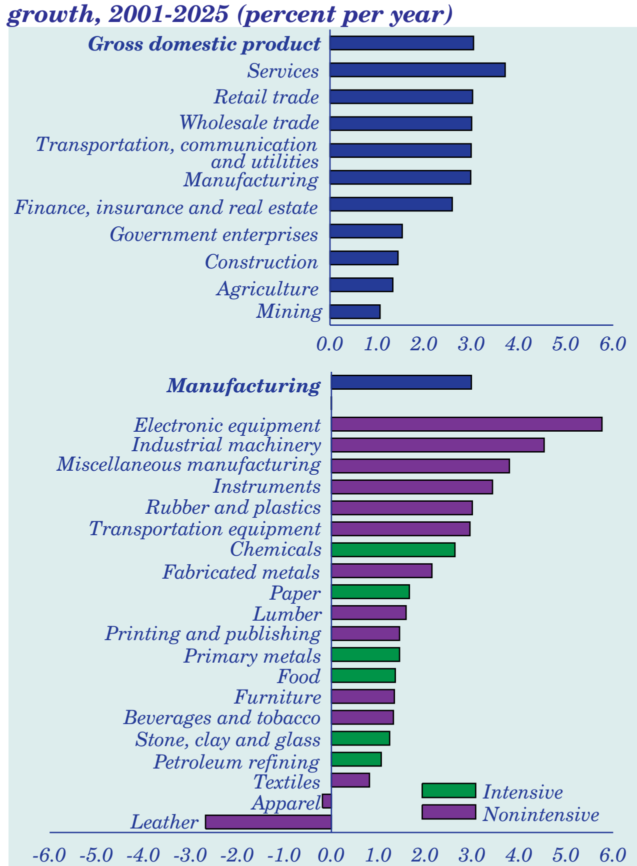


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 3.0 percent per year between 2001 and 2025 (with GDP based on 1996 chain-weighted dollars) (Figure 28). The projected growth rate through 2020 is 3.1 percent, the same as projected in *AEO2002*. The labor force is projected to increase by 0.9 percent per year between 2001 and 2025, slightly higher than last year's forecast through 2020. Productivity (GDP over labor force) growth is 2.1 percent per year, slightly down from 2.2 percent per year in *AEO2002*.

Compared with the second half of the 1990s, the projected rates of growth in GDP and labor force productivity are much lower in the period 2000-2005, reflecting present economic uncertainties and revisions to historical trends. They are expected to pick up as productivity increases and the economy moves back to its long-term growth path. Total population growth (including armed forces overseas) is expected to remain fairly constant after 2001, with an annual growth rate of 0.8 percent per year. Projected labor force growth slows down because of demographic changes but remains strong as more people over 65 decide to stay in the work force. After the first 5 years of the forecast period, labor force productivity growth is expected to remain at about 2 percent per year through 2025. For the forecast period (2001 through 2025), disposable income is projected to grow by 2.9 percent per year and disposable income per capita by 2.1 percent per year. Non-agriculture employment is projected to grow by 1.0 percent per year, and employment in manufacturing is projected to grow by 0.2 percent per year.

Electronic, Industrial Equipment Lead Manufacturing Growth

Figure 29. Projected sectoral composition of GDP growth, 2001-2025 (percent per year)

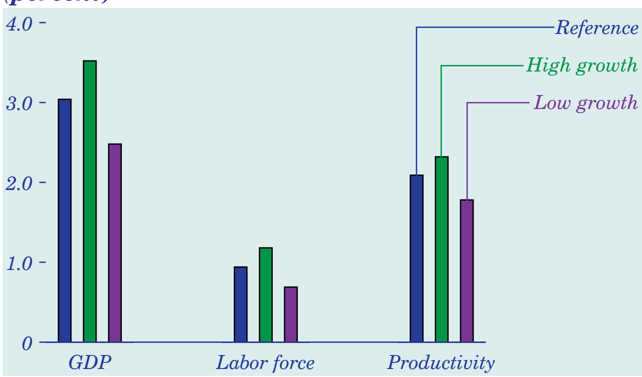


The projected growth rate for manufacturing production is 3.0 percent per year, the same as projected for the aggregate economy (Figure 29). Energy-intensive manufacturing sectors are expected to grow more slowly than the non-energy-intensive sectors (1.4 percent and 3.4 percent annual growth, respectively).

The electronic equipment and industrial machinery sectors lead the expected growth in manufacturing, as semiconductors and computers continue to find broader applications. Miscellaneous manufacturing and instruments are expected to grow faster than manufacturing as a whole, reflecting continued strong demand for high-quality consumer goods and high-tech instruments. Production of services (business and personal) is expected to grow at an average annual rate of 3.7 percent. The growth rates projected for retail trade, wholesale trade, transportation and communications are about the same as for overall manufacturing. Mining and agriculture remain the slowest-growing sectors of the economy.

High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 30. Projected average annual real growth rates of economic factors in three cases, 2001-2025 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2003* includes high and low economic growth cases in addition to the reference case (Figure 30). The high and low growth cases show the projected effects of alternative growth assumptions on energy markets. The alternative economic variables—including GDP and its components, interest rates, disposable income, population and employment—are set up as deviations from the reference case. The three economic growth cases are prepared by EIA and based on Global Insight's macroeconomic model.

The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), labor force (1.2 percent per year), and labor productivity (2.3 percent per year). With higher productivity gains, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow by 3.5 percent per year. GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case. The low economic growth case assumes lower growth rates for population (0.6 percent per year), labor force (0.7 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 2001 through 2025, and growth in GDP per capita is projected to slow to 1.9 percent per year.

Long-Run Trend Shows U.S. Economic Growth of About 3 Percent per Year

Figure 31. Average annual GDP growth rate for the preceding 24 years, 1970-2025 (percent)

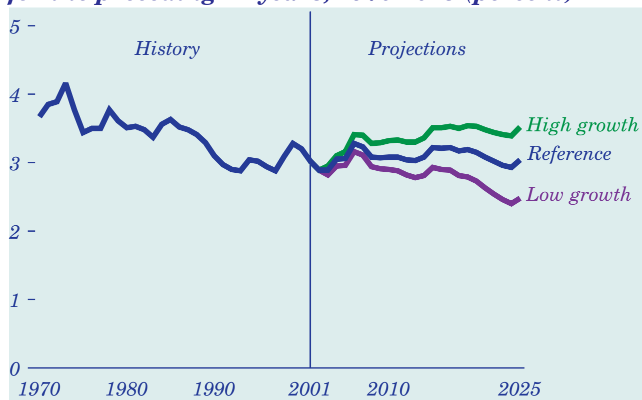
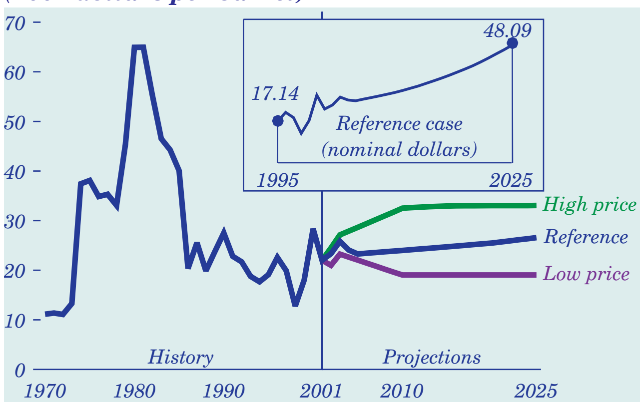


Figure 31 shows the trend in the moving 24-year average annual growth rate for GDP, including projections for the three *AEO2003* cases. The value for each year is calculated as the annual growth rate over the preceding 24 years. The 24-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes (although the increase shown for 1998-1999 reflects the negative growth of 1974-1975). Annual GDP growth has fluctuated considerably around the trend. The high and low growth cases capture the potential for different paths of long-term output growth.

One reason for the variability of the forecasts is the composition of economic output, reflected by growth rates of consumption and investment relative to overall GDP growth. In the reference case, consumption is projected to grow by 3.0 percent per year, while investment grows at a 4.5-percent annual rate. In the high growth case, growth in investment is projected to increase to 5.2 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, coupled with higher labor force growth, yield higher aggregate economic growth than projected in the reference case. In the low growth case, annual growth in investment expenditures is projected to slow to 3.3 percent. With the labor force also growing more slowly, aggregate economic growth is expected to slow considerably.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 32. World oil prices in three cases, 1970-2025 (2001 dollars per barrel)



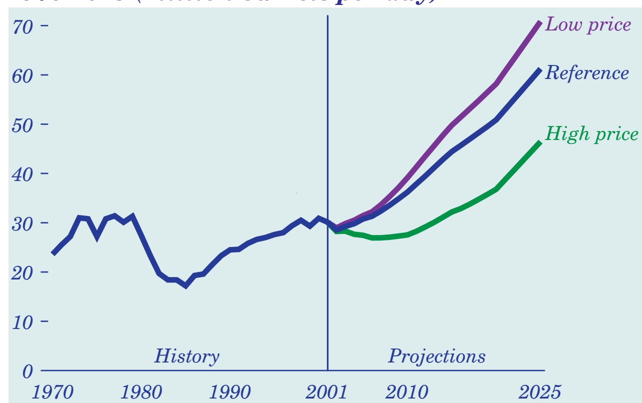
The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. Three *AEO2003* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 32). In the reference case, projected prices rise initially (through 2003), decline briefly (through 2005), then rise by about 0.7 percent per year to $26.57 in 2025 (all prices in 2001 dollars unless otherwise noted). In nominal dollars, the reference case price is expected to exceed $48 in 2025. In the low price case, prices are projected to decline from their high in 2003, reaching $19.04 by 2010, and to remain at that level out to 2025. The high price case projects a price rise of about 2.9 percent per year from 2001 to 2015, with prices remaining at about $33 out to 2025. The projected leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

The price projections in the three cases are somewhat higher than those in *AEO2002*, recognizing the recent success of OPEC production cutbacks in raising oil prices and acknowledging that such OPEC market management behavior will most likely continue in the future. Production from countries outside OPEC is expected to show a steady increase, from around 47 million barrels per day in 2002 to about 62 million barrels per day by 2025.

Total world demand for oil is expected to reach 112 million barrels per day by 2020 and 123 million by 2025. Developing countries in Asia show the largest projected growth in demand, averaging 3.3 percent per year, led by China at 3.9 percent per year.

Uncertain Prospects for Persian Gulf Production Shape Oil Price Cases

Figure 33. OPEC oil production in three cases, 1970-2025 (million barrels per day)



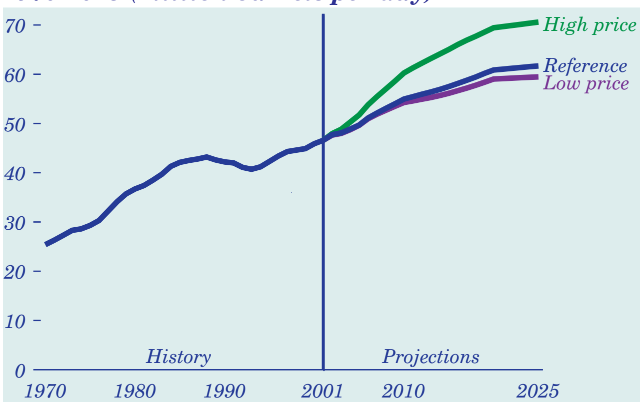
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher in the low price case and lower in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be the principal source of marginal supply to meet increases in demand.

The projected increase in OPEC production capacity in the reference case is consistent with announced plans for OPEC capacity expansion [*32*]. By 2025, OPEC production is projected to be about 61 million barrels per day (more than twice its 2001 production) in the reference case, 46 million in the high price case, and roughly 71 million in the low price case (Figure 33). Worldwide demand for oil varies across the price cases in response to the price paths. The forecasts of total world demand for oil range from 131 million barrels per day in the low price case to 117 million barrels per day in the high price case.

The variation in oil production forecasts reflects uncertainty about the prospects for future production from the Persian Gulf region. The expansion of productive capacity will require major capital investments, which could depend on the availability and acceptability of foreign investments. Iraq is assumed to continue selling oil at sanction-allowed volumes through 2003 and, once the sanctions are lifted, expand its production capacity to about 6 million barrels per day. Recent discoveries offshore of Nigeria, as well as Venezuela's plans to continue the expansion of its ultra-heavy-oil production capacity, will more than accommodate increasing demand in the absence of Iraq's full return to the oil market.

Production Increases Are Expected for Non-OPEC Oil Producers

Figure 34. Non-OPEC oil production in three cases, 1970-2025 (million barrels per day)

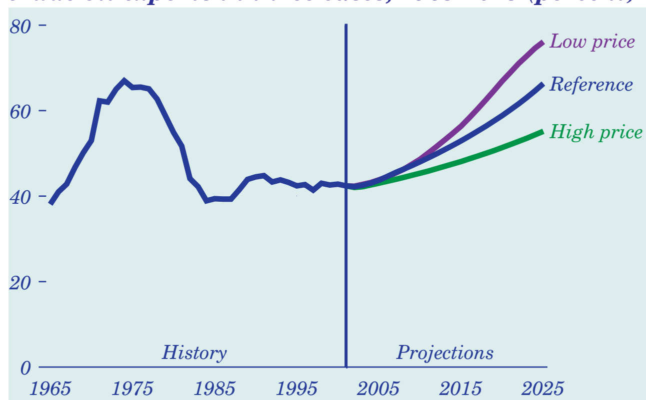


The growth and diversity in non-OPEC oil supply have shown surprising resilience even during the low price environment of the late 1990s. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. Countries in the Organization for Economic Cooperation and Development (OECD) that are expected to register production increases over the next decade include Norway, Australia, Canada, and Mexico. Canada is expected to almost double current production volumes by significantly increasing nonconventional output from oil sands in its western territory. In Latin America, Brazil, Argentina, Ecuador, Peru, and Trinidad are showing accelerated growth in oil production, due in part to privatization efforts. Deepwater projects off the coast of western Africa and in the South China Sea will start producing significant volumes of oil early in this decade. In addition, much of the increase in non-OPEC supply over the next decade is expected to come from the former Soviet Union, and political uncertainty appears to be the only potential barrier to the development of vast oil resources in the Caspian Basin.

In the *AEO2003* reference case, non-OPEC supply is projected to reach almost 62 million barrels per day by 2025 (Figure 34). In the low oil price case, non-OPEC supply is projected to grow to more than 59 million barrels per day by 2025, whereas in the high oil price case it is projected to reach more than 70 million barrels per day by the end of the forecast period.

Persian Gulf Producers Could Take More Than Half of World Oil Trade

Figure 35. Persian Gulf share of worldwide crude oil exports in three cases, 1965-2025 (percent)

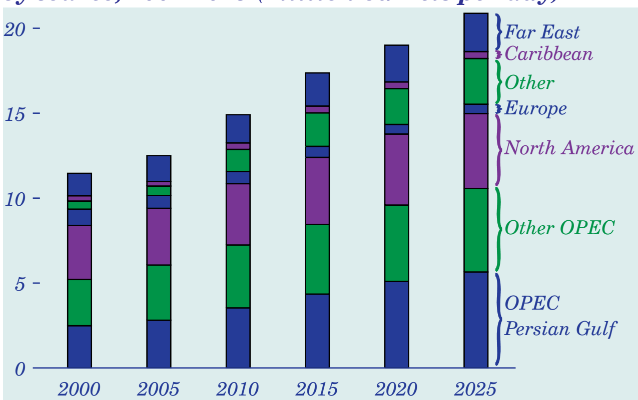


Considering the world market in crude oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the crude oil traded in world markets (Figure 35). The most recent historical low for Persian Gulf oil exports came in 1984 as a result of more than a decade of high oil prices, which led to significant reductions in worldwide petroleum consumption. Less than 40 percent of the crude oil traded in 1984 came from Persian Gulf suppliers. Following the 1985 oil price collapse, the Persian Gulf export percentage again began a gradual increase, but it leveled off in the 1990s at 40 to 45 percent when non-OPEC supply proved to be unexpectedly resilient.

In the *AEO2003* reference case, Persian Gulf producers are expected to account for 45 percent of worldwide trade by 2007—for the first time since the early 1980s. After 2007, the Persian Gulf share of worldwide petroleum exports is projected to increase gradually to 66 percent by 2025. In the low oil price case, the Persian Gulf share of total exports is projected to reach 76 percent by 2025. All Persian Gulf producers are expected to increase oil production capacity significantly over the forecast period, and both Saudi Arabia and Iraq (assuming the lifting of United Nations export sanctions after 2003) are expected to nearly triple their current production capacity.

OPEC Is Expected To Account for Half of U.S. Oil Imports by 2025

Figure 36. Projected U.S. gross petroleum imports by source, 2001-2025 (million barrels per day)



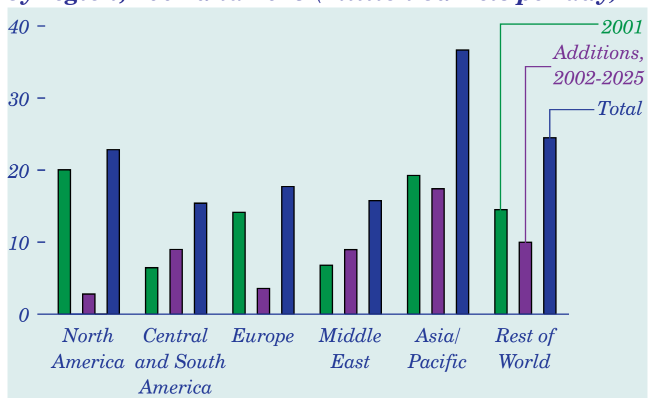
In the reference case, total U.S. gross oil imports are projected to grow from 11.9 million barrels per day in 2001 to 20.9 million in 2025 (Figure 36). Crude oil accounts for most of the expected increase in imports through 2010, but imports of petroleum products make up a larger share after 2010. Product imports are projected to grow more rapidly as U.S. production stabilizes, because U.S. refineries lack the capacity to process much larger quantities of imported crude oil.

OPEC is expected to account for less than 50 percent of total projected U.S. petroleum imports through most of the forecast. The OPEC share is expected to increase gradually to 50 percent by 2019 and exceed 50 percent for the remainder of the forecast. The Persian Gulf share of U.S. imports from OPEC is projected to range between 46 and 54 percent consistently throughout the forecast. Crude oil imports from the North Sea are projected to increase slightly through 2007, then to decline gradually as the United Kingdom's North Sea production ebbs. Significant imports of petroleum from Canada and Mexico are expected to continue, and West Coast refiners are expected to import crude oil from the Far East to replace the declining production of Alaskan crude oil.

Imports of light products are expected to more than triple by 2025, to 5.3 million barrels per day. Most of the projected increase is from refiners in the Caribbean Basin, North Africa, and the Middle East, where refining capacity is expected to expand significantly. Vigorous growth in demand for lighter petroleum products in developing countries means that U.S. refiners are likely to import smaller volumes of light, low-sulfur crude oils.

Asia/Pacific Region Is Expected To Surpass U.S. Refining Capacity

Figure 37. Projected worldwide refining capacity by region, 2001 and 2025 (million barrels per day)



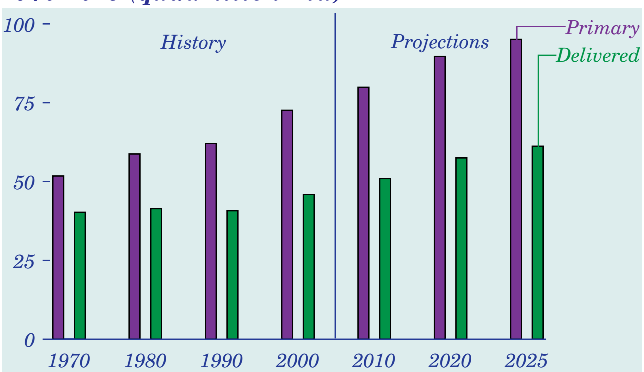
Worldwide crude oil distillation capacity was 81.2 million barrels per day at the beginning of 2002. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by 64 percent—to almost 133 million barrels per day—by 2025. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 37).

The Asia/Pacific region was the fastest growing refining center in the 1990s. It surpassed Western Europe as the world's second largest refining center and, in terms of distillation capacity, is expected to surpass North America before 2005. While not adding significantly to their distillation capacity, refiners in the United States and Europe have tended to improve product quality and enhance the usefulness of heavier oils through investment in downstream capacity.

Future investments in the refinery operations of developing countries must include configurations that are more advanced than those currently in operation. Their refineries will be called upon to meet increased worldwide demand for lighter products, to upgrade residual fuel, to supply transportation fuels with reduced lead, and to supply both distillate and residual fuels with decreased sulfur levels. An additional burden on new refineries will be the need to supply lighter products from crude oils whose quality is expected to deteriorate over the forecast period.

Annual Growth in Energy Use Is Projected To Continue

Figure 38. Primary and delivered energy consumption, excluding transportation use, 1970-2025 (quadrillion Btu)



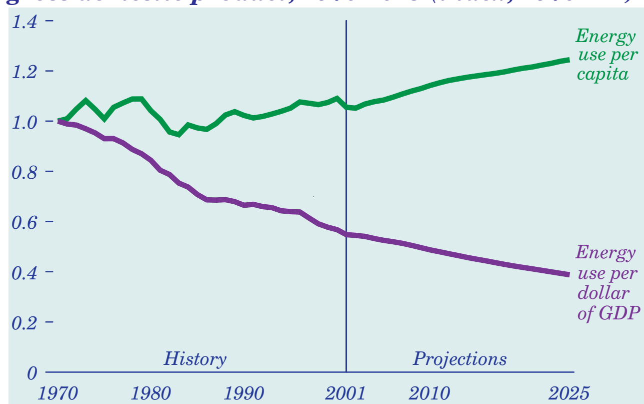
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*33*].

How energy consumption is measured has become more important over time, as reliance on electricity has expanded. In 1970, electricity accounted for only 12 percent of energy delivered to the end-use sectors, excluding transportation. Since then, the growth in electricity use for applications such as space conditioning, consumer appliances, telecommunication equipment, and industrial machinery has resulted in greater divergence between primary and delivered energy consumption (Figure 38). This trend is expected to stabilize in the forecast, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption and delivered energy consumption grow by 1.3 and 1.4 percent per year, respectively, excluding transportation use.

At the end-use sectoral level, tracking of primary energy consumption is necessary to link specific policies with overall goals. Carbon dioxide emissions, for example, are closely correlated with primary energy consumption. In the development of carbon dioxide stabilization policies, growth rates for primary energy consumption are generally more important than those for delivered energy.

Average Energy Use per Person Increases Slightly in the Forecast

Figure 39. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)

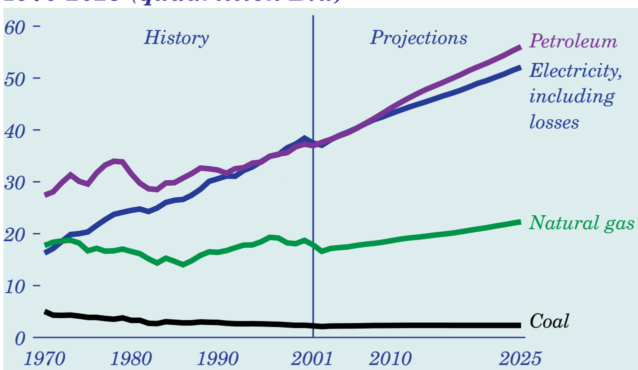


Energy intensity, both as measured by primary energy consumption per dollar of GDP and as measured on a per capita basis, declined between 1970 and the mid-1980s (Figure 39). Although the overall GDP-based energy intensity of the economy is projected to continue declining between 2001 and 2025, the decline is not expected to be as rapid as it was in the earlier period. GDP is estimated to increase by 105 percent between 2001 and 2025, compared with a 43-percent increase in primary energy use. Relatively stable energy prices are expected to slow the decline in energy intensity, as is increased use of electricity-based energy services. When electricity claims a greater share of energy use, consumption of primary energy per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption.

In the *AEO2003* forecast, the demand for energy services in 2025 is projected to increase markedly over 2001 levels. The average home in 2025 is expected to be 6.6 percent larger and to use electricity more intensively. Personal highway travel and air travel per capita are expected to average 1.4 percent and 2.2 percent growth per year, respectively, between 2001 and 2025. With the growth in demand for energy services, primary energy use per capita is projected to increase by 0.7 percent per year through 2025, with efficiency improvements in many end-use energy applications making it possible to provide higher levels of service without significant increases in total energy use per capita.

Petroleum Products Lead Growth in Energy Consumption

Figure 40. Delivered energy use by fossil fuel and primary energy use for electricity generation, 1970-2025 (quadrillion Btu)



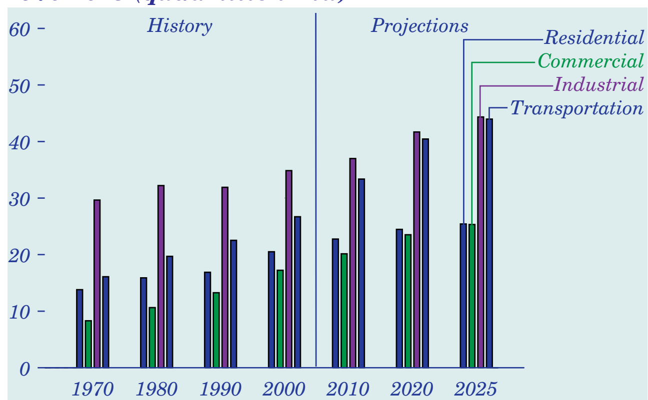
Consumption of petroleum products, mainly for transportation, makes up the largest share of primary energy use in the *AEO2003* forecast (Figure 40). Growth in energy demand for transportation averaged 2.0 percent per year in the 1970s but was slowed in the 1980s by rising fuel prices and new Federal efficiency standards that led to a 2.1-percent annual increase in average vehicle fuel economy. Fuel economy gains are projected to slow as a result of expected stable real fuel prices and the absence of new legislative mandates. Growth in population and in travel per capita are expected to increase demand for gasoline throughout the forecast.

Increased competition and technological advances in electricity generation and distribution are expected to slightly reduce the real cost of electricity. Despite low projected prices, however, growth in electricity use is expected to be slower than the rapid growth of the 1970s because of efficiency improvements and market saturation of certain end uses such as air conditioning. Excluding consumption for electricity generation, demand for natural gas is projected to grow at a slightly slower rate than overall end-use energy demand, in contrast to the recent trend of more rapid growth in the use of gas as the industry was deregulated. Natural gas is projected to meet 24 percent of end-use energy requirements in 2025.

End-use demand for energy from renewables such as wood and ethanol is projected to increase by 1.8 percent per year. Geothermal and solar energy use in buildings is expected to increase by about 2.5 percent per year but is not expected to exceed 1 percent of energy use for space and water heating.

U.S. Primary Energy Use Exceeds 139 Quadrillion Btu per Year by 2025

Figure 41. Primary energy consumption by sector, 1970-2025 (quadrillion Btu)



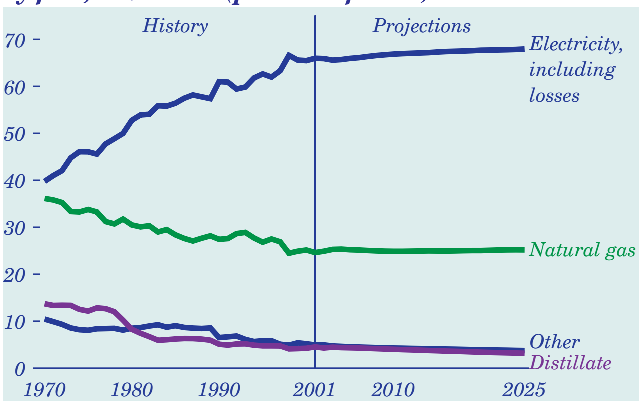
Primary energy use in the reference case is projected to reach 139.1 quadrillion Btu by 2025, 40 percent higher than the 2000 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 41). Between 1980 and 2000, however, stable energy prices contributed to a marked increase in sectoral energy consumption.

In the forecast, energy demand in the residential sector is projected to grow at one-third the expected growth rate for GDP and in the commercial sector at just over one-half the GDP growth rate. Demand for energy is expected to grow more rapidly in the transportation sector than in the buildings sectors as a result of increased per capita travel and slower fuel efficiency gains. Assumed efficiency gains in the industrial sector are projected to cause the demand for primary energy to grow more slowly than GDP.

To bracket the uncertainty inherent in any long-term forecast, alternative cases were used to highlight the sensitivity of the forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Projected oil use for transportation in the high world oil price case is 4.7 percent lower than in the low world oil price case in 2025, as consumer choices favor more fuel-efficient vehicles and the demand for travel services is reduced slightly. In contrast, variations in economic growth assumptions lead to larger changes in the projections of overall energy demand in each of the end-use sectors [*34*]. For 2025, the projection of total annual energy use in the high economic growth case is 15 percent higher than in the low economic growth case.

Residential Energy Use Grows by 27 Percent From 2001 to 2025

Figure 42. Residential primary energy consumption by fuel, 1970-2025 (percent of total)



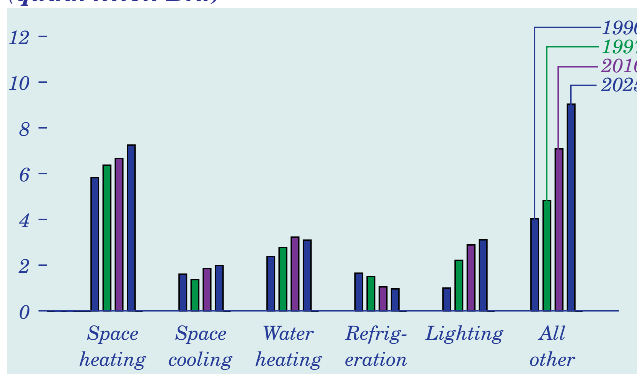
Residential energy consumption is projected to increase by 27 percent between 2001 and 2025. Most (75 percent) of the growth in total energy use is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 42).

While its share of total residential primary energy consumption remains about the same over time, natural gas use in the residential sector is projected to grow by 1.1 percent per year through 2025. After 2001, natural gas prices to residential customers are projected to increase by nearly 10 percent over the forecast but to remain lower than the prices of other fuels, such as heating oil. The number of homes heated by natural gas is projected to increase more than the number heated by electricity and oil. Petroleum use is projected to fall, with the number of homes using petroleum-based fuels for space heating applications expected to decrease over time.

Newly built homes today are, on average, 18 percent larger than the existing housing stock, with correspondingly greater needs for heating, cooling, and lighting. Under current building codes and appliance standards, however, energy use per square foot is typically lower for new construction than for the existing stock. Further reductions in residential energy use per square foot could result from additional gains in equipment efficiency and more stringent building codes, requiring more insulation, better windows, and more efficient building designs.

Efficiency Standards Moderate Residential Energy Use

Figure 43. Residential primary energy consumption by end use, 1990, 1997, 2010, and 2025 (quadrillion Btu)



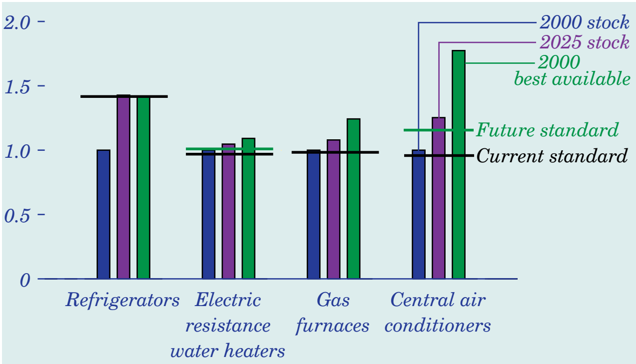
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 1.3 percent per year from 1990 to 1997 (Figure 43). Future growth is expected to be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand by about 9 percent per household in 2025 relative to the demand in 1997.

A variety of appliances are now subject to minimum efficiency standards, including heat pumps, air conditioners, furnaces, refrigerators, and water heaters. Current standards for a typical residential refrigerator, which became effective in July 2001, limit electricity use to 478 kilowatthours per year. Energy use for refrigeration has declined by 1.3 percent per year from 1990 to 1997 and is expected to decline by about 1.4 percent per year through 2025, as older, less efficient refrigerators are replaced with newer models.

The "all other" category, which includes smaller appliances such as personal computers, dishwashers, clothes washers, and dryers, has grown by 2.6 percent per year from 1990 to 1997 and now accounts for 28 percent of residential primary energy use. It is projected to account for 36 percent in 2025, as small electric appliances continue to penetrate the market. The promotion of voluntary standards, both within and outside the appliance industry, is expected to forestall even larger increases. Even so, the "all other" category is projected to exceed other components of residential demand by 2025, growing at an annual rate of 2.0 percent from 2001 to 2025.

Available Technologies Can Slow Growth in Residential Energy Use

Figure 44. Efficiency indicators for selected residential appliances, 2000 and 2025 (index, 2000 stock efficiency =1)

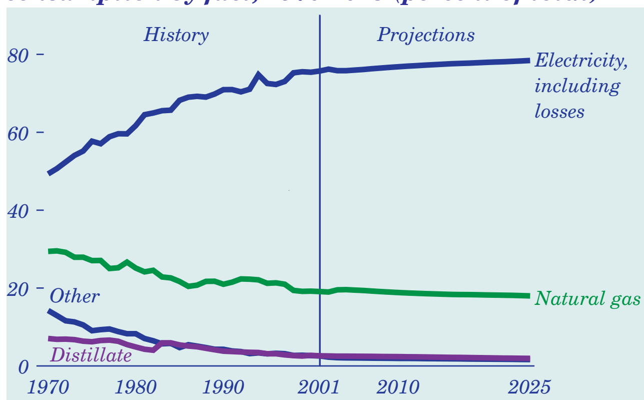


The *AEO2003* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 2001 stock, ensuring an increase in stock efficiency (Figure 44) without any additional new standards. Future updates to the Federal standards could have a significant effect on residential energy consumption, but they are not included in the reference case. The new efficiency standards for water heaters, clothes washers, central air conditioners, and heat pumps that were announced in January 2001 are included in the reference case.

For almost all end-use services, existing technologies can significantly curtail future energy demand if they are purchased by consumers. The most efficient technologies can provide significant long-run savings in energy bills, but their higher purchase costs tend to restrict their market penetration. For example, condensing technology for natural gas furnaces, which reclaims heat from exhaust gases, can raise efficiency by more than 20 percent over the current standard; and variable-speed scroll compressors for air conditioners and refrigerators can increase their efficiency by 50 percent or more. In contrast, there is little room for efficiency improvements in electric resistance water heaters, because the technology is approaching its thermal limit.

Energy Fuel Shares for Commercial Users Are Expected To Remain Stable

Figure 45. Commercial primary energy consumption by fuel, 1970-2025 (percent of total)

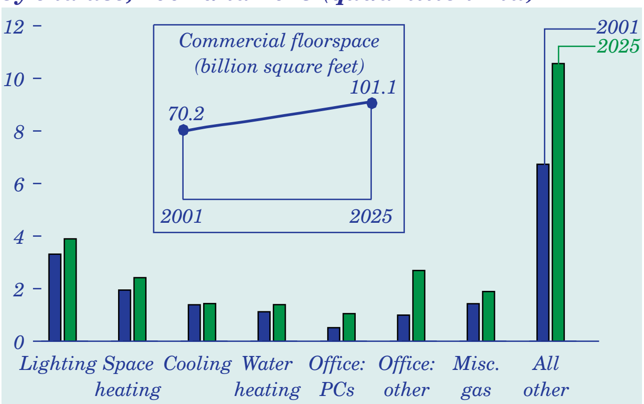


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past three decades (Figure 45). Commercial energy use, including electricity-related losses, is projected to grow at about the same rate as commercial floorspace, by 1.6 percent per year between 2001 and 2025. Energy consumption per square foot is projected to show no increase, with efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements expected to balance the effects of a projected increase in demand for electricity-based services and stable or declining fuel prices.

Electricity accounted for 76 percent of commercial primary energy consumption in 2001, and its share is projected to increase to 78 percent in 2025. Expected efficiency gains in electric equipment are expected to be offset by the continuing penetration of new technologies and greater use of office equipment. Natural gas, which accounted for 19 percent of commercial energy consumption in 2001, is projected to maintain an 18-percent share through the latter half of the forecast. Distillate fuel oil made up only 3 percent of commercial demand in 2001, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate declines to 2 percent in 2025, as natural gas continues to compete for space and water heating uses. With stable prices projected for conventional fuels, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Lighting Is the Commercial Sector's Most Important Energy Application

Figure 46. Commercial primary energy consumption by end use, 2001 and 2025 (quadrillion Btu)

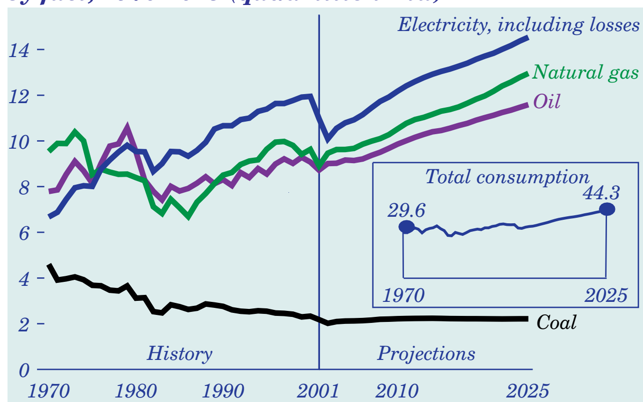


Through 2025, lighting is projected to remain the most important individual end use in the commercial sector [*35*]. Energy use for lighting is projected to increase slightly, as growth in lighting requirements is expected to outpace the adoption of more energy-efficient lighting equipment. Efficiency of space heating, space cooling, and water heating is also expected to improve, moderating growth in overall commercial energy demand. A projected increase in building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 46).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers is projected to grow by 3.0 percent per year and for other office equipment, such as copiers, fax machines, and larger computers, by 4.2 percent per year. The projected growth in electricity use for office equipment reflects a trend toward more powerful equipment, the response to projected declines in real electricity prices, and increases in the market for commercial electronic equipment. Natural gas use for such miscellaneous uses as cooking and self-generated electricity is expected to grow by 1.2 percent per year. New telecommunications technologies and medical imaging equipment are projected to increase electricity demand in the "all other" end-use category, which also includes ventilation, refrigeration, minor fuel consumption, and energy use for a myriad of other uses such as municipal water services, service station equipment, and vending machines. Annual growth of 1.9 percent is expected for the "all other" category.

Industrial Energy Use Could Grow by 36 Percent by 2025

Figure 47. Industrial primary energy consumption by fuel, 1970-2025 (quadrillion Btu)

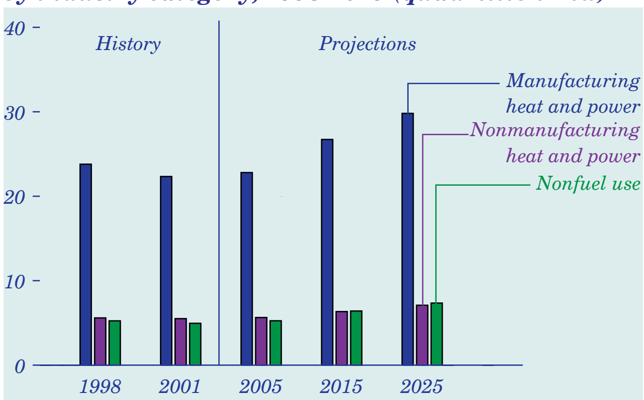


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 33 percent. The natural gas share fell from 32 percent to 24 percent, and coal's share fell from 16 percent to 9 percent. After 1986, natural gas began to recover its share as end-use regulations were lifted and supplies became more certain and less costly. As on-site cogeneration increased, the share of industrial delivered energy use made up by purchased electricity declined.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—is projected to increase by 1.3 percent per year (Figure 47). Electricity (for machine drive and some production processes) and natural gas (given its ease of handling) are the major energy sources for heat and power in the industrial sector. Industrial purchased electricity use is projected to increase by 47 percent, with competition in the generation market keeping electricity prices low. Despite a projected increase in natural gas prices after 2002, its use for energy in the industrial sector is expected to increase by 45 percent between 2001 and 2025. Petroleum use for energy in the industrial sector is projected to grow by 22 percent. Coal use is expected to remain essentially constant, as new steelmaking technologies continue to reduce demand for metallurgical coal, offsetting modest growth in coal use for boiler fuel and as a substitute for coke in steelmaking.

Industrial Energy Use Grows Steadily in the Projections

Figure 48. Industrial primary energy consumption by industry category, 1998-2025 (quadrillion Btu)



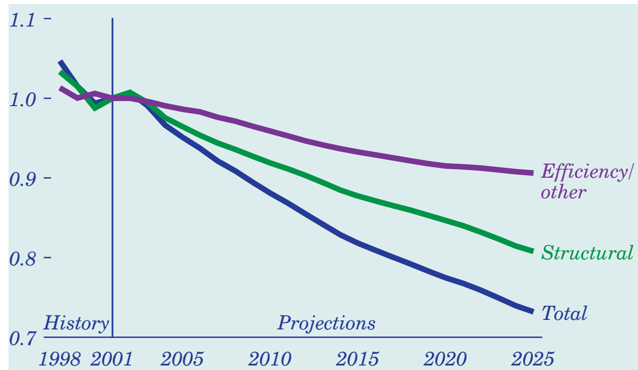
About two-thirds of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing. The remainder is approximately equally distributed between nonmanufacturing heat and power and consumption for nonfuel purposes, such as raw materials and asphalt (Figure 48).

Nonfuel use of energy in the industrial sector is projected to grow more rapidly (1.5 percent per year) than heat and power consumption (1.2 percent per year). The feedstock portion of nonfuel use is projected to grow at a slightly lower rate (1.6 percent per year) than the output of the bulk chemical industry (1.8 percent per year) due to limited substitution possibilities. In 2025, feedstock consumption is projected to be 5.5 quadrillion Btu. Asphalt use, the other component of nonfuel energy use, is projected to grow by 1.1 percent per year, to 1.7 quadrillion Btu in 2025. The construction industry is the principal consumer of asphalt for paving and roofing. Asphalt use does not grow as rapidly as construction output (1.4 percent per year), because not all construction activities require asphalt.

Petroleum refining, chemicals, and pulp and paper are among the largest end-use consumers of energy for heat and power in the manufacturing sector. These three energy-intensive industries used 8.3 quadrillion Btu of delivered energy in 2001. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for approximately 60 percent of the delivered energy consumed for heat and power. The pulp and paper industry uses the most renewables, in the form of wood and spent liquor.

Output From U.S. Industries Grows Faster Than Energy Use

Figure 49. Components of improvement in industrial delivered energy intensity, 1998-2025 (index, 2001 = 1)

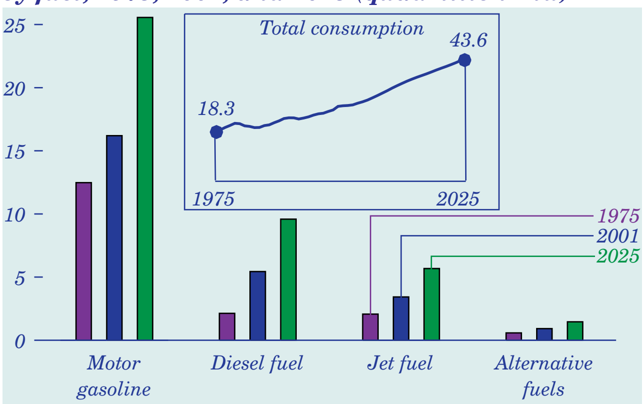


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of industrial value of shipments. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has dampened growth in industrial energy consumption. Thus, despite a 45-percent increase in industrial shipments, total energy use in the sector grew by only 1 percent between 1980 and 2001. Energy consumption is projected to grow more slowly than industrial shipments in the *AEO2003* reference case.

Industrial value of shipments is projected to grow by 2.6 percent per year from 2001 to 2025. The share of total industrial shipments attributed to the energy-intensive industries is projected to fall from 20 percent in 2001 to 15 percent in 2025. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial intensity would decline. Figure 49 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*36*]. Over the forecast period, industrial delivered energy intensity is projected to drop by 26 percent, and the changing composition of industrial output alone is projected to result in approximately an 18-percent drop. Thus, two-thirds of the expected change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with projected increases in equipment and production efficiencies.

Alternative Fuels Make Up 1.5 Percent of Light-Duty Vehicle Fuel Use in 2025

Figure 50. Transportation energy consumption by fuel, 1975, 2001, and 2025 (quadrillion Btu)



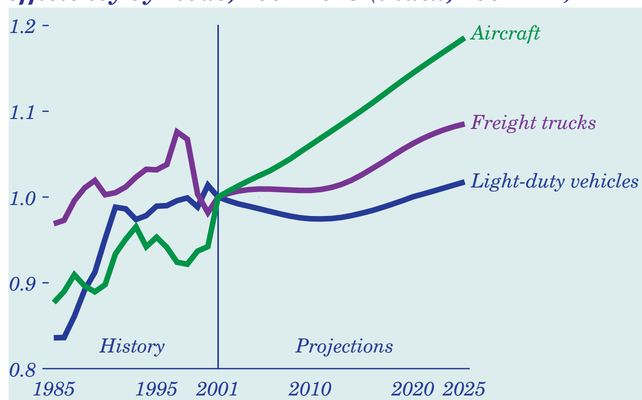
By 2025, total energy demand for transportation is expected to be 43.7 quadrillion Btu, compared with 26.9 quadrillion Btu in 2001 (Figure 50). Petroleum products dominate energy use in the sector. Motor gasoline use is projected to increase by 2.0 percent per year in the reference case, making up 59.2 percent of transportation energy demand. Alternative fuels are projected to displace 182,000 barrels of oil equivalent per day [*37*] by 2025 (1.5 percent of light-duty vehicle fuel consumption), in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is expected to be sustained, however, by low gasoline prices and slower fuel efficiency gains for conventional light-duty vehicles (cars, vans, pickup trucks, and sport utility vehicles) than were achieved during the 1980s.

Assumed industrial output growth of 2.6 percent per year through 2025 leads to an increase in freight transport, with a corresponding 2.4-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield a 2.4-percent projected annual increase in air travel, causing jet fuel use to increase by 2.1 percent per year.

In the forecast, energy prices directly affect the level of oil use through travel costs and average vehicle fuel efficiency. Most of the price sensitivity is seen as variations in motor gasoline use in light-duty vehicles, because the stock of light-duty vehicles turns over more rapidly than the stock for other modes of travel. In the high oil price case, gasoline use increases by 1.8 percent per year, compared with 2.1 percent per year in the low oil price case.

Average Horsepower for New Cars Is Projected To Grow by 27 Percent

Figure 51. Projected transportation stock fuel efficiency by mode, 2001-2025 (index, 2001 = 1)



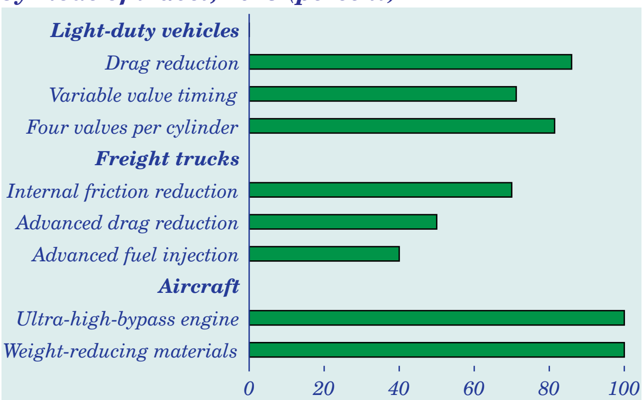
Fuel efficiency is projected to improve at a slower rate through 2025 than it did in the 1980s, with fuel efficiency standards for light-duty vehicles assumed to stay at current levels and projected low fuel prices and higher personal income expected to increase the demand for larger, more powerful vehicles (Figure 51). Average horsepower for new cars in 2025 is projected to be 27 percent above the 2001 average (Table 7), but advanced technologies and materials are expected to keep new vehicle fuel economy from declining [*38*]. Advanced technologies such as variable valve timing and direct fuel injection, as well as electric hybrids for both gasoline and diesel engines, are projected to boost the average fuel economy of new light-duty vehicles by about 2 miles per gallon, to 26.1 miles per gallon in 2025. A small percentage gain in efficiency is expected for freight trucks (from 6.0 miles per gallon in 2001 to 6.5 in 2025), and a larger gain is expected for aircraft (an 18.6-percent increase over the forecast period).

Table 7. New car and light truck horsepower ratings and market shares, 1990-2025

	Cars			Light trucks		
Year	Small	Medium	Large	Small	Medium	Large
1990						
Horsepower	119	145	176	132	157	185
Sales share	0.60	0.28	0.12	0.48	0.21	0.30
2000						
Horsepower	145	177	221	173	185	229
Sales share	0.50	0.35	0.15	0.30	0.34	0.36
2010						
Horsepower	174	214	248	209	222	273
Sales share	0.50	0.35	0.15	0.30	0.34	0.35
2025						
Horsepower	191	236	267	229	231	289
Sales share	0.51	0.34	0.15	0.30	0.34	0.35

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 52. Projected technology penetration by mode of travel, 2025 (percent)



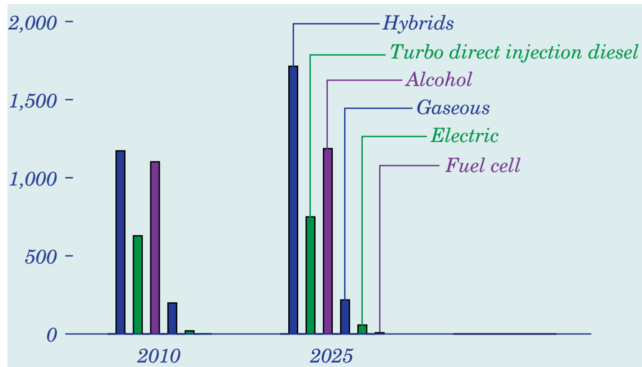
New automobile fuel economy is projected to reach approximately 30.1 miles per gallon by 2025, as a result of advances in fuel-saving technologies (Figure 52). Three of the most promising, each of which would provide more than 8 percent higher fuel economy, are advanced drag reduction, variable valve timing and lift, and extension of four valve per cylinder technology to six-cylinder engines. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and increasing the number of valves on the cylinder improves efficiency through more complete combustion of fuel in the engine.

Due to concerns about economic payback, the trucking industry is more sensitive to the marginal cost of fuel-efficient technologies; however, several technologies can increase fuel economy significantly, including components to reduce internal friction (2 percent improvement), advanced drag reduction (2 percent), and advanced fuel injection systems (5 percent). These technologies are anticipated to penetrate the heavy-duty truck market by 2025. Advanced technology penetration is projected to increase new freight truck fuel efficiency from 6.1 miles per gallon to 6.5 miles per gallon between 2001 and 2025.

New aircraft fuel efficiencies are projected to increase by 19 percent from 2001 levels by 2025. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Could Reach 21 Percent of Sales by 2025

Figure 53. Projected sales of advanced technology light-duty vehicles by fuel type, 2010 and 2025 (thousand vehicles sold)

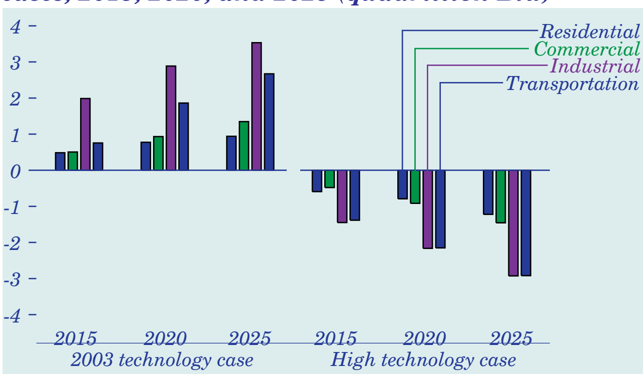


Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 3.9 million vehicle sales per year by 2025 (21 percent of total projected light-duty vehicle sales). Hybrid electric vehicles, introduced into the U.S. market by two manufacturers in 2000, are anticipated to sell well, at 1.7 million units by 2025, leading advanced technology vehicle sales (Figure 53). Alcohol flexible-fueled vehicles follow with approximately 1.2 million vehicle sales by 2025. Sales of turbo direct injection diesel vehicles are projected to increase to 750,000 units by 2025. These advanced technologies will initially sell for less than $7,000 above an equivalent gasoline vehicle, but only the gasoline hybrid and the turbo direct injection diesel can achieve vehicle ranges that exceed 500 miles while delivering 20 to 35 percent better fuel economy than a comparable gasoline vehicle.

About 80 percent of advanced technology sales are a result of Federal and State mandates for fuel economy standards, emissions programs, or other energy regulations. Alcohol flexible-fueled vehicles are currently sold by manufacturers who receive fuel economy credits to comply with corporate average fuel economy regulations. The majority of projected gasoline hybrid and electric vehicle sales result from compliance with low-emission vehicle programs in California, New York, Maine, Vermont, and Massachusetts.

Alternative Cases Analyze Effects of Advances in Technology

Figure 54. Projected variation from reference case primary energy use by sector in two alternative cases, 2015, 2020, and 2025 (quadrillion Btu)



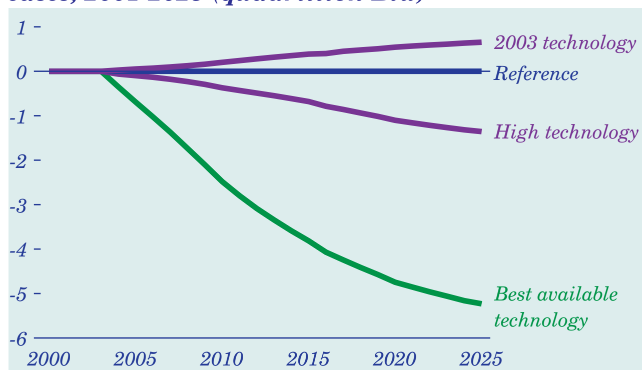
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of these assumptions (Figure 54). The alternative cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or on economic growth.

For the residential and commercial sectors, the 2003 technology case holds equipment and building shell efficiencies at 2003 levels. The best available technology case assumes that the most energy-efficient equipment and best residential building shells available are chosen for new construction each year regardless of cost, and that the efficiencies of existing residential and all commercial building shells improve from their reference case levels. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced technologies than in the reference case.

The 2003 technology cases for the industrial and transportation sectors and the high technology case for the industrial sector use the same assumptions as the buildings sector cases. The high transportation technology case includes lower costs for advanced light-duty vehicle and aircraft technologies and improved efficiencies, comparable to those used in a Department of Energy (DOE) interlaboratory study for air, rail, and marine travel and provided by DOE's Office of Energy Efficiency and Renewable Energy and the American Council for an Energy-Efficient Economy for light-duty vehicles and by Argonne National Laboratory for freight trucks [*39*].

Advanced Technologies Could Reduce Residential Energy Use by 21 Percent

Figure 55. Projected variation from reference case primary residential energy use in three alternative cases, 2001-2025 (quadrillion Btu)



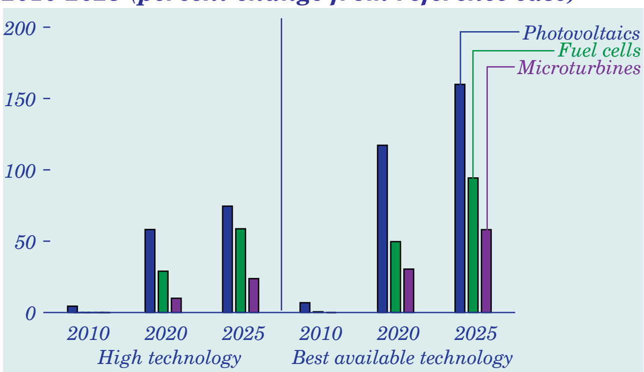
The *AEO2003* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2003 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 2003, 3 percent more energy would be required in 2025 (Figure 55).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected energy use in 2025 is 21 percent lower than in the reference case, and household primary energy use in 2025 is 23 percent lower than in the 2003 technology case. Through 2025, projected additional investment of $341 billion would be necessary to save a projected $164 billion in energy costs in this case [*40*].

The high technology case does not constrain consumer choices. Instead, the most energy-efficient technologies are assumed to be available earlier, with lower costs and higher efficiencies. The consumer discount rates used to determine the purchased efficiency of all residential appliances in the high technology case do not vary from those used in the reference case; that is, consumers value efficiency equally across the two cases. Energy consumption in 2025 in this case is projected to be 5 percent lower than in the reference case; however, the savings are not as great as those projected in the best available technology case.

Advanced Technologies Could Slow Electricity Sales Growth for Buildings

Figure 56. Buildings sector electricity generation from advanced technologies in alternative cases, 2010-2025 (percent change from reference case)



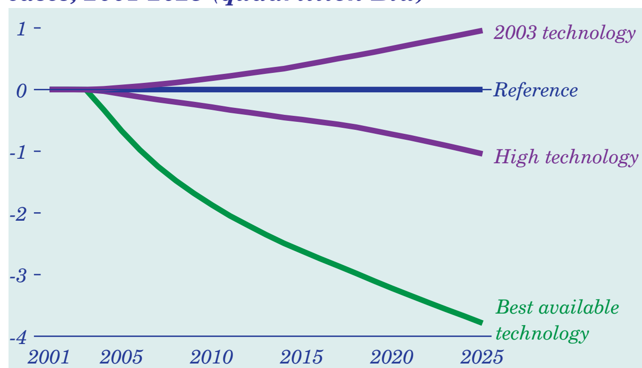
Alternative technology cases for the buildings sectors include a range of assumptions for the availability and market penetration of advanced distributed generation technologies. Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing system efficiency and the attractiveness of the advanced technologies, particularly in alternative cases with more optimistic technology assumptions.

In the high technology case, solar photovoltaic systems, fuel cells, and microturbines are projected to provide 6 billion kilowatthours (27 percent) more electricity in 2025 than in the reference case, most of which offsets residential and commercial electricity purchases (Figure 56). In the best technology case, projected electricity generation in buildings in 2025 is 11 billion kilowatthours (51 percent) higher than in the reference case. In the 2003 technology case, assuming no further technological progress or cost reductions after 2003, electricity generation in buildings in 2025 is 12 billion kilowatthours (55 percent) lower than projected in the reference case.

The additional natural gas use projected for fuel cells and microturbines to provide heat and power in commercial buildings in the high technology case offsets reductions from improved building shells and end-use equipment. Although the best technology case projects even higher adoption of these technologies, the additional end-use savings projected when the most efficient technologies are chosen, regardless of cost, outweigh the additional natural gas consumption needed to fuel distributed generation systems.

Advanced Technologies Could Reduce Commercial Energy Use by 15 Percent

Figure 57. Projected variation from reference case primary commercial energy use in three alternative cases, 2001-2025 (quadrillion Btu)

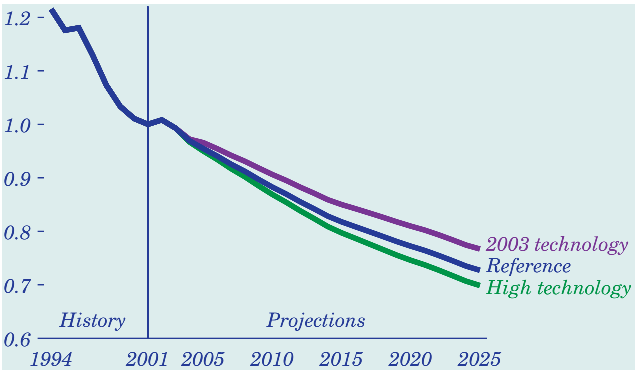


The *AEO2003* reference case incorporates efficiency improvements for commercial equipment and building shells, preventing any increase in commercial energy intensity over the forecast. The 2003 technology case assumes that future equipment and building shells will be no more efficient than those available in 2003. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at the rate assumed in the high technology case.

Energy use in the 2003 technology case is projected to be 4 percent higher than in the reference case by 2025 (Figure 57) as the result of a 0.2-percent annual increase in commercial primary energy intensity. The high technology case projects an additional 4-percent energy savings in 2025, with primary energy intensity falling by 0.1 percent per year from 2001 to 2025. Assuming the purchase of only the most efficient equipment in the best available technology case yields energy use that is 15 percent lower than in the reference case by 2025. Commercial primary energy intensity in this case is projected to decline more rapidly than in the high technology case, by 0.6 percent per year. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. By 2025, commercial solar photovoltaic systems are projected to generate 56 percent more electricity in the best technology case than in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 58. Projected industrial primary energy intensity in two alternative cases, 1998-2025 (index, 2001 = 1)



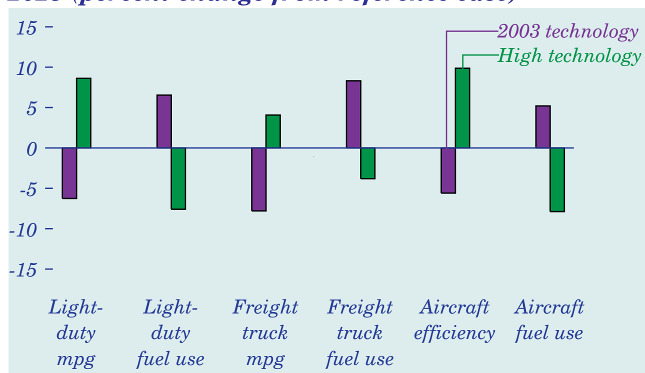
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor. In the reference case, these less energy-intensive industries are projected to grow 57 percent faster than the industrial average (4.1 and 2.6 percent per year, respectively).

In the high technology case, 2.0 quadrillion Btu less energy is projected to be used in 2025 than for the same level of output in the reference case. Industrial primary energy intensity is projected to decline by 1.5 percent per year through 2025 in this case, compared with a 1.3-percent annual decline in the reference case (Figure 58). Industrial cogeneration capacity is projected to increase more rapidly in the high technology case (2.9 percent per year) than in the reference case (2.3 percent per year).

In the 2003 technology case, industry is projected to use 2.9 quadrillion Btu more energy in 2025 than in the reference case. Energy efficiency remains at the level achieved by new plants in 2003, but average efficiency still improves as old plants are retired. Aggregate industrial energy intensity is projected to decline by 1.1 percent per year because of reduced efficiency gains. The change in industrial structure is the same in the 2003 technology and high technology cases as in the reference case, because the same macroeconomic assumptions are used for the three cases. Industrial cogeneration capacity is projected to increase by 2.0 percent per year from 2001 through 2025 in the 2003 technology case.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 59. Projected changes in key components of the transportation sector in two alternative cases, 2025 (percent change from reference case)



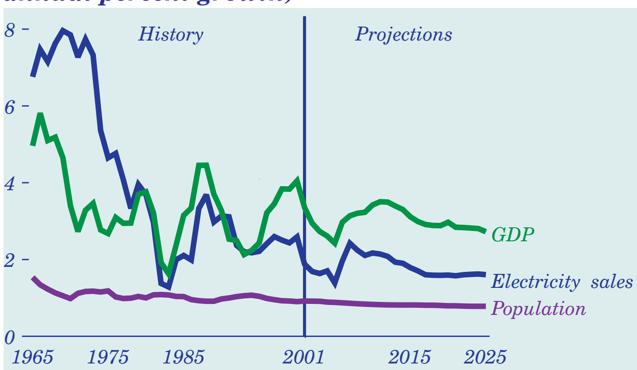
The transportation high technology case assumes lower costs, higher efficiencies, and earlier introduction for new technologies. Projected energy use for transportation is 2.9 quadrillion Btu (6.5 percent) lower in 2025 than in the reference case, reducing projected carbon dioxide emissions by 56 million metric tons carbon equivalent. About 68 percent (1.9 quadrillion Btu) of the difference is attributed to light-duty vehicles. Advances in conventional technologies and in vehicle attributes for advanced technologies are projected to raise the average efficiency of the light-duty vehicle fleet to 21.9 miles per gallon, as compared with a projected increase to 20.2 miles per gallon in the reference case (Figure 59).

Projected fuel demand for freight trucks in 2025 is 0.3 quadrillion Btu lower in the high technology case than in the reference case, and the projected stock efficiency is 4.1 percent higher. Advanced aircraft technologies are also projected to improve aircraft efficiency by 10 percent above the reference case projection, reducing the projected fuel use for air travel in 2025 by 0.5 quadrillion Btu.

In the 2003 technology case, with new technology efficiencies fixed at 2003 levels, efficiency improvements can result only from stock turnover. In 2025, the total projected energy demand for transportation is 2.8 quadrillion Btu (6.5 percent) higher than in the reference case, and projected carbon dioxide emissions are higher by 54 million metric tons carbon equivalent. The average fuel economy of new light-duty vehicles is projected to be 23.7 miles per gallon in 2025 in the 2003 technology case, 2.4 miles per gallon lower than projected in the reference case.

Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 60. Population, gross domestic product, and electricity sales, 1965-2025 (5-year moving average annual percent growth)



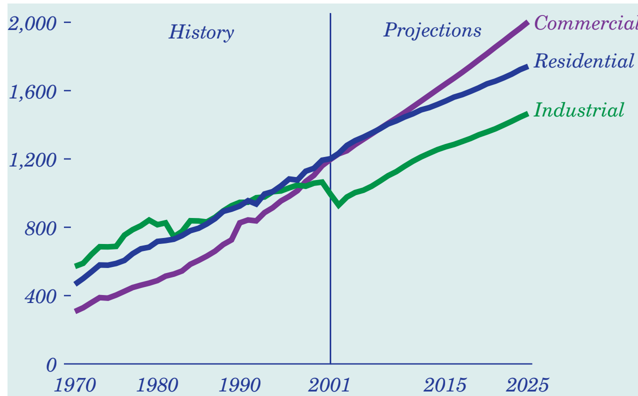
As generators and combined heat and power plants adjust to the evolving structure of the electricity market, they face slower growth in demand than in the past. Historically, demand for electricity has been related to economic growth; that positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 60). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is offset by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electric appliances, the availability and adoption of more efficient equipment, and promulgation of efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 2001 and 2025, compared with 3.0-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset some or all of the projected efficiency gains.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 61. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



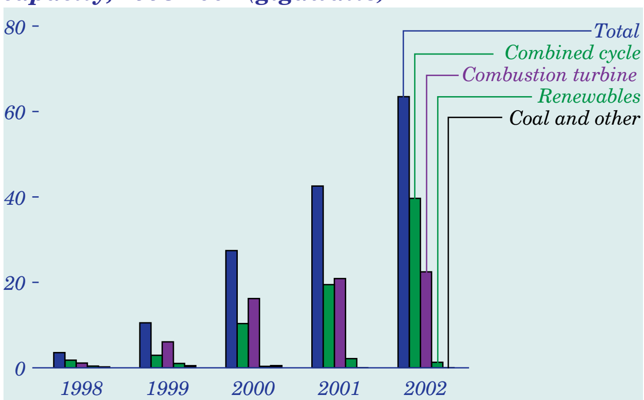
With the number of U.S. households projected to rise by 1.0 percent per year between 2001 and 2025, residential demand for electricity is expected to grow by 1.6 percent annually (Figure 61), a slower rate than in the recent past. Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to meet peak demand. Twenty gigawatts of peaking capacity was added in 2001, and an additional 28 gigawatts is expected by 2003. Peaking capacity from natural gas turbines and internal combustion engines is projected to increase steadily to 179 gigawatts in 2025.

With continued growth in commercial and industrial electricity demand between 2001 and 2025 (2.2 and 1.6 percent per year, respectively), significant additions of baseload generating capacity are projected. Projected growth in commercial floorspace of 1.5 percent per year and growth in industrial shipments of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, combined heat and power plants in 2001 produced 137 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2025, their own-use generation is expected to increase to 212 billion kilowatthours as the demand for manufactured products increases.

Recent Surge in Capacity Additions Is Expected To Meet Near-Term Needs

Figure 62. Additions to electricity generating capacity, 1998-2002 (gigawatts)



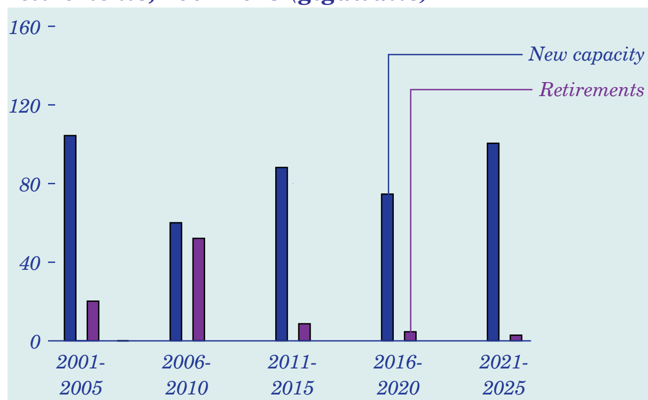
From 1960 to 1969, U.S. power suppliers brought 180 gigawatts of new generating capacity on line—an average of 18 gigawatts per year—and over the next 5 years, from 1970 to 1974, the pace doubled to an average of 36 gigawatts per year. Nearly 314 gigawatts of new capacity was brought on between 1970 and 1979, almost 75 percent more than in the previous 10 years. New capacity additions slowed to 172 gigawatts in the 1980s and 84 gigawatts in the 1990s, and by the mid- to late 1990s many regions of the country needed or were close to needing new capacity in order to meet consumer requirements reliably.

In 2001 and 2002, higher wholesale electricity prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000 and 43 gigawatts in 2001 and are on pace to build 62 gigawatts in 2002 (Figure 62)—by far the most ever built in a single year in the United States. More recently, developers have reported that they are delaying or canceling plants they were planning to build, and new additions are expected to slow in the near term.

Most of the recent additions are natural-gas-fired. Of the 144 gigawatts added between 1999 and 2002, 138 gigawatts is natural-gas-fired, including 72 gigawatts of efficient combined-cycle capacity and 66 gigawatts of combustion turbine capacity, which is used mainly when demand for electricity is high. Only about 5 gigawatts of new renewable plants—mostly wind—and less than 1 gigawatt of new coal-fired capacity were added over the same period.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 63. Projected new generating capacity and retirements, 2001-2025 (gigawatts)



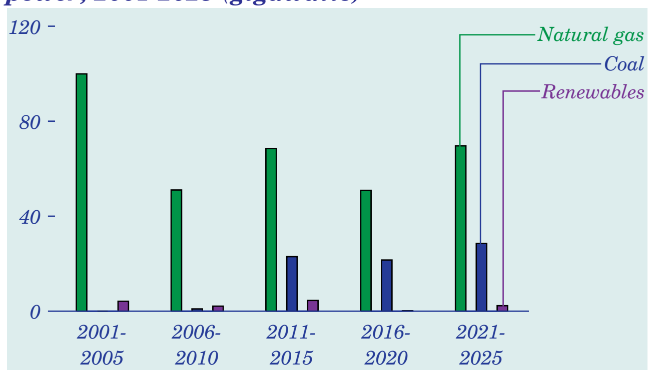
From 2001 to 2025, 428 gigawatts of new generating capacity (excluding combined heat and power plants) is expected to be needed to meet growing demand and to replace retiring units (Figure 63). Between 2001 and 2025, 3 gigawatts (3 percent) of current nuclear capacity and 79 gigawatts (13 percent) of current fossil-fueled capacity [*41*] are expected to be retired, including 56 gigawatts of oil- and natural-gas-fired steam plants. Nearly all the retirements are expected before 2010. Of the 164 gigawatts of new capacity expected by 2010, 30 percent is projected to replace retired oil- and natural-gas-fired steam capacity.

Because of their favorable economics, combined-cycle units are projected to be used for most new requirements. Efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 47 percent for coal-steam units, and the expected construction costs for combined-cycle units are only about 44 percent of those for coal-steam plants. As a result, about one-half (47 percent) of the projected combined-cycle additions are expected by 2010. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become more competitive, and 91 percent of the projected additions of new coal-fired capacity are expected to be brought on line from 2010 to 2025.

Only a few older, higher cost nuclear power plants, about 3 percent of current operating capacity, are expected to be retired by 2025. Planned capacity expansions at existing nuclear units are expected to raise net nuclear capacity slightly, from 98.2 gigawatts in 2001 to 99.6 gigawatts in 2025.

Natural Gas Units Are Expected To Dominate New Capacity Additions

Figure 64. Projected electricity generation capacity additions by fuel type, including combined heat and power, 2001-2025 (gigawatts)

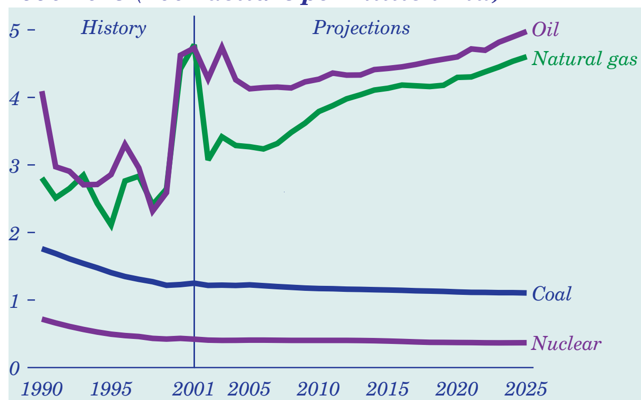


The electric power industry has added capacity at unprecedented speed over the past 2 years, and that trend is expected to continue through 2003. Even so, a total of 428 gigawatts of capacity (excluding combined heat and power plants) is projected to be needed by 2025 to meet growing demand and to offset retirements. Of the new capacity, 80 percent is projected to be natural-gas-fired combined-cycle or combustion turbine technology, including distributed generation capacity (Figure 64). These technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

A total of 74 gigawatts of new coal-fired capacity is projected to come on line between 2001 and 2025, accounting for almost 17 percent of all the capacity expansion expected. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in an effort to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for 3 percent of expected capacity expansion by 2025—primarily wind, geothermal, and municipal solid waste units. About 16 gigawatts of distributed generation capacity is projected to be added by 2025, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, which have higher fuel costs and lower efficiencies, are not expected to account for any new capacity in the forecast.

Rising Natural Gas Prices, Falling Coal Prices Are Projected

Figure 65. Fuel prices to electricity generators, 1990-2025 (2001 dollars per million Btu)

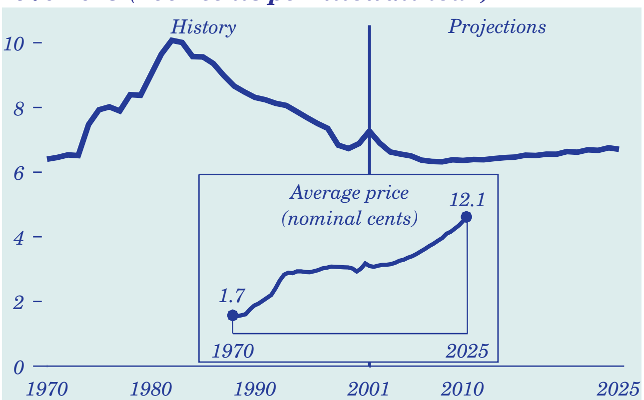


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. Falling coal prices have reduced the fuel share of operating costs for coal-fired plants, to about 76 percent in 2000, whereas volatile prices and rapidly increasing usage rates have raised the fuel share for natural-gas-fired combined-cycle plants to 88 percent in 2000. For nuclear units, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power units than for plants that use fossil fuels.

The impact of volatile natural gas prices in the forecast is more than offset by a combination of falling coal prices and stable nuclear fuel costs. After the price spikes of 2000 and 2001, natural gas prices to electricity suppliers are projected to rise by 1.8 percent per year in the forecast, from $3.07 per million Btu in 2002 to $4.60 in 2025 (Figure 65). The increases after 2002 are offset by forecasts of declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2025. Oil prices to utilities are expected to increase by 0.7 percent per year after 2002, leading to a 51-percent decline in oil-fired generation (excluding combined heat and power) between 2001 and 2025. Oil currently accounts for 3 percent of total generation, and that share is expected to decline to 1 percent by 2025 as oil-fired steam generators are replaced by gas turbine technologies.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Figure 66. Average U.S. retail electricity prices, 1970-2025 (2001 cents per kilowatthour)



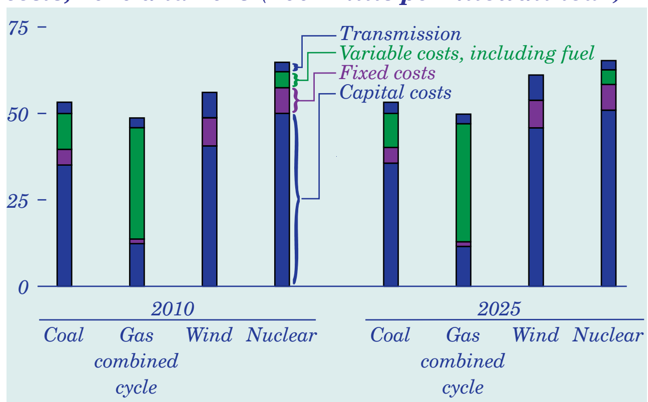
The average price of electricity in real 2001 dollars is expected to decline by an average of 1.6 percent per year from 2001 to 2008 (Figure 66) and then increase by 0.3 percent per year from 2008 to 2025 as natural gas prices rise. Electricity distribution prices are expected to decline as the cost of the distribution infrastructure is spread out over a growing amount of total electricity sales. Delivered electricity prices for residential, commercial, and industrial customers in 2025 are projected to be 7, 8, and 3 percent lower, respectively, than in 2001.

In 2002, 17 States and the District of Columbia had operating competitive retail electricity markets; Texas and Virginia opened their markets to competition in 2002; and Oregon restarted its restructuring process in November 2002. Five States with restructuring legislation on the books (Montana, Nevada, New Mexico, Oklahoma, and Arkansas) have delayed opening competitive retail markets. In addition, California's competitive retail market was suspended throughout 2002.

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in over 10 years, starting from the inception of restructuring in each region. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 67. Projected levelized electricity generation costs, 2010 and 2025 (2001 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 67) [*42*]. The reference case assumes a capital recovery period of 18 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

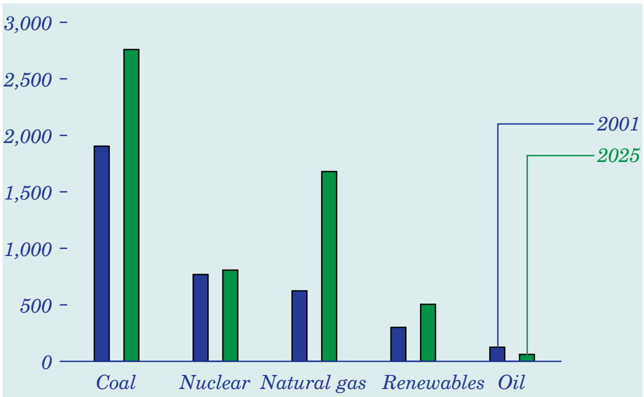
The costs and performance characteristics for new plants are expected to improve over time (Table 8), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,350 and 7,200 Btu per kilowatthour, respectively, by 2010. No further improvement is assumed after 2010.

Table 8. Costs of producing electricity from new plants, 2010 and 2025

Costs	2010 Advanced coal	2010 Advanced combined cycle	2025 Advanced coal	2025 Advanced combined cycle
	2001 mills per kilowatthour			
Capital	35.08	12.33	35.62	11.55
Fixed	4.53	1.34	4.53	1.34
Variable	10.37	32.21	9.85	34.14
Transmission	3.28	2.82	3.23	2.77
Total	**53.26**	**48.70**	**53.23**	**49.80**

Capacity Additions Are Expected at Existing Nuclear Power Plants

Figure 68. Projected electricity generation by fuel, 2001 and 2025 (billion kilowatthours)



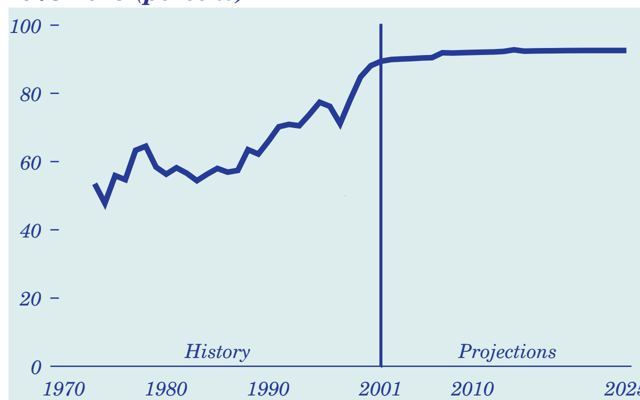
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2025 (Figure 68). In 2001, coal accounted for 1,904 billion kilowatthours or 51 percent of total generation, including output at combined heat and power plants. Although coal-fired generation is projected to increase to 2,760 billion kilowatthours in 2025, increasing gas-fired generation is expected to reduce coal's share to 47 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built in the near term. Nevertheless, the huge investment in existing coal plants and high utilization rates at those plants are expected to keep coal in its dominant position. By 2025, it is projected that 23 gigawatts of coal-fired capacity will be retrofitted with scrubbers to comply with environmental regulations.

As a result of improvements in performance and ongoing expansions of existing capacity, nuclear generation is expected to increase modestly through 2014 before leveling off. Between 2001 and 2016, about 4 gigawatts of total generating capacity is expected to be added through expansions at 88 of the Nation's 104 operable nuclear power units.

In percentage terms, natural-gas-fired generation is projected to show the largest increase, from 17 percent of the total in 2001 to 29 percent in 2025. As a result, by 2006, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

Figure 69. Nuclear power plant capacity factors, 1973-2025 (percent)



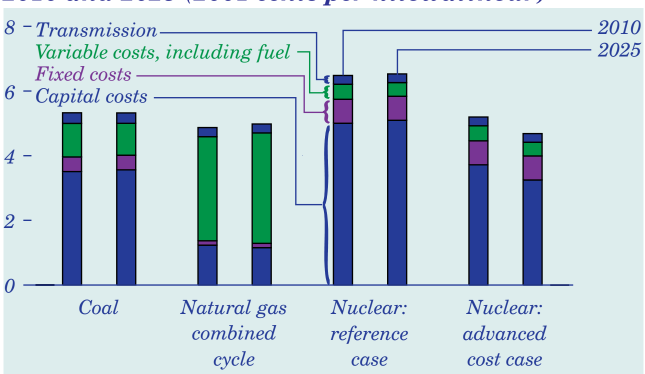
The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2001. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 89 percent in 2001 (Figure 69). It is assumed that performance improvements will continue, to an expected average capacity factor of 92 percent by 2010.

In the reference case, 3 percent of current nuclear capacity is projected to be taken out of service by 2025, but the retirements are more than offset by assumed increases in capacity at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 22 applications for power uprates in 2001, and another 22 were approved or pending in 2002. The reference case assumes that all the uprates will be made, as well as others expected by the NRC over the next 10 years, leading to an increase of 4.2 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2001 and 2025, because natural gas and coal-fired units are projected to be more economical.

Nuclear units are projected to be retired when their operation is no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original licensed lifetimes. As of October 2002, license renewals for 10 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 23 additional applicants have announced intentions to pursue license renewals over the next 5 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

Figure 70. Projected levelized electricity costs by fuel type in the advanced nuclear cost case, 2010 and 2025 (2001 cents per kilowatthour)

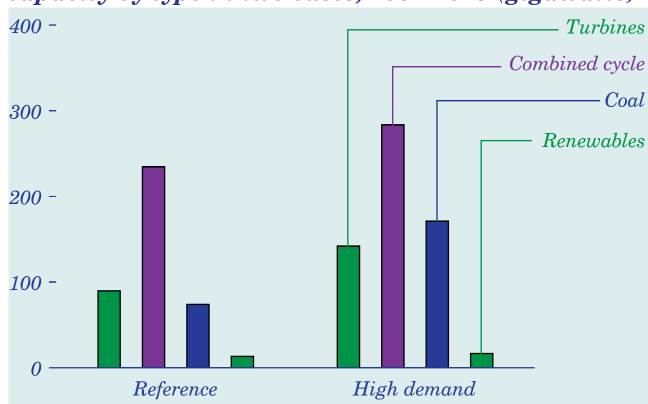


The *AEO2003* reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. For nuclear power plants, an advanced nuclear cost case analyzes the sensitivity of the projections to lower costs for new plants. The more optimistic cost assumptions for the advanced cost case are consistent with goals endorsed by DOE's Office of Nuclear Energy, including progressively lower overnight construction costs—by 28 percent initially compared with the reference case and by 36 percent in 2025. Achieving those goals may require government support, including cost sharing for the first few units constructed. Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the advanced nuclear cost case are competitive with the generating costs for new coal- and natural-gas-fired units toward the end of the projection period (Figure 70). A total of 2 gigawatts of new nuclear capacity is projected to come on line by 2020 in the advanced nuclear cost case, and 14 gigawatts by 2025; however, when the advanced nuclear cost assumptions are combined with improved costs and efficiencies for fossil and renewable fuel technologies, along with improvements in end-use technologies, no increase in total nuclear capacity is projected. The projections in Figure 70 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 71. Projected cumulative new generating capacity by type in two cases, 2001-2025 (gigawatts)

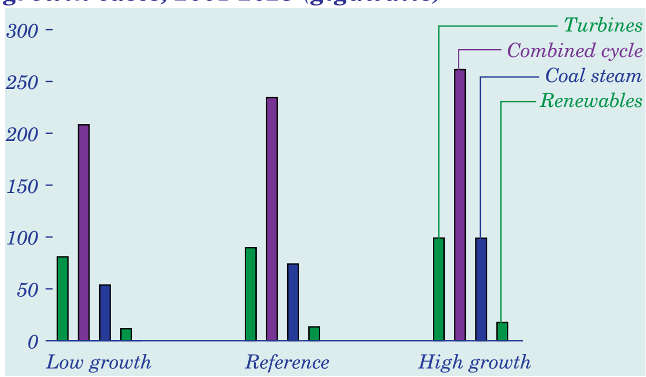


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 2001 and 2025, as compared with annual growth of 2.2 percent per year between 1990 and 1999. In the reference case, electricity demand is projected to grow by 1.8 percent per year.

In the high demand case, 210 gigawatts more generating capacity is projected to be built between 2001 and 2025 than in the reference case (Figure 71). The shares of coal- and natural-gas-fired capacity additions (including combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 27 percent and 70 percent, respectively, in the high demand case, compared with 17 and 80 percent, respectively, in the reference case. Coal consumption for electricity generation is projected to be 20 percent higher in the high demand case than in the reference case in 2025, natural gas consumption 13 percent higher, and carbon dioxide emissions 19 percent (163 million metric tons carbon equivalent) higher. More rapid assumed growth in electricity demand also leads to higher projected prices for electricity in 2025, averaging 7.0 cents per kilowatthour in the high demand case, compared with 6.7 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the difference in electricity prices.

Rapid Economic Growth Would Boost New Natural Gas and Coal Capacity

Figure 72. Projected cumulative new generating capacity by technology type in three economic growth cases, 2001-2025 (gigawatts)



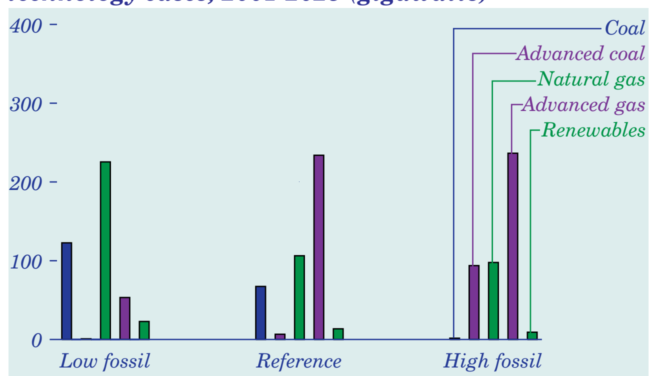
The projected annual average growth rate for GDP from 2001 to 2025 ranges from 3.5 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 13-percent change in projected electricity demand in 2025, with a corresponding difference of 128 gigawatts in the amount of new capacity projected to be built in the high and low economic growth cases. In the high economic growth case, generators are expected to retire about 11 percent of their current capacity by 2025 as the result of increased operating costs for aging units.

More than half of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new natural-gas-fired plants, which make up 56 percent of the projected additional new capacity. The stronger assumed growth also is projected to stimulate additions of coal-fired plants, accounting for 36 percent of the increase in projected capacity additions in the high economic growth case over those projected in the reference case (Figure 72).

Current construction costs for a typical plant range from $536 per kilowatt for combined-cycle technologies to $1,367 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option. Between 2001 and 2025, generators are expected to maintain most of their older coal-fired plants while retiring many older, higher cost oil- and natural-gas-fired steam generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 73. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 2001-2025 (gigawatts)

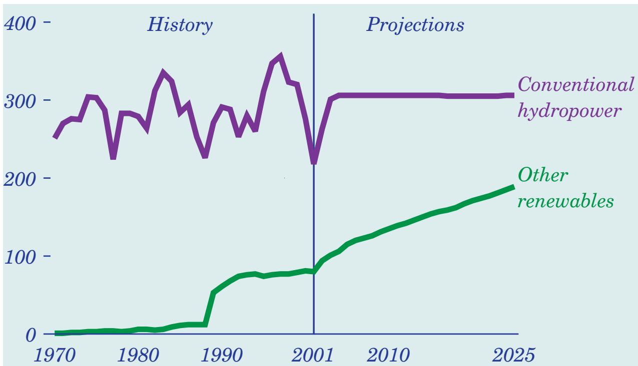


The *AEO2003* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs and/or heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that capital costs and heat rates for advanced technologies will remain flat throughout the forecast at 2002 levels.

The projected share of additions accounted for by natural gas technologies varies from 66 percent to 80 percent across the cases, and the projected mix between current and advanced gas technologies varies significantly (Figure 73). In the low fossil fuel case 19 percent (53 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with 71 percent (236 gigawatts) in the high fossil fuel case. Coal-fired capacity makes up a higher share of projected additions in both the low and high fossil fuel cases (29 percent and 22 percent, respectively) than in the reference case (17 percent). In the low case, conventional coal-fired generating capacity is more competitive with new natural-gas-fired capacity because no improvement is assumed for advanced natural gas technologies. In the high case, advanced coal technologies are more competitive as a result of the assumed rapid pace of technology improvements.

Increases in Nonhydropower Renewable Generation Are Expected

Figure 74. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

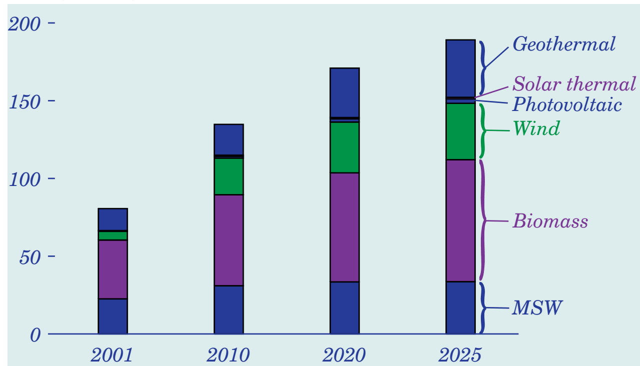


In the *AEO2003* reference case, despite improvements and incentives, grid-connected generators that use renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply, increasing from 298 billion kilowatthours of generation in 2001 (8.0 percent of total generation and 8.7 percent of retail sales) to 495 billion kilowatthours in 2025 (8.5 percent of generation and 9.4 percent of sales). Extremely low precipitation in 2001 reduced hydroelectric generation to 218 billion kilowatthours. Despite the net addition of 560 megawatts of new capacity by 2025, environmental and other requirements are projected to limit conventional hydroelectric generation to 306 billion kilowatthours in 2025—5.3 percent of generation and 5.8 percent of sales (Figure 74).

Nonhydroelectric renewables account for 4 percent of projected additions to generating capacity from 2001 to 2025. Generation from nonhydropower renewable energy sources is projected to increase from 80 billion kilowatthours in 2001 (2.1 percent of generation and 2.3 percent of sales) to 189 billion in 2025 (3.3 percent of generation and 3.6 percent of sales). The largest source of nonhydroelectric renewable generation in the forecast is biomass, including combined heat and power and co-firing in coal-fired power plants. Electricity generation from biomass is projected to increase from 38 billion kilowatthours in 2001 to 78 billion kilowatthours (1.3 percent of generation and 1.5 percent of sales) in 2025. Most of the increase (62 percent) is expected to come from combined heat and power and a smaller amount from co-firing with coal.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 75. Projected nonhydroelectric renewable electricity generation by energy source, 2010, 2020, and 2025 (billion kilowatthours)



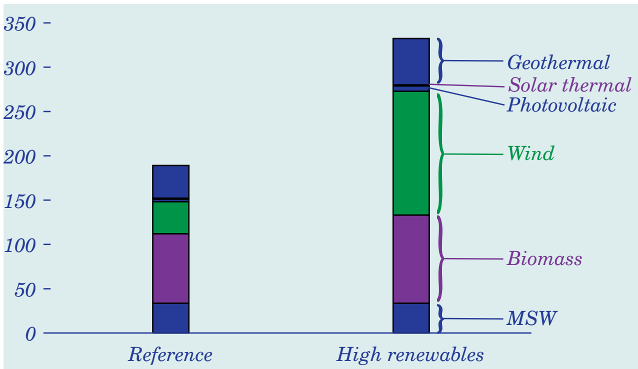
In addition to biomass, significant increases are projected for both geothermal energy and wind power capacity from 2001 to 2025 (Figure 75). Geothermal capacity, all located in western States, is projected to increase to 5.6 gigawatts, supplying 37 billion kilowatthours of electricity (0.6 percent of total generation) in 2025. Wind capacity increases by nearly 300 percent, to 12.0 gigawatts in 2025, much of it in response to State mandates. Generation from wind plants is projected to increase more rapidly than capacity, from less than 6 billion kilowatthours in 2001 to more than 36 billion in 2025, reflecting both a full year's output from capacity that entered service in mid-2001 and expected improvement in the productivity of future wind turbines. Despite expected significant near-term growth, mid-term prospects for wind power expansion are uncertain, depending on future cost and performance, transmission availability, extension of the Federal production tax credit and other incentives, energy security and public interest, and environmental preferences.

Electricity generation from municipal solid waste, including waste combustion and landfill gas, is projected to increase by 12 billion kilowatthours from 2001 to 2025, to nearly 34 billion kilowatthours. No new waste-burning capacity is expected, but landfill gas capacity is projected to increase by 1.1 gigawatts.

Solar technologies overall are not expected to make significant contributions to U.S. grid-connected electricity supplies through 2025. In total, grid-connected photovoltaic and solar thermal generators are projected to supply about 4 billion kilowatthours (0.07 percent of total generation) in 2025 [*43*].

Wind Energy Could Gain Most From Cost Reductions and Tax Credits

Figure 76. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2025 (billion kilowatthours)

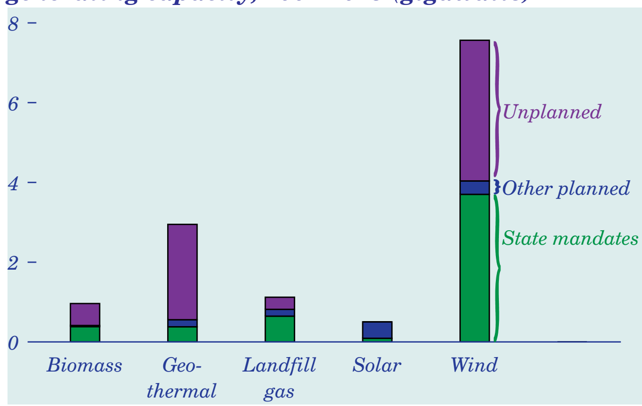


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including lower capital costs, higher capacity factors, and lower operating costs for some technologies [*44*]. The assumptions in the high renewables case approximate the renewable energy goals of the U.S. Department of Energy [*45*]. Fossil and nuclear technology assumptions are not changed from the reference case.

More rapid technology improvements are projected to increase renewable energy use in the high renewables case, but the predominant role of fossil-fueled technologies in U.S. electricity supply does not change. Total generation from nonhydroelectric renewables is projected to reach 332 billion kilowatthours in 2025, compared with about 189 billion kilowatthours in the reference case (Figure 76), increasing from about 3 percent to almost 6 percent of total generation. About 103 billion kilowatthours of the projected increase is generated from wind power, 15 billion kilowatthours from baseload geothermal, and 21 billion kilowatthours from net increases in biomass use, with increases for dedicated biomass plants and industrial combined heat and power applications more than offsetting reductions in biomass co-firing. Central-station solar technologies remain too expensive for use in new capacity additions, but the use of distributed photovoltaics in end-use markets is expected to more than double from the reference case. The projected increase in renewable energy use in the high renewables case reduces fossil fuel use relative to the reference case projection, lowering total projected carbon dioxide emissions by 31 million metric tons carbon equivalent (1.4 percent).

State Mandates Call for More Generation From Renewable Energy

Figure 77. Projected additions of renewable generating capacity, 2001-2025 (gigawatts)

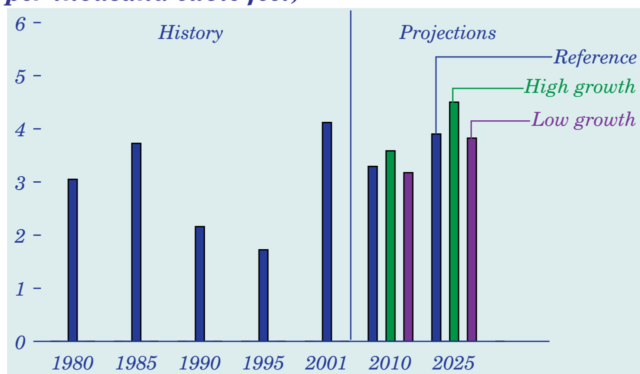


AEO2003 projects additions of 19 gigawatts of new renewable generating capacity through 2025, including 14 gigawatts in the electric power sector, 4 gigawatts in end-use combined heat and power, and 0.9 gigawatts in small-scale end-use applications. In the electric power sector, 5.2 gigawatts is projected as a result of State mandates (wind power 3.7 gigawatts, landfill gas 0.6 gigawatts, geothermal 0.4 gigawatts, solar thermal 0.09 gigawatts, solar photovoltaics 3 megawatts) and the rest from commercial projects (Figure 77). Projected commercial projects include 0.08 gigawatts of central-station solar thermal and 0.3 gigawatts of grid-connected central-station photovoltaic capacity that is assumed to be built for testing, demonstration, environmental, and other reasons.

In the reference case, a number of States with mandates and renewable portfolio standards in place are projected to add significant amounts of renewable capacity after 2001, including Massachusetts (1,112 megawatts), Texas (1,001 megawatts), Nevada (778 megawatts), California (623 megawatts), Minnesota (399 megawatts), New Jersey (340 megawatts), and New York (335 megawatts). Other States with smaller mandate requirements include Arizona, Hawaii, Iowa, Illinois, Montana, Oregon, West Virginia, and Wisconsin. Most of the new capacity is expected to be constructed in the near term—47 percent by 2003 and more than 60 percent by 2005. Because the current Federal production tax credit for new wind capacity is scheduled to expire after December 2003, 2,475 megawatts (58 percent) of identified new wind capacity is projected to be built before the end of 2003.

Natural Gas Prices Increase in All Economic Growth Cases

Figure 78. Projected lower 48 natural gas wellhead prices in three cases, 2010 and 2025 (2001 dollars per thousand cubic feet)



In the reference case, average wellhead natural gas prices are expected to increase to $3.90 per thousand cubic feet (2001 dollars) in 2025 (Figure 78). The 2025 wellhead price is projected to reach $3.83 per thousand cubic feet in the low growth case and $4.50 per thousand cubic feet in the high growth case. Technically recoverable natural gas resources (Table 9) are expected to be adequate to support the production increases projected in the three cases. As gas resources are depleted, however, wellhead prices are expected to increase, and a larger portion of U.S. natural gas consumption is projected to be met by foreign supplies and by production from Alaska.

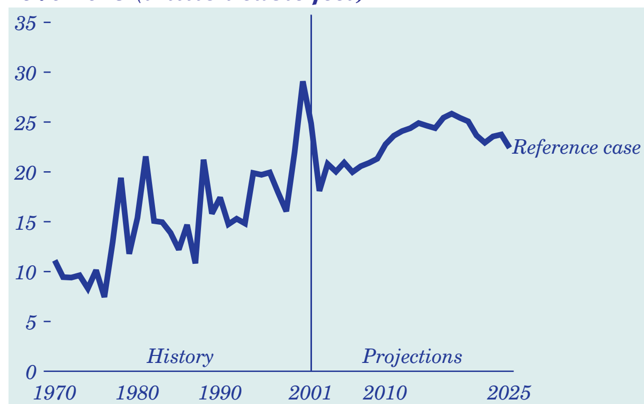
In the high growth case, higher levels of natural gas consumption are projected to stimulate the construction of the Alaskan North Slope and MacKenzie Delta pipelines and new liquefied natural gas (LNG) terminals earlier than in the reference case. Incremental supplies from those projects are projected to become available 2 years earlier than in the reference case. After the incremental volumes have been fully absorbed by growing gas consumption, prices are expected to escalate, beginning around 2020. In the low growth case, with lower price projections and lower demand for natural gas, supplies from the new projects do not come online until 2024.

Table 9. Technically recoverable U.S. natural gas resources as of January 1, 2002 (trillion cubic feet)

Proved	183.5
Unproved	1,105.4
Total	**1,288.9**

High Levels of Gas Reserve Additions Are Projected Through 2025

Figure 79. Lower 48 natural gas reserve additions, 1970-2025 (trillion cubic feet)



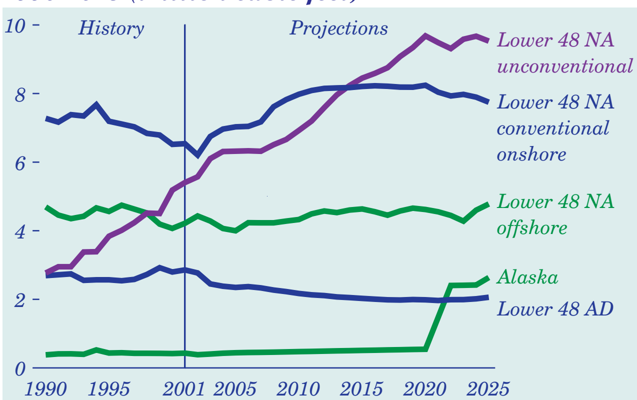
Projected lower 48 natural gas reserve additions reflect the expected increase in exploratory and developmental drilling that results from increasing natural gas prices and production revenues. Reserve additions also reflect projected productivity gains from technology improvements.

In the reference case, lower 48 reserve additions are expected to peak in 2018 at 25.8 trillion cubic feet and then slowly decline to 22.4 trillion cubic feet by 2025 (Figure 79). In the high growth case, reserve additions peak in 2017 at 25.9 trillion cubic feet and decline to 22.5 trillion cubic feet by 2025. In both cases, declining reserve additions at the end of the forecast reflect the rising cost of developing and producing the remaining domestic natural gas resource. Rising natural gas prices before 2020 are projected to stimulate lower 48 natural gas reserve additions, which generally exceed production in both the reference and high growth cases. After 2020, projected natural gas reserve additions are somewhat less than projected production.

In the low growth case, projected reserve additions remain relatively constant during the last 10 years of the forecast (2016-2025), averaging 24.3 trillion cubic feet per year. Because the Alaskan gas pipeline is not expected to be built and only one new LNG facility is expected to begin operation in 2024 in this case, natural gas prices remain roughly constant. As a result, reserve additions generally are expected to equal or exceed production through 2025 in the low growth case.

Growing Numbers of New Wells Increase Natural Gas Production

Figure 80. Natural gas production by source, 1990-2025 (trillion cubic feet)



As a result of technological improvements and rising natural gas prices, natural gas production from unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production. In the reference case, lower 48 unconventional gas production is projected to grow from 5.4 trillion cubic feet in 2001 to 9.5 trillion cubic feet in 2025 (Figure 80), increasing from 28 percent of total U.S. production in 2001 to 36 percent in 2025. Production of lower 48 nonassociated (NA) conventional natural gas is projected to grow from 10.8 trillion cubic feet in 2001 to 12.9 trillion cubic feet in 2020 and then decline to 12.5 trillion cubic feet in 2025.

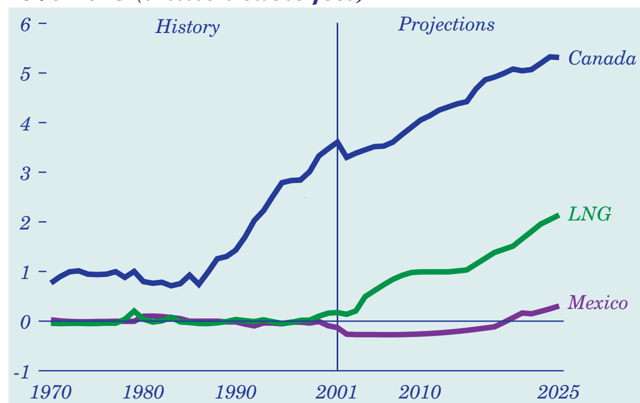
Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves declines by 1.3 percent per year in the reference case, consistent with a projected decline in crude oil production. Lower 48 AD natural gas is projected to account for 8 percent of U.S. natural gas production in 2025, compared with 15 percent in 2001.

Between 2001 and 2025, with increased drilling activity in deep waters, offshore natural gas production is projected to increase gradually from 5.3 trillion cubic feet in 2001 to 5.7 trillion cubic feet in 2025; however, the share of total U.S. production declines from 27 percent in 2001 to 21 percent by 2025.

The North Slope Alaskan gas pipeline is expected to begin transporting Alaskan natural gas production to the lower 48 States in 2021. In 2025, total Alaskan gas production is projected to be 2.6 trillion cubic feet in the reference case.

Net Imports of Natural Gas Grow in the Projections

Figure 81. Net U.S. imports of natural gas, 1970-2025 (trillion cubic feet)



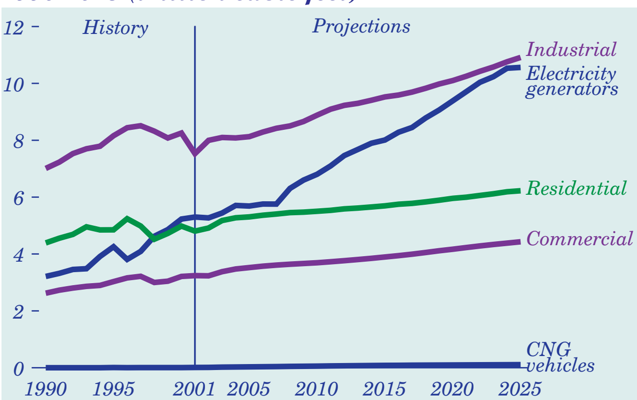
Net imports of natural gas make up the difference between U.S. production and consumption (Figure 81). Imports are expected to be priced competitively with domestic sources. Natural gas supplies from western Canada and the Scotian Shelf in the offshore Atlantic are expected to account for most of the increase in U.S. imports. In addition, the reference case projects that a new natural gas pipeline from the MacKenzie Delta will begin operation in 2016. Net imports from Canada are projected to provide 15 percent of total U.S. supply in 2025 in the reference case, about the same as in 2001.

LNG imports are expected to increase to 2.1 trillion cubic feet per year in 2025, equal to 6 percent of total U.S. gas supply. The projected 2025 LNG import level is based on expectations that all four existing LNG import facilities will be fully reopened and expanded—and that three new facilities will be constructed in the Gulf of Mexico and Florida areas—by 2025. The three new LNG facilities are expected to have a combined gas delivery rate of 2 billion cubic feet per day.

Although Mexico has a considerable natural gas resource base, trade with Mexico has until recently consisted primarily of exports from the United States. In the reference case, Mexico is projected to remain a net importer of U.S. natural gas through 2019. After 2019, Mexican natural gas imports are expected to come from an LNG import terminal built in Baja California, Mexico. By 2025, the United States is expected to import about 300 billion cubic feet of natural gas from Mexico per year.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

Figure 82. Natural gas consumption by sector, 1990-2025 (trillion cubic feet)



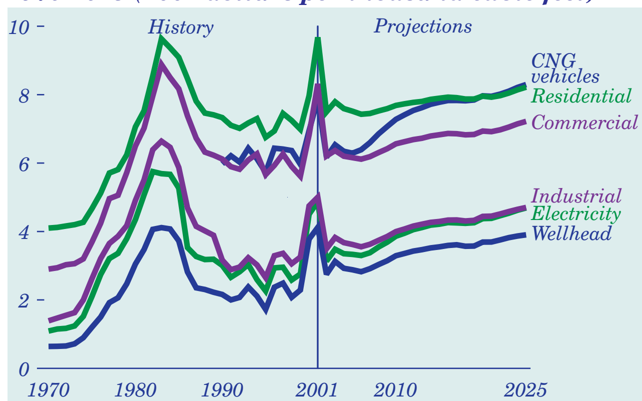
Total natural gas consumption is projected to increase between 2001 and 2025 in all the *AEO2003* cases. The projections for domestic natural gas consumption in 2025 range from 31.8 trillion cubic feet per year in the low economic growth case to 37.5 trillion cubic feet in the high economic growth case, as compared with 22.6 trillion cubic feet in 2001. In the reference case, natural gas consumption for electricity generation is projected to increase from 5.3 trillion cubic feet in 2001 to 10.6 trillion cubic feet in 2025, an average annual growth rate of 2.9 percent (Figure 82). Demand by electricity generators is expected to account for 33 percent of total end-use natural gas consumption in 2025.

Most new electricity generation capacity is expected to be fueled by natural gas, and natural gas consumption in the electricity generation sector is projected to grow rapidly throughout the forecast as electricity consumption increases. Although average coal prices to electricity generators are projected to fall throughout the forecast, natural-gas-fired generators are expected to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions.

Demand growth is also expected in the residential, commercial, industrial, and transportation sectors. Industrial consumption is expected to be the second largest source of demand growth. In the reference case, industrial consumption is projected to increase from 7.5 trillion cubic feet in 2001 to 10.9 trillion cubic feet in 2025, accounting for 34 percent of total end-use natural gas consumption in 2025.

Delivered Prices Increase More Slowly Than Wellhead Prices

Figure 83. Natural gas end-use prices by sector, 1970-2025 (2001 dollars per thousand cubic feet)

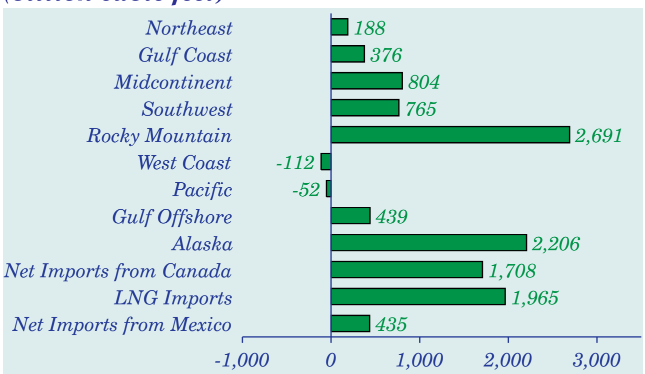


End-use natural gas prices are expected to decline in the early part of the forecast, from their relatively high levels in 2000 and 2001, followed by a gradual increase starting in about 2005 as a result of increasing wellhead prices (Figure 83). A portion of the increase in wellhead prices is expected to be offset by a projected decline in average transmission and distribution margins as a larger proportion of the natural gas delivery infrastructure becomes fully depreciated. The average end-use price is expected to increase by 89 cents per thousand cubic feet between 2005 and 2025 (in constant 2001 dollars), compared with an increase of $1.07 per thousand cubic feet in the average price of domestic and imported natural gas supplies over the same period.

The relative magnitude of the natural gas transmission and distribution margin reflects both the volume of gas delivered and the infrastructure requirements of the particular sector. For example, the margin associated with compressed natural gas vehicles is expected to increase, because the cost of the refueling infrastructure must be added to serve non-fleet vehicles. Conversely, the industrial and electricity generation sectors have the lowest end-use prices, in part because they receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges. Summer-peaking electric generators reduce their transmission costs by using lower cost interruptible transportation rates during the summer when spare pipeline capacity is available; however, as electric generators take an increasing share of the natural gas market, they are expected to rely on higher cost firm transportation to a greater extent.

Natural Gas Supplies from the West Are Expected To Grow

Figure 84. Projected changes in U.S. natural gas supply by region and source, 2001-2025 (billion cubic feet)



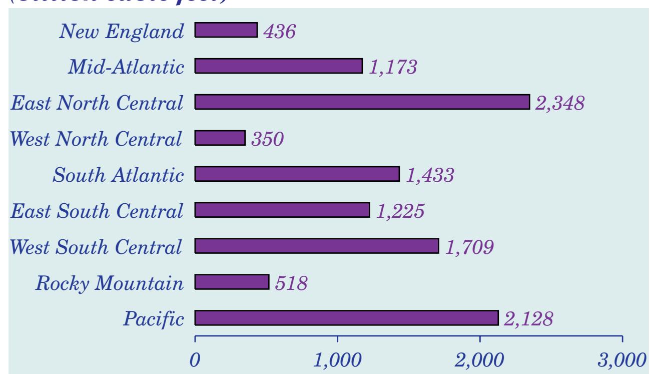
In the reference case, total foreign and domestic natural gas supplies are projected to grow by 11.4 trillion cubic feet between 2001 and 2025. Domestic natural gas production is expected to increase by 7.3 trillion cubic feet, accounting for 64 percent of the total growth in supply, and net imports are projected to increase by 4.1 trillion cubic feet, accounting for the remaining 36 percent.

The largest increase in domestic natural gas production from 2001 through 2025 is projected to come from the Rocky Mountain region, predominantly from unconventional sources. Rocky Mountain natural gas production is projected to increase by 2.7 trillion cubic feet between 2001 and 2025 (Figure 84). The next largest increase in domestic production is projected to come from Alaska, primarily as a result of the expected completion of a pipeline from the North Slope. Alaskan natural gas production in 2025 is expected to be 2.2 trillion cubic feet above its 2001 level. Other production regions, both onshore and offshore, collectively increase domestic natural gas production by a projected 2.4 trillion cubic feet between 2001 and 2025.

Net imports of Canadian natural gas and LNG are expected to increase by 1.7 trillion cubic feet and 2.0 trillion cubic feet, respectively, between 2001 and 2025. The growth in LNG imports is expected to occur primarily in the South Atlantic and Gulf Coast regions as a result of the reactivation and expansion of the four existing LNG import facilities in the United States and the construction and later expansion of three new LNG facilities.

Natural Gas Consumption Is Expected To Increase in All Regions

Figure 85. Projected changes in end-use natural gas consumption by region, 2001-2025 (billion cubic feet)

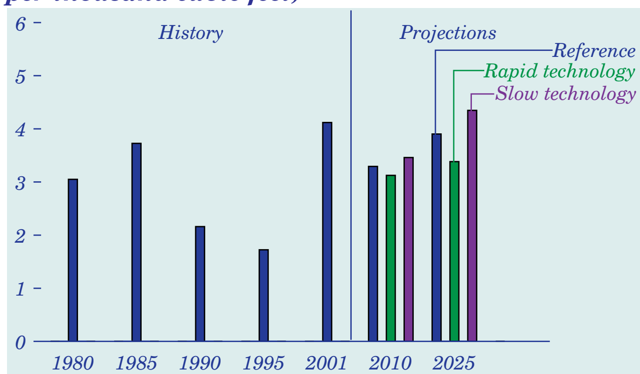


In the reference case, 58 percent of the growth in lower 48 end-use natural gas consumption between 2001 and 2025 is projected to occur east of the Mississippi River, with the remaining 42 percent occurring west of the Mississippi River (Figure 85). In the East, the largest increase in end-use consumption is expected in the East North Central region, which accounts for 2.3 trillion cubic feet of incremental consumption. The next largest consumption increase in the East occurs in the South Atlantic region at 1.4 trillion cubic feet. In the West, natural gas demand in the Pacific and West South Central regions is expected to increase by 2.1 trillion cubic feet and 1.7 trillion cubic feet, respectively. Together, these four regions are projected to account for 67 percent of the total increase in end-use natural gas consumption between 2001 and 2025 in the reference case. Differences in the projected growth rates for the various regions result from different prospects for population growth, economic activity, and electricity generation.

Between 2001 and 2025, the West—including Alaska, Western Canadian and most of the offshore Gulf of Mexico—is expected to provide about 80 percent of the incremental natural gas supply in the reference case. Because most of the growth in natural gas consumption is expected east of the Mississippi River, new natural gas pipelines are projected to be built from the West to the East, including a North Slope Alaska natural gas pipeline, whose terminus is expected to be near Chicago. An exception is the construction of new pipeline capacity originating in Canada and the Rocky Mountains, which will be needed to meet growth in natural gas consumption along the Pacific Coast.

Natural Gas Price Projections Change With Technology Assumptions

Figure 86. Projected lower 48 natural gas wellhead prices in three cases, 2010 and 2025 (2001 dollars per thousand cubic feet)



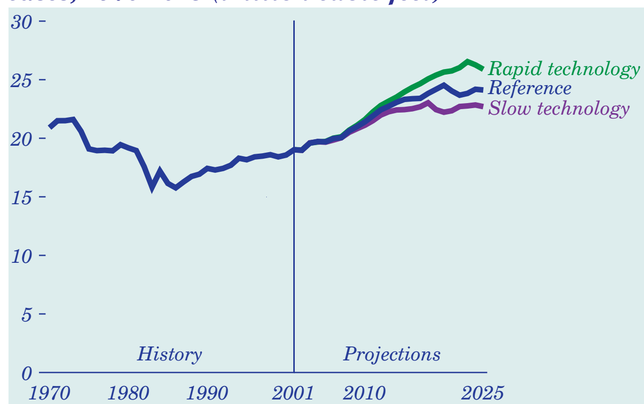
Continued improvements in technology are projected to result in lower production costs for natural gas from the Nation's resource base. Because wellhead gas prices reflect the underlying production cost structure, wellhead natural gas prices are relatively sensitive to variation in technological progress. The *AEO2003* reference case assumes that improvements in technology will continue at historical rates. The slow and rapid technology cases assume that the annual rate of technological improvement in production costs, finding rates, and success rates will decrease or increase by 15 percent relative to the historical rate.

An Alaskan natural gas pipeline and new LNG facilities are expected to come into operation by 2025 in both technology cases, but at different times. In the slow technology case, natural gas wellhead prices are projected to rise sooner and more rapidly (Figure 86), leading to earlier completion of the new facilities. In the rapid technology case, prices increase more slowly, delaying their completion until the end of the forecast period.

The slow technology case projects a wellhead price of $4.35 per thousand cubic feet in 2025, which is 12 percent higher than the reference case price of $3.90 per thousand cubic feet in 2025. In the rapid technology case, lower 48 natural gas wellhead prices are projected to reach $3.38 per thousand cubic feet in 2025, which is 13 percent lower than in the reference case.

Natural Gas Production Projections Reflect Technological Progress

Figure 87. Lower 48 natural gas production in three cases, 1970-2025 (trillion cubic feet)



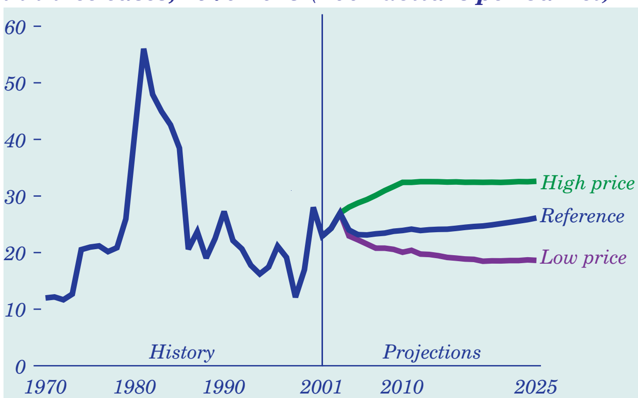
Generally, technological progress reduces the cost of natural gas production, leading to lower wellhead prices, higher levels of end-use consumption, and—in order to meet the increase in demand—more production. Therefore, a higher rate of technological progress is expected to result in a higher projection for domestic natural gas production.

Total U.S. natural gas production in 2025 is projected to be 6 percent higher in the rapid technology case and 6 percent lower in the slow technology case than in the reference case (Figure 87). The strongest impact of the rapid and slow technology assumptions is on projected production from unconventional natural gas sources, which in 2025 is 15 percent higher in the rapid technology case and 6 percent lower in the slow technology case than in the reference case.

Projected natural gas consumption in 2025 is 3 percent higher in the rapid technology case than in the reference case, but as a result of the increase in domestic production projected in the rapid technology case, net natural gas imports in 2025 are 7 percent lower than in the reference case. In the slow technology case, with consumption of natural gas projected to be 2 percent lower than in the reference case in 2025, net imports are projected to be 11 percent higher.

Oil Prices Are Expected To Remain Above Low 1998 Levels

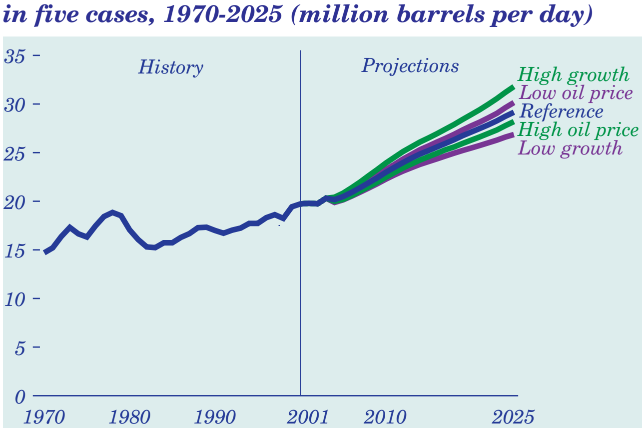
Figure 88. Lower 48 crude oil wellhead prices in three cases, 1970-2025 (2001 dollars per barrel)



Crude oil prices are determined largely by the international market and production in OPEC and non-OPEC nations. In the reference case, the average lower 48 crude oil price is projected to increase on average by 0.5 percent per year after 2001, to $26.12 per barrel in 2025. The high and low world oil price cases project different levels of OPEC production. In the high price case, the lower 48 crude oil price increases by 1.5 percent per year from 2001 to 2025, to $32.59 per barrel in 2025, or 25 percent higher than in the reference case (Figure 88). In the low price case, the lower 48 price generally declines through 2020 and reaches $18.62 per barrel in 2025.

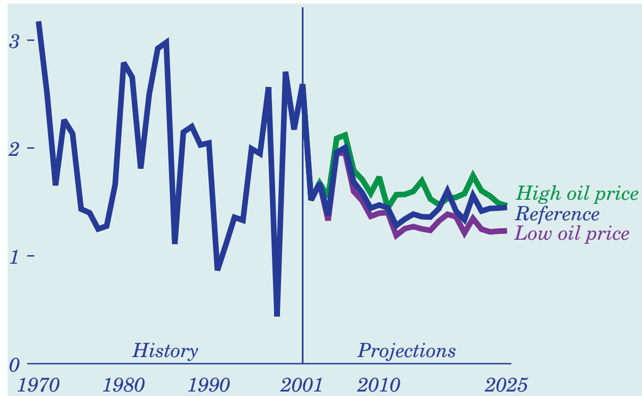
Projected U.S. petroleum consumption varies with the projected crude oil price, but the largest variation is seen for different assumptions about economic growth. Total consumption in 2025 ranges from 26.9 million to 31.8 million barrels per day in the low and high growth cases, respectively (Figure 89).

Figure 89. U.S. petroleum consumption in five cases, 1970-2025 (million barrels per day)



Projected Oil Reserve Additions Are Sensitive to Oil Price Assumptions

Figure 90. Lower 48 crude oil reserve additions in three cases, 1970-2025 (billion barrels)



Lower 48 crude oil reserve additions are sensitive to crude oil price projections (Figure 90). In the projections for 2025, lower 48 crude oil reserve additions range from a low of 1.2 billion barrels in the low world oil price case to 1.5 billion barrels in the high world oil price case.

The variation in crude oil prices in the world oil price cases primarily affects the development and production of offshore oil resources (Table 10), because smaller deepwater fields that are not profitable when price are low are expected to become profitable when oil prices rise.

Crude oil reserve additions reflect the number of oil wells completed during the forecast period, the size of the crude oil resource base (Table 11) and the pace of technological progress. In the reference case, technological progress is expected to continue at the historical rate.

Table 10. Onshore and offshore lower 48 crude oil production in three cases, 2025 (million barrels per day)

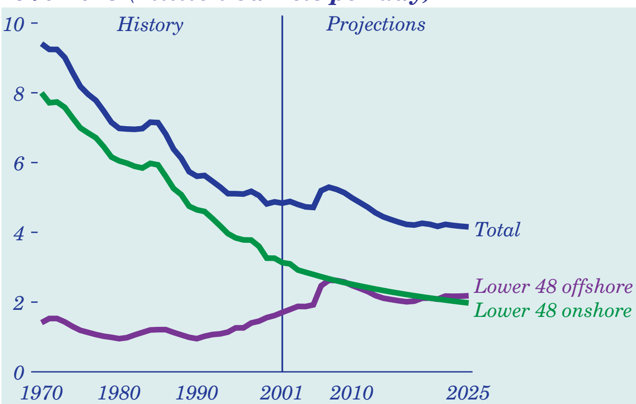
	Onshore	Offshore	Total
Low oil price	1.90	1.86	3.76
Reference	1.98	2.18	4.16
High oil price	2.02	2.50	4.52

Table 11. Technically recoverable U.S. oil resources as of January 1, 2002 (billion barrels)

Proved	24
Unproved	117
Total	**141**

Lower 48 Crude Oil Production Is Expected To Decline After 2007

Figure 91. Lower 48 crude oil production by source, 1970-2025 (million barrels per day)



In the reference case, total lower 48 crude oil production is projected to increase from 4.8 million barrels day in 2001 to 5.3 million barrels per day in 2007, then to decline to 4.2 million barrels per day in 2025. The low and high oil price cases also project production peaks in 2007, followed by declines to 3.8 and 4.5 million barrels per day, respectively, in 2025. The projected peak in 2007 is attributable primarily to offshore oil production (Figure 91). In the reference case, total offshore oil production (including the Gulf of Mexico and offshore California) rises to 2.6 million barrels per day in 2007 and then declines to 2.2 million barrels per day in 2025. The decline in offshore oil production is expected to occur on the shallow, outer continental shelf in the Gulf of Mexico (Table 12).

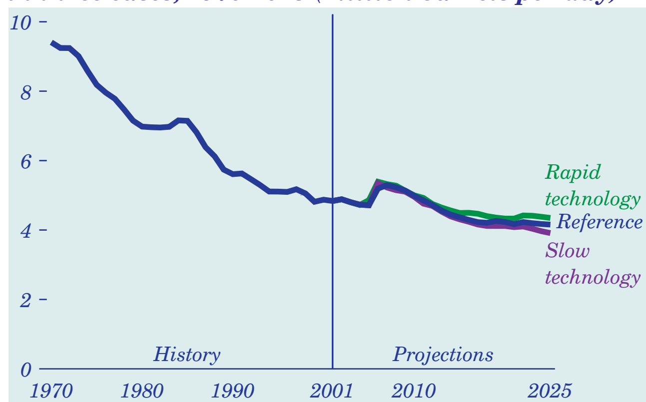
Offshore oil production is more sensitive to oil prices than onshore production. In the low and high oil prices cases, lower 48 offshore production is projected to be 1.9 and 2.5 million barrels per day, respectively, in 2025. Onshore lower 48 oil production is projected to decline in all cases, with 2025 values ranging from 1.9 million barrels per day in the low world oil price cases to 2.0 million in the high price case.

Table 12. Crude oil production from Gulf of Mexico offshore, 2001-2025 (million barrels per day)

	2001	2010	2020	2025
Shallow	0.7	0.8	0.3	0.2
Deep	0.9	1.6	1.8	1.9
Total	**1.6**	**2.4**	**2.1**	**2.1**

More Rapid Technology Advances Could Raise Oil Production Slightly

Figure 92. Lower 48 crude oil production in three cases, 1970-2025 (million barrels per day)



Lower 48 crude oil production is projected to reach 4.3 and 3.9 million barrels per day in 2025 in the rapid and slow technology cases, respectively, compared with 4.2 million barrels per day in the reference case (Figure 92). The technology cases assume the same world oil prices as in the reference case, but the rate of technological progress is assumed to be 15 percent higher (in the rapid technology case) or lower (in the slow technology case) than the historical rate. Because oil prices are determined by world markets and domestic consumption is not expected to change significantly in the technology cases, changes in production result in different levels of petroleum imports. In 2025, net petroleum imports are projected to range from 19.4 million barrels per day in the rapid technology case to 20.3 million barrels per day in the slow technology case.

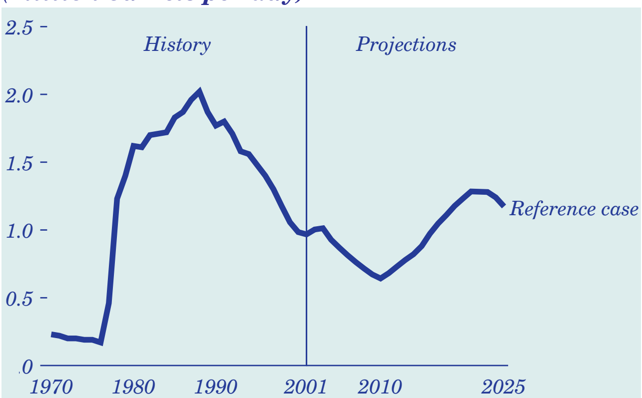
Offshore crude oil production in the lower 48 States is expected to be more sensitive to changes in technological progress than onshore production. Relative to the reference case, cumulative offshore production from 2001 through 2025 is projected to be 768 million barrels (3.9 percent) higher in the rapid technology case and 389 million barrels (2.0 percent) lower in the slow technology case.

Projected lower 48 onshore crude oil production shows less variation in cumulative volumes produced between 2001 and 2025 than does offshore production. Cumulative onshore production from 2001 through 2025 is projected to be 22.2 billion barrels in the reference case, and the cumulative production total is about 0.9 percent higher and lower, respectively, in the rapid and slow technology cases.

Alaskan Oil Production and Oil Imports

Crude Oil Production in Alaska Is Projected To Rebound

Figure 93. Alaskan crude oil production, 1970-2025 (million barrels per day)



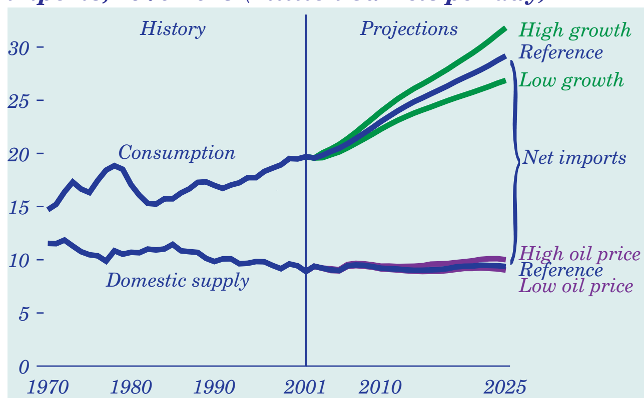
Alaskan crude oil production is expected mainly on the Alaskan North Slope, which includes the National Petroleum Reserve-Alaska (NPR-A) and the State lands surrounding Prudhoe Bay. NPR-A lease sales were held on May 5, 1999, and June 3, 2002. Because oil and gas producers are prohibited from building permanent roads in NPR-A, oil exploration and production is expected to be about 30 percent more expensive than is typical for the North Slope of Alaska. Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), *AEO2003* does not project any production from ANWR.

In the reference case, crude oil production from Alaska is expected to decline to about 640 thousand barrels per day in 2010 (Figure 93). After 2010, the projected drop in oil production is expected to be offset by new oil production from NPR-A. This date is based on the expectation that a decade will be required to explore and develop new oil fields and to build the associated infrastructure. After 2010, total Alaskan crude oil production is projected to grow to a peak of 1.3 million barrels per day in 2021. NPR-A oil production begins to decline after 2021, and total Alaskan oil production is projected to be 1.2 million barrels per day in 2025.

Alaska's oil production is expected to show similar sensitivity to changes in assumed technological progress as lower 48 oil production. Relative to the reference case, cumulative Alaskan production from 2001 through 2025 is projected to be 172 million barrels (2.0 percent) higher in the rapid technology case and 164 million barrels (1.9 percent) lower in the slow technology case.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 94. Petroleum supply, consumption, and imports, 1970-2025 (million barrels per day)



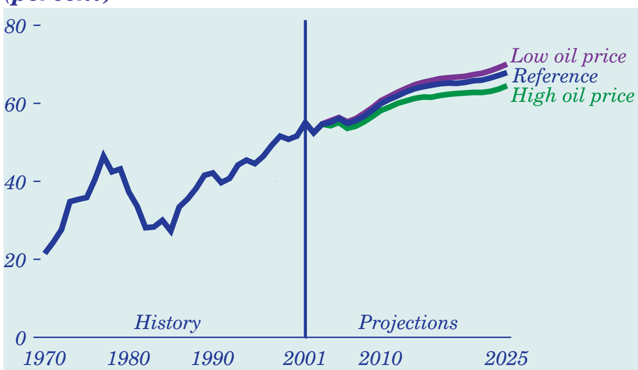
In the reference case, domestic petroleum supply is projected to increase from its 2001 level of 8.9 million barrels per day to 9.4 million barrels per day in 2025 (Figure 94). Although U.S. crude oil production falls off, refinery gain and production of natural gas plant liquids are projected to increase. Domestic supply in 2025 is projected to total 9.0 million barrels per day in the low oil price case and to rise to 10.0 million barrels per day in the high oil price case.

The greatest variation in petroleum consumption levels is seen across the economic growth cases, with a projected increase of 12.1 million barrels per day over the 2001 level in the high growth case, compared with a projected increase of only 7.2 million barrels per day in the low growth case.

Additional petroleum imports would be needed to fill the projected widening gap between supply and consumption. The greatest gap between supply and consumption is projected in the high growth case and the smallest in the low growth case. The projections for net petroleum imports in 2025 range from a high of 22.2 million barrels per day in the high growth case to a low of 17.8 million barrels per day in the low growth case, compared with 19.8 million barrels per day in the reference case, increasing from 10.9 million barrels per day in 2001. The expected value of petroleum imports in 2025 ranges from about $160 billion in the low world oil price case to nearly $250 billion in the high economic growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $142.7 billion (in 2001 dollars) in 1980, were $102.9 billion in 2001 [*46*].

Growing Dependence on Petroleum Imports Is Projected

Figure 95. Share of U.S. petroleum consumption supplied by net imports in three cases, 1970-2025 (percent)



In 2001, net imports of petroleum accounted for 55 percent of domestic petroleum consumption. Increasing dependence on petroleum imports is projected, reaching 68 percent in 2025 in the reference case (Figure 95). The corresponding import shares of total consumption in 2025 are expected to be 65 percent in the high oil price case and 70 percent in the low oil price case.

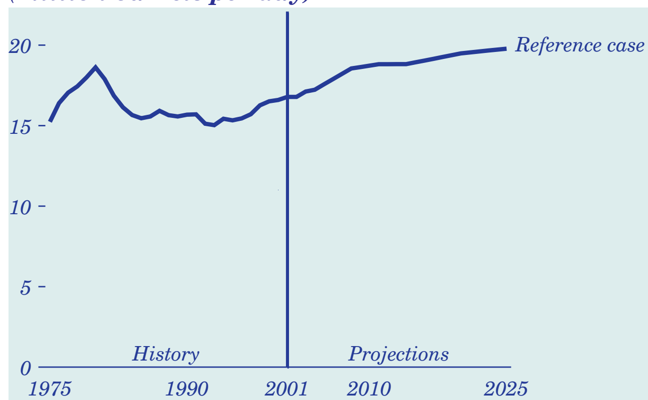
Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 27 percent of net petroleum imports in 2025 in the low economic growth case and 39 percent in the high growth case, compared with 34 percent in the reference case, increasing from a 15-percent share in 2001 (Table 13).

Table 13. Petroleum consumption and net imports in five cases, 2001 and 2025 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
2001	19.8	10.9	9.3	1.6
2025				
Reference	29.2	19.8	13.1	6.7
Low oil price	30.1	21.1	14.1	7.1
High oil price	28.2	18.2	12.5	5.7
Low growth	26.9	17.8	13.1	4.8
High growth	31.8	22.2	13.5	8.6

New U.S. Oil Refining Capacity Is Likely To Be at Existing Refineries

Figure 96. Domestic refining capacity, 1975-2025 (million barrels per day)



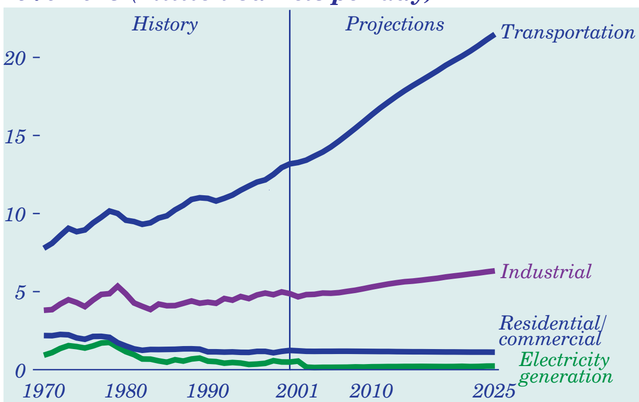
Falling demand for petroleum and deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1995, and 1.4 million barrels per day of distillation capacity was added between 1995 and 2001. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but additions at existing refineries are expected to increase total U.S. refining capacity in all the *AEO2003* cases (Figure 96).

Distillation capacity is projected to grow from the 2001 year-end level of 16.8 million barrels per day to 19.8 million barrels per day in 2025 in the reference case, 19.6 million barrels per day in the low economic growth case, and 20.4 million barrels per day in the high growth case, compared with the 1981 peak of 18.6 million barrels per day. Almost all the capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively (91 to 95 percent of operable capacity) throughout the forecast. The 2001 utilization rate was 93 percent, well above the lows of 69 percent during the 1980s and 88 percent during the early 1990s but consistent with capacity utilization rates since the mid-1990s.

Additional "downstream" processing units are expected to allow domestic refineries to produce less residual fuel, which has a shrinking market, and more of the higher value "light products," such as gasoline, distillate, jet fuel, and liquefied petroleum gas.

Petroleum Use Increases Mainly in the Transportation Sector

Figure 97. Petroleum consumption by sector, 1970-2025 (million barrels per day)

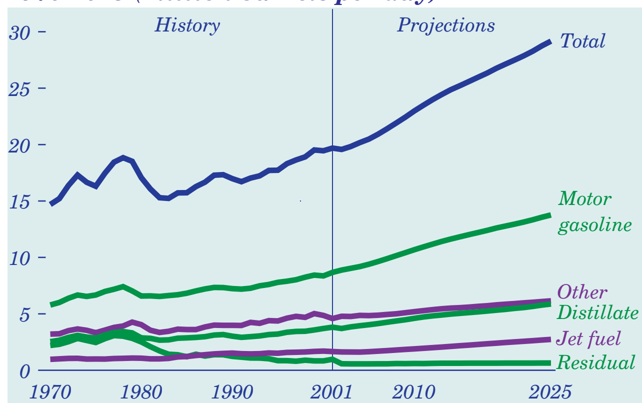


U.S. petroleum consumption is projected to increase by 9.5 million barrels per day between 2001 and 2025. Most of the increase is in the transportation sector (Figure 97), which accounted for two-thirds of U.S. petroleum use in 2001. Petroleum use for transportation increases by 8.2 million barrels per day in the reference case, as the number and usage of vehicles grow. In the industrial sector, which currently accounts for 23 percent of U.S. petroleum use, consumption in 2025 is projected to be higher than in 2001 by 1.7 million barrels per day in the reference case. About 89 percent of the growth is expected in the petrochemical, construction, and refining sectors.

In the reference case, petroleum use for heating and for electricity generation is expected to decline as oil loses market share to natural gas and electricity for heating and to natural gas for electricity generation. Increased oil use for heating and electricity generation is projected, however, in the low oil price case. Natural gas use for home heating is projected to grow in the Northeast, the last stronghold of home heating oil, in the low oil price case. Compared with 2001, U.S. residential and commercial heating oil use is projected to be 94,000 barrels per day lower in 2025 in the high oil price case and 42,000 barrels per day higher in the low oil price case. For electricity generation, oil-fired steam plants are being retired in favor of natural gas combined-cycle units. Oil use for electricity generation (excluding combined heat and power) is projected to be 430,000 barrels per day lower in 2025 than in 2001 in the high price case and 64,000 barrels per day higher in the low price case.

Light Products Account for Most of the Increase in Demand for Petroleum

Figure 98. Consumption of petroleum products, 1970-2025 (million barrels per day)

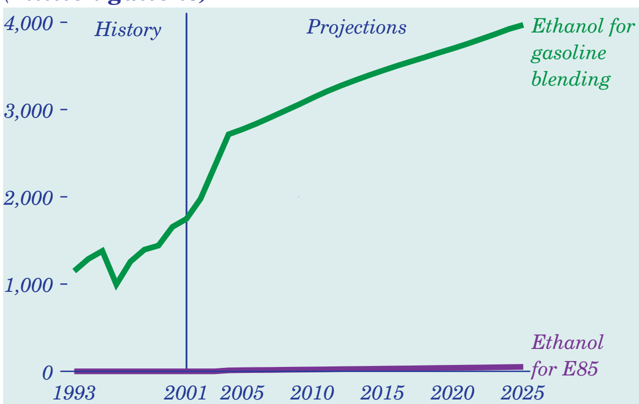


About 97 percent of the projected growth in petroleum consumption stems from increased consumption of “light products,” including gasoline, diesel, heating oil, jet fuel, and liquefied petroleum gases, which are more difficult and costly to produce than heavy products (Figure 98). Although refinery investments and enhancements are expected to increase the ability of domestic refineries to produce light products, imports of light products are expected to more than quadruple by 2025.

In the forecast, gasoline continues to account for about 47 percent of all the petroleum used in the United States. Between 2001 and 2025, U.S. gasoline consumption is projected to rise from 8.7 million barrels per day to 13.8 million barrels per day. Consumption of distillate fuel is projected to be 2.1 million barrels per day higher in 2025 than it was in 2001. An even greater increase is projected for diesel fuel, as a larger portion of total distillate supply is used for diesel production and less is used in other sectors. With air travel also expected to increase, jet fuel consumption is projected to be 1.1 million barrels per day higher in 2025 than in 2001. Consumption of liquefied petroleum gas (LPG) is projected to increase by about 980,000 barrels per day between 2001 and 2025, largely for use as a feedstock in the industrial sector. Consumption of “other” petroleum products —including LPG, petrochemical feedstocks, still gas used to fuel refineries, asphalt and road oil, and other miscellaneous products—is projected to grow by 1.6 million barrels per day. Residual fuel use is projected to decline from 970,000 barrels per day in 2001 to 640,000 barrels per day in 2025. Most of the projected decline is in the electricity generation sector.

State Bans on MTBE Are Expected To Result in Increased Use of Ethanol

Figure 99. U.S. ethanol consumption, 1993-2025 (million gallons)



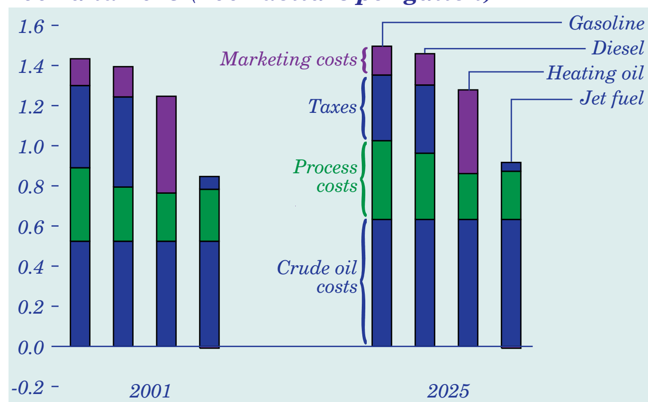
U.S. ethanol production, with corn as the primary feedstock, reached 1.7 billion gallons in 2001. Production is projected to increase to 4.0 billion gallons by 2025 (Figure 99), with about 25 percent of the growth from the conversion of cellulosic biomass. Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer and also serves as an oxygenate in areas that are required to use oxygenated fuels (minimum 2.7 percent oxygen content by volume) during the winter months to reduce carbon monoxide emissions. The high renewables case projects similar production, but all the projected growth is from cellulose, due to more rapid improvement in the technology. In the reference case, corn-based ethanol production drops from 96 percent of total ethanol output in 2015 to 85 percent in 2025.

Ethanol is expected to replace MTBE as the oxygenate for reformulated gasoline (RFG) in 17 States that have placed limits on MTBE use mainly because of concerns about groundwater contamination. It is assumed that the Federal requirement for 2 percent oxygen in RFG will continue in all States. Ethanol consumption in E85 vehicles is also projected to increase, from the national total of 8.7 million gallons in 2001 to 52 million gallons in 2025. E85 vehicles currently are used as government fleet vehicles, flexible-fuel passenger vehicles, and urban transit buses.

The Federal Highway Bill of 1998 extended the excise tax exemption for ethanol through 2007 with reductions from 54 cents per gallon to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. It is assumed that the exemption will be extended at 51 cents per gallon (nominal dollars) through 2025.

Refining Costs for Most Petroleum Products Rise in the Forecast

Figure 100. Components of refined product costs, 2001 and 2025 (2001 dollars per gallon)



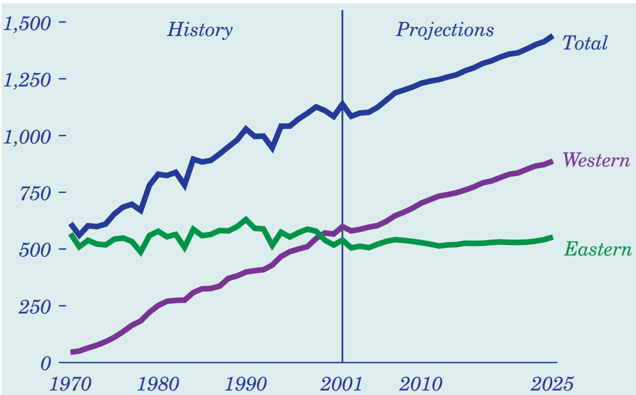
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 100). In the *AEO2003* projection, crude oil costs are projected to continue to be the largest component of product prices, and marketing costs are projected to remain stable, but the contributions of processing costs and taxes are expected to change considerably.

Refining costs, including processing costs and profits for gasoline and diesel fuel, are expected to increase by 2 to 6 cents per gallon from 2001 to 2025. The increases result primarily from projected growth in demand for gasoline and diesel fuels and the investment needed to meet new Federal requirements for low-sulfur gasoline between 2004 and 2007 and ultra-low-sulfur diesel fuel between 2006 and 2010. Refining costs for heating oil and jet fuel fall by a projected 1 to 2 cents per gallon from 2001 to 2025.

Whereas processing costs tend to increase refined product prices in the forecast, the assumptions made about Federal taxes tend to slow the growth of motor fuel prices. In keeping with the *AEO2003* assumption of current laws and legislation, Federal motor fuel taxes are assumed to remain at nominal 2001 levels throughout the forecast. Although Federal motor fuel taxes have been raised occasionally in the past, the assumption of constant nominal Federal taxes is consistent with history. The net impact of the assumption is an expected decrease in Federal taxes in 2001 dollars between 2001 and 2025—8 cents per gallon for gasoline, 11 cents for diesel fuel, and 2 cents for jet fuel. State motor fuels taxes are assumed to keep up with inflation, as they have in the past.

Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 101. Coal production by region, 1970-2025 (million short tons)



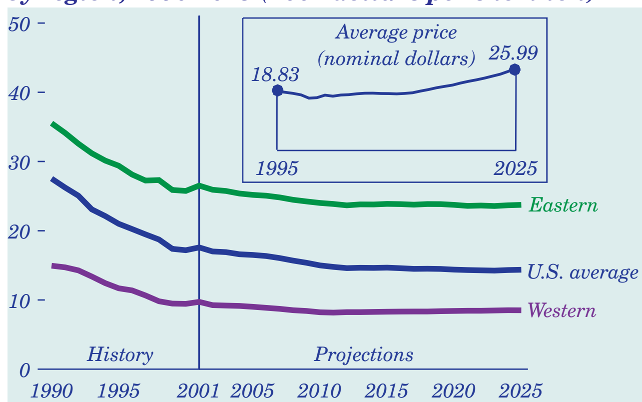
Continued improvements in mine productivity (which have averaged 6.2 percent per year since 1980) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to an overall sulfur emissions cap from CAAA90, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coal. As coal demand grows in the forecast, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal is projected to grow, there are still expected to be market opportunities for higher sulfur coal throughout the forecast.

From 2001 to 2025, high- and medium-sulfur coal production is projected to increase from 598 to 607 million tons (0.1 percent per year), and low-sulfur coal production is projected to rise from 540 to 833 million tons (1.8 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue its historical growth, reaching 887 million tons in 2025 (Figure 101), but its annual growth rate is projected to fall from the 8.7 percent achieved between 1970 and 2001 to 1.7 percent in the forecast period.

Rate of Decline in Minemouth Coal Price Is Expected To Slow

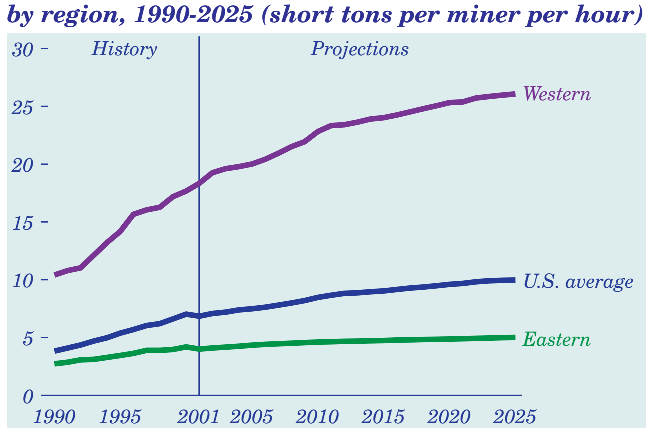
Figure 102. Average minemouth price of coal by region, 1990-2025 (2001 dollars per short ton)



Minemouth coal prices declined by $6.27 per ton (in 2001 dollars) between 1970 and 2001, and they are projected to decline by 0.8 percent per year, or $3.23 per ton, between 2001 and 2025 (Figure 102). The price of coal delivered to electricity generators, which declined by $2.17 per ton between 1970 and 2001, is projected to fall to $22.17 per ton in 2025—a 0.5-percent annual decline.

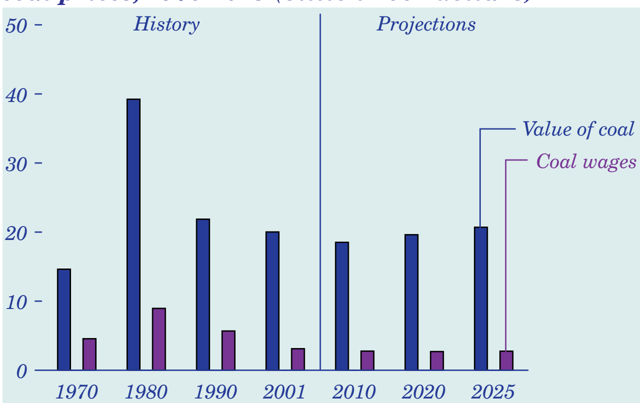
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 103) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 103. Coal mining labor productivity by region, 1990-2025 (short tons per miner per hour)



Labor Costs as Share of Minemouth Coal Revenues Continue to Decline

Figure 104. Labor cost component of minemouth coal prices, 1970-2025 (billion 2001 dollars)



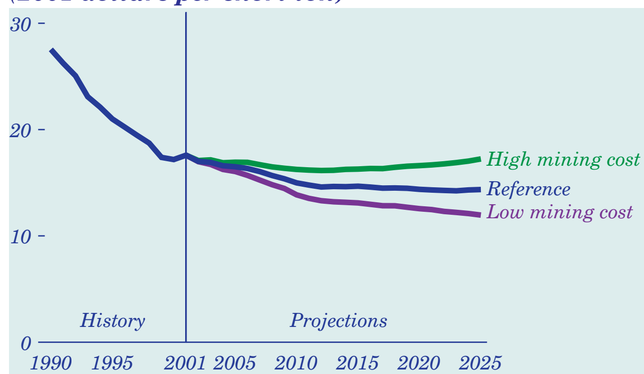
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested by many electricity generators, and its use in eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Continued penetration of technologies for extracting and hauling large volumes of coal in both surface and underground mining suggests that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 2001, the average number of miners working daily fell by 2.0 percent per year. With production increases and productivity improvements expected to continue through 2025, a further decline of 0.5 percent per year in the number of miners is projected. The share of wages (excluding irregular bonuses, welfare benefits, and payroll taxes paid by employers) in minemouth coal prices [*47*], which fell from 31 percent to 16 percent between 1970 and 2001, is projected to decline to 13 percent by 2025 (Figure 104).

Lower Mining Cost Assumptions Lead to Higher Production in the East

Figure 105. Average minemouth coal prices in three mining cost cases, 1990-2025 (2001 dollars per short ton)



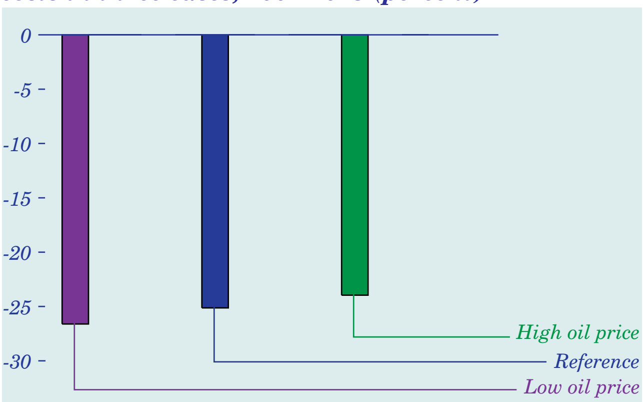
Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production levels vary with changes in projected mining costs.

Productivity is assumed to increase by 1.6 percent per year through 2025 in the reference case, while wage rates and equipment costs are constant in 2001 dollars. The national minemouth coal price is projected to decline by 0.8 percent per year to $14.36 per ton in 2025 (Figure 105).

In the low mining cost case, productivity is assumed to increase by 3.1 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*48*]. As a result, the average minemouth price is projected to fall by 1.6 percent per year to $11.96 per ton in 2025 (17 percent less than projected in the reference case). Eastern coal production is projected to be 46 million tons higher in the low mining cost case than in the reference case in 2025, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by 0.1 percent per year, and real wages and equipment costs are assumed to increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to fall by 0.1 percent per year to $17.24 per ton in 2025 (20 percent higher than in the reference case). Eastern production in 2025 is projected to be 60 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 106. Projected change in coal transportation costs in three cases, 2001-2025 (percent)



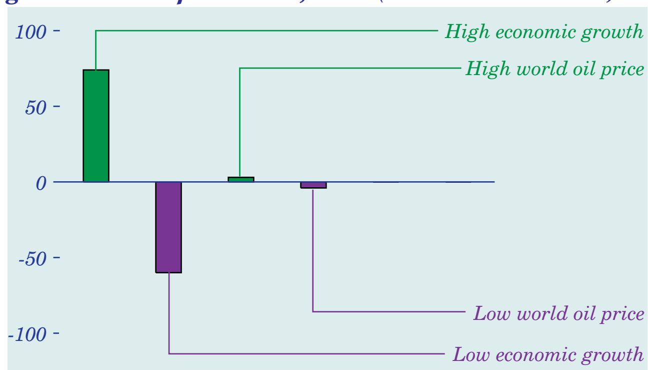
Changes in transportation costs affect the competition between coal and other fuels and among coalfields. In 1997, transportation costs averaged 41 percent of the delivered price of contract coal shipments to electric utilities [*49*]. With the expectation of nationally declining minemouth prices, along with increases in average shipping distances as western coal expands market share, the average percentage is expected to rise. Increases in fuel costs affect transportation costs (Figure 106), but they are also influenced by improvements in transportation fuel efficiency. Overall, in the reference case, average coal transportation costs are projected to decline by 1.2 percent per year between 2001 and 2025.

Historically, the most rapid declines in coal transportation costs have occurred on routes originating in coalfields that have had the greatest declines in real minemouth prices and increases in production. For instance, in the Powder River Basin supply region, the average transportation rate per ton for contract shipments to electric utilities decreased by 35 percent between 1988 and 1997, while shipped tonnage increased by 74 percent [*50*]. For coal from the Powder River Basin, where transportation can make up 60 percent or more of delivered cost, lower transportation costs could further increase its market share.

Also, with Phase 2 of CAAA90, which became effective on January 1, 2000, mines in the Powder River Basin will require expansion of their train-loading capacities to meet the increase in demand for low-sulfur coal. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 107. Projected variation from reference case projections of coal demand for electricity generators in four cases, 2025 (million short tons)

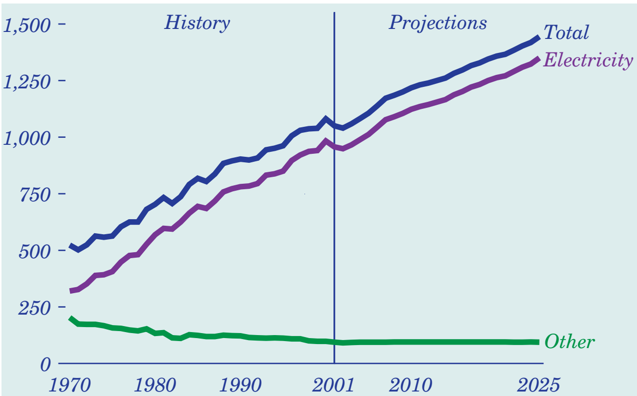


A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 107), with domestic coal consumption in 2025 projected to range from 1,381 to 1,524 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 133 million tons. The difference in total projected coal production between the two economic growth cases is 144 million tons, of which 54 million tons (37 percent) is projected to be western production. Although western coal must travel up to 2,000 miles to reach some of its markets, it is expected to be competitively priced in all regions except the Northeast.

The world oil price cases show relatively small changes in coal use for electricity generation. The low price case projects only 8 million tons less coal use for electricity generation in 2025 than is projected in the high price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels, but because oil-fired generation represents a very small proportion of total generation, its impact on coal consumption is minor, even in the high world oil price case. Although changes in oil prices are expected to have little effect on coal-fired generation, high oil prices could stimulate the coal-to-liquids market. In the high world oil price case, 19 million tons of coal is projected to be converted to roughly 35 million barrels of fuel liquids in 2025.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 108. Electricity and other coal consumption, 1970-2025 (million short tons)



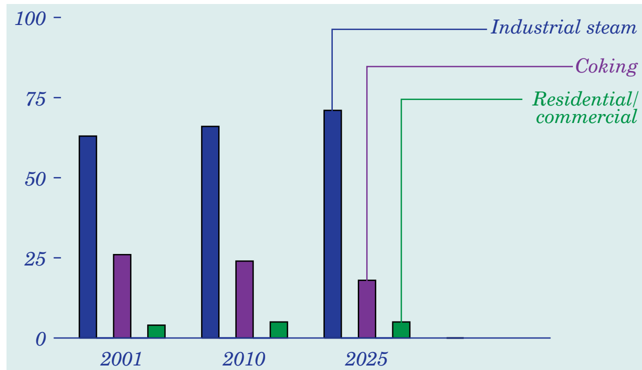
Domestic coal demand is projected to increase by 394 million tons in the reference case forecast, from 1,050 million tons in 2001 to 1,444 million tons in 2025 (Figure 108), because of projected growth in coal use for electricity generation. Total coal demand in other domestic end-use sectors is projected to remain relatively constant.

Coal consumption for electricity generation is projected to increase from 957 million tons in 2001 to 1,350 million tons in 2025 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate is projected to increase from 69 percent in 2001 to 83 percent in 2025. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous and lignite than for bituminous coals, the shift to western coal is projected to increase the tonnage per kilowatthour of generation in the Midwest and Southeast regions. In the East, generators are expected to shift to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal is projected to maintain its fuel cost advantage over both oil and natural gas, gas-fired generation is expected to be the most economical choice for construction of new power generation units in most situations, when capital, operating, and fuel costs are considered. Between 2005 and 2025, rising natural gas costs, increasing demand for electricity, and retirements of existing fossil-fired steam capacity are projected to result in increasing demand for coal-fired baseload capacity.

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 109. Projected coal consumption in the industrial and buildings sectors, 2010 and 2025 (million short tons)



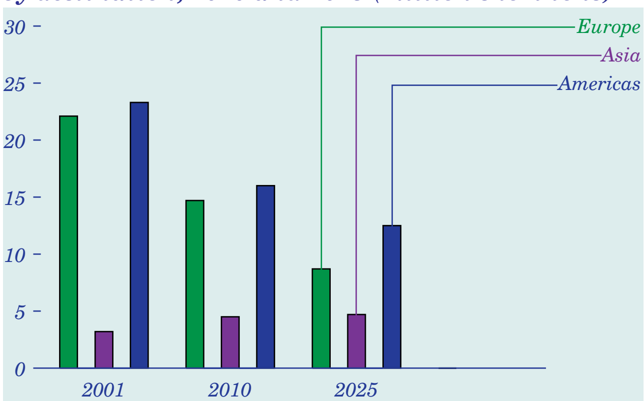
For applications other than electricity generation, a projected increase of 8 million tons in industrial steam coal consumption between 2001 and 2025 (0.5 percent annual growth) is expected to be offset by a decrease of 8 million tons in coking coal consumption (Figure 109). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.5 percent per year through 2025.

Although total energy consumption in the combined residential and commercial sectors is projected to grow by 1.3 percent per year, most of the growth is expected to be captured by electricity and natural gas. Coal consumption in the residential and commercial sectors is projected to remain constant, accounting for less than 1 percent of total U.S. coal demand in the forecast.

U.S. Coal Exports to Europe and the Americas Are Projected To Decline

Figure 110. Projected U.S. coal exports by destination, 2010 and 2025 (million short tons)



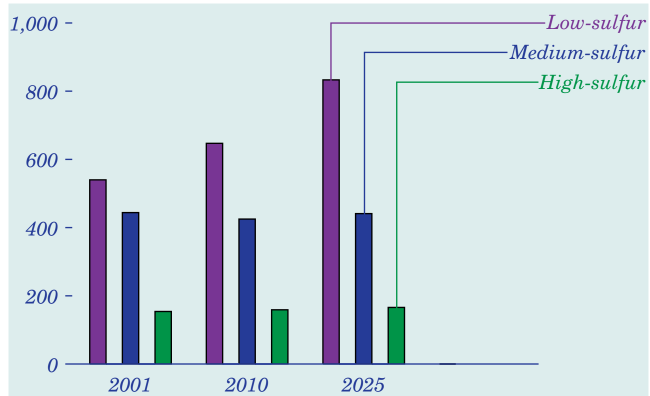
U.S. coal exports declined sharply between 1998 and 2001, from 78 million tons to 49 million tons, and are projected to continue to decline over the forecast horizon, reaching 26 million tons by 2025 (Figure 110). The most recent decline in U.S. coal exports occurred against the backdrop of a world coal market that saw an increase in trade from 546 million tons in 1998 to 650 million tons in 2001. While China and Indonesia satisfied much of the growth in international steam coal demand, low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in the world market.

The U.S. share of total world coal trade is projected to decline from 7 percent in 2001 to 3 percent by 2025 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 2001 to 2025, U.S. steam coal exports are projected to decline from 23 million tons to 10 million tons, despite substantial projected growth in world steam coal trade. Steam coal exports from Australia, South Africa, China, and Indonesia are expected to increase in response to growing import demand in Asian countries. Increasing exports from South America (Colombia and Venezuela) are expected to lead to a gradual increase in that region's share of the market for steam coal both in Europe and in the Americas.

U.S. coking coal exports are projected to decline from 25 million tons in 2001 to 16 million tons in 2025. A small increase in the world trade in coking coal is expected, primarily in Asia.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 111. Projected coal production by sulfur content, 2010 and 2025 (million short tons)



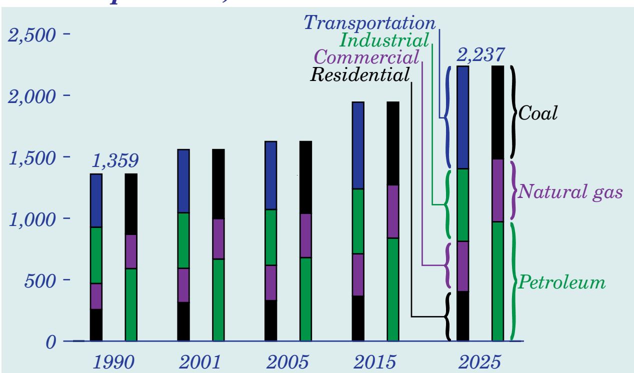
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas [*51*].

During Phase 1, many generators switched either partly or entirely from higher sulfur bituminous coals to low-sulfur subbituminous coal, incurring relatively modest capital investments. Such fuel switching often generated sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 111). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions, and coal imported from Colombia.

Coal users are likely to incur additional costs in the future as additional or new restrictions on emissions of nitrogen oxides, particulates, mercury, or carbon dioxide are adopted. An example of a proposal to further reduce emissions from U.S. power plants is the Bush Administration's Clear Skies Initiative. Relative to current law and regulations, the Administration's proposal specifies further restrictions on emissions of nitrogen oxides and sulfur dioxide and would introduce a national cap on mercury emissions.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 112. Projected carbon dioxide emissions by sector and fuel, 2005-2025 (million metric tons carbon equivalent)



Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2001 to 2025, to 2,237 million metric tons carbon equivalent (Figure 112), and emissions per capita are projected to grow by 0.7 percent per year.

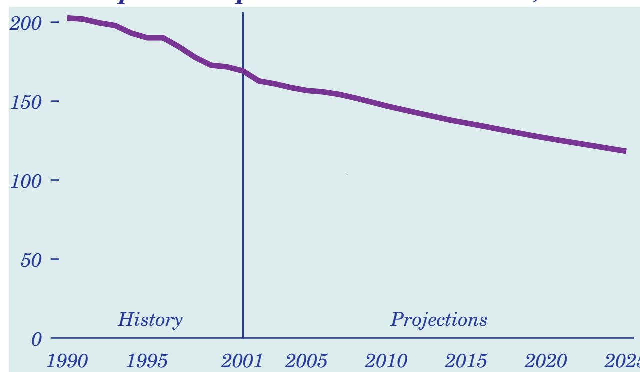
Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.0 percent per year, reflecting increased electrification and penetration of computers, electronics, and appliances in the sector. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector. As a result, carbon dioxide emissions from the commercial sector are projected to increase by 1.6 percent per year. Industrial emissions are projected to grow by 1.1 percent per year, as shifts to less energy-intensive industries and efficiency gains help to moderate growth in energy use.

In the transportation sector, carbon dioxide emissions grow at an average annual rate of 2.0 percent. Increases in highway, rail, and air travel are partially offset by efficiency improvements in rail freight and aircraft, but passenger vehicle fuel economy is projected to increase only slightly above 2001 levels.

In all sectors, potential growth in carbon dioxide emissions is expected to be moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon dioxide mitigation programs, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Dioxide Emissions From Energy Use

Figure 113. Carbon dioxide emissions per unit of gross domestic product, 1990-2025 (metric tons carbon equivalent per million 1996 dollars)



Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2025, petroleum is projected to account for 971 million metric tons carbon equivalent, a 43-percent share of the projected total. About 84 percent (811 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use.

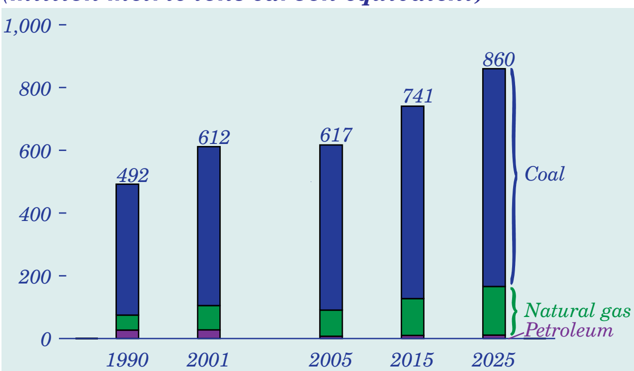
Coal is the second leading source of carbon dioxide emissions, projected to produce 753 million metric tons carbon equivalent in 2025, or 34 percent of the total. The coal share is projected to decline from 36 percent in 2001, because coal consumption is expected to increase at a slower rate through 2025 than consumption of petroleum and natural gas. Most of the increases in emissions from coal use result from electricity generation.

In 2025, natural gas use is projected to produce a 23-percent share of total carbon dioxide emissions, 512 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2025, at an average annual rate of 1.9 percent. Because carbon dioxide emissions from natural gas combustion, per Btu of energy produced, are only 56 percent of those from coal combustion, carbon intensity is reduced as natural gas replaces coal.

As the economy becomes more energy-efficient, its carbon intensity also declines. Between 2001 and 2025, the carbon intensity of the economy is expected to decline at an average rate of 1.5 percent per year (Figure 113).

Electricity Generation Is Also a Major Cause of Carbon Dioxide Emissions

Figure 114. Projected carbon dioxide emissions from the electric power sector by fuel, 2005-2025 (million metric tons carbon equivalent)



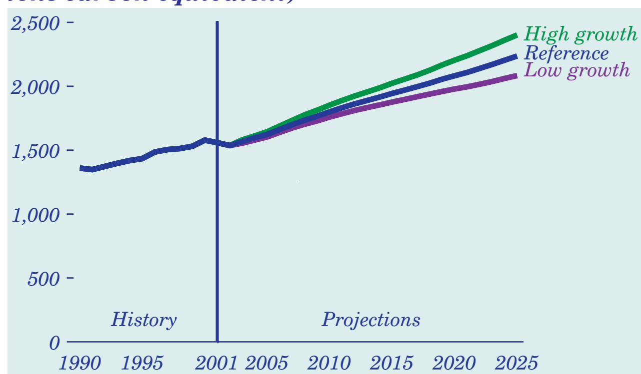
The use of fossil fuels in the electric power industry accounted for 39 percent of total energy-related carbon dioxide emissions in 2001, and the share is projected to be 38 percent in 2025. Coal is projected to account for 50 percent of the power industry's electricity generation in 2025 and to produce 81 percent of electricity-related carbon dioxide emissions (Figure 114). In 2025, natural gas is projected to account for 27 percent of electricity generation but only 18 percent of electricity-related carbon dioxide emissions.

Between 2001 and 2025, the electric power industry is projected to retire 82 gigawatts of generating capacity—about 10 percent of the 2001 level—and to see a 54-percent increase in electricity sales. As a result, the industry is projected to add 414 gigawatts of new fossil-fueled capacity by 2025. Although most of the new plants are expected to be relatively efficient combined-cycle plants fueled by natural gas, the net effect will be to raise the industry's carbon dioxide emissions by 248 million metric tons carbon equivalent, or 41 percent, from 2001 levels.

The electric power industry is projected to increase its reliance on renewable energy, which generally does not contribute to carbon dioxide emissions. Renewable generation is expected to increase by 170 billion kilowatthours, or 65 percent, between 2001 and 2025, helping to offset the projected increase in carbon dioxide emissions from fossil fuels. Average carbon dioxide emissions per kilowatthour of total generation are projected to decline by about 9 percent from 2001 to 2025.

Emissions Projections Change With Economic Growth Assumptions

Figure 115. Carbon dioxide emissions in three economic growth cases, 1990-2025 (million metric tons carbon equivalent)



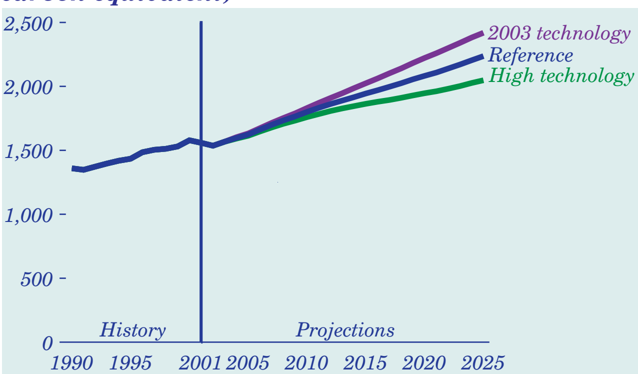
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.5 percent per year from 2001 to 2025, as compared with 3.0 percent per year in the reference case. In the low economic growth case, which assumes lower growth in population, labor force, and productivity, GDP growth averages 2.5 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case, and energy consumption totals 149 quadrillion Btu in 2025, 7 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to reach 2,401 million metric tons carbon equivalent in 2025, also 7 percent higher than in the reference case (Figure 115). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.7 percent per year in the high growth case, as compared with 1.5 percent in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity to turn over the stock of energy-using technologies, adding new equipment and increasing the overall efficiency of the capital stock.

In the low growth case, energy consumption reaches 129 quadrillion Btu in 2025, 7 percent lower than projected in the reference case, and carbon dioxide emissions in 2025 are also 7 percent lower at 2,083 million metric tons carbon equivalent. Energy intensity is projected to decline at a rate of 1.3 percent annually through 2025 in the low growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 116. Carbon dioxide emissions in three technology cases, 1990-2025 (million metric tons carbon equivalent)

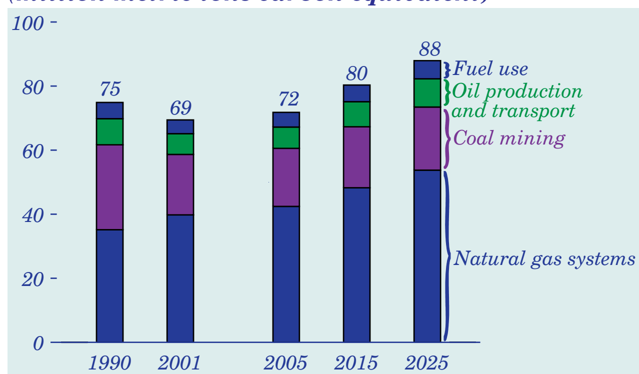


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*52*]. Energy intensity is expected to decline on average by 1.8 percent per year through 2025 in the high technology case, as compared with 1.5 percent in the reference case. As a result, energy consumption is projected to be 6 percent lower than in the reference case in 2025, at 130 quadrillion Btu, and carbon dioxide emissions are projected to be 9 percent lower than in the reference case, at 2,046 million metric tons carbon equivalent (Figure 116).

The 2003 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2003; that new building shell and plant efficiencies will remain at their 2003 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2003 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.3 percent per year through 2025. Energy consumption reaches 147 quadrillion Btu in 2025 in the 2003 technology case, and carbon dioxide emissions in 2025 are projected to be 9 percent higher than in the reference case, at 2,429 million metric tons carbon equivalent.

Moderate Growth in Methane Emissions Is Expected

Figure 117. Projected methane emissions from energy use, 2005-2025 (million metric tons carbon equivalent)

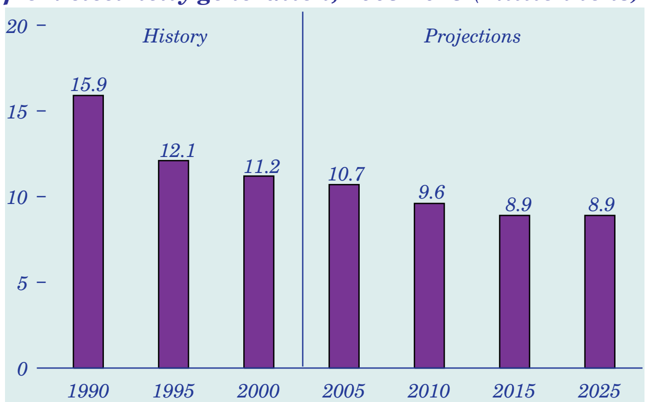


Methane emissions from energy use are projected to increase at an average rate of 1.0 percent per year from 2001 to 2025, somewhat slower than the 1.5-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered by the Kyoto Protocol. In 2001, methane accounted for 9.5 percent of total U.S. greenhouse gas emissions of 1,887 million metric tons carbon equivalent. About a third of methane emissions are related to energy activities, mostly from energy production and its transportation and to a much smaller extent from incomplete fuel combustion. Other sources of methane emissions include waste management, agriculture, and industrial processes.

Much of the projected increase in energy-related methane emissions is tied to increases in oil and gas use (Figure 117). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase by 35 percent by 2025, despite declines in the average rate of emissions per unit of production. Emissions related to oil production, refining, and transport are also expected to increase by about the same proportion. Coal-related methane emissions are expected to increase slowly, with little change projected in coal production from methane-intensive underground mining while progress in the recovery of vented gas continues. Methane emissions related to wood and fossil fuel combustion are projected to remain a small share of the total (6 percent) through 2025.

Sulfur Emissions Are Cut in Response to Tightening Regulations

Figure 118. Projected sulfur dioxide emissions from electricity generation, 2005-2025 (million tons)



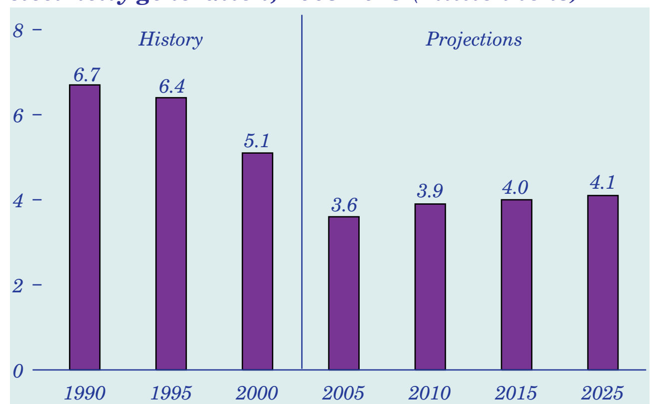
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year is not expected to be reached until after 2011. More than 95 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, which began in 1995, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances could also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, as only about 12 gigawatts of capacity had been retrofitted with scrubbers by 1995.

In recent years, power companies have announced plans to add scrubbers to 23 gigawatts of capacity to comply with State or Federal initiatives. No additional SO_2 scrubbers are projected to be added beyond those that have been announced. Emissions are projected to decline from 10.6 million tons in 2001 to 8.9 million in 2025 (Figure 118). The price of allowances is projected to vary between about \$100 and \$190 between 2002 and 2020 before declining through 2025.

Nitrogen Oxide Emissions Are Projected To Stay Below 2000 Levels

Figure 119. Projected nitrogen oxide emissions from electricity generation, 2005-2025 (million tons)



Nitrogen oxide (NO_x) emissions from U.S. electricity generation are projected to fall as new regulations take effect (Figure 119). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. CAAA90 NO_x reduction program called for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 resulted in NO_x reductions of 0.6 million tons between 1999 and 2000.

For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

Interpretations of ozone transport studies have been controversial. In September 1998 the EPA issued a rule, referred to as the Ozone Transport Rule (OTR), to address the problem. The OTR called for capping NO_x emissions in 22 Midwestern and Eastern States during the summer season, and following a court challenge, emissions limits were finalized for 19 States. These limits, which are included in the projections beginning in 2004, are projected to stimulate the addition of emissions control equipment to many existing plants, further lowering NO_x emissions by 0.5 million tons between 2003 and 2004.

Forecast Comparisons

Only one other organization—Global Insight, Inc. (GII, formerly DRI-WEFA)—produces a comprehensive energy projection with a time horizon similar to that of *AEO2003*. The most recent projection from GII, as well as other forecasts that concentrate on economic growth, international oil prices, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2003* projections.

Economic Growth

The *AEO2003* forecast period has been extended through 2025. Through 2020 the macroeconomic forecast is similar to the *AEO2003* forecast for the same period. From 2001 to 2020 both *AEO2002* and *AEO2003* project real gross domestic product (GDP) growth of 3.1 percent per year (Table 14). From 2001 to 2025, *AEO2003* projects real GDP grow of 3.0 percent per year, slightly less than the May 2002 GII forecast of 3.1 percent. Through 2012, the *AEO2003* forecast of 3.2 percent is similar to other forecasts: the GII forecast is 3.2 percent, the same as the July 2002 forecast by the Office of Management and Budget (OMB), and the August 2002 forecasts by the Congressional Budget Office (CBO) and Oxford Economic Forecasting (OEF) show 3.1-percent growth per year through 2012. The September 2002 forecast by Deutsche Banc Alex.Brown (DBAB) shows U.S. economic growth at 3.5 percent per year from 2000 to 2025.

Table 14. Forecasts of annual average economic growth, 2001-2025

Forecast	Average annual percentage growth 2001-2012	2001-2020	2001-2025
AEO2002	3.2	3.1	
AEO2003			
Reference	3.2	3.1	3.0
Low growth	2.8	2.6	2.5
High growth	3.8	3.6	3.5
GII	3.2	3.1	3.1
OMB	3.2	—	—
CBO	3.1	—	—
OEF	3.1	—	—
DBAB	—	—	3.5*

*DBAB average annual growth rate is for 2000-2025.
Note: Totals may not equal sum of components due to independent rounding.

World Oil Prices

Comparisons with other oil price forecasts—including GII, the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), DBAB, Altos Partners, and Energy and Environmental Analysis, Inc. (EEA)—are shown in Table 15 (GII, Spring-Summer 2002; IEA, September 2002; PEL, June 2002; PIRA, October 2002; NRCan, 1997, reaffirmed in September 2002; DBAB, September 2002; Altos, October 2002; EEA, October 2002). With the exception of PEL, which falls below the *AEO2003* low world oil price case in 2010 and 2015; EEA, GII, IEA, PEL, and DBAB, which fall below the *AEO2003* low price case in 2005; and DBAB, which falls below the *AEO2003* low price case in 2015, the range between the *AEO2003* low and high world oil price cases spans the range of published forecasts.

Table 15. Forecasts of world oil prices, 2000-2025

Forecast	2001 dollars per barrel 2000	2005	2010	2015	2020	2025
AEO2003						
Reference	28.35	23.27	23.99	24.72	25.48	26.57
High price	28.35	28.65	32.51	32.95	33.02	33.05
Low price	28.35	22.04	19.04	19.04	19.04	19.04
Altos	NA	22.64	23.40	25.58	27.90	31.61
GII	28.12	21.28	22.09	23.54	25.08	NA
IEA	28.63	21.47	21.47	21.47	25.56	27.61
PEL	28.63	21.21	18.46	17.47	NA	NA
PIRA	31.00	22.43	23.33	26.32	NA	NA
NRCan	22.28	22.28	22.28	22.28	22.28	NA
DBAB	28.01	19.04	19.04	18.94	19.34	19.18
EEA	28.87	20.98	20.47	19.98	19.50	NA

NA = not available.

Total Energy Consumption

The *AEO2003* forecast of end-use sector energy consumption shows relatively greater growth in petroleum, natural gas, and coal consumption and slower growth in electricity consumption (Table 16) than occurred between 1980 and 2001. Much of the

Table 16. Forecasts of average annual growth rates for energy consumption (percent)

Energy use	History 1980-2001	Projections: AEO2003 2001-2020	AEO2003 2001-2025	GII 2001-2020
Petroleum*	0.8	1.8	1.7	1.5
Natural gas*	0.3	1.4	1.4	1.4
Coal*	-1.7	0.1	0.1	0.1
Electricity	2.3	1.9	1.8	2.0
Delivered energy	0.7	1.7	1.6	1.4
Electricity losses	1.9	1.2	1.1	0.6
Primary energy	1.0	1.5	1.5	1.3

*Excludes consumption by electricity generators.

projected growth in petroleum consumption is driven by increased demand in the industrial sector for petrochemical and manufacturing applications and in the transportation sector as improvement in vehicle efficiency slows. Natural gas consumption is expected to grow more rapidly in the residential, commercial, and industrial sectors as it displaces a portion of petroleum and coal consumption. Coal consumption is projected to remain virtually constant as a result of growing emissions concerns and fuel switching.

Electricity is expected to remain the fastest growing source of delivered energy, although its projected rate of growth in both the *AEO2003* and GII forecasts is down from historical rates, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. The *AEO2003* projections are generally consistent with the outlook from GII; however, GII forecasts slightly faster growth in natural gas and electricity consumption and slower growth in petroleum and coal consumption, resulting from differences in relative prices and projected growth in each sector.

Residential Sector

The projected growth rates for primary energy demand in the residential sector are lower than the rates between 1980 and 2001, largely because of projected lower growth in households. Other contributing factors include increasing energy efficiency due to technical innovations and legislated standards; voluntary government efficiency programs; and reduced opportunities for additional market penetration of such end uses as air conditioning.

Differing views on the growth of new uses for energy contribute to variations among the forecasts. By fuel, electricity (excluding generation and transmission losses) remains the fastest growing energy source for the sector in both the *AEO2003* and GII forecasts (Table 17). Both project faster growth in electricity use than in the number of households, implying that new uses for electricity will outweigh future efficiency improvements. Natural gas use is projected to grow at roughly the rate of households in the *AEO2003* forecast, whereas GII projects stronger growth in natural gas use than in households. Petroleum use in the residential sector fell by 0.7 percent per year from 1980 to 2001, and *AEO2003* shows that trend continuing through 2025, with petroleum use projected to fall by 0.5 percent per year. GII, on the other hand, projects 0.2-percent annual growth for residential petroleum use through 2020.

Commercial Sector

The recent historical growth trend for delivered commercial energy use is projected to continue, with *AEO2003* and GII projecting slightly higher and slightly lower growth rates, respectively, than occurred between 1980 and 2001. The growth rate for primary energy demand in the commercial sector is expected to decrease significantly from the rate between 1980 and 2001, largely because of lower projected growth in electricity demand and in the energy losses associated with the generation, transmission, and distribution of electricity.

As in the residential sector, electricity (excluding generation and transmission losses) remains the fastest growing energy source in both forecasts (Table 18). The forecasts show substantial growth in electricity use, with slower growth in the *AEO2003* projections toward the end of the forecast. Natural gas use is projected to grow more slowly than electricity use, and petroleum use continues to fall in both projections. *AEO2003* projects a slower decline in commercial oil demand than GII, because GII projects a shift from oil to electricity for heating and more rapid improvement in building shell efficiency than is projected in *AEO2003*.

Table 17. Forecasts of average annual growth in residential energy demand (percent)

		Projections		
	History	AEO2003		GII
Energy use	1980-2001	2001-2020	2001-2025	2001-2020
Petroleum	-0.7	-0.5	-0.5	0.2
Natural gas	0.1	1.1	1.1	1.4
Electricity	2.5	1.7	1.6	2.1
Delivered energy	0.4	1.1	1.1	1.5
Electricity losses	2.1	1.0	0.9	0.7

Table 18. Forecasts of average annual growth in commercial energy demand (percent)

		Projections		
	History	AEO2003		GII
Energy use	1980-2001	2001-2020	2001-2025	2001-2020
Petroleum	-2.8	-0.2	-0.1	-0.4
Natural gas	1.1	1.3	1.3	1.1
Electricity	3.7	2.2	2.2	2.0
Delivered energy	1.6	1.7	1.6	1.4
Electricity losses	3.3	1.5	1.5	0.6

Industrial Sector

The projected growth rates for delivered energy consumption in the industrial sector are 1.4 percent per year in *AEO2003* (Table 19) and 1.2 percent per year in the GII forecast. A source of difference in the two forecasts is renewable energy consumption, which was 1.8 quadrillion British thermal units (Btu) in 2001 but is not reflected in the GII forecast. In *AEO2003*, industrial renewable energy use is projected to grow by 2.2 percent per year. Growth of renewables reduces the requirements for other fuels, including purchased electricity, because biomass is used extensively for combined heat and power. Neither forecast reflects the 0.1-percent annual decline in industrial delivered energy consumption over the 1980-2001 period (primarily the result of a sharp drop in industrial economic activity in 2001, which also reduced energy consumption). In the *AEO2003* and GII forecasts, electricity and natural gas use are projected to grow more rapidly than either petroleum or coal use in the industrial sector.

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow at a rate similar to its growth rate over the recent past in both the *AEO2003* and GII forecasts (Table 20). The projection for gasoline demand is higher in *AEO2003* than in the GII forecast, primarily because higher growth is projected for light-duty vehicle travel and lower growth is projected for new car efficiency in *AEO2003* than in the GII projection. GII projects more rapid growth in air travel, and therefore more rapid growth in jet fuel consumption, and projects slower growth in diesel fuel demand. Both forecasts anticipate slower growth in light-duty vehicle travel and in air travel than in recent history. Demand for diesel fuel is also expected to grow more slowly in both forecasts than it has in the past.

Table 19. Forecasts of average annual growth in industrial energy demand (percent)

Energy use	History 1980-2001	Projections: AEO2003 2001-2020	Projections: AEO2003 2001-2025	Projections: GII 2001-2020
Petroleum	-0.4	1.2	1.2	1.0
Natural gas	0.3	1.6	1.6	1.4
Coal	-1.7	0.1	0.1	0.1
Electricity	1.0	1.7	1.6	2.0
Delivered energy	-0.1	1.4	1.4	1.2
Electricity losses	0.6	1.0	1.0	0.6
Primary energy	0.1	1.3	1.3	1.0

Electricity

Comparison across the *AEO2003*, GII, and EEA forecasts shows slight variation in projected electricity sales (Table 21). The forecasts for total electricity sales in 2020 range from 4,643 billion kilowatthours in the *AEO2003* low economic growth case to 5,095 billion kilowatthours in the *AEO2003* high economic growth case. The *AEO2003* reference case projection of 4,850 is slightly less than the GII forecast and nearly identical to the EEA forecast. Demand growth rates range from 1.8 percent in the *AEO2003* reference case, to 1.9 percent in both the GII and EEA forecasts, to 2.1 percent in the *AEO2003* high economic growth case. Both price forecasts (EEA does not forecast electricity prices) show competition in wholesale markets and slow growth in electricity demand relative to GDP growth contributing to declining electricity prices in real terms through 2025.

The GII forecast assumes that the U.S. electric power industry will be fully restructured, resulting in average electricity prices that approach long-run marginal costs. *AEO2003* assumes that partial restructuring will lead to increased competition in the electric power industry, lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient generating units, and other cost reductions. *AEO2003* projects a slight decline in electricity prices over the full range of the forecast; however, average prices increase slightly over the last 7 years of the forecast as capacity margins tighten and natural gas prices climb. In contrast,

Table 20. Forecasts of average annual growth in transportation energy demand and key indicators (percent)

Energy use	History 1980-2001	Projections: AEO2003 2001-2020	Projections: AEO2003 2001-2025	Projections: GII 2001-2020
Motor gasoline	1.5	2.1	2.0	1.6
Diesel fuel	3.6	2.5	2.4	1.4
Jet fuel	2.4	2.1	2.1	3.4
Residual fuel	-2.7	0.1	0.2	0.2
All energy	1.6	2.1	2.0	1.8
	Key indicators			
Car and light truck travel	3.0	2.4	2.3	1.9
Air travel (revenue passenger-miles)	4.9	2.6	2.4	3.8
Average new car fuel efficiency	1.1	0.3	0.3	0.5
Gasoline prices	-1.7	0.0	0.2	-0.4

Table 21. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	2001	AEO2003			Other forecasts	
		Reference	Low economic growth	High economic growth	GII	EEA
				2015		
Average end-use price (2001 cents per kilowatthour)	**7.3**	**6.5**	**6.2**	**6.7**	**5.5**	**NA**
Residential	8.6	7.7	7.4	8.1	6.7	NA
Commercial	7.9	6.9	6.6	7.2	5.8	NA
Industrial	4.8	4.4	4.1	4.5	4.0	NA
Net energy for load, including CHP	**3,770**	**5,024**	**4,881**	**5,208**	**5,269**	**5,158**
Coal	1,904	2,391	2,331	2,468	2,546	2,320
Oil	125	53	50	53	118	124
Natural gas [a]	624	1,223	1,155	1,314	1,295	1,346
Nuclear	769	805	805	805	693	735
Hydroelectric/other [b]	301	469	463	478	420	366
Nonutility sales to grid [c]	27	56	52	62	164	229
Net imports	20	26	24	29	33	38
Electricity sales	**3,414**	**4,481**	**4,357**	**4,642**	**4,583**	**4,405**
Residential	1,201	1,539	1,518	1,557	1,613	1,557
Commercial/other [d]	1,219	1,671	1,644	1,698	1,599	1,584
Industrial	994	1,271	1,195	1,387	1,371	1,264
Capability, including CHP (gigawatts) [e]	**851**	**1,051**	**1,022**	**1,091**	**1,161**	**1,001**
Coal	315	333	327	342	388	331
Oil and natural gas	321	482	461	509	559	452
Nuclear	98	99	99	99	94	92
Hydroelectric/other	117	130	129	131	139	126
				2020 [f]		
Average end-use price (2001 cents per kilowatthour)	**7.3**	**6.6**	**6.4**	**6.8**	**5.2**	**NA**
Residential	8.6	7.8	7.5	8.1	6.3	NA
Commercial	7.9	7.2	6.9	7.3	5.5	NA
Industrial	4.8	4.5	4.3	4.7	3.7	NA
Net energy for load, including CHP	**3,770**	**5,434**	**5,198**	**5,722**	**5,697**	**5,680**
Coal	1,904	2,553	2,441	2,687	2,826	2,562
Oil	125	52	58	49	106	106
Natural gas [a]	624	1,452	1,341	1,585	1,492	1,585
Nuclear	769	807	807	807	657	739
Hydroelectric/other [b]	301	486	475	498	417	397
Nonutility sales to grid [c]	27	67	59	77	167	250
Net imports	20	17	17	17	31	40
Electricity sales	**3,414**	**4,850**	**4,643**	**5,095**	**4,973**	**4,835**
Residential	1,201	1,640	1,598	1,670	1,781	1,693
Commercial/other [d]	1,219	1,852	1,799	1,902	1,715	1,793
Industrial	994	1,358	1,246	1,523	1,477	1,349
Capability, including CHP (gigawatts) [e]	**851**	**1,129**	**1,081**	**1,185**	**1,240**	**1,070**
Coal	315	353	339	370	408	364
Oil and natural gas	321	532	504	565	624	467
Nuclear	98	100	100	100	88	92
Hydroelectric/other	117	133	131	135	139	148

[a]Includes supplemental gaseous fuels.

[b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, plus a small quantity of petroleum coke.

[c]For *AEO2003*, includes only net sales from combined heat and power plants.

[d]"Other" includes sales of electricity to government, railways, and street lighting authorities.

[e]EIA capacity is net summer capability, including combined heat and power plants. GII capacity is nameplate, excluding cogeneration plants.

[f]Electric power projections for 2025 were not available from GII and EEA. For *AEO2003* projections, see Appendixes A and B.

CHP = combined heat and power. NA = not available.

Sources: ***AEO2003:*** AEO2003 National Energy Modeling System, runs AEO2003.D110502C (reference case), LM2003.D110502C (low economic growth case), and HM2003.D110502C (high economic growth case). **GII:** DRI-WEFA (now Global Insight, Inc.), *Winter 2001-2002 U.S. Energy Outlook* (May 2002). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2002).

GII projects a larger decline over the forecast period from 2001-2020, despite higher natural gas prices and more nuclear retirements than are projected in *AEO2003*. The difference is largely attributable to greater net additions in the GII forecast (116 gigawatts), and a retirement rate for older units nearly twice that projected in the *AEO2003* reference case.

Both *AEO2003* and GII incorporate large amounts of planned capacity in the short term, with *AEO2003* projecting about 91 gigawatts through 2003 and GII projecting about 85 gigawatts, virtually all of which is expected to be gas-fired. The two forecasts project a glut of capacity with falling prices in the near term, along with steady capacity margins that begin to erode only in the later years. All three forecasts project that demand will grow fastest in the commercial sector and that more cycling and baseload capability will be built than peaking units, which typically are more sensitive to residential demand. All the forecasts show growth rates for electricity demand in the commercial sector of 2.3 percent through 2010, compared with residential sector demand growth of 2.1 percent in *AEO2003* and GII and 1.7 percent in EEA, leading to moderate increases in the share of baseload capacity relative to all additions. All the forecasts show significant gross additions to coal-fired capacity: 45 gigawatts by 2020 in *AEO2003*, 57 gigawatts in the EEA forecast, and nearly 89 gigawatts in the GII forecast. GII projects 15 gigawatts of nuclear retirements, much more than *AEO2003* (3 gigawatts) or EEA (4 gigawatts). Moreover, *AEO2003* projects incremental capacity increases at many existing nuclear units, as well as the entry of Browns Ferry 1 into service, for a net increase in total nuclear capacity and generation over the forecast.

Natural Gas

The difference among published forecasts of natural gas prices, production, consumption, and imports (Table 22) indicate the uncertainty of future market trends. Because the forecasts depend heavily on the underlying assumptions that shape them, the assumptions should be considered when different projections are compared. For instance, the GII forecast incorporates a cyclical price trend based on exploration and production cycles, which can be deceptive when isolated years are considered.

In both 2015 and 2020, the other forecasts are within the range of projected consumption levels in the *AEO2003* low and high economic growth cases. Total natural gas consumption in the other forecasts is lower than the *AEO2003* reference case projection in both 2015 and 2020. While the expected growth in residential consumption in *AEO2003* is slightly lower than in the GII and EEA forecasts, PIRA's projection is markedly lower than the rest, by about half. Growth in commercial natural gas use is similar across the forecasts, with the EEA forecast showing a somewhat higher growth rate. Natural gas consumption in the industrial and electric power sectors is more difficult to compare, given potential definitional differences. Although all the forecasts show significantly greater growth in the electric power sector, both PIRA and EEA show faster growth in the electric power sector and less in the industrial sector than do the other forecasts.

Domestic natural gas consumption is met by domestic production and imports. All the forecasts show domestic production providing a decreasing share of total natural gas supply, but *AEO2003* shows a smaller shift in that direction. Both PIRA and EEA show significantly higher (more than double) liquefied natural gas (LNG) imports and notably lower pipeline imports than *AEO2003* and GII. GII shows somewhat higher pipeline imports than *AEO2003*.

With the exception of EEA's projection for 2015, all the wellhead price projections in *AEO2003* are higher than the other forecasts, in part because *AEO2003* projects generally higher domestic production levels, except in the low economic growth case. Unfortunately, price comparisons in isolated years can be deceptive. For instance, the projected wellhead price in 2020 is lower in the *AEO2003* high economic growth case than in the reference case, because initial flows from the Alaskan pipeline occur earlier in the high growth case than in the reference case, causing prices to drop below the reference case even with higher total production levels in that year. In addition, the incorporation of production cycles in the GII forecast makes particular year comparisons deceptive. Information about whether or when the other forecasts include Alaskan gas flows to the lower 48 States was not available.

For the residential and commercial sectors, end-use margins relative to wellhead prices are in a similar range in the *AEO2003* and GII forecasts, whereas the EEA forecast shows significantly lower margins relative to wellhead prices. Price margins for the electric power sector are similar across all the forecasts, but industrial price margins are notably lower in

Table 22. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	2001	AEO2003			Other forecasts		
		Reference	Low economic growth	High economic growth	GII [a]	EEA [b]	PIRA
		2015					
Lower 48 wellhead price (2001 dollars per thousand cubic feet)	**4.12**	**3.55**	**3.26**	**3.71**	**3.14**	**3.81**	**NA**
Dry gas production [c]	**19.36**	**23.83**	**23.08**	**24.16**	**23.44**	**23.40**	**22.34**
Net imports	**3.64**	**5.27**	**4.89**	**6.33**	**6.21**	**6.40**	**6.35**
Consumption	**22.64**	**29.50**	**28.38**	**30.90**	**29.42**	**29.20**	**28.80**
Residential	4.81	5.69	5.60	5.78	5.94	6.00	5.25
Commercial	3.25	3.89	3.84	3.95	3.90	4.00	3.68
Industrial [d]	7.53	9.53	9.00	10.24	7.52 [e]	8.40 [f]	5.61 [g]
Electricity generators [h]	5.26	8.01	7.63	8.51	9.63 [i]	8.60 [j]	12.17 [k]
Other [l]	1.79	2.38	2.30	2.43	2.44	2.20	2.08
End-use prices (2001 dollars per thousand cubic feet)							
Residential	9.96	7.90	7.57	8.07	7.33	7.33	NA
Commercial	8.29	6.83	6.50	7.01	6.27	6.62	NA
Industrial [d]	4.97	4.29	3.98	4.50	4.31 [m]	4.98	NA
Electricity generators [h]	4.69	4.21	3.90	4.42	3.73	4.59	NA
		2020 [n]					
Lower 48 wellhead price (2001 dollars per thousand cubic feet)	**4.12**	**3.69**	**3.58**	**3.63**	**3.23**	**3.10**	**NA**
Dry gas production [c]	**19.36**	**25.07**	**24.48**	**26.60**	**24.31**	**24.50**	**NA**
Net imports	**3.64**	**6.66**	**5.40**	**7.58**	**6.73**	**7.80**	**NA**
Consumption	**22.64**	**32.14**	**30.30**	**34.59**	**30.79**	**31.90**	**NA**
Residential	4.81	5.96	5.76	6.14	6.31	6.40	NA
Commercial	3.25	4.17	4.03	4.32	3.97	4.40	NA
Industrial [d]	7.53	10.10	9.30	11.27	7.74 [e]	8.50 [f]	NA
Electricity generators [h]	5.26	9.39	8.76	10.12	10.27 [i]	10.20 [j]	NA
Other [l]	1.79	2.53	2.45	2.75	2.51	2.40	NA
End-use prices (2001 dollars per thousand cubic feet)							
Residential	9.96	7.96	7.87	7.88	7.37	6.39	NA
Commercial	8.29	6.94	6.82	6.88	6.32	5.71	NA
Industrial [d]	4.97	4.44	4.29	4.43	4.38 [m]	4.24	NA
Electricity generators [h]	4.69	4.38	4.23	4.38	3.93	3.86	NA

[a]Previously DRI-WEFA. A factor of 1.0236 was applied to convert prices in 2000 dollars to 2001 dollars.
[b]The baseline projection includes a cyclical price trend based on exploration and production cycles; therefore, forecast values for an isolated year may be misleading. EEA's average wellhead price is $3.30 between 2010 and 2020.
[c]Does not include supplemental fuels.
[d]Includes consumption for combined heat and power; excludes consumption by nonutility generators.
[e]Excludes natural gas used for cogeneration or other nonutility generation.
[f]Includes natural gas consumed in cogeneration.
[g]Excludes gas demand for nonutility generation.
[h]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[i]Includes gas used in cogeneration and other nonutility generation.
[j]Includes independent power producers and excludes cogenerators.
[k]Equals the sum of gas demand for nonutility generation (NUG) plus gas demand for utility generation.
[l]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[m]On system sales or system sales (i.e., does not include gas delivered for the account of others).
[n]Natural gas projections for 2025 were not available from GII, EEA, and PIRA. For *AEO2003* projections, see Appendixes A and B.
NA = not available.
Sources: **2001:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). ***AEO2003*:** AEO2003 National Energy Modeling System, runs AEO2003.D110502C (reference case), LM2003.D110502C (low economic growth case), and HM2003.D110502C (high economic growth case). **GII:** DRI-WEFA (now Global Insight, Inc.), *Winter 2001-2002 U.S. Energy Outlook* (May 2002). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2002). **PIRA:** PIRA Energy Group (October 2002).

AEO2003 than in the other forecasts. Given that there are similar disparities in the historical prices provided with the other forecasts, the difference is probably attributable to differences in definition.

Petroleum

Eight world oil price forecasts are compared with the *AEO2003* reference, low world oil price, and high world oil price cases in Table 15. The *AEO2003* high price case projects the highest oil price in 2015, $32.95 per barrel (2001 dollars). Petroleum Economics Ltd. (PEL) projects the lowest price for 2015, $17.47 per barrel. For 2020, the *AEO2003* high world oil price case is highest at $33.02 per barrel, and the *AEO2003* low world oil price case is lowest at $19.04 per barrel. Overall, only PEL projects a substantial decline in the world oil price. NRCan is constant at $22.28 per barrel through 2020, and the low world oil price case and DBAB are consistent, varying by at most 40 cents per barrel. The other forecasts show increasing real crude oil prices.

More detailed projections of domestic petroleum production, consumption, and imports were obtained from GII and DBAB (Table 23). Both project peak domestic crude oil and natural gas liquids (NGL) production in 2015. U.S. crude oil and NGL production was 7.67 million barrels per day in 2001. DBAB projects an increase in crude oil and NGL production of 130,000 barrels per day from 2001 to 2015; after 2015, projected production declines rapidly, falling to a level that is 1.8 million barrels per day below 2001 levels in 2025. GII projects an increase in crude oil and NGL production of 200,000 barrels per day by 2015, falling to 50,000 barrels per day above 2001 levels in 2020. GII and the *AEO2003* reference and low and high world oil price cases project monotonically increasing NGL production from 2001 on. The reason for comparing total crude oil and NGL production is that DBAB does not separate crude oil and NGL production.

The *AEO2003* low world oil price and reference cases project that domestic crude and natural gas liquid production will reach a minimum, rather than a maximum, around 2015. The high world oil price case projects monotonically rising crude oil and NGL production from 2001 to 2025. The *AEO2003* reference and high world oil price cases and DBAB project an increase in crude oil and NGL production over 2001 levels by 2025. The *AEO2003* low world oil price case projects output that is 160,000 barrels per day below the 2001 level, and DBAB projects an even greater decline of 1.8 million barrels per day by 2025. The *AEO2003* reference case projects 290,000 barrels per day more, and the high world oil price case projects 720,000 barrels per day more in 2025.

GII's projected oil price path assumes global economic growth of about 3 percent annually. It further assumes that OPEC and its allies will be disciplined enough to prevent oversupply while not attempting to raise prices excessively. No greenhouse gas emissions limits are assumed. The *AEO2003* reference case also leaves aside greenhouse gas emissions limits.

GII's oil demand forecast for the United States is driven by projected 1.6-percent annual growth in gasoline consumption. Distillate demand is projected to grow at a slower rate of 1.7 percent per year. Demand for air transport is projected to grow more rapidly than demand for road transport, resulting in a 3.4-percent annual increase in jet fuel demand from 2001 to 2020. The *AEO2003* reference case assumes somewhat higher gasoline and distillate demand growth over the same period, at 2.1 percent and 1.9 percent per year, respectively.

Apparently small differences in expected growth rates of petroleum product demand compound over time. The *AEO2003* reference case projects gasoline demand in 2020 that is higher than GII's by 1.13 million barrels per day and distillate demand that is higher by 630,000 barrels per day. GII's gasoline and distillate demand projections for 2020 are the lowest of the five forecasts examined. The *AEO2003* reference case projects much slower growth in jet fuel demand, 2.7 percent annually from 2001 to 2020, and its projections for jet fuel demand in 2020 is 660,000 barrels per day below the GII projection. DBAB's jet fuel demand projection for 2020 is 120,000 barrels per day below the *AEO2003* reference case and is the lowest of the five projections.

The imported share of petroleum product supply is projected to increase, even if real crude oil prices rise substantially. The share of demand met by imports was 55.4 percent in 2001. The *AEO2003* high world oil price case projects the smallest imported share of total petroleum product supply, 64.5 percent, for 2025. DBAB projects the highest import share at 73.6 percent in 2025.

Table 23. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	2001	AEO2003 Reference	AEO2003 Low world oil price	AEO2003 High world oil price	Other forecasts GII	Other forecasts DBAB
				2015		
World oil price (2001 dollars per barrel)	**22.01**	**24.72**	**19.04**	**32.95**	**23.69** [a]	**19.04**
Crude oil and NGL production	**7.67**	**7.66**	**7.48**	**8.08**	**7.87**	**7.80**
Crude oil	5.80	5.25	5.09	5.61	5.51 [b]	NA
Natural gas liquids	1.87	2.41	2.39	2.46	2.36	NA
Total net imports	**10.90**	**16.20**	**16.79**	**15.15**	**15.44**	**15.19**
Crude oil	9.31	12.36	12.79	11.91	11.10	NA
Petroleum products	1.59	3.84	4.01	3.24	4.34	NA
Petroleum demand	**19.69**	**25.23**	**25.71**	**24.59**	**24.77**	**24.56**
Motor gasoline	8.67	11.83	11.97	11.50	11.03 [c]	10.96
Jet fuel	1.66	2.17	2.18	2.15	2.68	2.14
Distillate fuel	3.81	5.05	5.18	4.97	4.53	4.56
Residual fuel	0.97	0.63	0.75	0.56	0.67	0.89
Kerosene	0.07	0.06	0.06	0.05	0.07	NA
Liquefied petroleum gas	2.05	2.66	2.69	2.59	2.75	NA
Other	2.46	2.83	2.88	2.78	3.04 [d]	NA
Import share of product supplied (percent)	**55.4**	**64.2**	**65.3**	**61.6**	**62.3**	**61.9**
				2020		
World oil price (2001 dollars per barrel)	**22.01**	**25.48**	**19.04**	**33.02**	**25.05** [a]	**19.04**
Crude oil and NGL production	**7.67**	**7.99**	**7.71**	**8.36**	**7.72**	**6.69**
Crude oil	5.80	5.46	5.22	5.79	5.30 [b]	NA
Natural gas liquids	1.87	2.53	2.49	2.58	2.42	NA
Total net imports	**10.90**	**17.72**	**18.57**	**16.47**	**17.09**	**18.25**
Crude oil	9.31	12.66	13.32	12.10	11.47	NA
Petroleum products	1.59	5.06	5.25	4.37	5.62	NA
Petroleum demand	**19.69**	**27.13**	**27.77**	**26.28**	**26.31**	**26.58**
Motor gasoline	8.67	12.78	13.00	12.27	11.65 [c]	11.81
Jet fuel	1.66	2.46	2.47	2.42	3.12	2.34
Distillate fuel	3.81	5.40	5.57	5.30	4.77	4.91
Residual fuel	0.97	0.64	0.76	0.58	0.60	0.95
Kerosene	0.07	0.05	0.06	0.05	0.07	NA
Liquefied petroleum gas	2.05	2.85	2.89	2.77	2.94	NA
Other	2.46	2.95	3.03	2.88	3.16 [d]	NA
Import share of product supplied (percent)	**55.4**	**65.3**	**66.9**	**62.7**	**65.0**	**68.7**
				2025		
World oil price (2001 dollars per barrel)	**22.01**	**26.57**	**19.04**	**33.05**	**NA**	**18.94**
Crude oil and NGL production	**7.67**	**7.96**	**7.51**	**8.39**	**NA**	**5.87**
Crude oil	5.80	5.33	4.92	5.71	NA	NA
Natural gas liquids	1.87	2.63	2.59	2.68	NA	NA
Total net imports	**10.90**	**19.79**	**21.12**	**18.19**	**NA**	**21.18**
Crude oil	9.31	13.06	14.05	12.53	NA	NA
Petroleum products	1.59	6.73	7.06	5.66	NA	NA
Petroleum demand	**19.69**	**29.17**	**30.17**	**28.19**	**NA**	**28.76**
Motor gasoline	8.67	13.77	14.10	13.12	NA	12.72
Jet fuel	1.66	2.74	2.75	2.70	NA	2.56
Distillate fuel	3.81	5.87	6.23	5.75	NA	5.29
Residual fuel	0.97	0.64	0.77	0.59	NA	1.01
Kerosene	0.07	0.05	0.05	0.05	NA	NA
Liquefied petroleum gas	2.05	3.03	3.10	2.98	NA	NA
Other	2.46	3.07	3.17	3.01	NA	NA
Import share of product supplied (percent)	**55.4**	**67.8**	**70.0**	**64.5**	**NA**	**73.6**

NA = Not available.

Notes: [a]GII world oil price is imported refiner acquisition cost in 2000 dollars, converted to 2001 dollars using *AEO2003* reference case chain-weighted price indexes. [b]GII crude oil production includes "other" domestic supply. [c]GII total for motor gasoline includes methanol. [d]GII "other" petroleum demand total includes naphthas, which are reported separately in GII's forecast.

Sources: ***AEO2003:*** AEO2003 National Energy Modeling System, runs AEO2003.D110502C (reference case), LW2003.D110502C (low world oil price case), and HW2003.D110502C (high world oil price case). **GII:** DRI-WEFA (now Global Insight, Inc.), *Winter 2001-2002 U.S. Energy Outlook* (May 2002). **DBAB:** Deutsche Banc Alex.Brown, "World Oil Supply and Demand Estimates," e-mail from Adam Sieminski, September 20, 2002.

Coal

The unknown factors affecting the future of the coal industry, including the continued uncertainty of pending environmental regulations, are evident when the *AEO2003* forecast for 2015 and 2020 is compared against those of Energy Ventures Analysis, Inc. (EVA) and Hill & Associates, Inc. The *AEO2003* reference case does not attempt to surmise when and how new environmental requirements may take effect, whereas the other forecasts may represent such assumptions. For instance, although *AEO2003* does represent the provisions of the State implementation plan (SIP) call for 19 States where NO_x caps have been finalized, it does not include revised limits on emissions of particulates, because no specific plan is yet in place. Other forecasts, including EVA and Hill & Associates, include further reductions of SO_2 beyond those set by CAAA90. EVA assumes that SO_2 emissions will be restricted to 4.5 million tons by 2008 and then further to 3 million tons in 2013. Hill & Associates assumes that SO_2 emissions face a further 50 percent reduction in 2010. The EVA forecast includes a 26 ton per year national limit on mercury emissions in 2008, followed by a 15 ton per year limit in 2013. It also includes a $5 per ton fee on carbon dioxide emissions beginning in 2013 and restricts emissions of nitrogen oxides to 2.1 million tons in 2008 and 1.7 million tons in 2013. Neither Hill & Associates nor *AEO2003* represents mercury or carbon dioxide reductions in its reference case.

Given the more restrictive assumptions of EVA's forecast, it is not surprising that *AEO2003* projects higher coal consumption levels in 2020. Hill & Associates and *AEO2003* project similar levels of consumption in 2020. All the forecasts show an increase in coal production and consumption between 2015 and 2020.

While *AEO2003* projects growing domestic consumption over the forecast horizon, it also projects a simultaneous reduction in real coal prices (Table 24). Hill & Associates projects average minemouth prices—excluding coking coal and exports—that are 5 cents per million Btu higher in 2015 and 17 cents per million Btu higher in 2020 than projected in the *AEO2003* reference case. EVA's projected national average minemouth price, although lower than the historical average in 2001, shows an increase of 1 percent (on a Btu basis) between 2015 and 2020. *AEO2003*, unlike EVA and Hill & Associates, projects a decline in minemouth prices between 2015 and 2020 of 1 percent (on a Btu basis). The decline in prices in the *AEO2003* forecast is driven by the expectation of continued improvements in labor productivity, which has a high negative correlation with prices, and the continued market expansion of western coal, which has a lower minemouth price than eastern coals.

As western production makes further inroads into markets traditionally supplied by eastern coal, the average heat content of the coals produced and consumed will drop as well, reflecting the lower thermal content per ton of western than eastern coals. The *AEO2003* and EVA forecasts indicate similar average heat contents (calculated by dividing dollars per ton by dollars per million Btu). The average heat content of coal production in the EVA and *AEO2003* forecasts is 20.4 million Btu per ton in 2015 and 20.3 in 2020. These similarities seem to indicate comparable shares of western production in the two forecasts. In contrast, the average heat content associated with coal production in the Hill & Associates projections for 2015 and 2020 is 21.7 million Btu per ton, indicating a relatively larger share of eastern production.

Gross exports of coal represent a small part of domestic coal production. In *AEO2003*, their share of total production is expected to fall from 4 percent in 2001 to 2 percent in 2020. Currently, coal is the only domestic energy resource whose net exports are still positive. EVA projects that this will change by 2020, and the United States will import more coal than it exports. *AEO2003* also projects that the United States will become a net importer of coal, but not until 2024. Hill & Associates projects that net coal exports will decline as well, but by a less significant margin, estimating net exports of 17 million tons in 2015 and 16 million tons in 2020. Strong price competition from other exporters and the loss of markets as Europe moves away from coal for environmental reasons are among the causes for the long-term decline in export projections.

The coal forecasts reviewed reflect the great uncertainties facing the U.S. coal industry as it must simultaneously adapt to the financial pressures arising from increasing environmental restrictions on coal use (both here and in Europe), deregulation of the U.S. electricity generation industry, and increasing competition from the younger coal fields of international competitors.

Table 24. Comparison of coal forecasts (million short tons, except where noted)

Projection	2001	AEO2003 Reference	AEO2003 Low economic growth	AEO2003 High economic growth	Other forecasts EVA	Other forecasts Hill & Associates
		2015				
Production	1,138	1,286	1,258	1,322	1,121	1,357
Consumption by sector						
Electricity generation	957	1,187	1,162	1,221	1,039	1,260
Coking plants	26	22	22	22	24	18
Industrial/other	67	73	71	76	58	62
Total	1,050	1,282	1,254	1,319	1,120	1,339
Net coal exports	29	6	6	6	1	17
Exports	49	29	29	29	34	NA
Imports	20	22	22	22	34	NA
Minemouth price						
(2001 dollars per short ton)	17.59	14.67	14.54	14.76	15.73 [a]	16.73 [b,c]
(2001 dollars per million Btu)	0.83	0.72	0.71	0.72	0.77 [a]	0.77 [b,c]
Average delivered price to electricity generators						
(2001 dollars per short ton)	25.06	23.16	22.78	23.62	NA	20.95 [c]
(2001 dollars per million Btu)	1.25	1.15	1.13	1.17	NA	1.06 [c]
		2020 [d]				
Production	1,138	1,359	1,314	1,412	1,171	1,402
Consumption by sector						
Electricity generation	957	1,263	1,222	1,313	1,093	1,312
Coking plants	26	20	20	20	23	15
Industrial/other	67	74	71	78	57	59
Total	1,050	1,358	1,313	1,411	1,172	1,387
Net coal exports	29	4	4	4	-1	16
Exports	49	29	29	29	35	NA
Imports	20	25	25	25	36	NA
Minemouth price						
(2001 dollars per short ton)	17.59	14.38	14.06	14.79	15.83 [a]	19.11 [b,c]
(2001 dollars per million Btu)	0.83	0.71	0.69	0.72	0.78 [a]	0.88 [b,c]
Average delivered price to electricity generators						
(2001 dollars per short ton)	25.06	22.45	21.85	23.20	NA	22.20 [c]
(2001 dollars per million Btu)	1.25	1.12	1.10	1.15	NA	1.11 [c]

[a]The average coal price is a weighted average of the projected spot market FOB mine price for all domestic coal.
[b]The minemouth price represents an average for domestic steam coal only. Exports and coking coal are not included in the average.
[c]The prices provided by Hill & Associates were converted from 2002 dollars to 2001 dollars in order to be consistent with *AEO2003*.
[d]Coal projections for 2025 were not available from EVA and Hill & Associates. For *AEO2003* projections, see Appendixes A and B.
Btu = British thermal unit. NA = Not available.
Sources: ***AEO2003*:** AEO2003 National Energy Modeling System, runs AEO2003.D110502C (reference case), LM2003.D110502C (low economic growth case), and HM2003.D110502C (high economic growth case). **EVA:** Energy Ventures Analysis, Inc., *Energy Ventures Analysis Forecast—August 2002* (August 2002). **Hill & Associates:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2021* (May 2002).

List of Acronyms

AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AER	*Annual Energy Review*
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
ATVs	All-terrain vehicles
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate Average Fuel Economy
CARB	California Air Resources Board
CBO	Congressional Budget Office
CCAP	Climate Change Action Plan
CCC	Commodity Credit Corporation
CHP	Combined heat and power
CI	Compression-ignition
CO	Carbon monoxide
DBAB	Deutsche Banc Alex. Brown
DOE	U.S. Department of Energy
E85	Motor fuel with 85 percent ethanol
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GII	Global Insight, Inc. (formerly DRI-WEFA)
HC	Hydrocarbons
IEA	International Energy Agency
IECC	International Energy Conservation Code
IOU	Investor-owned electric utility
IPP	Independent power producer
LEVP	Low-Emission Vehicle Program
LMP	Location marginal pricing
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
M85	Motor fuel with 85 percent methanol
MEF	Modified Energy Factor
MISO	Midwest Independent System Operator
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NMHCs	Nonmethane hydrocarbons
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPR-A	National Petroleum Reserve-Alaska
NRC	U.S. Nuclear Regulatory Commission
NRCan	Natural Resources Canada
OASIS	Open Access Same-Time Information System
OECD	Organization for Economic Cooperation and Development
OEF	Oxford Economic Forecasting
OPEC	Organization of Petroleum Exporting Countries
OTR	Ozone Transport Rule
PEL	Petroleum Economics Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
PR ratio	Production divided by reserves
PTC	Production tax credit (renewables)
PV	Photovoltaic
REPI	Renewable Energy Production Incentive
RFG	Reformulated gasoline
RFS	Renewable fuels standard
RP ratio	Reserves divided by production
RPS	Renewable portfolio standard
RTO	Regional transmission organization
SI	Spark-ignition
SMD	Standard Market Design
SO_2	Sulfur dioxide
SPR	Strategic Petroleum Reserve
TAME	Tertiary amyl methyl ether
ULSD	Ultra-low-sulfur diesel fuel
USGS	United States Geological Survey

Notes and Sources

Text Notes

Legislation and Regulations

[*1*] Federal Energy Regulatory Commission, *Regional Transmission Organizations*, 18 CFR Part 35 (Washington, DC, December 20, 1999).

[*2*] Federal Energy Regulatory Commission, "Commission Proposes New Foundation for Bulk Power Markets With Clear, Standardized Rule and Vigilant Oversight," Press Release (Washington, DC, July 31, 2002).

[*3*] "70 State Regulators Endorse US FERC Market Proposal," *Platts Global Energy* (August 16, 2002).

[*4*] Farm Security and Rural Investment Act of 2002, P.L. 107-171, Section 6013.

[*5*] Farm Security and Rural Investment Act of 2002, P.L. 107-171, Sections 7134 and 7223.

[*6*] Farm Security and Rural Investment Act of 2002, P.L. 107-171, Sections 8002 and 8102.

[*7*] Farm Security and Rural Investment Act of 2002, P.L. 107-171, Sections 9003-9009.

[*8*] U.S. Department of Agriculture, Farm Services Agency, web site www.fsa.usda.gov/daco/bio_daco.htm.

[*9*] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution from Non-road Diesel Engines: Final Rule," *Federal Register*, 40 CFR Parts 9, 86, and 89 (October 23, 1998).

[*10*] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution from New Marine Compression-Ignition Engines at or Above 37 kW: Final Rule," *Federal Register*, 40 CFR Parts 89, 92, and 94 (December 29, 1999).

[*11*] U.S. Environmental Protection Agency, "Emission Standards for Locomotives and Locomotive Engines: Final Rule," *Federal Register*, 40 CFR Parts 85, 86, and 92 (April 16, 1998).

[*12*] U.S. Environmental Protection Agency, *Emission Standards for New Non-road Engines*, EPA 420-F-02-03 (Washington, DC, September 2002).

Issues in Focus

[*13*] Letter from Senator Frank Murkowski (R-AK), Ranking Member, to Mary J. Hutzler, Acting Administrator, December 20, 2001.

[*14*] The analysis reports can be found on the EIA web site at www.eia.doe.gov/ bookshelf/services.html.

[*15*] Energy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, SR/OIAF/2001-04 (Washington, DC, October 2001).

[*16*] Combined heat and power (CHP) plants produce both electricity and useful thermal output. EIA formerly referred to these plants as cogenerators, but has determined that CHP better describes the facilities because some of the plants included in EIA's data do not produce heat and power in a sequential fashion, and as a result do not meet the legal definition of cogeneration specified in the Public Utilities Regulatory Policy Act (PURPA).

[*17*] There is a small impact from improved estimates of the quantity of natural gas consumed by independent power producers. For additional information, see Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), Appendix H, "Estimating and Presenting Power Sector Fuel Use in EIA Publications and Analyses," web site www.eia.doe.gov/emeu/aer/pdf/pages/sec_h.pdf.

[*18*] A developmental well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. An exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend the limit of a known oil or gas reservoir.

[*19*] Natural gas reserves that have been located but are isolated from potential markets are commonly referred to as "stranded gas." Such reserves are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[*20*] Flared natural gas is natural gas burned in flares at the well site or at gas processing plants. It is often associated with oil production that is considered to be unmarketable.

[*21*] "Alaska Producer Pipeline Update," PowerPoint presentation by BP/ExxonMobil/Phillips (May 2002).

[*22*] Canadian National Energy Board, *Canadian Energy: Supply and Demand to 2025* (1999).

[*23*] Based on an estimate of 5.3 billion cubic feet per day capacity after expansion from 4.3 billion cubic feet per day.

[*24*] Heavy oil sands, also referred to as tar sands, are naturally occurring bitumen-impregnated sands that yield liquid hydrocarbons that require further processing beyond mechanical blending before becoming finished petroleum products. One thousand cubic feet of natural gas is required to produce 1.2 barrels of bitumen. According to an October 19, 2001, article in *First Facts*, "Where Will Gas from the Mackenzie Delta Go? Bitumen Development!," published by the First Energy Capital Corporation of Calgary, Alberta, almost 1,500 thousand cubic feet per day of natural gas could be needed to support bitumen production by 2010.

[*25*] Energy Information Administration, *International Energy Outlook 2002*, DOE/EIA-0484(2002) (Washington, DC, March 2002). International reserves definitions do not necessarily correspond to the categorizations of U.S. proved reserves and may include estimates of resources as well as proved reserves.

[*26*] Zeus Development Corporation, *2001 World LNG/GTL Review* (Houston, TX, 2001), p iii.

[*27*] El Paso's EP Energy Bridge™ is a ship-based LNG regasification system that uses proven offshore buoy technology to moor the ship and proprietary technology to regasify LNG onboard the ship and discharge it through a subsea pipeline. El Paso has three ships on order and expects the first to be in service by 2005.

[*28*] Capacity estimates are based in part on estimates for terminals that have been proposed in the different regions. New LNG facilities represent generic facilities in each of the coastal regions and may represent more than one facility.

[29] Five-year moving average growth rates are used to smooth the effects of annual variations caused by short-term shifts in weather or economic growth. The growth rates shown in Figure 25 are calculated as [(current year sales / current year-5 sales)$^{1/5}$ – 1] x 100.

[30] "President Announces Clear Skies & Global Climate Change Initiatives" web site www.whitehouse.gov/news/releases/2002/02/ 20020214-5.html (February 14, 2002).

[31] U.S. Department of State, *U.S. Climate Action Report 2002* (Washington, DC, May 2002), Chapter 5, "Projected Greenhouse Gas Emissions," pp. 70-80, web site http:// yosemite.epa.gov/ oar/ globalwarming.nsf/ content/ ResourceCenterPublicationsUSClimateActionReport.html.

Market Trends

[32] I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures," presented to the Sixth Meeting of the International Energy Workshop (Vienna, Austria, June 1993).

[33] The transportation sector has been left out of these calculations because levels of transportation sector electricity use have historically been far less than 1 percent of delivered electricity. In the transportation sector, the difference between total and delivered energy consumption is also less than 1 percent.

[34] The high and low macroeconomic growth cases are linked to higher and lower population growth, respectively, which affects energy use in all sectors.

[35] The definition of the commercial sector for *AEO2003* is based on data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS). See Energy Information Administration, 1999 CBECS Public Use Data Files (August 2002), web site www.eia.doe.gov/emeu/cbecs/. Nonsampling and sampling errors (found in any statistical sample survey) resulted in a higher commercial floorspace estimate than found with the 1995 CBECS. In addition, 1999 CBECS energy intensities varied from earlier estimates, providing a different composition of end-use consumption. These factors contribute to the pattern of commercial energy use projected for *AEO2003*. Further discussion is provided in Appendix G.

[36] The intensities shown were disaggregated using the divisia index. The divisia index is a weighted sum of growth rates and is separated into a sectoral shift or "output" effect and an energy efficiency or "substitution" effect. It has at least two properties that make it superior to other indexes. First, it is not sensitive to where in the time period or in which direction the index is computed. Second, when the effects are separated, the individual components have the same magnitude, regardless of which is calculated first. See Energy Information Administration, "Structural Shift and Aggregate Energy Efficiency in Manufacturing" (unpublished working paper in support of the National Energy Strategy, May 1990); and Boyd et al., "Separating the Changing Effects of U.S. Manufacturing Production from Energy Efficiency Improvements," *Energy Journal*, Vol. 8, No. 2 (1987).

[37] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence.

[38] Small light trucks (compact pickup trucks and compact vans) are used primarily as passenger vehicles, whereas medium light trucks (compact utility trucks and standard vans) and large light trucks (standard utility trucks and standard pickup trucks) are used more heavily for commercial purposes.

[39] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCiro et al, *Technical Options for Improving the Fuel Economy of U.S. Cars and Light Trucks by 2010-2015* (Washington, DC: American Council for an Energy Efficient Economy, April 2001); M.A. Weiss et al, *On the Road in 2020 A Life-Cycle Analysis of New Automotive Technologies* (Cambridge, MA: Massachusetts Institute of Technology, October 2000); and A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[40] Values for incremental investments and energy expenditure savings are discounted back to 2003 at a 7-percent real discount rate.

[41] Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and combined heat and power capacity.

[42] Includes the cost to connect to the transmission grid but does not include the cost of any required backup capacity for wind-powered generators. Partial or full backup generation capability may be required to allow wind power to provide reliable capacity equivalent to the other generation types shown.

[43] *AEO2003* does not include off-grid photovoltaics (PV). EIA estimates that as much as 91 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2000, plus an additional 256 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See *Annual Energy Review 2001*, Table 10.6 (annual PV shipments, 1989-2000). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[44] Hydroelectric and landfill gas assumptions are unchanged from the reference case. Assumptions are obtained or derived from the Electric Power Research Institute and DOE, Office of Energy Efficiency and Renewable Energy, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997), web site www.eren.doe.gov/power/techchar.html.

[45] The EPRI *Renewable Energy Technology Characterizations* represent projections as of 1997. Where the EPRI projected cost or performance values for 2002 do not match EIA estimates for 2002, the EIA estimate is used, and the EPRI rate of cost decline though 2025 is used to establish the 2025 target value.

[46] Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384 (2001) (Washington, DC, November 2002).

[47] Total labor costs are estimated by multiplying the average hourly earnings of coal mine production workers by total annual labor hours worked. Average hourly earnings do not represent total labor costs per hour for the employer, because they exclude retroactive payments and irregular bonuses, employee benefits, and the employer's share of payroll taxes.

[48] Variations in mining costs are not necessarily limited to changes in labor productivity and wage rates. Other factors that affect mining costs and, subsequently, the price of coal include such items as severance taxes, royalties, fuel costs, and the costs of parts and supplies.

[49] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation*, DOE/EIA-0597(2000) (Washington, DC, October 2000).

[50] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation*, DOE/EIA-0597(2000) (Washington, DC, October 2000). Tons refers to short tons.

[51] U.S. Environmental Protection Agency, web site http://www.epa.gov/airmarkets/arp/overview.html (October 25, 2002).

[52] Buildings: Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001). Industrial: EIA, *Industrial Model: Update on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001). Transportation: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond,* ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001). Fossil-fired generating technologies: U.S. Department of Energy, Office of Fossil Energy. Renewable Generating Technologies: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

Table Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, and C of this report.

Table 1. Summary of results: Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Table 2. Proposed LNG import terminals to serve U.S. markets as of August 2002: Energy Information Administration, Office of Oil and Gas. **Note:** Design capacity for the EP Energy Bridge™ terminal is based on three ships with a design capacity of 400 million cubic feet per day each, (as indicated in a May 8, 2002, press release from El Paso Global LNG, a subsidiary of El Paso Corporation).

Table 3. LNG facility trigger prices by facility and region: Energy Information Administration, Office of integrated Analysis and Forecasting. **Note:** The individual trigger price represents the lowest feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility (see Table 4). Regasification costs at new facilities include capital costs for their construction.

Table 4. Components of LNG trigger prices for new facilities: Stranded natural gas production costs represent expert judgments based on sources that include Zeus Development Corporation, *2001 World LNG/GTL Review* (Houston, TX, 2001), and "Asian Gas Prospects-1," *Oil & Gas Journal* (March 5, 2001). Liquefaction costs for different supply sources are based on an average liquefaction capital cost of $1 billion for one train (3 million metric tons of LNG or 143 billion cubic feet per year) amortized over a 20-year period with a 12-percent discount rate and a 3-year construction period, adjusted to account for individual plant factors such as age and location. LNG per-mile transportation costs are based on the distance-weighted average of per-mile shipment costs from Australia to Japan and from Indonesia to Japan. The shipment costs are drawn from "Asian Gas Prospects-1," *Oil & Gas Journal* (March 5, 2001). The per-unit average cost is applied to the distances from supply sources to different LNG receiving terminals in the United States to arrive at initial transportation costs. Final transportation costs are computed taking into account the return on capital (12-percent rate of return) based on a $165 million capital cost per ship, depreciation over a 20-year period, and an assumed tanker capacity of 3 billion cubic feet per trip. Regasification costs were arrived at using expert judgment based on capital and operating expenses developed by PTL Associates for a generic LNG import terminal with two storage tanks and a total capacity of 183 billion cubic feet per year, at a seismically inactive site with no requirement for dredging or piling. The costs were adjusted to account for land purchase, rate of return, site-specific permitting, special land and waterway preparation and/or acquisitions, and regulatory costs.

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Table 12. Crude oil production from Gulf of Mexico offshore, 2001-2025: AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Table 13. Petroleum consumption and net imports in five cases, 2001 and 2025: 2001: Energy Information Administration, *Petroleum Supply Annual 2001*, Vol. 1, DOE/EIA-0340 (2001)/1 (Washington, DC, June 2001). **2025:** Tables A11, B11, and C11.

Table 14. Forecasts of annual average economic growth, 2001-2025: *AEO2003*: Table B20. ***AEO2002:*** AEO2002 National Energy Modeling System, run AEO2003.D102001B. **GII (formerly DRI-WEFA):** Global Insight Macroeconomic Model AII250502 (May 2002). **OMB:** Office of Management and Budget (July 2002). **CBO:** Congressional Budget Office (August 2002). **OEF:** Oxford Economic Forecasting, *World Long-Term Economic Prospects* (August 2002). **DBAB:** Deutsche Banc Alex.Brown, *Oil Market Outlook* (September 5, 2002).

Table 15. Forecasts of world oil prices, 2000-2025: *AEO2003*: Tables A1 and C1. ***AEO2002:*** AEO2002 National Energy Modeling System, run AEO2003.D102001B. **GII (formerly DRI-WEFA):** Global Insight, *Oil Market Outlook: Long-Term Focus* (Spring-Summer 2002). Note: Prices shown here differ from those shown in Table 22. The source is a later edition of the *Long-Term Focus* that was developed in a nonintegrated run. **Altos:** Altos Partners, World Oil Model, e-mail from Tom Choi (October 9, 2002). Note: Price is WTI at Cushing. **IEA:** International Energy Agency, *World Energy Outlook 2002* (September 2002). Note: Price is crude oil import price. **PEL:** Petroleum Economics, Ltd., *World Long Term Oil and Energy Outlook* (June 2002). Note: Brent price. **PIRA:** PIRA Energy Group, *Retainer Client Seminar* (October 2002). Note: Price is WTI at Cushing. **NRCan:** Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (April 1997 and reaffirmed in August 2002). **DBAB:** Deutsche Banc Alex.Brown, *World Oil Supply and Demand Estimates* (September 2002). **EEA:** Energy and Environmental Analysis, Inc., EEA Compass Service (October 2002). Note: Price is U.S. refiner's acquisition cost of crude oil.

Table 16. Forecasts of average annual growth rates for energy consumption: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). ***AEO2003*:** Table A2. **GII (formerly DRI-WEFA):** Global Insight, *Winter 2001-2002 U.S. Energy Outlook* (May 2002). Note: Delivered energy includes petroleum, natural gas, coal, and electricity (excluding generation and transmission losses) consumed in the residential, commercial, industrial, and transportation sectors.

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Table 21. Comparison of electricity forecasts: *AEO2003*: AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LM2002.D110502C, and HM2002.D110502C. **GII (formerly DRI-WEFA):** Global Insight, *Winter 2001-2002 U.S. Energy Outlook* (May 2002).

Table 22. Comparison of natural gas forecasts: *AEO2003*: AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LM2002.D110502C, and HM2002.D110502C. **GII (formerly DRI-WEFA):** Global Insight, *Winter 2001-2002 U.S. Energy Outlook* (May 2002).

Table 23. Comparison of petroleum forecasts: *AEO2003*: AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LW2002.D110502C, and HW2002.D110502C. **GII (formerly DRI-WEFA):** Global Insight, *Winter 2001-2002 U.S. Energy Outlook* (May 2002). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 2001).

Table 24. Comparison of coal forecasts: *AEO2003*: AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LM2003.D110502C, and HM2003.D110502C. **EVA:** Energy Ventures Analysis, Inc., "Energy Ventures Analysis Forecast—August 2002." **Hill & Associates:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2021* (May 2002).

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Figure 1. Energy price projections, 2001-2025: *AEO2002* and *AEO2003* compared: *AEO2002* projections: Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001). ***AEO2003* projections:** Table A1.

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Figure 78. Projected lower 48 natural gas wellhead prices in three cases, 2010 and 2025: 2001: Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, October 2001). **2010 and 2025:** Tables A1 and B1.

Figure 79. Lower 48 natural gas reserve additions, 1970-2025: 1970-1976: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, computations based on well reports submitted to the American Petroleum Institute. **1977-2000:** EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(77-2000). **2001 and projections:** AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Figure 80. Natural gas production by source, 1990-2025: History: Total production and Alaska: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, October 2001). Offshore, associated-dissolved, and conventional: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216. Unconventional: EIA, Office of Integrated Analysis and Forecasting. **2001 and projections:** Table A15. Note: Unconventional gas recovery consists principally of production from reservoirs with low permeability (tight sands) but also includes methane from coal seams and gas from shales.

Figure 81. Net U.S. imports of natural gas, 1970-2025: History: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table A13.

Figure 82. Natural gas consumption by sector, 1990-2025: History: Electric utilities: Energy Information Administration (EIA), *Electric Power Annual 2001*, Vol. 1, DOE/EIA-0348(2001)/1 (Washington, DC, August 2001). Nonutilities: EIA, Form EIA-860B, "Annual Electric Generator Report—Nonutility." Other: EIA, *State Energy Data Report 2000*, DOE/EIA-0214(2000) (Washington, DC, May 2002). **Projections:** Table A13.

Figure 83. Natural gas end-use prices by sector, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table A14.

Figure 84. Projected changes in U.S. natural gas supply by region and source, 2001-2025: AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Figure 85. Projected changes in end-use natural gas consumption by region, 2001-2025: AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Figure 86. Projected lower 48 natural gas wellhead prices in three cases, 2010 and 2025: 2001: Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, October 2001). **2010 and 2025:** Table F10.

Figure 87. Lower 48 natural gas production in three cases, 1970-2025: History: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131 (2000) (Washington, DC, October 2001). **2001 and Projections:** Table F10.

Figure 88. Lower 48 crude oil wellhead prices in three cases, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Tables A15 and C15.

Figure 89. U.S. petroleum consumption in five cases, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Tables A11, B11, and C11.

Figure 90. Lower 48 crude oil reserve additions in three cases, 1970-2025: 1970-1976: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, computations based on well reports submitted to the American Petroleum Institute. **1977-2000:** EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(77-2000). **2001 and projections:** AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LW2002.D110502C, and HW2002. D110502C.

Figure 91. Lower 48 crude oil production by source, 1970-2025: 1970-1976: 1970-1976: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, computations based on well reports submitted to the American Petroleum Institute. **1977-2000:** EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(77-2000). **2001 and projections:** AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LW2002.D110502C, and HW2002.

D110502C.EIA-0384(2001) (Washington, DC, August 2002). Lower 48 offshore, 1970-1985: U.S. Department of the Interior, *Federal Offshore Statistics: 1985*. Lower 48 offshore, 1986-2001: EIA, *Petroleum Supply Annual*, DOE/EIA-0340 (86-00). Lower 48 onshore, conventional, and enhanced oil recovery: EIA, Office of Integrated Analysis and Forecasting. **Projections:** Table A15.

Figure 92. Lower 48 crude oil production in three cases, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table F11.

Figure 93. Alaskan crude oil production, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table F11.

Figure 94. Petroleum supply, consumption, and imports, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Tables A11, B11, and C11. **Note:** Domestic supply includes domestic crude oil and natural gas plant liquids, other crude supply, other inputs, and refinery processing gain.

Figure 95. Share of U.S. petroleum consumption supplied by net imports in three cases, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Tables A11 and C11.

Figure 96. Domestic refining capacity, 1975-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Tables A11 and B11. Note: Beginning-of-year capacity data are used for previous year's end-of-year capacity.

Figure 97. Petroleum consumption by sector, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table A11.

Figure 98. Consumption of petroleum products, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November2002). **Projections:** Table A11.

Figure 99. U.S. ethanol consumption, 1993-2025: History: History: Energy Information Administration, *Petroleum Supply Annual 2001*, Vol. 1, DOE/EIA-0340 (2001)/1 (Washington, DC, June 2002). **Projections:** Table A18.

Figure 100. Components of refined product costs, 2001 and 2025: Gasoline and diesel taxes: Federal Highway Administration, *Monthly Motor Fuel Reported by State* (Washington, DC, November 1998), web site www.fhwa.dot.gov/ohim/novmmfr.pdf. **Jet fuel taxes:** Energy Information Administration (EIA), Office of Oil and Gas. **2001:** Estimated from EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2002/03) (Washington, DC, March 2002). **Projections:** Estimated from AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Figure 101. Coal production by region, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Table A16.

Figure 102. Average minemouth price of coal by region, 1990-2025: History: Energy Information Administration, *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). **Projections:** AEO2003 National Energy Modeling System, run AEO2003. D110502C.

Figure 103. Coal mining labor productivity by region, 1990-2025: History: Energy Information Administration, *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). **Projections:** AEO2003 National Energy Modeling System, run AEO2003 .D110502C.

Figure 104. Labor cost component of minemouth coal prices, 1970-2025: History: U.S. Department of Labor, Bureau of Labor Statistics (2001), series id: eeu10120006, and Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** AEO2003 National Energy Modeling System, run AEO2003. D110502C.

Figure 105. Average minemouth coal prices in three mining cost cases, 1990-2025: Tables A16 and F13.

Figure 106. Projected change in coal transportation costs in three cases, 2001-2025: AEO2003 National Energy Modeling System, runs AEO2003.D110502C, LW2003. D110502C, and HW2003.D110502C.

Figure 107. Projected variation from reference case projections of coal demand for electricity generators in four cases, 2025: Tables A16, B16, and C17.

Figure 108. Electricity and other coal consumption, 1970-2025: History: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and EIA, *Short-Term Energy Outlook October 2001*. **Projections:** Table A16.

Figure 109. Projected coal consumption in the industrial and buildings sectors, 2010 and 2025: Table A16.

Figure 110. Projected U.S. coal exports by destination, 2010 and 2025: History: U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545." **Projections:** AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Figure 111. Projected coal production by sulfur content, 2010 and 2025: AEO2003 National Energy Modeling System, run AEO2003.D110502C.

Figure 112. Projected carbon dioxide emissions by sector and fuel, 2005-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** Table A19.

Figure 113. Carbon dioxide emissions per unit of gross domestic product, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** Tables A19 and A20.

Figure 114. Projected carbon dioxide emissions from the electric power sector by fuel, 2005-2025: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** Table A19.

Notes and Sources

Figure 115. Carbon dioxide emissions in three economic growth cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** Table B19.

Figure 116. Carbon dioxide emissions in three technology cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** Table F4.

Figure 117. Projected methane emissions from energy use, 2005-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** AEO2003 National Energy Modeling System, run AEO2003.D110502C110502C.

Figure 118. Projected sulfur dioxide emissions from electricity generation, 2005-2025: History: U.S. Environmental Protection Agency, *Acid Rain Program Emissions Scorecard 1999. SO_2, NO_x, Heat Input, and CO_2 Emissions Trends in the Electric Utility Industry*, EPA-430-R-98-020 (Washington, DC, June 2001). **Projections:** Table A8.

Figure 119. Projected nitrogen oxide emissions from electricity generation, 2005-2025: History: U.S. Environmental Protection Agency, *Acid Rain Program Emissions Scorecard 1999. SO_2, NO_x, Heat Input, and CO_2 Emissions Trends in the Electric Utility Industry*, EPA-430-R-98-020 (Washington, DC, June 2001). **Projections:** Table A8.

Appendixes

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Production								
Crude Oil and Lease Condensate	12.44	12.29	11.82	11.91	11.11	11.56	11.29	-0.4%
Natural Gas Plant Liquids	2.71	2.65	2.95	3.16	3.42	3.59	3.76	1.5%
Dry Natural Gas	19.50	19.97	20.68	22.47	24.47	25.75	27.47	1.3%
Coal	22.58	23.97	23.33	25.30	26.37	27.69	29.29	0.8%
Nuclear Power	7.87	8.03	8.28	8.36	8.41	8.43	8.43	0.2%
Renewable Energy[1]	5.96	5.33	6.71	7.23	7.75	8.28	8.78	2.1%
Other[2]	1.09	0.57	0.83	0.84	0.74	0.80	0.80	1.4%
Total	**72.15**	**72.81**	**74.60**	**79.27**	**82.25**	**86.10**	**89.83**	**0.9%**
Imports								
Crude Oil[3]	19.69	20.26	22.34	25.13	26.93	27.61	28.47	1.4%
Petroleum Products[4]	4.73	5.04	4.25	6.41	9.59	11.97	15.17	4.7%
Natural Gas	3.86	4.10	4.54	5.52	5.94	7.22	8.30	3.0%
Other Imports[5]	0.69	0.73	0.81	0.90	0.98	0.96	0.94	1.1%
Total	**28.98**	**30.13**	**31.94**	**37.96**	**43.43**	**47.76**	**52.88**	**2.4%**
Exports								
Petroleum[6]	2.15	2.01	2.05	2.24	2.26	2.34	2.41	0.8%
Natural Gas	0.25	0.37	0.59	0.62	0.55	0.41	0.37	0.1%
Coal	1.53	1.27	1.00	0.91	0.74	0.74	0.67	-2.6%
Total	**3.92**	**3.64**	**3.64**	**3.76**	**3.55**	**3.49**	**3.45**	**-0.2%**
Discrepancy[7]	**-2.18**	**1.99**	**-0.27**	**0.21**	**0.23**	**0.25**	**0.19**	**N/A**
Consumption								
Petroleum Products[8]	38.53	38.46	39.79	44.65	48.93	52.60	56.56	1.6%
Natural Gas	24.07	23.26	25.24	27.75	30.25	32.96	35.81	1.8%
Coal	22.64	22.02	22.82	24.98	26.30	27.68	29.42	1.2%
Nuclear Power	7.87	8.03	8.28	8.36	8.41	8.43	8.43	0.2%
Renewable Energy[1]	5.96	5.33	6.71	7.23	7.75	8.28	8.78	2.1%
Other[9]	0.31	0.21	0.32	0.29	0.27	0.17	0.07	-4.4%
Total	**99.38**	**97.30**	**103.16**	**113.26**	**121.91**	**130.12**	**139.07**	**1.5%**
Net Imports - Petroleum	**22.28**	**23.29**	**24.54**	**29.31**	**34.26**	**37.24**	**41.23**	**2.4%**
Prices (2001 dollars per unit)								
World Oil Price (dollars per barrel)[10]	28.35	22.01	23.27	23.99	24.72	25.48	26.57	0.8%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.83	4.12	2.88	3.29	3.55	3.69	3.90	-0.2%
Coal Minemouth Price (dollars per ton)	17.18	17.59	16.50	14.99	14.67	14.38	14.36	-0.8%
Average Electricity Price (cents per kilowatthour)	6.9	7.3	6.5	6.4	6.5	6.6	6.7	-0.3%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001). 2001 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2000 coal minemouth prices: EIA, *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). 2000 petroleum supply values: EIA *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2000 and 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Energy Consumption								
Residential								
Distillate Fuel	0.86	0.91	0.94	0.91	0.87	0.83	0.81	-0.5%
Kerosene	0.09	0.10	0.08	0.08	0.07	0.06	0.06	-2.2%
Liquefied Petroleum Gas	0.54	0.50	0.48	0.47	0.47	0.47	0.48	-0.2%
Petroleum Subtotal	1.50	1.50	1.50	1.46	1.41	1.37	1.34	-0.5%
Natural Gas	5.12	4.94	5.45	5.66	5.85	6.12	6.40	1.1%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.4%
Renewable Energy[1]	0.41	0.39	0.41	0.41	0.41	0.41	0.40	0.2%
Electricity	4.07	4.10	4.53	4.93	5.25	5.59	5.94	1.6%
Delivered Energy	**11.11**	**10.94**	**11.90**	**12.47**	**12.93**	**13.51**	**14.10**	**1.1%**
Electricity Related Losses	9.26	9.15	9.74	10.28	10.54	10.96	11.33	0.9%
Total	**20.37**	**20.09**	**21.64**	**22.75**	**23.47**	**24.47**	**25.43**	**1.0%**
Commercial								
Distillate Fuel	0.47	0.46	0.46	0.48	0.49	0.49	0.49	0.3%
Residual Fuel	0.09	0.09	0.04	0.04	0.05	0.05	0.05	-2.5%
Kerosene	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-0.7%
Liquefied Petroleum Gas	0.10	0.09	0.09	0.09	0.09	0.09	0.10	0.4%
Motor Gasoline[2]	0.05	0.05	0.03	0.03	0.03	0.04	0.04	-1.1%
Petroleum Subtotal	0.73	0.71	0.65	0.67	0.68	0.69	0.70	-0.1%
Natural Gas	3.30	3.33	3.62	3.80	4.00	4.29	4.56	1.3%
Coal	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.7%
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Electricity	3.96	4.09	4.49	5.02	5.59	6.20	6.83	2.2%
Delivered Energy	**8.19**	**8.32**	**8.95**	**9.69**	**10.49**	**11.38**	**12.30**	**1.6%**
Electricity Related Losses	9.01	9.12	9.64	10.46	11.23	12.14	13.03	1.5%
Total	**17.20**	**17.44**	**18.59**	**20.15**	**21.72**	**23.52**	**25.33**	**1.6%**
Industrial[4]								
Distillate Fuel	1.12	1.13	1.11	1.21	1.29	1.36	1.45	1.0%
Liquefied Petroleum Gas	2.30	2.10	2.30	2.55	2.87	3.10	3.33	1.9%
Petrochemical Feedstock	1.32	1.14	1.27	1.43	1.58	1.69	1.82	2.0%
Residual Fuel	0.24	0.23	0.17	0.19	0.19	0.20	0.20	-0.4%
Motor Gasoline[2]	0.15	0.15	0.15	0.17	0.18	0.18	0.19	1.0%
Other Petroleum[5]	3.96	4.03	4.15	4.31	4.35	4.49	4.60	0.5%
Petroleum Subtotal	9.09	8.79	9.14	9.86	10.46	11.02	11.59	1.2%
Natural Gas	8.48	7.74	8.35	9.13	9.79	10.38	11.22	1.6%
Lease and Plant Fuel[6]	1.16	1.20	1.32	1.39	1.51	1.59	1.74	1.5%
Natural Gas Subtotal	9.65	8.94	9.67	10.52	11.30	11.97	12.96	1.6%
Metallurgical Coal	0.79	0.72	0.68	0.66	0.60	0.55	0.50	-1.5%
Steam Coal	1.46	1.42	1.39	1.44	1.48	1.50	1.53	0.3%
Net Coal Coke Imports	0.07	0.03	0.05	0.11	0.15	0.16	0.18	8.6%
Coal Subtotal	2.32	2.16	2.13	2.22	2.23	2.21	2.21	0.1%
Renewable Energy[7]	1.86	1.82	1.95	2.22	2.51	2.77	3.05	2.2%
Electricity	3.63	3.39	3.47	3.95	4.34	4.63	5.00	1.6%
Delivered Energy	**26.55**	**25.10**	**26.36**	**28.76**	**30.84**	**32.61**	**34.81**	**1.4%**
Electricity Related Losses	8.27	7.57	7.45	8.23	8.70	9.08	9.54	1.0%
Total	**34.82**	**32.67**	**33.82**	**36.99**	**39.54**	**41.69**	**44.35**	**1.3%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Transportation								
Distillate Fuel[8]	5.34	5.44	5.98	7.08	7.98	8.70	9.58	2.4%
Jet Fuel[9]	3.58	3.43	3.41	3.93	4.50	5.09	5.66	2.1%
Motor Gasoline[2]	16.05	16.26	17.66	20.09	22.25	24.04	25.90	2.0%
Residual Fuel	0.89	0.84	0.82	0.83	0.84	0.85	0.87	0.2%
Liquefied Petroleum Gas	0.01	0.02	0.04	0.05	0.07	0.08	0.09	7.0%
Other Petroleum[10]	0.22	0.24	0.24	0.26	0.28	0.30	0.32	1.2%
Petroleum Subtotal	26.09	26.22	28.15	32.24	35.92	39.06	42.41	2.0%
Pipeline Fuel Natural Gas	0.66	0.63	0.66	0.78	0.85	0.91	1.02	2.0%
Compressed Natural Gas	0.01	0.01	0.03	0.06	0.09	0.10	0.11	10.4%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.01	8.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.07	0.07	0.08	0.09	0.11	0.12	0.14	2.8%
Delivered Energy	**26.83**	**26.94**	**28.93**	**33.17**	**36.96**	**40.20**	**43.70**	**2.0%**
Electricity Related Losses	0.16	0.17	0.18	0.19	0.21	0.24	0.27	2.1%
Total	**27.00**	**27.10**	**29.11**	**33.36**	**37.18**	**40.44**	**43.97**	**2.0%**
Delivered Energy Consumption for All Sectors								
Distillate Fuel	7.79	7.94	8.49	9.69	10.62	11.38	12.32	1.8%
Kerosene	0.14	0.15	0.12	0.12	0.12	0.11	0.10	-1.5%
Jet Fuel[9]	3.58	3.43	3.41	3.93	4.50	5.09	5.66	2.1%
Liquefied Petroleum Gas	2.95	2.70	2.90	3.16	3.50	3.74	3.99	1.6%
Motor Gasoline[2]	16.25	16.46	17.85	20.29	22.46	24.26	26.13	1.9%
Petrochemical Feedstock	1.32	1.14	1.27	1.43	1.58	1.69	1.82	2.0%
Residual Fuel	1.22	1.15	1.03	1.06	1.08	1.10	1.12	-0.1%
Other Petroleum[12]	4.16	4.24	4.37	4.54	4.61	4.76	4.89	0.6%
Petroleum Subtotal	37.41	37.21	39.45	44.23	48.46	52.14	56.03	1.7%
Natural Gas	16.91	16.02	17.46	18.65	19.73	20.89	22.29	1.4%
Lease and Plant Fuel[6]	1.16	1.20	1.32	1.39	1.51	1.59	1.74	1.5%
Pipeline Natural Gas	0.66	0.63	0.66	0.78	0.85	0.91	1.02	2.0%
Natural Gas Subtotal	18.74	17.86	19.44	20.82	22.09	23.39	25.05	1.4%
Metallurgical Coal	0.79	0.72	0.68	0.66	0.60	0.55	0.50	-1.5%
Steam Coal	1.57	1.53	1.50	1.55	1.60	1.62	1.65	0.3%
Net Coal Coke Imports	0.07	0.03	0.05	0.11	0.15	0.16	0.18	8.6%
Coal Subtotal	2.42	2.27	2.23	2.33	2.35	2.33	2.34	0.1%
Renewable Energy[13]	2.38	2.31	2.47	2.74	3.03	3.29	3.57	1.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.73	11.65	12.57	13.99	15.29	16.55	17.92	1.8%
Delivered Energy	**72.68**	**71.29**	**76.16**	**84.10**	**91.22**	**97.70**	**104.91**	**1.6%**
Electricity Related Losses	26.71	26.01	27.01	29.16	30.69	32.42	34.17	1.1%
Total	**99.38**	**97.30**	**103.16**	**113.26**	**121.91**	**130.12**	**139.07**	**1.5%**
Electric Power[14]								
Distillate Fuel	0.11	0.17	0.08	0.11	0.11	0.10	0.17	0.0%
Residual Fuel	1.01	1.08	0.26	0.31	0.36	0.36	0.36	-4.5%
Petroleum Subtotal	1.12	1.25	0.34	0.42	0.47	0.46	0.52	-3.6%
Natural Gas	5.33	5.40	5.80	6.93	8.16	9.57	10.76	2.9%
Steam Coal	20.22	19.75	20.59	22.65	23.95	25.35	27.09	1.3%
Nuclear Power	7.87	8.03	8.28	8.36	8.41	8.43	8.43	0.2%
Renewable Energy[15]	3.58	3.02	4.25	4.50	4.72	5.00	5.21	2.3%
Electricity Imports	0.31	0.21	0.32	0.29	0.27	0.17	0.07	-4.5%
Total	**38.44**	**37.66**	**39.58**	**43.15**	**45.98**	**48.97**	**52.09**	**1.4%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Total Energy Consumption								
Distillate Fuel	7.90	8.11	8.58	9.80	10.73	11.48	12.49	1.8%
Kerosene	0.14	0.15	0.12	0.12	0.12	0.11	0.10	-1.5%
Jet Fuel[9]	3.58	3.43	3.41	3.93	4.50	5.09	5.66	2.1%
Liquefied Petroleum Gas	2.95	2.70	2.90	3.16	3.50	3.74	3.99	1.6%
Motor Gasoline[2]	16.25	16.46	17.85	20.29	22.46	24.26	26.13	1.9%
Petrochemical Feedstock	1.32	1.14	1.27	1.43	1.58	1.69	1.82	2.0%
Residual Fuel	2.23	2.23	1.29	1.37	1.44	1.46	1.47	-1.7%
Other Petroleum[12]	4.16	4.24	4.37	4.54	4.61	4.76	4.89	0.6%
Petroleum Subtotal	38.53	38.46	39.79	44.65	48.93	52.60	56.56	1.6%
Natural Gas	22.24	21.42	23.26	25.58	27.90	30.46	33.05	1.8%
Lease and Plant Fuel[6]	1.16	1.20	1.32	1.39	1.51	1.59	1.74	1.5%
Pipeline Natural Gas	0.66	0.63	0.66	0.78	0.85	0.91	1.02	2.0%
Natural Gas Subtotal	24.07	23.26	25.24	27.75	30.25	32.96	35.81	1.8%
Metallurgical Coal	0.79	0.72	0.68	0.66	0.60	0.55	0.50	-1.5%
Steam Coal	21.78	21.28	22.08	24.21	25.55	26.97	28.74	1.3%
Net Coal Coke Imports	0.07	0.03	0.05	0.11	0.15	0.16	0.18	8.6%
Coal Subtotal	22.64	22.02	22.82	24.98	26.30	27.68	29.42	1.2%
Nuclear Power	7.87	8.03	8.28	8.36	8.41	8.43	8.43	0.2%
Renewable Energy[16]	5.96	5.33	6.71	7.23	7.75	8.28	8.78	2.1%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports	0.31	0.21	0.32	0.29	0.27	0.17	0.07	-4.5%
Total	**99.38**	**97.30**	**103.16**	**113.26**	**121.91**	**130.12**	**139.07**	**1.5%**
Energy Use and Related Statistics								
Delivered Energy Use	72.68	71.29	76.16	84.10	91.22	97.70	104.91	1.6%
Total Energy Use	99.38	97.30	103.16	113.26	121.91	130.12	139.07	1.5%
Population (millions)	275.69	278.18	288.09	300.24	312.66	325.32	338.24	0.8%
Gross Domestic Product (billion 1996 dollars)	9191	9215	10361	12258	14288	16450	18917	3.0%
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1578.2	1558.6	1623.7	1800.5	1944.2	2082.5	2236.9	1.5%

[1]Includes wood used for residential heating. See Table A18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2000 and 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2000 and 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2000 and 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A3. Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Residential	**14.58**	**15.80**	**13.74**	**13.84**	**14.25**	**14.53**	**14.82**	**-0.3%**
Primary Energy[1]	8.50	9.73	7.82	7.96	8.18	8.27	8.50	-0.6%
Petroleum Products[2]	11.12	10.85	9.74	9.90	10.32	10.70	11.01	0.1%
Distillate Fuel	9.67	8.99	7.88	7.96	8.36	8.72	8.93	-0.0%
Liquefied Petroleum Gas	13.85	14.84	13.70	14.01	14.31	14.52	14.84	-0.0%
Natural Gas	7.75	9.41	7.31	7.48	7.68	7.74	7.99	-0.7%
Electricity	24.49	25.35	22.83	22.34	22.66	22.93	23.07	-0.4%
Commercial	**14.14**	**15.47**	**13.16**	**13.35**	**13.96**	**14.55**	**15.00**	**-0.1%**
Primary Energy[1]	6.74	7.81	6.00	6.34	6.61	6.74	7.01	-0.4%
Petroleum Products[2]	7.82	7.27	6.67	6.78	7.15	7.50	7.78	0.3%
Distillate Fuel	7.27	6.40	5.57	5.66	6.09	6.49	6.75	0.2%
Residual Fuel	3.53	3.46	3.91	4.01	4.12	4.23	4.38	1.0%
Natural Gas	6.64	8.09	5.99	6.38	6.64	6.75	7.02	-0.6%
Electricity	21.86	23.22	20.12	19.73	20.25	20.96	21.26	-0.4%
Industrial[3]	**7.08**	**7.10**	**5.97**	**6.26**	**6.63**	**6.88**	**7.15**	**0.0%**
Primary Energy	5.91	5.83	4.77	5.07	5.44	5.62	5.88	0.0%
Petroleum Products[2]	8.21	7.72	6.66	6.94	7.42	7.63	7.94	0.1%
Distillate Fuel	7.38	6.55	5.62	5.73	6.28	6.80	7.25	0.4%
Liquefied Petroleum Gas	12.03	12.34	9.33	9.59	9.91	10.12	10.40	-0.7%
Residual Fuel	3.34	3.28	3.60	3.71	3.82	3.94	4.10	0.9%
Natural Gas[4]	4.62	4.87	3.52	3.89	4.18	4.32	4.57	-0.3%
Metallurgical Coal	1.66	1.69	1.57	1.51	1.46	1.41	1.35	-0.9%
Steam Coal	1.43	1.46	1.44	1.38	1.35	1.31	1.29	-0.5%
Electricity	13.46	14.10	12.75	12.64	12.78	13.25	13.46	-0.2%
Transportation	**11.11**	**10.28**	**9.93**	**10.28**	**10.19**	**10.39**	**10.81**	**0.2%**
Primary Energy	11.08	10.25	9.90	10.25	10.16	10.37	10.79	0.2%
Petroleum Products[2]	11.08	10.25	9.91	10.26	10.17	10.37	10.80	0.2%
Distillate Fuel[5]	10.99	10.05	9.36	10.22	10.09	10.16	10.52	0.2%
Jet Fuel[6]	7.26	6.20	5.61	5.62	6.03	6.33	6.72	0.3%
Motor Gasoline[7]	12.42	11.57	11.30	11.53	11.34	11.60	12.08	0.2%
Residual Fuel	4.48	3.90	3.45	3.55	3.66	3.77	3.94	0.0%
Liquefied Petroleum Gas[8]	16.45	16.93	14.89	15.21	15.46	15.50	15.63	-0.3%
Natural Gas[9]	6.76	7.65	6.12	7.08	7.57	7.75	8.07	0.2%
Ethanol (E85)[10]	17.72	17.72	19.50	21.32	22.43	22.87	23.44	1.2%
Electricity	22.07	21.84	19.72	18.99	18.75	18.37	17.82	-0.8%
Average End-Use Energy	**10.63**	**10.74**	**9.67**	**9.92**	**10.13**	**10.42**	**10.78**	**0.0%**
Primary Energy	8.65	8.52	7.67	8.05	8.22	8.43	8.80	0.1%
Electricity	20.17	21.30	19.06	18.65	18.95	19.45	19.66	-0.3%
Electric Power[11]								
Fossil Fuel Average	2.01	2.14	1.71	1.82	1.94	2.02	2.14	0.0%
Petroleum Products	4.62	4.73	4.13	4.27	4.43	4.60	4.98	0.2%
Distillate Fuel	6.73	6.20	5.01	5.13	5.60	6.06	6.18	-0.0%
Residual Fuel	4.39	4.50	3.85	3.97	4.07	4.21	4.40	-0.1%
Natural Gas	4.42	4.78	3.27	3.79	4.14	4.30	4.60	-0.2%
Steam Coal	1.23	1.25	1.22	1.17	1.15	1.12	1.10	-0.5%

Table A3. Energy Prices by Sector and Source (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Average Price to All Users[12]								
Petroleum Products[2]	10.23	9.54	9.13	9.48	9.56	9.78	10.18	0.3%
Distillate Fuel	10.05	9.16	8.47	9.17	9.26	9.46	9.83	0.3%
Jet Fuel	7.26	6.20	5.61	5.62	6.03	6.33	6.72	0.3%
Liquefied Petroleum Gas	12.38	12.85	10.20	10.42	10.67	10.85	11.11	-0.6%
Motor Gasoline[7]	12.42	11.57	11.29	11.53	11.34	11.60	12.08	0.2%
Residual Fuel	4.28	4.11	3.57	3.68	3.80	3.92	4.08	-0.0%
Natural Gas	5.59	6.40	4.74	5.03	5.26	5.35	5.60	-0.6%
Coal	1.24	1.26	1.24	1.18	1.16	1.13	1.12	-0.5%
Ethanol (E85)[10]	17.72	17.72	19.50	21.32	22.43	22.87	23.44	1.2%
Electricity	20.17	21.30	19.06	18.65	18.95	19.45	19.66	-0.3%
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)								
Residential	155.98	166.69	157.91	166.98	178.50	190.35	202.99	0.8%
Commercial	114.28	127.06	116.43	127.99	144.89	164.11	182.88	1.5%
Industrial	143.44	135.20	118.73	135.28	153.72	169.19	188.45	1.4%
Transportation	290.84	270.40	280.74	332.93	367.91	408.34	461.42	2.3%
Total Non-Renewable Expenditures	704.53	699.35	673.81	763.18	845.02	932.00	1035.75	1.6%
Transportation Renewable Expenditures	0.01	0.01	0.03	0.05	0.07	0.10	0.13	10.2%
Total Expenditures	**704.54**	**699.36**	**673.84**	**763.22**	**845.09**	**932.10**	**1035.88**	**1.7%**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2000 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2001).. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2000 residential, commercial, and transportation natural gas delivered prices: EIA,*Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001) . 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2000 and 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2000 and 2001 industrial natural gas delivered prices are based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2000 and 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2000 and 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2000 and 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Key Indicators and Consumption	Reference Case 2000	2001	2005	2010	2015	2020	2025	Annual Growth 2001-2025 (percent)
Key Indicators								
Households (millions)								
Single-Family	76.57	77.50	81.18	85.79	90.14	93.77	97.27	1.0%
Multifamily	22.01	22.19	22.86	24.12	25.61	27.05	28.78	1.1%
Mobile Homes	6.61	6.57	6.73	7.33	7.76	8.01	8.23	0.9%
Total	**105.19**	**106.27**	**110.78**	**117.24**	**123.51**	**128.84**	**134.28**	**1.0%**
Average House Square Footage	**1678**	**1685**	**1710**	**1737**	**1760**	**1780**	**1797**	**0.3%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	105.6	102.9	107.5	106.4	104.7	104.8	105.0	0.1%
Total Energy Consumption	193.7	189.0	195.4	194.1	190.1	189.9	189.4	0.0%
(thousand Btu per square foot)								
Delivered Energy Consumption	62.9	61.1	62.8	61.3	59.5	58.9	58.4	-0.2%
Total Energy Consumption	115.4	112.2	114.2	111.7	108.0	106.7	105.4	-0.3%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.41	0.39	0.43	0.46	0.49	0.51	0.52	1.2%
Space Cooling	0.52	0.52	0.57	0.60	0.62	0.65	0.68	1.1%
Water Heating	0.46	0.45	0.47	0.47	0.45	0.44	0.44	-0.1%
Refrigeration	0.43	0.42	0.38	0.34	0.32	0.32	0.33	-1.0%
Cooking	0.10	0.10	0.10	0.11	0.12	0.12	0.13	1.1%
Clothes Dryers	0.22	0.22	0.24	0.25	0.26	0.27	0.28	1.0%
Freezers	0.11	0.11	0.10	0.09	0.09	0.09	0.09	-0.8%
Lighting	0.74	0.74	0.83	0.93	0.98	1.03	1.07	1.5%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.2%
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.2%
Color Televisions	0.13	0.13	0.17	0.20	0.22	0.25	0.27	2.9%
Personal Computers	0.06	0.06	0.07	0.08	0.09	0.10	0.11	2.7%
Furnace Fans	0.07	0.07	0.08	0.09	0.09	0.10	0.11	1.6%
Other Uses[2]	0.78	0.83	1.04	1.26	1.46	1.66	1.87	3.5%
Delivered Energy	**4.07**	**4.10**	**4.53**	**4.93**	**5.25**	**5.59**	**5.94**	**1.6%**
Natural Gas								
Space Heating	3.32	3.13	3.52	3.73	3.90	4.12	4.32	1.4%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.2%
Water Heating	1.48	1.48	1.58	1.56	1.55	1.59	1.64	0.4%
Cooking	0.20	0.20	0.21	0.22	0.24	0.25	0.25	0.9%
Clothes Dryers	0.06	0.06	0.07	0.08	0.09	0.10	0.10	1.9%
Other Uses[3]	0.06	0.06	0.06	0.07	0.07	0.07	0.08	1.0%
Delivered Energy	**5.12**	**4.94**	**5.45**	**5.66**	**5.85**	**6.12**	**6.40**	**1.1%**
Distillate								
Space Heating	0.71	0.74	0.77	0.76	0.73	0.71	0.69	-0.3%
Water Heating	0.14	0.16	0.16	0.14	0.13	0.12	0.11	-1.4%
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.5%
Delivered Energy	**0.86**	**0.91**	**0.94**	**0.91**	**0.87**	**0.83**	**0.81**	**-0.5%**
Liquefied Petroleum Gas								
Space Heating	0.30	0.26	0.26	0.25	0.25	0.25	0.25	-0.1%
Water Heating	0.10	0.09	0.08	0.07	0.07	0.06	0.06	-1.5%
Cooking	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-0.6%
Other Uses[3]	0.13	0.12	0.12	0.13	0.13	0.14	0.14	0.6%
Delivered Energy	**0.54**	**0.50**	**0.48**	**0.47**	**0.47**	**0.47**	**0.48**	**-0.2%**
Marketed Renewables (wood)[5]	0.41	0.39	0.41	0.41	0.41	0.41	0.40	0.2%
Other Fuels[6]	0.10	0.11	0.10	0.09	0.09	0.08	0.07	-1.8%

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

Key Indicators and Consumption	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Delivered Energy Consumption by End-Use								
Space Heating	5.24	5.01	5.49	5.70	5.86	6.06	6.26	0.9%
Space Cooling	0.52	0.52	0.57	0.60	0.62	0.65	0.68	1.1%
Water Heating	2.18	2.19	2.29	2.24	2.20	2.21	2.26	0.1%
Refrigeration	0.43	0.42	0.38	0.34	0.32	0.32	0.33	-1.0%
Cooking	0.32	0.33	0.34	0.36	0.38	0.39	0.40	0.9%
Clothes Dryers	0.28	0.28	0.31	0.33	0.35	0.36	0.38	1.2%
Freezers	0.11	0.11	0.10	0.09	0.09	0.09	0.09	-0.8%
Lighting	0.74	0.74	0.83	0.93	0.98	1.03	1.07	1.5%
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.2%
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.2%
Color Televisions	0.13	0.13	0.17	0.20	0.22	0.25	0.27	2.9%
Personal Computers	0.06	0.06	0.07	0.08	0.09	0.10	0.11	2.7%
Furnace Fans	0.07	0.07	0.08	0.09	0.09	0.10	0.11	1.6%
Other Uses[7]	0.98	1.01	1.24	1.46	1.67	1.87	2.09	3.1%
Delivered Energy	**11.11**	**10.94**	**11.90**	**12.47**	**12.93**	**13.51**	**14.10**	**1.1%**
Electricity Related Losses	**9.26**	**9.15**	**9.74**	**10.28**	**10.54**	**10.96**	**11.33**	**0.9%**
Total Energy Consumption by End-Use								
Space Heating	6.18	5.89	6.42	6.66	6.83	7.05	7.25	0.9%
Space Cooling	1.69	1.68	1.78	1.85	1.88	1.93	1.98	0.7%
Water Heating	3.22	3.20	3.30	3.22	3.10	3.08	3.09	-0.1%
Refrigeration	1.39	1.36	1.19	1.05	0.97	0.95	0.96	-1.4%
Cooking	0.54	0.55	0.56	0.59	0.61	0.63	0.64	0.7%
Clothes Dryers	0.78	0.78	0.82	0.85	0.86	0.88	0.91	0.6%
Freezers	0.37	0.36	0.30	0.27	0.26	0.26	0.27	-1.2%
Lighting	2.43	2.40	2.61	2.88	2.96	3.04	3.10	1.1%
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.09	0.08	-0.7%
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.8%
Color Televisions	0.42	0.43	0.53	0.60	0.67	0.75	0.77	2.4%
Personal Computers	0.19	0.19	0.22	0.25	0.28	0.31	0.33	2.2%
Furnace Fans	0.23	0.23	0.25	0.27	0.28	0.30	0.31	1.2%
Other Uses[7]	2.76	2.86	3.48	4.08	4.61	5.12	5.65	2.9%
Total	**20.37**	**20.09**	**21.64**	**22.75**	**23.47**	**24.47**	**25.43**	**1.0%**
Non-Marketed Renewables								
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	2.2%
Total	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**2.3%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002).
Projections: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	65.1	66.6	73.0	78.7	85.0	91.2	97.6	1.6%
New Additions	3.4	3.6	3.0	3.1	3.2	3.4	3.5	-0.1%
Total	**68.5**	**70.2**	**76.1**	**81.8**	**88.2**	**94.6**	**101.1**	**1.5%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	119.5	118.4	117.7	118.5	118.9	120.3	121.6	0.1%
Electricity Related Losses	131.5	129.9	126.7	127.9	127.3	128.3	128.9	-0.0%
Total Energy Consumption	251.0	248.3	244.4	246.4	246.2	248.6	250.5	0.0%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.15	0.14	0.16	0.16	0.16	0.15	0.15	0.2%
Space Cooling[1]	0.41	0.43	0.43	0.44	0.45	0.47	0.48	0.5%
Water Heating[1]	0.15	0.15	0.15	0.16	0.16	0.16	0.15	0.2%
Ventilation	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.6%
Cooking	0.04	0.03	0.03	0.03	0.03	0.03	0.03	-0.8%
Lighting	1.02	1.02	1.13	1.21	1.27	1.31	1.34	1.1%
Refrigeration	0.21	0.21	0.23	0.24	0.25	0.26	0.27	1.0%
Office Equipment (PC)	0.15	0.16	0.19	0.24	0.28	0.32	0.36	3.5%
Office Equipment (non-PC)	0.30	0.31	0.36	0.47	0.60	0.75	0.93	4.7%
Other Uses[2]	1.36	1.46	1.64	1.90	2.21	2.57	2.93	2.9%
Delivered Energy	**3.96**	**4.09**	**4.49**	**5.02**	**5.59**	**6.20**	**6.83**	**2.2%**
Natural Gas								
Space Heating[1]	1.45	1.32	1.54	1.58	1.62	1.70	1.76	1.2%
Space Cooling[1]	0.01	0.01	0.01	0.02	0.03	0.03	0.04	4.9%
Water Heating[1]	0.59	0.57	0.65	0.70	0.76	0.82	0.87	1.8%
Cooking	0.26	0.25	0.29	0.30	0.32	0.35	0.37	1.6%
Other Uses[3]	0.99	1.17	1.13	1.20	1.27	1.39	1.52	1.1%
Delivered Energy	**3.30**	**3.33**	**3.62**	**3.80**	**4.00**	**4.29**	**4.56**	**1.3%**
Distillate								
Space Heating[1]	0.17	0.17	0.19	0.20	0.21	0.22	0.22	1.2%
Water Heating[1]	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.1%
Other Uses[4]	0.22	0.22	0.20	0.20	0.20	0.20	0.20	-0.4%
Delivered Energy	**0.47**	**0.46**	**0.46**	**0.48**	**0.49**	**0.49**	**0.49**	**0.3%**
Other Fuels[5]	**0.35**	**0.34**	**0.28**	**0.29**	**0.30**	**0.30**	**0.31**	**-0.4%**
Marketed Renewable Fuels								
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
Delivered Energy Consumption by End-Use								
Space Heating[1]	1.77	1.63	1.89	1.94	1.99	2.07	2.13	1.1%
Space Cooling[1]	0.42	0.44	0.44	0.46	0.48	0.50	0.52	0.7%
Water Heating[1]	0.81	0.79	0.88	0.93	0.99	1.05	1.10	1.4%
Ventilation	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.6%
Cooking	0.29	0.29	0.32	0.34	0.36	0.38	0.40	1.4%
Lighting	1.02	1.02	1.13	1.21	1.27	1.31	1.34	1.1%
Refrigeration	0.21	0.21	0.23	0.24	0.25	0.26	0.27	1.0%
Office Equipment (PC)	0.15	0.16	0.19	0.24	0.28	0.32	0.36	3.5%
Office Equipment (non-PC)	0.30	0.31	0.36	0.47	0.60	0.75	0.93	4.7%
Other Uses[6]	3.03	3.30	3.36	3.69	4.09	4.57	5.07	1.8%
Delivered Energy	**8.19**	**8.32**	**8.95**	**9.69**	**10.49**	**11.38**	**12.30**	**1.6%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Electricity Related Losses	**9.01**	**9.12**	**9.64**	**10.46**	**11.23**	**12.14**	**13.03**	**1.5%**
Total Energy Consumption by End-Use								
Space Heating[1]	2.13	1.95	2.22	2.26	2.30	2.37	2.42	0.9%
Space Cooling[1]	1.35	1.39	1.35	1.37	1.39	1.41	1.43	0.1%
Water Heating[1]	1.15	1.12	1.21	1.26	1.30	1.35	1.39	0.9%
Ventilation	0.56	0.55	0.55	0.56	0.56	0.56	0.57	0.2%
Cooking	0.38	0.37	0.39	0.41	0.42	0.44	0.45	0.9%
Lighting	3.34	3.31	3.54	3.73	3.81	3.87	3.89	0.7%
Refrigeration	0.69	0.69	0.71	0.73	0.75	0.77	0.78	0.5%
Office Equipment (PC)	0.50	0.52	0.60	0.74	0.85	0.95	1.05	3.0%
Office Equipment (non-PC)	0.98	0.99	1.12	1.44	1.80	2.21	2.69	4.2%
Other Uses[6]	6.13	6.56	6.89	7.65	8.54	9.60	10.65	2.0%
Total	**17.20**	**17.44**	**18.59**	**20.15**	**21.72**	**23.52**	**25.33**	**1.6%**
Non-Marketed Renewable Fuels								
Solar[7]	0.02	0.02	0.03	0.03	0.03	0.03	0.03	1.3%
Total	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**1.3%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Key Indicators								
Value of Shipments (billion 1996 dollars)								
Manufacturing	4378	4079	4542	5453	6393	7220	8257	3.0%
Nonmanufacturing	1341	1346	1340	1505	1636	1743	1869	1.4%
Total	**5719**	**5425**	**5882**	**6959**	**8029**	**8963**	**10126**	**2.6%**
Energy Prices (2001 dollars per million Btu)								
Electricity	13.46	14.10	12.75	12.64	12.78	13.25	13.46	-0.2%
Natural Gas	4.62	4.87	3.52	3.89	4.18	4.32	4.57	-0.3%
Steam Coal	1.43	1.46	1.44	1.38	1.35	1.31	1.29	-0.5%
Residual Oil	3.34	3.28	3.60	3.71	3.82	3.94	4.10	0.9%
Distillate Oil	7.38	6.55	5.62	5.73	6.28	6.80	7.25	0.4%
Liquefied Petroleum Gas	12.03	12.34	9.33	9.59	9.91	10.12	10.40	-0.7%
Motor Gasoline	12.39	11.57	10.82	11.49	11.28	11.56	12.07	0.2%
Metallurgical Coal	1.66	1.69	1.57	1.51	1.46	1.41	1.35	-0.9%
Energy Consumption[1]								
Purchased Electricity	3.63	3.39	3.47	3.95	4.34	4.63	5.00	1.6%
Natural Gas	8.48	7.74	8.35	9.13	9.79	10.38	11.22	1.6%
Lease and Plant Fuel[2]	1.16	1.20	1.32	1.39	1.51	1.59	1.74	1.5%
Natural Gas Subtotal	9.65	8.94	9.67	10.52	11.30	11.97	12.96	1.6%
Steam Coal	1.46	1.42	1.39	1.44	1.48	1.50	1.53	0.3%
Metallurgical Coal and Coke[3]	0.86	0.74	0.73	0.77	0.75	0.71	0.68	-0.3%
Residual Fuel	0.24	0.23	0.17	0.19	0.19	0.20	0.20	-0.4%
Distillate	1.12	1.13	1.11	1.21	1.29	1.36	1.45	1.0%
Liquefied Petroleum Gas	2.30	2.10	2.30	2.55	2.87	3.10	3.33	1.9%
Petrochemical Feedstocks	1.32	1.14	1.27	1.43	1.58	1.69	1.82	2.0%
Other Petroleum[4]	4.11	4.18	4.30	4.47	4.53	4.67	4.79	0.6%
Renewables[5]	1.86	1.82	1.95	2.22	2.51	2.77	3.05	2.2%
Delivered Energy	**26.55**	**25.10**	**26.36**	**28.76**	**30.84**	**32.61**	**34.81**	**1.4%**
Electricity Related Losses	8.27	7.57	7.45	8.23	8.70	9.08	9.54	1.0%
Total	**34.82**	**32.67**	**33.82**	**36.99**	**39.54**	**41.69**	**44.35**	**1.3%**
Energy Consumption per dollar of Shipments[1] **(thousand Btu per 1996 dollars)**								
Purchased Electricity	0.63	0.63	0.59	0.57	0.54	0.52	0.49	-1.0%
Natural Gas	1.48	1.43	1.42	1.31	1.22	1.16	1.11	-1.0%
Lease and Plant Fuel[2]	0.20	0.22	0.22	0.20	0.19	0.18	0.17	-1.1%
Natural Gas Subtotal	1.69	1.65	1.64	1.51	1.41	1.34	1.28	-1.1%
Steam Coal	0.26	0.26	0.24	0.21	0.18	0.17	0.15	-2.3%
Metallurgical Coal and Coke[3]	0.15	0.14	0.12	0.11	0.09	0.08	0.07	-2.9%
Residual Fuel	0.04	0.04	0.03	0.03	0.02	0.02	0.02	-3.0%
Distillate	0.20	0.21	0.19	0.17	0.16	0.15	0.14	-1.6%
Liquefied Petroleum Gas	0.40	0.39	0.39	0.37	0.36	0.35	0.33	-0.7%
Petrochemical Feedstocks	0.23	0.21	0.22	0.21	0.20	0.19	0.18	-0.7%
Other Petroleum[4]	0.72	0.77	0.73	0.64	0.56	0.52	0.47	-2.0%
Renewables[5]	0.33	0.33	0.33	0.32	0.31	0.31	0.30	-0.4%
Delivered Energy	**4.64**	**4.63**	**4.48**	**4.13**	**3.84**	**3.64**	**3.44**	**-1.2%**
Electricity Related Losses	1.45	1.40	1.27	1.18	1.08	1.01	0.94	-1.6%
Total	**6.09**	**6.02**	**5.75**	**5.32**	**4.92**	**4.65**	**4.38**	**-1.3%**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Represents natural gas used in the field gathering and processing plant machinery.
[3]Includes net coal coke imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2000 prices for motor gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2001). 2001 prices for motor gasoline and distillate are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2000 and 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2000 and 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2000 and 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2000 and 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2000 and 2001 shipments: Global Insight macroeconomic model CTL0802 **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Key Indicators								
Level of Travel (billions)								
Light-Duty Vehicles <8,500 pounds (VMT)	2355	2409	2642	3004	3380	3753	4132	2.3%
Commercial Light Trucks (VMT)[1]	69	66	72	84	96	107	120	2.5%
Freight Trucks >10,000 pounds (VMT)	207	206	225	263	301	338	380	2.6%
Air (seat miles available)	1168	1109	1110	1355	1636	1942	2256	3.0%
Rail (ton miles traveled)	1390	1448	1475	1669	1833	1991	2155	1.7%
Domestic Shipping (ton miles traveled)	647	788	803	874	937	1009	1087	1.4%
Energy Efficiency Indicators								
New Light-Duty Vehicle (miles per gallon)[2]	24.1	24.1	24.2	24.3	25.0	25.6	26.1	0.3%
New Car (miles per gallon)[2]	28.2	28.1	28.3	28.5	29.3	29.8	30.1	0.3%
New Light Truck (miles per gallon)[2]	20.6	20.7	20.9	21.0	21.8	22.5	23.0	0.4%
Light-Duty Fleet (miles per gallon)[3]	20.1	19.8	19.5	19.3	19.4	19.8	20.2	0.1%
New Commercial Light Truck (MPG)[1]	13.9	13.8	13.9	13.9	14.4	14.8	15.2	0.4%
Stock Commercial Light Truck (MPG)[1]	13.6	13.7	13.9	13.8	14.0	14.4	14.8	0.3%
Aircraft Efficiency (seat miles per gallon)	50.8	51.2	52.5	54.3	56.3	58.6	60.7	0.7%
Freight Truck Efficiency (miles per gallon)	5.9	6.0	6.0	6.0	6.1	6.3	6.5	0.3%
Rail Efficiency (ton miles per thousand Btu)	2.8	2.8	2.9	3.1	3.3	3.4	3.6	1.0%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	0.2%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	14.95	15.28	16.83	19.36	21.60	23.47	25.36	2.1%
Commercial Light Trucks[1]	0.63	0.60	0.64	0.76	0.86	0.93	1.02	2.2%
Freight Trucks[4]	4.72	4.68	5.06	5.89	6.57	7.09	7.79	2.1%
Air[5]	3.62	3.47	3.46	3.97	4.55	5.14	5.72	2.1%
Rail[6]	0.61	0.63	0.63	0.68	0.71	0.75	0.78	0.9%
Marine[7]	1.46	1.45	1.44	1.49	1.54	1.59	1.64	0.5%
Pipeline Fuel	0.66	0.63	0.66	0.78	0.85	0.91	1.02	2.0%
Lubricants	0.18	0.19	0.20	0.22	0.24	0.26	0.28	1.5%
Total	**26.83**	**26.94**	**28.93**	**33.17**	**36.96**	**40.20**	**43.70**	**2.0%**
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	7.86	8.05	8.90	10.23	11.40	12.38	13.37	2.1%
Commercial Light Trucks[1]	0.33	0.32	0.34	0.40	0.45	0.49	0.54	2.2%
Freight Trucks	2.08	2.05	2.21	2.60	2.91	3.15	3.48	2.2%
Railroad	0.23	0.24	0.24	0.25	0.27	0.27	0.28	0.7%
Domestic Shipping	0.13	0.16	0.16	0.17	0.18	0.20	0.21	1.1%
International Shipping	0.37	0.34	0.33	0.33	0.33	0.34	0.34	0.0%
Air[5]	1.52	1.44	1.40	1.65	1.92	2.18	2.45	2.2%
Military Use	0.28	0.30	0.33	0.34	0.35	0.38	0.40	1.2%
Bus Transportation	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.4%
Rail Transportation[6]	0.05	0.05	0.06	0.06	0.07	0.08	0.08	1.8%
Recreational Boats	0.17	0.16	0.17	0.18	0.19	0.19	0.20	0.9%
Lubricants	0.09	0.09	0.10	0.10	0.11	0.12	0.13	1.5%
Pipeline Fuel	0.33	0.32	0.34	0.39	0.43	0.46	0.52	2.0%
Total	**13.56**	**13.64**	**14.70**	**16.84**	**18.75**	**20.38**	**22.13**	**2.0%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck “on-the-road” estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2000 and 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, “Vehicle Inventory and Use Survey,” EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1911	1848	1990	2189	2335	2497	2703	1.6%
Petroleum	98	113	31	39	44	43	52	-3.2%
Natural Gas[3]	399	411	509	708	939	1143	1335	5.0%
Nuclear Power	754	769	793	800	805	807	807	0.2%
Pumped Storage/Other	-5	-9	-1	-1	-1	-1	-1	-8.9%
Renewable Sources[4]	316	258	378	393	405	416	429	2.1%
Distributed Generation (Natural Gas)	0	0	0	1	3	5	7	N/A
Non-Utility Generation for Own Use	-12	-21	-24	-24	-24	-24	-24	0.6%
Total	**3460**	**3370**	**3677**	**4105**	**4505**	**4887**	**5309**	**1.9%**
Combined Heat and Power[5]								
Coal	33	33	30	33	33	33	33	0.1%
Petroleum	7	7	3	4	3	3	3	-2.9%
Natural Gas	119	124	176	167	148	150	146	0.7%
Renewable Sources	4	5	4	4	4	4	4	-0.6%
Non-Utility Generation for Own Use	-9	-9	-18	-18	-18	-18	-18	2.7%
Total	**155**	**162**	**196**	**190**	**171**	**173**	**169**	**0.2%**
Net Available to the Grid	**3616**	**3532**	**3873**	**4295**	**4676**	**5059**	**5478**	**1.8%**
End-Use Sector Generation								
Combined Heat and Power[6]								
Coal	23	23	23	23	23	23	23	0.0%
Petroleum	6	6	6	6	6	6	6	0.5%
Natural Gas	83	83	98	115	129	151	183	3.4%
Other Gaseous Fuels[7]	6	6	7	7	7	7	8	1.4%
Renewable Sources[4]	31	31	34	39	45	50	56	2.5%
Other[8]	11	11	11	11	11	11	11	-0.0%
Total	**160**	**159**	**180**	**202**	**222**	**249**	**287**	**2.5%**
Other End-Use Generators[9]	4	4	4	5	5	6	6	1.6%
Generation for Own Use	-135	-137	-147	-160	-171	-188	-212	1.8%
Total Sales to the Grid	**29**	**27**	**37**	**48**	**56**	**67**	**82**	**4.7%**
Net Imports	**31**	**20**	**32**	**28**	**26**	**17**	**7**	**-4.5%**
Electricity Sales by Sector								
Residential	1193	1201	1328	1445	1539	1640	1742	1.6%
Commercial	1160	1197	1315	1471	1640	1816	2003	2.2%
Industrial	1064	994	1017	1157	1271	1358	1466	1.6%
Transportation	21	22	24	27	31	36	42	2.8%
Total	**3438**	**3414**	**3684**	**4101**	**4481**	**4850**	**5252**	**1.8%**
End-Use Prices[10] (2001 cents per kilowatthour)								
Residential	8.4	8.6	7.8	7.6	7.7	7.8	7.9	-0.4%
Commercial	7.5	7.9	6.9	6.7	6.9	7.2	7.3	-0.4%
Industrial	4.6	4.8	4.3	4.3	4.4	4.5	4.6	-0.2%
Transportation	7.5	7.5	6.7	6.5	6.4	6.3	6.1	-0.8%
All Sectors Average	**6.9**	**7.3**	**6.5**	**6.4**	**6.5**	**6.6**	**6.7**	**-0.3%**
Prices by Service Category[10] (2001 cents per kilowatthour)								
Generation	4.2	4.7	3.9	3.8	3.9	4.1	4.2	-0.5%
Transmission	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7%
Distribution	2.1	2.0	2.0	2.0	1.9	1.9	1.9	-0.2%

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Emissions								
Sulfur Dioxide (million tons)	11.19	10.63	10.71	9.57	8.95	8.95	8.95	-0.7%
Nitrogen Oxide (million tons)	5.09	4.75	3.61	3.92	3.99	4.06	4.12	-0.6%
Mercury (tons)	47.84	51.05	49.33	51.30	51.11	52.01	52.63	0.1%

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2000 and 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2000 and 2001 prices: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. **Projections**: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Electric Power Sector[2]								
Power Only[3]								
Coal Steam	305.4	305.3	303.1	306.4	323.0	343.2	370.6	0.8%
Other Fossil Steam[4]	134.8	133.8	118.6	83.4	78.4	77.2	76.2	-2.3%
Combined Cycle	28.8	43.6	103.6	145.0	197.8	228.3	270.4	7.9%
Combustion Turbine/Diesel	78.8	98.1	126.8	128.2	139.7	152.7	173.9	2.4%
Nuclear Power[5]	98.0	98.2	100.2	99.3	99.5	99.6	99.6	0.1%
Pumped Storage	19.8	19.9	20.3	20.3	20.3	20.3	20.3	0.1%
Fuel Cells	0.0	0.0	0.0	0.1	0.2	0.2	0.2	33.2%
Renewable Sources[6]	88.4	90.6	95.1	97.3	99.8	102.0	104.3	0.6%
Distributed Generation[7]	0.0	0.0	0.3	1.7	4.9	10.1	15.8	N/A
Total	**754.0**	**789.4**	**868.0**	**881.8**	**963.5**	**1033.7**	**1131.2**	**1.5%**
Combined Heat and Power[8]								
Coal Steam	5.2	5.2	5.2	5.1	5.1	5.1	5.1	-0.0%
Other Fossil Steam[4]	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.0%
Combined Cycle	17.4	22.6	31.2	31.0	31.0	31.0	31.0	1.3%
Combustion Turbine/Diesel	3.4	4.5	5.2	5.2	5.2	5.2	5.2	0.6%
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0%
Total	27.4	33.7	43.0	42.8	42.8	42.8	42.8	1.0%
Total Electric Power Industry	**781.4**	**823.1**	**911.1**	**924.7**	**1006.4**	**1076.5**	**1174.1**	**1.5%**
Cumulative Planned Additions[9]								
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	63.1	63.1	63.1	63.1	63.1	N/A
Combustion Turbine/Diesel	0.0	0.0	27.8	27.8	27.8	27.8	27.8	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.3	0.3	0.3	0.3	0.3	N/A
Fuel Cells	0.0	0.0	0.0	0.1	0.2	0.2	0.2	N/A
Renewable Sources[6]	0.0	0.0	3.8	4.9	5.8	6.4	6.5	N/A
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**95.0**	**96.2**	**97.2**	**97.9**	**98.0**	**N/A**
Cumulative Unplanned Additions[9]								
Coal Steam	0.0	0.0	0.0	6.8	23.9	45.5	74.0	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	4.2	46.1	98.8	129.3	171.4	N/A
Combustion Turbine/Diesel	0.0	0.0	4.5	12.3	24.8	40.0	61.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.4	1.4	3.0	4.5	6.7	N/A
Distributed Generation[7]	0.0	0.0	0.3	1.7	4.9	10.1	15.8	N/A
Total	**0.0**	**0.0**	**9.3**	**68.3**	**155.4**	**229.4**	**329.8**	**N/A**
Cumulative Total Additions	**0.0**	**0.0**	**104.4**	**164.5**	**252.7**	**327.3**	**427.8**	**N/A**
Cumulative Retirements[10]								
Coal Steam	0.0	0.0	2.1	5.8	6.3	7.6	8.7	N/A
Other Fossil Steam[4]	0.0	0.0	13.7	48.9	53.9	55.1	56.1	N/A
Combined Cycle	0.0	0.0	0.0	0.5	0.5	0.5	0.5	N/A
Combustion Turbine/Diesel	0.0	0.0	3.0	9.4	10.4	12.6	13.4	N/A
Nuclear Power	0.0	0.0	0.0	1.8	2.8	2.8	2.8	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**18.9**	**66.5**	**74.1**	**78.7**	**81.7**	**N/A**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
End-Use Sector								
Combined Heat and Power[11]								
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	0.0%
Petroleum	0.9	0.9	1.0	1.0	1.0	1.0	1.0	0.6%
Natural Gas	14.2	14.5	16.1	18.3	20.2	23.3	27.7	2.7%
Other Gaseous Fuels	2.1	2.1	2.2	2.2	2.2	2.2	2.3	0.3%
Renewable Sources[6]	4.7	4.7	5.2	6.2	7.2	8.0	9.0	2.7%
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**27.4**	**27.6**	**29.9**	**33.1**	**36.0**	**40.0**	**45.4**	**2.1%**
Other End-Use Generators[12]								
Renewable Sources[13]	1.1	1.1	1.2	1.5	1.5	1.7	2.0	2.5%
Cumulative Additions[9]								
Combined Heat and Power[11]	0.0	0.0	2.3	5.5	8.4	12.3	17.8	N/A
Other End-Use Generators[12]	0.0	0.0	0.1	0.4	0.4	0.6	0.9	N/A

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2001.
[10]Cumulative retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table A17 for more detail.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability estimates for electric utility generators.
Sources: 2000 and 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Interregional Electricity Trade								
Gross Domestic Firm Power Trade	157.0	142.7	125.3	102.9	45.7	0.0	0.0	N/A
Gross Domestic Economy Trade	148.4	176.8	202.8	199.8	191.9	180.0	177.9	0.0%
Gross Domestic Trade	**305.3**	**319.5**	**328.1**	**302.8**	**237.6**	**180.0**	**177.9**	**-2.4%**
Gross Domestic Firm Power Sales (million 2001 dollars)	7748.5	7047.1	6185.7	5080.9	2258.2	0.0	0.0	N/A
Gross Domestic Economy Sales (million 2001 dollars)	6305.6	8240.1	5806.3	6203.2	6295.4	6063.7	6238.5	-1.2%
Gross Domestic Sales (million 2001 dollars)	**14054.1**	**15287.3**	**11992.0**	**11284.1**	**8553.6**	**6063.7**	**6238.5**	**-3.7%**
International Electricity Trade								
Firm Power Imports From Canada and Mexico	16.0	12.1	10.7	5.8	2.6	0.0	0.0	N/A
Economy Imports From Canada and Mexico	27.8	26.3	37.6	38.7	34.9	24.4	14.4	-2.5%
Gross Imports From Canada and Mexico	**43.8**	**38.5**	**48.3**	**44.5**	**37.5**	**24.4**	**14.4**	**-4.0%**
Firm Power Exports To Canada and Mexico	6.5	6.5	9.7	8.7	3.9	0.0	0.0	N/A
Economy Exports To Canada and Mexico	6.7	11.7	7.0	7.7	7.7	7.7	7.7	-1.7%
Gross Exports To Canada and Mexico	**13.2**	**18.2**	**16.7**	**16.4**	**11.5**	**7.7**	**7.7**	**-3.5%**

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2000 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1999. 2000 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 2000 firm/economy share: National Energy Board, *Annual Report 2000* . **2001 and projections:** Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Supply and Disposition	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Crude Oil								
Domestic Crude Production[1]	5.87	5.80	5.58	5.63	5.25	5.46	5.33	-0.4%
Alaska	0.99	0.97	0.87	0.64	0.88	1.23	1.17	0.8%
Lower 48 States	4.89	4.84	4.71	4.98	4.37	4.23	4.16	-0.6%
Net Imports	9.02	9.31	10.23	11.51	12.36	12.66	13.06	1.4%
Gross Imports	9.07	9.33	10.29	11.58	12.41	12.72	13.11	1.4%
Exports	0.05	0.02	0.06	0.06	0.05	0.06	0.05	3.9%
Other Crude Supply[2]	0.23	0.02	0.00	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**15.12**	**15.13**	**15.81**	**17.14**	**17.61**	**18.12**	**18.39**	**0.8%**
Natural Gas Plant Liquids	**1.91**	**1.87**	**2.08**	**2.23**	**2.41**	**2.53**	**2.63**	**1.4%**
Other Inputs[3]	**0.35**	**0.30**	**0.43**	**0.44**	**0.41**	**0.44**	**0.45**	**1.6%**
Refinery Processing Gain[4]	**0.95**	**0.90**	**0.89**	**0.91**	**0.95**	**0.96**	**0.96**	**0.2%**
Net Product Imports[5]	**1.40**	**1.59**	**1.27**	**2.25**	**3.84**	**5.06**	**6.73**	**6.2%**
Gross Refined Product Imports[6]	2.04	2.08	1.79	2.59	3.82	5.02	6.76	5.0%
Unfinished Oil Imports	0.27	0.38	0.39	0.66	1.04	1.09	1.07	4.4%
Ether Imports	0.08	0.08	0.00	0.00	0.00	0.00	0.00	N/A
Exports	0.99	0.95	0.91	1.00	1.03	1.06	1.10	0.6%
Total Primary Supply[7]	**19.73**	**19.80**	**20.48**	**22.97**	**25.21**	**27.11**	**29.16**	**1.6%**
Refined Petroleum Products Supplied								
Motor Gasoline[8]	8.54	8.67	9.40	10.69	11.83	12.78	13.77	1.9%
Jet Fuel[9]	1.73	1.66	1.65	1.90	2.17	2.46	2.74	2.1%
Distillate Fuel[10]	3.72	3.81	4.03	4.61	5.05	5.40	5.87	1.8%
Residual Fuel	0.97	0.97	0.56	0.60	0.63	0.64	0.64	-1.7%
Other[11]	4.82	4.58	4.84	5.20	5.55	5.85	6.15	1.2%
Total	**19.78**	**19.69**	**20.49**	**22.99**	**25.23**	**27.13**	**29.17**	**1.7%**
Refined Petroleum Products Supplied								
Residential and Commercial	1.23	1.21	1.18	1.17	1.15	1.13	1.12	-0.3%
Industrial[12]	4.87	4.67	4.89	5.30	5.67	6.00	6.33	1.3%
Transportation	13.18	13.27	14.26	16.33	18.20	19.79	21.48	2.0%
Electric Generators[13]	0.49	0.55	0.15	0.19	0.21	0.20	0.23	-3.5%
Total	**19.78**	**19.69**	**20.49**	**22.99**	**25.23**	**27.13**	**29.17**	**1.7%**
Discrepancy[14]	**-0.05**	**0.10**	**-0.01**	**-0.01**	**-0.01**	**-0.02**	**-0.02**	**N/A**
World Oil Price (2001 dollars per barrel)[15]	**28.35**	**22.01**	**23.27**	**23.99**	**24.72**	**25.48**	**26.57**	**0.8%**
Import Share of Product Supplied	**0.53**	**0.55**	**0.56**	**0.60**	**0.64**	**0.65**	**0.68**	**0.9%**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**108.88**	**89.20**	**98.32**	**122.96**	**151.12**	**174.57**	**206.94**	**3.6%**
Domestic Refinery Distillation Capacity[16]	**16.6**	**16.8**	**17.6**	**18.7**	**18.9**	**19.5**	**19.8**	**0.7%**
Capacity Utilization Rate (percent)	**93.0**	**93.0**	**91.5**	**93.2**	**94.7**	**94.6**	**94.6**	**0.1%**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2000 data EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A12. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
World Oil Price (2001 dollars per barrel)	**28.35**	**22.01**	**23.27**	**23.99**	**24.72**	**25.48**	**26.57**	**0.8%**
Delivered Sector Product Prices								
Residential								
Distillate Fuel	134.1	124.6	109.4	110.4	116.0	121.0	123.8	-0.0%
Liquefied Petroleum Gas	118.8	127.3	117.5	120.2	122.8	124.5	127.3	-0.0%
Commercial								
Distillate Fuel	100.8	88.7	77.3	78.4	84.4	90.0	93.7	0.2%
Residual Fuel	52.9	51.8	58.5	60.0	61.7	63.3	65.6	1.0%
Residual Fuel (2001 dollars per barrel)	22.22	21.75	24.59	25.21	25.92	26.57	27.55	1.0%
Industrial[1]								
Distillate Fuel	102.4	90.8	77.9	79.4	87.1	94.3	100.6	0.4%
Liquefied Petroleum Gas	103.2	105.9	80.0	82.2	85.0	86.8	89.3	-0.7%
Residual Fuel	50.0	49.1	53.8	55.5	57.2	58.9	61.4	0.9%
Residual Fuel (2001 dollars per barrel)	21.02	20.61	22.60	23.32	24.03	24.74	25.77	0.9%
Transportation								
Diesel Fuel (distillate)[2]	152.4	139.4	129.8	141.7	139.9	140.9	145.9	0.2%
Jet Fuel[3]	98.0	83.7	75.8	75.9	81.4	85.4	90.7	0.3%
Motor Gasoline[4]	154.1	143.3	140.0	142.8	140.4	143.7	149.6	0.2%
Liquid Petroleum Gas	141.1	145.2	127.7	130.5	132.6	133.0	134.1	-0.3%
Residual Fuel	67.0	58.4	51.7	53.2	54.8	56.4	58.9	0.0%
Residual Fuel (2001 dollars per barrel)	28.14	24.52	21.70	22.35	23.01	23.71	24.75	0.0%
Ethanol (E85)	158.5	158.4	174.3	190.7	200.5	204.4	209.6	1.2%
Electric Generators[5]								
Distillate Fuel	93.3	86.0	69.5	71.1	77.7	84.0	85.7	-0.0%
Residual Fuel	65.7	67.4	57.7	59.4	60.9	62.9	65.9	-0.1%
Residual Fuel (2001 dollars per barrel)	27.59	28.30	24.22	24.94	25.59	26.44	27.67	-0.1%
Refined Petroleum Product Prices[6]								
Distillate Fuel	139.4	127.0	117.5	127.2	128.5	131.3	136.3	0.3%
Jet Fuel[3]	98.0	83.7	75.8	75.9	81.4	85.4	90.7	0.3%
Liquefied Petroleum Gas	106.2	110.3	87.5	89.4	91.6	93.1	95.3	-0.6%
Motor Gasoline[4]	154.1	143.3	139.9	142.8	140.4	143.7	149.6	0.2%
Residual Fuel	64.0	61.5	53.4	55.1	56.9	58.6	61.1	-0.0%
Residual Fuel (2001 dollars per barrel)	26.88	25.85	22.43	23.16	23.88	24.62	25.68	-0.0%
Average	**132.3**	**123.6**	**118.1**	**122.4**	**122.4**	**125.4**	**130.4**	**0.2%**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2001). 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2000 and 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2000 and 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2000 and 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2000 and 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Production								
Dry Gas Production[1]	18.99	19.45	20.13	21.88	23.83	25.07	26.75	1.3%
Supplemental Natural Gas[2]	0.09	0.08	0.10	0.10	0.10	0.10	0.10	0.9%
Net Imports	**3.54**	**3.65**	**3.86**	**4.78**	**5.27**	**6.66**	**7.76**	**3.2%**
Canada	3.47	3.61	3.52	4.05	4.42	5.08	5.31	1.6%
Mexico	-0.09	-0.13	-0.27	-0.26	-0.19	0.07	0.30	N/A
Liquefied Natural Gas	0.16	0.17	0.61	0.99	1.03	1.51	2.14	11.0%
Total Supply	**22.61**	**23.17**	**24.09**	**26.76**	**29.19**	**31.82**	**34.60**	**1.7%**
Consumption by Sector								
Residential	4.98	4.81	5.30	5.50	5.69	5.96	6.22	1.1%
Commercial	3.21	3.24	3.52	3.69	3.89	4.17	4.43	1.3%
Industrial[3]	8.25	7.53	8.13	8.88	9.53	10.10	10.91	1.6%
Electric Generators[4]	5.23	5.30	5.69	6.80	8.01	9.39	10.56	2.9%
Transportation[5]	0.01	0.01	0.03	0.06	0.08	0.10	0.11	10.4%
Pipeline Fuel	0.64	0.61	0.65	0.76	0.83	0.88	1.00	2.0%
Lease and Plant Fuel[6]	1.13	1.17	1.29	1.35	1.47	1.55	1.69	1.5%
Total	**23.46**	**22.67**	**24.60**	**27.06**	**29.50**	**32.14**	**34.93**	**1.8%**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[7]	**-0.85**	**0.50**	**-0.52**	**-0.30**	**-0.31**	**-0.32**	**-0.32**	**N/A**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 and 2001 values include net storage injections.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 supply values: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001). 2001 supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2000 and 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A14. Natural Gas Prices, Margins, and Revenues
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Source Price								
Average Lower 48 Wellhead Price[1]	3.83	4.12	2.88	3.29	3.55	3.69	3.90	-0.2%
Average Import Price	4.04	4.43	2.99	3.33	3.77	3.81	4.19	-0.2%
Average[2]	**3.86**	**4.17**	**2.90**	**3.30**	**3.59**	**3.72**	**3.97**	**-0.2%**
Delivered Prices								
Residential	7.97	9.68	7.52	7.68	7.90	7.96	8.22	-0.7%
Commercial	6.82	8.32	6.16	6.56	6.83	6.94	7.22	-0.6%
Industrial[3]	4.75	5.00	3.62	4.00	4.29	4.44	4.70	-0.3%
Electric Generators[4]	4.51	4.87	3.33	3.86	4.21	4.38	4.69	-0.2%
Transportation[5]	6.95	7.87	6.29	7.28	7.78	7.97	8.30	0.2%
Average[6]	**5.74**	**6.57**	**4.86**	**5.17**	**5.41**	**5.50**	**5.75**	**-0.6%**
Transmission and Distribution Margins[7]								
Residential	4.11	5.50	4.61	4.38	4.30	4.24	4.25	-1.1%
Commercial	2.96	4.14	3.26	3.26	3.23	3.22	3.25	-1.0%
Industrial[3]	0.89	0.83	0.72	0.70	0.70	0.73	0.73	-0.5%
Electric Generators[4]	0.64	0.70	0.43	0.56	0.62	0.66	0.72	0.1%
Transportation[5]	3.08	3.69	3.39	3.98	4.18	4.25	4.33	0.7%
Average[6]	**1.88**	**2.40**	**1.96**	**1.87**	**1.81**	**1.78**	**1.78**	**-1.2%**
Transmission and Distribution Revenue (billion 2001 dollars)								
Residential	20.46	26.45	24.47	24.12	24.49	25.26	26.44	-0.0%
Commercial	9.50	13.43	11.48	12.04	12.59	13.42	14.40	0.3%
Industrial[3]	7.31	6.25	5.85	6.19	6.66	7.32	7.99	1.0%
Electric Generators[4]	3.36	3.70	2.45	3.82	4.97	6.20	7.60	3.0%
Transportation[5]	0.02	0.04	0.11	0.23	0.35	0.42	0.48	11.2%
Total	**40.65**	**49.86**	**44.35**	**46.41**	**49.05**	**52.62**	**56.91**	**0.6%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001). 2000 and 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2000 and 2001 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA,*Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2000 and 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Crude Oil								
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**28.18**	**22.91**	**23.17**	**23.90**	**24.13**	**24.89**	**26.12**	**0.5%**
Production (million barrels per day)[2]								
U.S. Total	**5.86**	**5.80**	**5.58**	**5.63**	**5.25**	**5.46**	**5.33**	**-0.4%**
Lower 48 Onshore	3.26	3.13	2.79	2.51	2.29	2.12	1.98	-1.9%
Lower 48 Offshore	1.62	1.71	1.92	2.47	2.07	2.11	2.18	1.0%
Alaska	0.98	0.97	0.87	0.64	0.88	1.23	1.17	0.8%
Lower 48 End of Year Reserves (billion barrels)[2]	**18.66**	**19.48**	**19.03**	**17.79**	**16.23**	**15.64**	**15.31**	**-1.0%**
Natural Gas								
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**3.83**	**4.12**	**2.88**	**3.29**	**3.55**	**3.69**	**3.90**	**-0.2%**
Dry Production (trillion cubic feet)[3]								
U.S. Total	**18.99**	**19.45**	**20.14**	**21.88**	**23.83**	**25.07**	**26.75**	**1.3%**
Lower 48 Onshore	13.45	13.72	14.84	16.28	17.94	19.14	18.43	1.2%
Associated-Dissolved[4]	1.75	1.77	1.50	1.38	1.29	1.21	1.15	-1.8%
Non-Associated	11.70	11.94	13.35	14.91	16.66	17.92	17.27	1.5%
Conventional	6.52	6.54	7.03	7.98	8.21	8.24	7.75	0.7%
Unconventional	5.18	5.40	6.32	6.93	8.45	9.68	9.53	2.4%
Lower 48 Offshore	5.12	5.30	4.85	5.12	5.37	5.39	5.69	0.3%
Associated-Dissolved[4]	1.05	1.08	0.85	0.79	0.74	0.77	0.91	-0.7%
Non-Associated	4.07	4.22	4.00	4.33	4.63	4.62	4.78	0.5%
Alaska	0.42	0.43	0.44	0.48	0.51	0.55	2.64	7.8%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**168.19**	**174.04**	**175.91**	**178.39**	**186.58**	**193.42**	**189.88**	**0.4%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.09**	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.9%**
Total Lower 48 Wells (thousands)	**27.09**	**33.94**	**24.88**	**25.83**	**27.26**	**27.37**	**28.41**	**-0.7%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2000 and 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2000 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2000) (Washington, DC, December 2001). 2000 natural gas lower 48 average wellhead price and total natural gas production: EIA, *Natural Gas Annual 2000, DOE/EIA-0131(2000) (Washington, DC, November 2001)*. 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002) Other 2000 and 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Production[1]								
Appalachia	430	443	414	422	418	419	431	-0.1%
Interior	144	147	165	158	150	150	159	0.3%
West	510	548	545	651	718	790	850	1.8%
East of the Mississippi	518	539	521	528	526	529	553	0.1%
West of the Mississippi	566	599	603	703	760	829	887	1.7%
Total	**1084**	**1138**	**1124**	**1231**	**1286**	**1359**	**1440**	**1.0%**
Net Imports								
Imports	13	20	17	20	22	25	28	1.4%
Exports	58	49	39	35	29	29	26	-2.6%
Total	**-46**	**-29**	**-22**	**-15**	**-6**	**-4**	**2**	**N/A**
Total Supply[2]	**1038**	**1109**	**1103**	**1215**	**1280**	**1355**	**1442**	**1.1%**
Consumption by Sector								
Residential and Commercial	4	4	5	5	5	5	5	1.2%
Industrial[3]	65	63	64	66	68	69	71	0.5%
of which: Coal to Liquids	0	0	0	0	0	0	0	N/A
Coke Plants	29	26	25	24	22	20	18	-1.5%
Electric Generators[4]	983	957	1012	1123	1187	1263	1350	1.4%
Total	**1081**	**1050**	**1106**	**1218**	**1282**	**1358**	**1444**	**1.3%**
Discrepancy and Stock Change[5]	**-43**	**59**	**-3**	**-3**	**-3**	**-3**	**-3**	**N/A**
Average Minemouth Price								
(2001 dollars per short ton)	17.18	17.59	16.50	14.99	14.67	14.38	14.36	-0.8%
(2001 dollars per million Btu)	0.81	0.83	0.80	0.73	0.72	0.71	0.71	-0.7%
Delivered Prices (2001 dollars per short ton)[6]								
Industrial	32.20	32.83	31.14	29.97	29.33	28.40	27.92	-0.7%
Coke Plants	45.43	46.42	43.17	41.38	40.03	38.62	37.09	-0.9%
Electric Generators								
(2001 dollars per short ton)	24.85	25.06	24.92	23.61	23.16	22.45	22.17	-0.5%
(2001 dollars per million Btu)	1.23	1.25	1.22	1.17	1.15	1.12	1.10	-0.5%
Average	**25.85**	**26.06**	**25.70**	**24.31**	**23.78**	**23.00**	**22.64**	**-0.6%**
Exports[7]	35.72	36.97	34.33	32.88	32.58	31.89	30.85	-0.8%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). 2001 data based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A17. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case 2000	2001	2005	2010	2015	2020	2025	Annual Growth 2001-2025 (percent)
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	78.23	78.36	78.80	78.92	78.92	78.92	78.92	0.0%
Geothermal[2]	2.85	2.86	3.03	3.54	4.08	5.00	5.64	2.9%
Municipal Solid Waste[3]	3.10	3.25	3.78	4.03	4.22	4.37	4.37	1.2%
Wood and Other Biomass[4]	1.67	1.77	2.01	2.07	2.14	2.18	2.78	1.9%
Solar Thermal	0.33	0.33	0.42	0.44	0.46	0.48	0.50	1.7%
Solar Photovoltaic[5]	0.01	0.02	0.04	0.10	0.18	0.27	0.36	13.9%
Wind	2.45	4.29	7.24	8.47	10.06	11.05	12.00	4.4%
Total	**88.64**	**90.88**	**95.33**	**97.57**	**100.05**	**102.25**	**104.56**	**0.6%**
Generation (billion kilowatthours)								
Conventional Hydropower	271.03	213.82	301.77	301.89	301.41	301.05	301.34	1.4%
Geothermal[2]	14.09	13.81	15.31	19.81	24.33	31.78	36.92	4.2%
Municipal Solid Waste[3]	20.05	19.55	27.01	28.88	30.26	31.34	31.49	2.0%
Wood and Other Biomass[4]	9.17	9.38	18.14	21.27	22.28	21.88	24.66	4.1%
Dedicated Plants	8.36	7.67	11.56	12.41	12.86	13.12	16.47	3.2%
Cofiring	0.81	1.71	6.58	8.85	9.41	8.76	8.19	6.7%
Solar Thermal	0.49	0.49	0.67	0.77	0.83	0.90	0.97	2.9%
Solar Photovoltaic[5]	0.00	0.00	0.10	0.24	0.44	0.66	0.88	26.7%
Wind	5.59	5.78	19.28	23.62	29.14	32.70	36.21	7.9%
Total	**320.43**	**262.85**	**382.28**	**396.47**	**408.69**	**420.31**	**432.48**	**2.1%**
End-Use Sector								
Net Summer Capacity								
Combined Heat and Power[6]								
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.0%
Biomass	4.41	4.41	4.96	5.88	6.89	7.76	8.71	2.9%
Total	**4.69**	**4.69**	**5.24**	**6.16**	**7.17**	**8.04**	**9.00**	**2.7%**
Other End-Use Generators[7]								
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.01	0.02	0.11	0.38	0.44	0.62	0.93	16.5%
Total	**1.11**	**1.12**	**1.20**	**1.47**	**1.54**	**1.71**	**2.03**	**2.5%**
Generation (billion kilowatthours)								
Combined Heat and Power[6]								
Municipal Solid Waste	2.50	2.46	2.15	2.15	2.15	2.15	2.15	-0.6%
Biomass	28.68	28.67	31.89	37.23	43.15	48.21	53.80	2.7%
Total	**31.18**	**31.13**	**34.04**	**39.38**	**45.30**	**50.36**	**55.95**	**2.5%**
Other End-Use Generators[7]								
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.01	0.02	0.23	0.82	0.96	1.33	1.98	22.1%
Total	**4.24**	**4.25**	**4.46**	**5.05**	**5.19**	**5.57**	**6.22**	**1.6%**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 2000 and 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2000 and 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Marketed Renewable Energy[2]								
Residential	**0.41**	**0.39**	**0.41**	**0.41**	**0.41**	**0.41**	**0.40**	**0.2%**
Wood	0.41	0.39	0.41	0.41	0.41	0.41	0.40	0.2%
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Industrial[3]	**1.86**	**1.82**	**1.95**	**2.22**	**2.51**	**2.77**	**3.05**	**2.2%**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.0%
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.0%
Biomass	1.82	1.77	1.90	2.17	2.46	2.72	3.01	2.2%
Transportation	**0.14**	**0.15**	**0.23**	**0.26**	**0.29**	**0.31**	**0.34**	**3.5%**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Ethanol used in Gasoline Blending	0.14	0.15	0.23	0.26	0.29	0.31	0.33	3.5%
Electric Generators[5]	**3.58**	**3.02**	**4.25**	**4.50**	**4.72**	**5.00**	**5.21**	**2.3%**
Conventional Hydroelectric	2.80	2.17	3.10	3.10	3.09	3.08	3.08	1.5%
Geothermal	0.29	0.29	0.35	0.49	0.63	0.86	1.01	5.3%
Municipal Solid Waste[6]	0.30	0.31	0.37	0.40	0.41	0.43	0.43	1.3%
Biomass	0.14	0.15	0.23	0.26	0.28	0.27	0.30	2.8%
Dedicated Plants	0.12	0.12	0.13	0.14	0.15	0.15	0.19	2.0%
Cofiring	0.01	0.03	0.09	0.12	0.13	0.12	0.11	4.9%
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.02	0.02	5.3%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.05	0.08	0.20	0.24	0.30	0.34	0.37	6.4%
Total Marketed Renewable Energy	**6.10**	**5.47**	**6.94**	**7.49**	**8.03**	**8.59**	**9.11**	**2.1%**
Sources of Ethanol								
From Corn	0.14	0.15	0.23	0.26	0.28	0.29	0.29	2.9%
From Cellulose	0.00	0.00	0.00	0.00	0.01	0.02	0.05	N/A
Total	**0.14**	**0.15**	**0.23**	**0.26**	**0.29**	**0.31**	**0.34**	**3.5%**
Non-Marketed Renewable Energy[7]								
Selected Consumption								
Residential	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**2.3%**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	2.1%
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.6%
Commercial	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**1.3%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	17.5%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2000 and 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2000 and 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Residential								
Petroleum	27.5	27.2	28.3	27.6	26.5	25.7	25.1	-0.3%
Natural Gas	73.7	71.1	78.5	81.5	84.3	88.2	92.1	1.1%
Coal	0.3	0.3	0.4	0.4	0.4	0.4	0.3	0.4%
Electricity	215.4	215.1	222.4	242.7	254.4	269.4	285.2	1.2%
Total	**317.0**	**313.8**	**329.6**	**352.1**	**365.6**	**383.7**	**402.8**	**1.0%**
Commercial								
Petroleum	14.0	14.0	12.6	13.1	13.3	13.4	13.5	-0.2%
Natural Gas	47.5	48.0	52.2	54.7	57.6	61.7	65.6	1.3%
Coal	2.3	2.3	2.3	2.5	2.6	2.7	2.8	0.7%
Electricity	209.6	214.5	220.2	247.0	271.0	298.4	328.0	1.8%
Total	**273.5**	**278.8**	**287.3**	**317.2**	**344.5**	**376.2**	**409.9**	**1.6%**
Industrial[1]								
Petroleum	96.0	97.9	93.3	98.6	102.1	106.5	110.4	0.5%
Natural Gas[2]	133.2	123.4	137.0	149.0	160.0	169.4	183.4	1.7%
Coal	56.0	52.1	53.9	56.2	56.6	56.1	56.1	0.3%
Electricity	192.3	178.1	170.3	194.3	210.0	223.1	240.0	1.3%
Total	**477.4**	**451.5**	**454.5**	**498.1**	**528.7**	**555.2**	**589.9**	**1.1%**
Transportation								
Petroleum[3]	496.7	501.4	538.2	616.4	686.8	746.9	811.0	2.0%
Natural Gas[4]	9.7	9.2	10.0	12.1	13.4	14.5	16.3	2.4%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Electricity	3.8	3.9	4.0	4.6	5.2	5.9	6.8	2.4%
Total	**510.2**	**514.5**	**552.2**	**633.0**	**705.4**	**767.3**	**834.2**	**2.0%**
Total Carbon Dioxide Emissions by Delivered Fuel								
Petroleum[3]	634.2	640.5	672.4	755.7	828.7	892.6	960.1	1.7%
Natural Gas	264.1	251.7	277.7	297.2	315.3	333.8	357.5	1.5%
Coal	58.7	54.7	56.6	59.0	59.5	59.2	59.3	0.3%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Electricity	621.1	611.6	616.9	688.5	740.6	796.9	860.1	1.4%
Total	**1578.2**	**1558.6**	**1623.7**	**1800.5**	**1944.2**	**2082.5**	**2236.9**	**1.5%**
Electric Generators[6]								
Petroleum	24.5	27.5	7.2	8.8	9.8	9.7	10.9	-3.8%
Natural Gas	76.5	77.7	83.5	99.9	117.5	137.8	155.0	2.9%
Coal	520.1	506.4	526.3	579.9	613.3	649.5	694.2	1.3%
Total	**621.1**	**611.6**	**616.9**	**688.5**	**740.6**	**796.9**	**860.1**	**1.4%**
Total Carbon Dioxide Emissions by Primary Fuel[7]								
Petroleum[3]	658.8	668.0	679.6	764.5	838.5	902.2	971.0	1.6%
Natural Gas	340.7	329.4	361.2	397.1	432.9	471.6	512.5	1.9%
Coal	578.7	561.1	582.9	638.9	672.8	708.7	753.4	1.2%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**1578.2**	**1558.6**	**1623.7**	**1800.5**	**1944.2**	**2082.5**	**2236.9**	**1.5%**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.7**	**5.6**	**5.6**	**6.0**	**6.2**	**6.4**	**6.6**	**0.7%**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 and 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
GDP Chain-Type Price Index (1996=1.000)	**1.069**	**1.094**	**1.195**	**1.313**	**1.486**	**1.708**	**1.981**	**2.5%**
Real Gross Domestic Product	**9191**	**9215**	**10361**	**12258**	**14288**	**16450**	**18917**	**3.0%**
Real Consumption	6224	6377	7151	8412	9826	11351	13012	3.0%
Real Investment	1763	1575	1888	2499	3151	3755	4492	4.5%
Real Government Spending	1583	1640	1790	1895	2026	2212	2429	1.6%
Real Exports	1137	1076	1287	1784	2426	3360	4695	6.3%
Real Imports	1536	1492	1788	2301	3044	4059	5398	5.5%
Real Disposable Personal Income	**6630**	**6748**	**7421**	**8637**	**10087**	**11713**	**13435**	**2.9%**
AA Utility Bond Rate (percent)	**7.91**	**7.43**	**8.10**	**7.24**	**8.05**	**9.18**	**9.63**	**N/A**
Real Yield on Government 10 Year Bonds (percent)	**4.85**	**3.51**	**5.10**	**5.26**	**5.69**	**6.56**	**6.76**	**N/A**
Real Utility Bond Rate (percent)	**6.32**	**5.45**	**5.61**	**5.35**	**5.42**	**6.32**	**6.56**	**N/A**
Energy Intensity (thousand Btu per 1996 dollar of GDP)								
Delivered Energy	7.91	7.74	7.36	6.87	6.39	5.94	5.55	-1.4%
Total Energy	10.82	10.57	9.96	9.24	8.54	7.92	7.36	-1.5%
Consumer Price Index (1982-84=1.00)	**1.72**	**1.77**	**1.97**	**2.19**	**2.50**	**2.93**	**3.47**	**2.8%**
Unemployment Rate (percent)	**4.02**	**4.79**	**5.57**	**4.41**	**4.88**	**5.89**	**5.77**	**N/A**
Housing Starts (millions)	**1.82**	**1.80**	**1.90**	**2.17**	**1.99**	**1.92**	**2.02**	**N/A**
Single-Family	1.23	1.27	1.22	1.34	1.19	1.12	1.12	N/A
Multifamily	0.34	0.33	0.34	0.47	0.46	0.48	0.57	N/A
Mobile Home Shipments	0.25	0.19	0.34	0.37	0.34	0.32	0.33	N/A
Commercial Floorspace, Total (billion square feet)	**68.5**	**70.2**	**76.1**	**81.8**	**88.2**	**94.6**	**101.1**	**1.5%**
Value of Shipments (billion 1996 dollars)								
Total Industrial	5719	5425	5882	6959	8029	8963	10126	2.6%
Nonmanufacturing	1341	1346	1340	1505	1636	1743	1869	1.4%
Manufacturing	4378	4079	4542	5453	6393	7220	8257	3.0%
Energy-Intensive Manufacturing	1113	1086	1141	1256	1360	1446	1532	1.4%
Non-Energy-Intensive Manufacturing	3264	2993	3402	4197	5033	5774	6725	3.4%
Unit Sales of Light-Duty Vehicles (millions)	**17.36**	**17.11**	**16.50**	**18.27**	**19.77**	**19.91**	**19.97**	**0.6%**
Population (millions)								
Population with Armed Forces Overseas	275.7	278.2	288.1	300.2	312.7	325.3	338.2	0.8%
Population (aged 16 and over)	213.1	215.4	224.8	236.6	246.7	256.5	266.6	0.9%
Employment, Non-Agriculture	131.3	131.7	137.0	147.1	154.0	159.2	165.9	1.0%
Employment, Manufacturing	18.3	17.5	17.4	17.9	17.5	17.3	18.4	0.2%
Labor Force	140.9	141.8	148.7	156.5	163.9	169.8	177.4	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 2000 and 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table A21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
World Oil Price[1] (2001 dollars per barrel)	**28.35**	**22.01**	**23.27**	**23.99**	**24.72**	**25.48**	**26.57**	**0.8%**
Production[2] (Conventional)								
Industrialized Countries								
U.S. (50 states)	9.08	8.88	8.99	9.20	9.01	9.39	9.36	0.2%
Canada	2.07	2.09	2.20	1.93	1.75	1.62	1.54	-1.3%
Mexico	3.48	3.59	3.93	4.26	4.34	4.42	4.57	1.0%
Western Europe[3]	6.74	6.92	6.43	6.33	5.87	5.45	5.00	-1.3%
Japan	0.08	0.08	0.08	0.08	0.08	0.07	0.07	-0.9%
Australia and New Zealand	0.85	0.80	0.77	0.84	0.81	0.79	0.78	-0.1%
Total Industrialized	**22.30**	**22.35**	**22.40**	**22.64**	**21.86**	**21.74**	**21.32**	**-0.2%**
Eurasia								
Former Soviet Union								
Russia	6.70	7.24	8.18	9.17	9.70	10.26	10.42	1.5%
Caspian Area[4]	1.44	1.59	2.15	3.60	4.11	4.70	5.01	4.9%
Eastern Europe[5]	0.24	0.22	0.25	0.28	0.32	0.38	0.42	2.6%
Total Eurasia	**8.38**	**9.05**	**10.58**	**13.04**	**14.13**	**15.34**	**15.84**	**2.4%**
Developing Countries								
OPEC[6]								
Asia	1.51	1.48	1.44	1.44	1.46	1.45	1.46	-0.1%
Middle East	21.11	19.42	18.58	22.43	29.07	33.82	42.02	3.3%
North Africa	2.91	3.06	3.90	4.60	5.03	5.62	6.44	3.2%
West Africa	2.15	2.23	2.73	3.23	3.95	4.64	5.45	3.8%
South America	2.78	2.92	3.59	3.87	3.97	4.26	4.75	2.1%
Non-OPEC								
China	3.25	3.30	3.36	3.44	3.41	3.33	3.28	-0.0%
Other Asia	2.39	2.38	2.39	2.54	2.64	2.55	2.53	0.3%
Middle East[7]	2.02	1.99	2.11	2.25	2.35	2.45	2.61	1.2%
Africa	2.79	2.70	3.34	4.47	5.44	6.60	6.85	4.0%
South and Central America	3.72	3.72	4.11	4.59	5.25	6.10	6.31	2.2%
Total Developing Countries	**44.63**	**43.20**	**45.55**	**52.86**	**62.56**	**70.83**	**81.72**	**2.7%**
Total Production (Conventional)	**75.31**	**74.61**	**78.54**	**88.54**	**98.55**	**107.92**	**118.88**	**2.0%**
Production[8] (Nonconventional)								
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Other North America	0.69	0.72	1.00	1.52	1.82	2.07	2.22	4.8%
Western Europe	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.8%
Asia	0.03	0.02	0.03	0.03	0.03	0.03	0.03	1.5%
Middle East[7]	0.00	0.01	0.01	0.01	0.02	0.02	0.03	6.5%
Africa.	0.16	0.15	0.17	0.19	0.22	0.25	0.28	2.7%
South and Central America	0.47	0.49	0.68	0.85	1.27	1.42	1.45	4.6%
Total Production (Nonconventional)	**1.38**	**1.42**	**1.92**	**2.64**	**3.39**	**3.83**	**4.05**	**4.5%**
Total Production	**76.69**	**76.02**	**80.46**	**91.18**	**101.94**	**111.75**	**122.93**	**2.0%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Consumption[9]								
Industrialized Countries								
U.S. (50 states)	19.78	19.69	20.49	22.99	25.23	27.13	29.17	1.7%
U.S. Territories	0.33	0.35	0.40	0.44	0.47	0.49	0.54	1.9%
Canada	2.07	1.91	2.06	2.22	2.32	2.41	2.50	1.1%
Mexico	1.99	1.94	2.17	2.78	3.47	3.94	4.47	3.5%
Western Europe[3]	13.77	13.87	14.33	14.95	15.38	15.65	15.93	0.6%
Japan	5.53	5.42	5.48	6.03	6.14	6.21	6.27	0.6%
Australia and New Zealand	1.01	1.01	1.08	1.25	1.45	1.60	1.75	2.3%
Total Industrialized	**44.48**	**44.19**	**45.99**	**50.66**	**54.45**	**57.42**	**60.64**	**1.3%**
Eurasia								
Former Soviet Union	3.66	3.63	3.97	4.67	5.22	5.50	5.78	2.0%
Eastern Europe[5]	1.35	1.37	1.46	1.61	1.85	2.08	2.33	2.3%
Total Eurasia	**5.01**	**5.00**	**5.44**	**6.28**	**7.08**	**7.58**	**8.12**	**2.0%**
Developing Countries								
China	4.78	4.82	5.35	6.55	8.28	10.05	12.20	3.9%
India	1.99	2.00	2.38	3.19	3.95	4.92	6.12	4.8%
South Korea	2.15	2.22	2.44	2.86	3.03	3.10	3.18	1.5%
Other Asia	5.30	5.34	5.85	6.98	8.03	8.98	10.13	2.7%
Middle East[7]	5.12	5.13	5.47	6.17	7.16	8.20	9.40	2.6%
Africa	2.44	2.46	2.72	3.19	3.60	4.01	4.46	2.5%
South and Central America	4.83	4.87	5.14	5.59	6.67	7.78	8.98	2.6%
Total Developing Countries	26.61	26.84	29.34	34.54	40.71	47.05	54.47	3.0%
Total Consumption	**76.10**	**76.03**	**80.76**	**91.48**	**102.24**	**112.04**	**123.23**	**2.0%**
OPEC Production[10]	30.81	29.48	30.76	36.22	44.44	50.88	61.24	3.1%
Non-OPEC Production[10]	45.88	46.54	49.70	54.96	57.50	60.86	61.69	1.2%
Net Eurasia Exports	3.38	4.07	5.16	6.78	7.07	7.78	7.74	2.7%
OPEC Market Share	0.40	0.39	0.38	0.40	0.44	0.46	0.50	1.0%

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2000 data derived from: Energy Information Administration (EIA), *International Energy Annual 2000*, DOE/EIA-0219(2000) (Washington, DC, May 2002). **2001 and projections:** EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	12.29	11.90	11.91	11.95	11.41	11.56	11.67	10.86	11.29	11.52
Natural Gas Plant Liquids	2.65	3.09	3.16	3.26	3.51	3.59	3.74	3.53	3.76	3.93
Dry Natural Gas	19.97	21.92	22.47	23.20	25.14	25.75	27.31	25.24	27.47	28.72
Coal	23.97	24.99	25.30	25.54	26.64	27.69	28.90	27.81	29.29	31.08
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.14	7.23	7.42	7.92	8.28	8.62	8.26	8.78	9.38
Other[2]	0.57	0.84	0.84	0.84	0.79	0.80	0.81	0.80	0.80	0.83
Total	**72.81**	**78.23**	**79.27**	**80.56**	**83.84**	**86.10**	**89.49**	**84.93**	**89.83**	**93.90**
Imports										
Crude Oil[3]	20.26	24.53	25.13	25.78	27.10	27.61	28.15	28.47	28.47	29.52
Petroleum Products[4]	5.04	5.69	6.41	7.45	9.60	11.97	14.54	11.49	15.17	18.78
Natural Gas	4.10	5.29	5.52	5.86	6.05	7.22	8.12	7.33	8.30	9.65
Other Imports[5]	0.73	0.86	0.90	0.98	0.92	0.96	1.04	0.89	0.94	1.05
Total	**30.13**	**36.37**	**37.96**	**40.07**	**43.66**	**47.76**	**51.85**	**48.19**	**52.88**	**59.00**
Exports										
Petroleum[6]	2.01	2.21	2.24	2.27	2.31	2.34	2.35	2.34	2.41	2.48
Natural Gas	0.37	0.64	0.62	0.59	0.52	0.41	0.37	0.40	0.37	0.36
Coal	1.27	0.89	0.91	0.89	0.74	0.74	0.74	0.67	0.67	0.67
Total	**3.64**	**3.74**	**3.76**	**3.75**	**3.57**	**3.49**	**3.46**	**3.41**	**3.45**	**3.51**
Discrepancy[7]	**1.99**	**0.19**	**0.21**	**0.18**	**0.28**	**0.25**	**0.17**	**0.31**	**0.19**	**0.14**
Consumption										
Petroleum Products[8]	38.46	43.27	44.65	46.48	49.48	52.60	56.04	52.16	56.56	61.61
Natural Gas	23.26	26.96	27.75	28.84	31.06	32.96	35.47	32.58	35.81	38.42
Coal	22.02	24.66	24.98	25.27	26.60	27.68	28.98	27.89	29.42	31.32
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.14	7.23	7.42	7.92	8.28	8.62	8.26	8.78	9.39
Other[9]	0.21	0.27	0.29	0.33	0.17	0.17	0.18	0.07	0.07	0.08
Total	**97.30**	**110.67**	**113.26**	**116.70**	**123.66**	**130.12**	**137.71**	**129.39**	**139.07**	**149.25**
Net Imports - Petroleum	**23.29**	**28.00**	**29.31**	**30.96**	**34.39**	**37.24**	**40.34**	**37.63**	**41.23**	**45.82**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.41	23.99	24.48	24.14	25.48	26.64	24.85	26.57	28.09
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.17	3.29	3.59	3.58	3.69	3.63	3.83	3.90	4.50
Coal Minemouth Price (dollars per ton)	17.59	14.95	14.99	15.11	14.06	14.38	14.79	13.99	14.36	14.93
Average Electricity Price (cents per kilowatthour)	7.3	6.2	6.4	6.6	6.4	6.6	6.8	6.5	6.7	7.1

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, HM2003.D110502C.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.83	0.83	0.80	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.48	0.46	0.47	0.48	0.46	0.48	0.49
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.37	1.38	1.32	1.34	1.35
Natural Gas	4.94	5.61	5.66	5.69	5.92	6.12	6.31	6.05	6.40	6.55
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.40	0.41	0.41	0.39	0.40	0.41
Electricity	4.10	4.90	4.93	4.96	5.45	5.59	5.70	5.71	5.94	6.05
Delivered Energy	**10.94**	**12.39**	**12.47**	**12.54**	**13.15**	**13.51**	**13.81**	**13.48**	**14.10**	**14.38**
Electricity Related Losses	9.15	10.25	10.28	10.27	10.83	10.96	10.97	11.10	11.33	11.32
Total	**20.09**	**22.63**	**22.75**	**22.81**	**23.98**	**24.47**	**24.79**	**24.58**	**25.43**	**25.70**
Commercial										
Distillate Fuel	0.46	0.48	0.48	0.48	0.50	0.49	0.50	0.50	0.49	0.50
Residual Fuel	0.09	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.67	0.67	0.68	0.69	0.69	0.70	0.69	0.70	0.71
Natural Gas	3.33	3.77	3.80	3.80	4.14	4.29	4.44	4.30	4.56	4.70
Coal	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.09	4.97	5.02	5.05	6.02	6.20	6.36	6.55	6.83	7.05
Delivered Energy	**8.32**	**9.61**	**9.69**	**9.73**	**11.06**	**11.38**	**11.72**	**11.76**	**12.30**	**12.68**
Electricity Related Losses	9.12	10.40	10.46	10.47	11.95	12.14	12.26	12.75	13.03	13.19
Total	**17.44**	**20.02**	**20.15**	**20.20**	**23.01**	**23.52**	**23.97**	**24.50**	**25.33**	**25.87**
Industrial[4]										
Distillate Fuel	1.13	1.16	1.21	1.28	1.24	1.36	1.48	1.27	1.45	1.62
Liquefied Petroleum Gas	2.10	2.43	2.55	2.75	2.77	3.10	3.49	2.86	3.33	3.91
Petrochemical Feedstock	1.14	1.36	1.43	1.54	1.51	1.69	1.92	1.55	1.82	2.14
Residual Fuel	0.23	0.18	0.19	0.20	0.19	0.20	0.21	0.19	0.20	0.23
Motor Gasoline[2]	0.15	0.16	0.17	0.17	0.17	0.18	0.20	0.17	0.19	0.22
Other Petroleum[5]	4.03	4.16	4.31	4.51	4.25	4.49	4.79	4.27	4.60	5.07
Petroleum Subtotal	8.79	9.46	9.86	10.45	10.13	11.02	12.09	10.31	11.59	13.19
Natural Gas	7.74	8.82	9.13	9.62	9.56	10.38	11.58	9.91	11.22	12.73
Lease and Plant Fuel[6]	1.20	1.37	1.39	1.43	1.56	1.59	1.71	1.58	1.74	1.81
Natural Gas Subtotal	8.94	10.18	10.52	11.05	11.11	11.97	13.29	11.48	12.96	14.53
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.42	1.41	1.44	1.49	1.44	1.50	1.58	1.44	1.53	1.66
Net Coal Coke Imports	0.03	0.09	0.11	0.15	0.12	0.16	0.24	0.13	0.18	0.29
Coal Subtotal	2.16	2.16	2.22	2.31	2.11	2.21	2.37	2.07	2.21	2.44
Renewable Energy[7]	1.82	2.13	2.22	2.37	2.52	2.77	3.07	2.68	3.05	3.49
Electricity	3.39	3.79	3.95	4.23	4.25	4.63	5.20	4.44	5.00	5.79
Delivered Energy	**25.10**	**27.72**	**28.76**	**30.41**	**30.13**	**32.61**	**36.02**	**30.98**	**34.81**	**39.45**
Electricity Related Losses	7.57	7.92	8.23	8.76	8.45	9.08	10.00	8.64	9.54	10.84
Total	**32.67**	**35.64**	**36.99**	**39.17**	**38.57**	**41.69**	**46.02**	**39.63**	**44.35**	**50.29**

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

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuell[8]	5.44	6.79	7.08	7.50	8.00	8.70	9.58	8.55	9.58	10.85
Jet Fuel[9]	3.43	3.80	3.93	4.00	4.85	5.09	5.29	5.29	5.66	6.00
Motor Gasoline[2]	16.26	19.56	20.09	20.70	22.74	24.04	25.29	24.23	25.90	27.56
Residual Fuel	0.84	0.82	0.83	0.84	0.84	0.85	0.87	0.85	0.87	0.88
Liquefied Petroleum Gas	0.02	0.05	0.05	0.06	0.07	0.08	0.08	0.08	0.09	0.10
Other Petroleum[10]	0.24	0.25	0.26	0.27	0.28	0.30	0.33	0.28	0.32	0.36
Petroleum Subtotal	26.22	31.28	32.24	33.36	36.78	39.06	41.44	39.28	42.41	45.75
Pipeline Fuel Natural Gas	0.63	0.76	0.78	0.81	0.87	0.91	1.00	0.89	1.02	1.08
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.09	0.10	0.11	0.10	0.11	0.13
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.13	0.14	0.14	0.15
Delivered Energy	**26.94**	**32.18**	**33.17**	**34.33**	**37.86**	**40.20**	**42.69**	**40.41**	**43.70**	**47.12**
Electricity Related Losses	0.17	0.19	0.19	0.20	0.24	0.24	0.24	0.27	0.27	0.28
Total	**27.10**	**32.38**	**33.36**	**34.53**	**38.10**	**40.44**	**42.93**	**40.68**	**43.97**	**47.39**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.35	9.69	10.18	10.58	11.38	12.39	11.12	12.32	13.78
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.80	3.93	4.00	4.85	5.09	5.29	5.29	5.66	6.00
Liquefied Petroleum Gas	2.70	3.04	3.16	3.37	3.40	3.74	4.15	3.50	3.99	4.59
Motor Gasoline[2]	16.46	19.75	20.29	20.91	22.94	24.26	25.53	24.44	26.13	27.81
Petrochemical Feedstock	1.14	1.36	1.43	1.54	1.51	1.69	1.92	1.55	1.82	2.14
Residual Fuel	1.15	1.05	1.06	1.08	1.08	1.10	1.12	1.08	1.12	1.16
Other Petroleum[12]	4.24	4.39	4.54	4.76	4.50	4.76	5.09	4.53	4.89	5.41
Petroleum Subtotal	37.21	42.87	44.23	45.96	48.97	52.14	55.61	51.60	56.03	61.00
Natural Gas	16.02	18.25	18.65	19.18	19.71	20.89	22.44	20.35	22.29	24.11
Lease and Plant Fuel Plant[6]	1.20	1.37	1.39	1.43	1.56	1.59	1.71	1.58	1.74	1.81
Pipeline Natural Gas	0.63	0.76	0.78	0.81	0.87	0.91	1.00	0.89	1.02	1.08
Natural Gas Subtotal	17.86	20.37	20.82	21.41	22.14	23.39	25.16	22.82	25.05	27.00
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.53	1.52	1.55	1.60	1.56	1.62	1.70	1.56	1.65	1.78
Net Coal Coke Imports	0.03	0.09	0.11	0.15	0.12	0.16	0.24	0.13	0.18	0.29
Coal Subtotal	2.27	2.27	2.33	2.42	2.23	2.33	2.49	2.19	2.34	2.57
Renewable Energy[13]	2.31	2.64	2.74	2.89	3.03	3.29	3.60	3.18	3.57	4.02
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.75	13.99	14.33	15.84	16.55	17.38	16.84	17.92	19.04
Delivered Energy	**71.29**	**81.91**	**84.10**	**87.01**	**92.20**	**97.70**	**104.23**	**96.64**	**104.91**	**113.63**
Electricity Related Losses	26.01	28.76	29.16	29.70	31.46	32.42	33.48	32.76	34.17	35.63
Total	**97.30**	**110.67**	**113.26**	**116.70**	**123.66**	**130.12**	**137.71**	**129.39**	**139.07**	**149.25**
Electric Power[14]										
Distillate Fuel	0.17	0.11	0.11	0.14	0.13	0.10	0.09	0.17	0.17	0.23
Residual Fuel	1.08	0.30	0.31	0.39	0.38	0.36	0.34	0.39	0.36	0.39
Petroleum Subtotal	1.25	0.40	0.42	0.53	0.51	0.46	0.43	0.56	0.52	0.61
Natural Gas	5.40	6.59	6.93	7.43	8.92	9.57	10.31	9.76	10.76	11.43
Steam Coal	19.75	22.39	22.65	22.85	24.37	25.35	26.49	25.70	27.09	28.75
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[15]	3.02	4.50	4.50	4.53	4.90	5.00	5.02	5.08	5.21	5.37
Electricity Imports	0.21	0.27	0.29	0.33	0.17	0.17	0.18	0.07	0.07	0.07
Total	**37.66**	**42.51**	**43.15**	**44.03**	**47.30**	**48.97**	**50.86**	**49.60**	**52.09**	**54.66**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2025 Low Economic Growth	2025 Reference	2025 High Economic Growth
Total Energy Consumption										
Distillate Fuel	8.11	9.45	9.80	10.32	10.71	11.48	12.48	11.29	12.49	14.01
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.80	3.93	4.00	4.85	5.09	5.29	5.29	5.66	6.00
Liquefied Petroleum Gas	2.70	3.04	3.16	3.37	3.40	3.74	4.15	3.50	3.99	4.59
Motor Gasoline[2]	16.46	19.75	20.29	20.91	22.94	24.26	25.53	24.44	26.13	27.81
Petrochemical Feedstock	1.14	1.36	1.43	1.54	1.51	1.69	1.92	1.55	1.82	2.14
Residual Fuel	2.23	1.35	1.37	1.46	1.45	1.46	1.47	1.47	1.47	1.55
Other Petroleum[12]	4.24	4.39	4.54	4.76	4.50	4.76	5.09	4.53	4.89	5.41
Petroleum Subtotal	38.46	43.27	44.65	46.48	49.48	52.60	56.04	52.16	56.56	61.61
Natural Gas	21.42	24.84	25.58	26.61	28.64	30.46	32.75	30.11	33.05	35.54
Lease and Plant Fuel[6]	1.20	1.37	1.39	1.43	1.56	1.59	1.71	1.58	1.74	1.81
Pipeline Natural Gas	0.63	0.76	0.78	0.81	0.87	0.91	1.00	0.89	1.02	1.08
Natural Gas Subtotal	23.26	26.96	27.75	28.84	31.06	32.96	35.47	32.58	35.81	38.42
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	21.28	23.91	24.21	24.46	25.93	26.97	28.19	27.26	28.74	30.53
Net Coal Coke Imports	0.03	0.09	0.11	0.15	0.12	0.16	0.24	0.13	0.18	0.29
Coal Subtotal	22.02	24.66	24.98	25.27	26.60	27.68	28.98	27.89	29.42	31.32
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[16]	5.33	7.14	7.23	7.42	7.92	8.28	8.62	8.26	8.78	9.39
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.27	0.29	0.33	0.17	0.17	0.18	0.07	0.07	0.07
Total	**97.30**	**110.67**	**113.26**	**116.70**	**123.66**	**130.12**	**137.71**	**129.39**	**139.07**	**149.25**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	81.91	84.10	87.01	92.20	97.70	104.23	96.64	104.91	113.63
Total Energy Use	97.30	110.67	113.26	116.70	123.66	130.12	137.71	129.39	139.07	149.25
Population (millions)	278.18	294.61	300.24	305.87	312.59	325.32	338.06	321.92	338.24	354.57
Gross Domestic Product (billion 1996 dollars)	9215	11754	12258	12941	14914	16450	17946	16589	18917	21155
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1759.0	1800.5	1852.4	1979.0	2082.5	2204.4	2083.3	2236.9	2401.5

[1]Includes wood used for residential heating. See Table B18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B3. Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**15.80**	**13.50**	**13.84**	**14.46**	**14.01**	**14.53**	**14.90**	**14.37**	**14.82**	**15.93**
Primary Energy[1]	9.73	7.82	7.96	8.25	8.12	8.27	8.25	8.46	8.50	8.99
Petroleum Products[2]	10.85	9.71	9.90	10.08	10.23	10.70	10.97	10.60	11.01	11.33
Distillate Fuel	8.99	7.87	7.96	8.14	8.27	8.72	8.93	8.63	8.93	9.15
Liquefied Petroleum Gas	14.84	13.63	14.01	14.16	14.13	14.52	14.83	14.34	14.84	15.28
Natural Gas	9.41	7.35	7.48	7.80	7.65	7.74	7.67	8.01	7.99	8.53
Electricity	25.35	21.72	22.34	23.43	21.90	22.93	23.88	22.02	23.07	25.01
Commercial	**15.47**	**12.98**	**13.35**	**14.02**	**14.06**	**14.55**	**14.85**	**14.62**	**15.00**	**16.05**
Primary Energy[1]	7.81	6.21	6.34	6.63	6.58	6.74	6.73	6.92	7.01	7.51
Petroleum Products[2]	7.27	6.64	6.78	6.96	7.04	7.50	7.75	7.36	7.78	8.05
Distillate Fuel	6.40	5.56	5.66	5.84	6.02	6.49	6.74	6.37	6.75	7.00
Residual Fuel	3.46	3.92	4.01	4.10	4.02	4.23	4.41	4.12	4.38	4.62
Natural Gas	8.09	6.26	6.38	6.69	6.63	6.75	6.70	6.98	7.02	7.58
Electricity	23.22	19.15	19.73	20.72	20.21	20.96	21.54	20.60	21.26	22.74
Industrial[3]	**7.10**	**6.06**	**6.26**	**6.58**	**6.57**	**6.88**	**7.11**	**6.83**	**7.15**	**7.78**
Primary Energy	5.83	4.91	5.07	5.29	5.36	5.62	5.79	5.59	5.88	6.38
Petroleum Products[2]	7.72	6.74	6.94	7.10	7.27	7.63	7.98	7.50	7.94	8.35
Distillate Fuel	6.55	5.62	5.73	5.93	6.25	6.80	7.20	6.63	7.25	7.52
Liquefied Petroleum Gas	12.34	9.22	9.59	9.72	9.76	10.12	10.40	9.96	10.40	10.81
Residual Fuel	3.28	3.62	3.71	3.79	3.73	3.94	4.11	3.84	4.10	4.34
Natural Gas[4]	4.87	3.76	3.89	4.19	4.17	4.32	4.31	4.45	4.57	5.19
Metallurgical Coal	1.69	1.51	1.51	1.52	1.39	1.41	1.43	1.34	1.35	1.37
Steam Coal	1.46	1.37	1.38	1.40	1.29	1.31	1.34	1.26	1.29	1.34
Electricity	14.10	12.25	12.64	13.36	12.74	13.25	13.68	13.00	13.46	14.57
Transportation	**10.28**	**10.04**	**10.28**	**10.52**	**9.78**	**10.39**	**10.85**	**10.03**	**10.81**	**11.34**
Primary Energy	10.25	10.02	10.25	10.49	9.75	10.37	10.83	10.01	10.79	11.31
Petroleum Products[2]	10.25	10.02	10.26	10.50	9.76	10.37	10.83	10.01	10.80	11.32
Distillate Fuel[5]	10.05	10.00	10.22	10.42	9.49	10.16	10.83	9.76	10.52	11.08
Jet Fuel[6]	6.20	5.50	5.62	5.84	5.83	6.33	6.78	6.10	6.72	7.01
Motor Gasoline[7]	11.57	11.25	11.53	11.77	10.98	11.60	11.97	11.23	12.08	12.64
Residual Fuel	3.90	3.46	3.55	3.63	3.56	3.77	3.95	3.67	3.94	4.17
Liquefied Petroleum Gas[8]	16.93	14.75	15.21	15.44	15.03	15.50	15.86	15.04	15.63	16.23
Natural Gas[9]	7.65	6.94	7.08	7.44	7.54	7.75	7.79	7.94	8.07	8.71
Ethanol (E85)[10]	17.72	21.19	21.32	21.39	22.70	22.87	22.78	23.17	23.44	23.58
Electricity	21.84	18.54	18.99	19.80	17.82	18.37	18.74	17.32	17.82	18.91
Average End-Use Energy	**10.74**	**9.70**	**9.92**	**10.24**	**9.98**	**10.42**	**10.70**	**10.31**	**10.78**	**11.37**
Primary Energy	8.52	7.86	8.05	8.28	8.02	8.43	8.69	8.32	8.80	9.28
Electricity	21.30	18.16	18.65	19.48	18.77	19.45	19.94	19.05	19.66	20.94
Electric Power[11]										
Fossil Fuel Average	2.14	1.76	1.82	1.94	1.95	2.02	2.07	2.04	2.14	2.35
Petroleum Products	4.73	4.19	4.27	4.36	4.38	4.60	4.82	4.59	4.98	5.26
Distillate Fuel	6.20	5.03	5.13	5.33	5.55	6.06	6.45	5.78	6.18	6.36
Residual Fuel	4.50	3.89	3.97	4.00	3.97	4.21	4.40	4.08	4.40	4.61
Natural Gas	4.78	3.66	3.79	4.10	4.15	4.30	4.30	4.45	4.60	5.21
Steam Coal	1.25	1.16	1.17	1.18	1.10	1.12	1.15	1.08	1.10	1.15

Table B3. Energy Prices by Sector and Source (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[12]										
Petroleum Products[2]	9.54	9.26	9.48	9.67	9.24	9.78	10.20	9.50	10.18	10.64
Distillate Fuel	9.16	8.97	9.17	9.38	8.81	9.46	10.08	9.12	9.83	10.33
Jet Fuel	6.20	5.50	5.62	5.84	5.83	6.33	6.78	6.10	6.72	7.01
Liquefied Petroleum Gas	12.85	10.07	10.42	10.51	10.54	10.85	11.09	10.72	11.11	11.46
Motor Gasoline[7]	11.57	11.25	11.53	11.77	10.98	11.60	11.97	11.23	12.08	12.64
Residual Fuel	4.11	3.59	3.68	3.77	3.71	3.92	4.09	3.81	4.08	4.32
Natural Gas	6.40	4.93	5.03	5.30	5.25	5.35	5.29	5.54	5.60	6.14
Coal	1.26	1.18	1.18	1.20	1.11	1.13	1.16	1.09	1.12	1.16
Ethanol (E85)[10]	17.72	21.19	21.32	21.39	22.70	22.87	22.78	23.17	23.44	23.58
Electricity	21.30	18.16	18.65	19.48	18.77	19.45	19.94	19.05	19.66	20.94
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.69	161.80	166.98	175.29	178.65	190.35	199.63	188.13	202.99	222.48
Commercial	127.06	123.43	127.99	134.99	154.08	164.11	172.40	170.28	182.88	201.78
Industrial	135.20	125.63	135.28	151.51	147.56	169.19	195.07	158.03	188.45	236.21
Transportation	270.40	315.54	332.93	352.50	361.78	408.34	452.33	396.42	461.42	521.94
Total Non-Renewable Expenditures	699.35	726.40	763.18	814.30	842.07	932.00	1019.43	912.85	1035.75	1182.41
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.09	0.10	0.11	0.11	0.13	0.14
Total Expenditures	**699.36**	**726.44**	**763.22**	**814.35**	**842.16**	**932.10**	**1019.54**	**912.96**	**1035.88**	**1182.56**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Households (millions)										
Single-Family	77.50	84.82	85.79	86.90	90.65	93.77	96.20	92.83	97.27	100.43
Multifamily	22.19	23.80	24.12	24.77	26.06	27.05	28.40	27.32	28.78	30.65
Mobile Homes	6.57	7.25	7.33	7.43	7.74	8.01	8.09	7.85	8.23	8.31
Total	**106.27**	**115.87**	**117.24**	**119.10**	**124.46**	**128.84**	**132.70**	**128.00**	**134.28**	**139.39**
Average House Square Footage	**1685**	**1734**	**1737**	**1739**	**1771**	**1780**	**1783**	**1784**	**1797**	**1800**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	106.9	106.4	105.3	105.6	104.8	104.1	105.3	105.0	103.2
Total Energy Consumption	189.0	195.3	194.1	191.5	192.6	189.9	186.8	192.0	189.4	184.4
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	61.7	61.3	60.5	59.7	58.9	58.4	59.0	58.4	57.3
Total Energy Consumption	112.2	112.7	111.7	110.1	108.8	106.7	104.7	107.6	105.4	102.4
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.46	0.49	0.51	0.51	0.50	0.52	0.53
Space Cooling	0.52	0.59	0.60	0.60	0.63	0.65	0.67	0.65	0.68	0.70
Water Heating	0.45	0.47	0.47	0.47	0.43	0.44	0.45	0.42	0.44	0.45
Refrigeration	0.42	0.34	0.34	0.35	0.31	0.32	0.33	0.32	0.33	0.34
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.13	0.12	0.13	0.13
Clothes Dryers	0.22	0.25	0.25	0.25	0.26	0.27	0.27	0.27	0.28	0.28
Freezers	0.11	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.10
Lighting	0.74	0.93	0.93	0.93	1.02	1.03	1.03	1.04	1.07	1.05
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.20	0.20	0.25	0.25	0.26	0.26	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.11	0.11	0.11	0.12
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11
Other Uses[2]	0.83	1.25	1.26	1.27	1.61	1.66	1.70	1.79	1.87	1.91
Delivered Energy	**4.10**	**4.90**	**4.93**	**4.96**	**5.45**	**5.59**	**5.70**	**5.71**	**5.94**	**6.05**
Natural Gas										
Space Heating	3.13	3.69	3.73	3.75	3.98	4.12	4.25	4.08	4.32	4.42
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.54	1.56	1.57	1.54	1.59	1.64	1.56	1.64	1.69
Cooking	0.20	0.22	0.22	0.23	0.24	0.25	0.25	0.25	0.25	0.26
Clothes Dryers	0.06	0.08	0.08	0.08	0.09	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.08	0.08
Delivered Energy	**4.94**	**5.61**	**5.66**	**5.69**	**5.92**	**6.12**	**6.31**	**6.05**	**6.40**	**6.55**
Distillate										
Space Heating	0.74	0.76	0.76	0.76	0.71	0.71	0.70	0.68	0.69	0.69
Water Heating	0.16	0.14	0.14	0.14	0.12	0.12	0.12	0.11	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.91**	**0.84**	**0.83**	**0.83**	**0.80**	**0.81**	**0.81**
Liquefied Petroleum Gas										
Space Heating	0.26	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26
Water Heating	0.09	0.07	0.07	0.07	0.06	0.06	0.07	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.13	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.48**	**0.46**	**0.47**	**0.48**	**0.46**	**0.48**	**0.49**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.40	0.41	0.41	0.39	0.40	0.41
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07

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

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.66	5.70	5.73	5.90	6.06	6.21	5.97	6.26	6.38
Space Cooling	0.52	0.59	0.60	0.60	0.63	0.65	0.67	0.65	0.68	0.70
Water Heating	2.19	2.23	2.24	2.25	2.15	2.21	2.27	2.15	2.26	2.31
Refrigeration	0.42	0.34	0.34	0.35	0.31	0.32	0.33	0.32	0.33	0.34
Cooking	0.33	0.35	0.36	0.36	0.38	0.39	0.40	0.39	0.40	0.42
Clothes Dryers	0.28	0.33	0.33	0.33	0.35	0.36	0.37	0.36	0.38	0.38
Freezers	0.11	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.10
Lighting	0.74	0.93	0.93	0.93	1.02	1.03	1.03	1.04	1.07	1.05
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.20	0.20	0.25	0.25	0.26	0.26	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.11	0.11	0.11	0.12
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11
Other Uses[7]	1.01	1.45	1.46	1.47	1.82	1.87	1.92	2.00	2.09	2.14
Delivered Energy	**10.94**	**12.39**	**12.47**	**12.54**	**13.15**	**13.51**	**13.81**	**13.48**	**14.10**	**14.38**
Electricity Related Losses	**9.15**	**10.25**	**10.28**	**10.27**	**10.83**	**10.96**	**10.97**	**11.10**	**11.33**	**11.32**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.62	6.66	6.69	6.88	7.05	7.20	6.94	7.25	7.37
Space Cooling	1.68	1.84	1.85	1.86	1.88	1.93	1.95	1.91	1.98	2.01
Water Heating	3.20	3.21	3.22	3.23	3.01	3.08	3.14	2.98	3.09	3.15
Refrigeration	1.36	1.04	1.05	1.06	0.93	0.95	0.97	0.93	0.96	0.98
Cooking	0.55	0.58	0.59	0.59	0.61	0.63	0.64	0.62	0.64	0.66
Clothes Dryers	0.78	0.84	0.85	0.85	0.87	0.88	0.89	0.88	0.91	0.91
Freezers	0.36	0.27	0.27	0.28	0.25	0.26	0.27	0.25	0.27	0.27
Lighting	2.40	2.89	2.88	2.85	3.04	3.04	3.01	3.07	3.10	3.02
Clothes Washers	0.10	0.10	0.10	0.10	0.08	0.09	0.09	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09
Color Televisions	0.43	0.60	0.60	0.60	0.74	0.75	0.75	0.76	0.77	0.78
Personal Computers	0.19	0.25	0.25	0.26	0.30	0.31	0.31	0.32	0.33	0.34
Furnace Fans	0.23	0.27	0.27	0.27	0.29	0.30	0.30	0.30	0.31	0.31
Other Uses[7]	2.86	4.06	4.08	4.10	5.03	5.12	5.19	5.48	5.65	5.72
Total	**20.09**	**22.63**	**22.75**	**22.81**	**23.98**	**24.47**	**24.79**	**24.58**	**25.43**	**25.70**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	77.7	78.7	79.5	88.0	91.2	94.4	92.8	97.6	102.0
New Additions	3.6	2.9	3.1	3.4	3.1	3.4	3.7	3.1	3.5	3.9
Total	**70.2**	**80.6**	**81.8**	**82.9**	**91.1**	**94.6**	**98.1**	**95.9**	**101.1**	**105.9**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	119.2	118.5	117.4	121.5	120.3	119.4	122.6	121.6	119.7
Electricity Related Losses	129.9	129.0	127.9	126.2	131.2	128.3	124.9	132.9	128.9	124.6
Total Energy Consumption	248.3	248.2	246.4	243.6	252.7	248.6	244.3	255.5	250.5	244.3
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.16	0.16	0.15	0.15	0.16	0.15	0.15	0.15
Space Cooling[1]	0.43	0.44	0.44	0.44	0.46	0.47	0.48	0.46	0.48	0.49
Water Heating[1]	0.15	0.16	0.16	0.16	0.15	0.16	0.16	0.15	0.15	0.16
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.02	1.20	1.21	1.21	1.29	1.31	1.32	1.31	1.34	1.34
Refrigeration	0.21	0.24	0.24	0.24	0.25	0.26	0.27	0.26	0.27	0.28
Office Equipment (PC)	0.16	0.24	0.24	0.25	0.31	0.32	0.33	0.34	0.36	0.38
Office Equipment (non-PC)	0.31	0.46	0.47	0.47	0.72	0.75	0.78	0.87	0.93	0.97
Other Uses[2]	1.46	1.88	1.90	1.92	2.48	2.57	2.65	2.79	2.93	3.05
Delivered Energy	**4.09**	**4.97**	**5.02**	**5.05**	**6.02**	**6.20**	**6.36**	**6.55**	**6.83**	**7.05**
Natural Gas										
Space Heating[1]	1.32	1.56	1.58	1.58	1.64	1.70	1.75	1.66	1.76	1.80
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Water Heating[1]	0.57	0.69	0.70	0.70	0.79	0.82	0.84	0.83	0.87	0.89
Cooking	0.25	0.30	0.30	0.30	0.34	0.35	0.36	0.36	0.37	0.38
Other Uses[3]	1.17	1.19	1.20	1.20	1.34	1.39	1.45	1.42	1.52	1.60
Delivered Energy	**3.33**	**3.77**	**3.80**	**3.80**	**4.14**	**4.29**	**4.44**	**4.30**	**4.56**	**4.70**
Distillate										
Space Heating[1]	0.17	0.20	0.20	0.21	0.22	0.22	0.22	0.22	0.22	0.23
Water Heating[1]	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.08
Other Uses[4]	0.22	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Delivered Energy	**0.46**	**0.48**	**0.48**	**0.48**	**0.50**	**0.49**	**0.50**	**0.50**	**0.49**	**0.50**
Other Fuels[5]	**0.34**	**0.28**	**0.29**	**0.29**	**0.30**	**0.30**	**0.31**	**0.30**	**0.31**	**0.32**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.92	1.94	1.94	2.01	2.07	2.13	2.03	2.13	2.19
Space Cooling[1]	0.44	0.46	0.46	0.46	0.49	0.50	0.51	0.50	0.52	0.53
Water Heating[1]	0.79	0.92	0.93	0.93	1.02	1.05	1.08	1.05	1.10	1.12
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20
Cooking	0.29	0.34	0.34	0.34	0.37	0.38	0.39	0.38	0.40	0.41
Lighting	1.02	1.20	1.21	1.21	1.29	1.31	1.32	1.31	1.34	1.34
Refrigeration	0.21	0.24	0.24	0.24	0.25	0.26	0.27	0.26	0.27	0.28
Office Equipment (PC)	0.16	0.24	0.24	0.25	0.31	0.32	0.33	0.34	0.36	0.38
Office Equipment (non-PC)	0.31	0.46	0.47	0.47	0.72	0.75	0.78	0.87	0.93	0.97
Other Uses[6]	3.30	3.66	3.69	3.71	4.42	4.57	4.72	4.82	5.07	5.27
Delivered Energy	**8.32**	**9.61**	**9.69**	**9.73**	**11.06**	**11.38**	**11.72**	**11.76**	**12.30**	**12.68**

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electricity Related Losses	**9.12**	**10.40**	**10.46**	**10.47**	**11.95**	**12.14**	**12.26**	**12.75**	**13.03**	**13.19**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.25	2.26	2.26	2.32	2.37	2.43	2.32	2.42	2.47
Space Cooling[1]	1.39	1.37	1.37	1.37	1.39	1.41	1.43	1.39	1.43	1.46
Water Heating[1]	1.12	1.25	1.26	1.25	1.33	1.35	1.38	1.34	1.39	1.42
Ventilation	0.55	0.56	0.56	0.56	0.55	0.56	0.57	0.55	0.57	0.58
Cooking	0.37	0.41	0.41	0.41	0.43	0.44	0.45	0.44	0.45	0.46
Lighting	3.31	3.71	3.73	3.71	3.84	3.87	3.85	3.87	3.89	3.83
Refrigeration	0.69	0.73	0.73	0.74	0.76	0.77	0.78	0.77	0.78	0.79
Office Equipment (PC)	0.52	0.74	0.74	0.75	0.92	0.95	0.97	1.01	1.05	1.09
Office Equipment (non-PC)	0.99	1.42	1.44	1.46	2.14	2.21	2.27	2.58	2.69	2.79
Other Uses[6]	6.56	7.58	7.65	7.69	9.34	9.60	9.83	10.24	10.65	10.98
Total	**17.44**	**20.02**	**20.15**	**20.20**	**23.01**	**23.52**	**23.97**	**24.50**	**25.33**	**25.87**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5238	5453	5867	6674	7220	8196	7411	8257	9714
Nonmanufacturing	1346	1427	1505	1604	1562	1743	1922	1599	1869	2119
Total	**5425**	**6666**	**6959**	**7470**	**8236**	**8963**	**10118**	**9011**	**10126**	**11833**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.10	12.25	12.64	13.36	12.74	13.25	13.68	13.00	13.46	14.57
Natural Gas	4.87	3.76	3.89	4.19	4.17	4.32	4.31	4.45	4.57	5.19
Steam Coal	1.46	1.37	1.38	1.40	1.29	1.31	1.34	1.26	1.29	1.34
Residual Oil	3.28	3.62	3.71	3.79	3.73	3.94	4.11	3.84	4.10	4.34
Distillate Oil	6.55	5.62	5.73	5.93	6.25	6.80	7.20	6.63	7.25	7.52
Liquefied Petroleum Gas	12.34	9.22	9.59	9.72	9.76	10.12	10.40	9.96	10.40	10.81
Motor Gasoline	11.57	11.20	11.49	11.72	10.93	11.56	11.94	11.18	12.07	12.63
Metallurgical Coal	1.69	1.51	1.51	1.52	1.39	1.41	1.43	1.34	1.35	1.37
Energy Consumption[1]										
Purchased Electricity	3.39	3.79	3.95	4.23	4.25	4.63	5.20	4.44	5.00	5.79
Natural Gas	7.74	8.82	9.13	9.62	9.56	10.38	11.58	9.91	11.22	12.73
Lease and Plant Fuel[2]	1.20	1.37	1.39	1.43	1.56	1.59	1.71	1.58	1.74	1.81
Natural Gas Subtotal	8.94	10.18	10.52	11.05	11.11	11.97	13.29	11.48	12.96	14.53
Steam Coal	1.42	1.41	1.44	1.49	1.44	1.50	1.58	1.44	1.53	1.66
Metallurgical Coal and Coke[3]	0.74	0.75	0.77	0.81	0.67	0.71	0.79	0.63	0.68	0.79
Residual Fuel	0.23	0.18	0.19	0.20	0.19	0.20	0.21	0.19	0.20	0.23
Distillate	1.13	1.16	1.21	1.28	1.24	1.36	1.48	1.27	1.45	1.62
Liquefied Petroleum Gas	2.10	2.43	2.55	2.75	2.77	3.10	3.49	2.86	3.33	3.91
Petrochemical Feedstocks	1.14	1.36	1.43	1.54	1.51	1.69	1.92	1.55	1.82	2.14
Other Petroleum[4]	4.18	4.32	4.47	4.68	4.41	4.67	4.99	4.44	4.79	5.29
Renewables[5]	1.82	2.13	2.22	2.37	2.52	2.77	3.07	2.68	3.05	3.49
Delivered Energy	**25.10**	**27.72**	**28.76**	**30.41**	**30.13**	**32.61**	**36.02**	**30.98**	**34.81**	**39.45**
Electricity Related Losses	7.57	7.92	8.23	8.76	8.45	9.08	10.00	8.64	9.54	10.84
Total	**32.67**	**35.64**	**36.99**	**39.17**	**38.57**	**41.69**	**46.02**	**39.63**	**44.35**	**50.29**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)										
Purchased Electricity	0.63	0.57	0.57	0.57	0.52	0.52	0.51	0.49	0.49	0.49
Natural Gas	1.43	1.32	1.31	1.29	1.16	1.16	1.14	1.10	1.11	1.08
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.19	0.19	0.18	0.17	0.17	0.17	0.15
Natural Gas Subtotal	1.65	1.53	1.51	1.48	1.35	1.34	1.31	1.27	1.28	1.23
Steam Coal	0.26	0.21	0.21	0.20	0.17	0.17	0.16	0.16	0.15	0.14
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.11	0.08	0.08	0.08	0.07	0.07	0.07
Residual Fuel	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.17	0.17	0.15	0.15	0.15	0.14	0.14	0.14
Liquefied Petroleum Gas	0.39	0.36	0.37	0.37	0.34	0.35	0.34	0.32	0.33	0.33
Petrochemical Feedstocks	0.21	0.20	0.21	0.21	0.18	0.19	0.19	0.17	0.18	0.18
Other Petroleum[4]	0.77	0.65	0.64	0.63	0.54	0.52	0.49	0.49	0.47	0.45
Renewables[5]	0.33	0.32	0.32	0.32	0.31	0.31	0.30	0.30	0.30	0.30
Delivered Energy	**4.63**	**4.16**	**4.13**	**4.07**	**3.66**	**3.64**	**3.56**	**3.44**	**3.44**	**3.33**
Electricity Related Losses	1.40	1.19	1.18	1.17	1.03	1.01	0.99	0.96	0.94	0.92
Total	**6.02**	**5.35**	**5.32**	**5.24**	**4.68**	**4.65**	**4.55**	**4.40**	**4.38**	**4.25**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Represents natural gas used in the field gathering and processing plant machinery.
[3]Includes net coal coke imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	2929	3004	3092	3544	3753	3954	3853	4132	4409
Commercial Light Trucks (VMT)[1]	66	81	84	88	99	107	118	108	120	136
Freight Trucks >10,000 pounds (VMT)	206	252	263	281	307	338	377	334	380	438
Air (seat miles available)	1109	1306	1355	1378	1843	1942	2028	2093	2256	2405
Rail (ton miles traveled)	1448	1618	1669	1743	1854	1991	2159	1954	2155	2399
Domestic Shipping (ton miles traveled)	788	846	874	914	938	1009	1093	970	1087	1197
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	24.2	24.3	24.3	25.5	25.6	25.8	25.9	26.1	26.2
New Car (miles per gallon)[2]	28.1	28.5	28.5	28.5	29.7	29.8	29.9	29.9	30.1	30.1
New Light Truck (miles per gallon)[2]	20.7	21.0	21.0	21.1	22.4	22.5	22.6	22.8	23.0	23.1
Light-Duty Fleet (miles per gallon)[3]	19.8	19.3	19.3	19.3	19.8	19.8	19.9	20.1	20.2	20.3
New Commercial Light Truck (MPG)[1]	13.8	13.9	13.9	13.9	14.8	14.8	15.0	15.1	15.2	15.3
Stock Commercial Light Truck (MPG)[1]	13.7	13.8	13.8	13.8	14.3	14.4	14.4	14.7	14.8	14.9
Aircraft Efficiency (seat miles per gallon)	51.2	54.2	54.3	54.3	58.3	58.6	59.0	60.2	60.7	61.1
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.3	6.3	6.3	6.4	6.5	6.5
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	18.85	19.36	19.95	22.19	23.47	24.66	23.73	25.36	26.95
Commercial Light Trucks[1]	0.60	0.73	0.76	0.80	0.87	0.93	1.02	0.92	1.02	1.14
Freight Trucks[4]	4.68	5.64	5.89	6.26	6.49	7.09	7.87	6.90	7.79	8.91
Air[5]	3.47	3.85	3.97	4.04	4.90	5.14	5.35	5.35	5.72	6.07
Rail[6]	0.63	0.66	0.68	0.70	0.70	0.75	0.80	0.72	0.78	0.85
Marine[7]	1.45	1.47	1.49	1.51	1.54	1.59	1.63	1.57	1.64	1.70
Pipeline Fuel	0.63	0.76	0.78	0.81	0.87	0.91	1.00	0.89	1.02	1.08
Lubricants	0.19	0.21	0.22	0.23	0.24	0.26	0.28	0.24	0.28	0.32
Total	**26.94**	**32.18**	**33.17**	**34.33**	**37.86**	**40.20**	**42.69**	**40.41**	**43.70**	**47.12**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.96	10.23	10.54	11.70	12.38	13.01	12.51	13.37	14.21
Commercial Light Trucks[1]	0.32	0.38	0.40	0.42	0.46	0.49	0.54	0.49	0.54	0.60
Freight Trucks	2.05	2.48	2.60	2.77	2.88	3.15	3.51	3.07	3.48	4.00
Railroad	0.24	0.25	0.25	0.27	0.26	0.27	0.30	0.26	0.28	0.31
Domestic Shipping	0.16	0.17	0.17	0.18	0.18	0.20	0.21	0.19	0.21	0.23
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.60	1.65	1.68	2.09	2.18	2.27	2.29	2.45	2.59
Military Use	0.30	0.33	0.34	0.35	0.35	0.38	0.40	0.37	0.40	0.43
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14
Rail Transportation[6]	0.05	0.06	0.06	0.07	0.08	0.08	0.08	0.08	0.08	0.09
Recreational Boats	0.16	0.17	0.18	0.18	0.19	0.19	0.20	0.20	0.20	0.21
Lubricants	0.09	0.10	0.10	0.11	0.11	0.12	0.13	0.11	0.13	0.15
Pipeline Fuel	0.32	0.38	0.39	0.41	0.44	0.46	0.51	0.45	0.52	0.55
Total	**13.64**	**16.34**	**16.84**	**17.42**	**19.20**	**20.38**	**21.63**	**20.47**	**22.13**	**23.84**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2164	2189	2205	2385	2497	2631	2543	2703	2902
Petroleum	113	37	39	50	48	43	39	54	52	62
Natural Gas[3]	411	665	708	780	1043	1143	1264	1182	1335	1450
Nuclear Power	769	800	800	800	807	807	807	807	807	807
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	393	395	410	416	422	419	429	444
Distributed Generation (Natural Gas)	0	1	1	1	5	5	6	7	7	9
Non-Utility Generation for Own Use	-21	-24	-24	-24	-24	-24	-24	-24	-24	-24
Total	**3370**	**4034**	**4105**	**4207**	**4674**	**4887**	**5145**	**4988**	**5309**	**5650**
Combined Heat and Power[5]										
Coal	33	33	33	33	33	33	33	33	33	33
Petroleum	7	4	4	4	4	3	3	3	3	4
Natural Gas	124	164	167	166	151	150	145	148	146	139
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-18	-18	-18	-18
Total	**162**	**187**	**190**	**189**	**174**	**173**	**167**	**170**	**169**	**162**
Net Available to the Grid	**3532**	**4221**	**4295**	**4396**	**4848**	**5059**	**5312**	**5158**	**5478**	**5812**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	83	113	115	120	139	151	169	158	183	213
Other Gaseous Fuels[7]	6	7	7	7	7	7	8	7	8	8
Renewable Sources[4]	31	37	39	42	45	50	56	48	56	65
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**159**	**198**	**202**	**210**	**232**	**249**	**273**	**254**	**287**	**326**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	6
Generation for Own Use	-137	-157	-160	-164	-178	-188	-201	-193	-212	-235
Total Sales to the Grid	**27**	**46**	**48**	**51**	**59**	**67**	**77**	**68**	**82**	**98**
Net Imports	**20**	**27**	**28**	**32**	**17**	**17**	**17**	**7**	**7**	**7**
Electricity Sales by Sector										
Residential	1201	1436	1445	1453	1598	1640	1670	1673	1742	1773
Commercial	1197	1458	1471	1481	1763	1816	1865	1921	2003	2066
Industrial	994	1110	1157	1240	1246	1358	1523	1302	1466	1698
Transportation	22	27	27	28	35	36	37	40	42	43
Total	**3414**	**4031**	**4101**	**4201**	**4643**	**4850**	**5095**	**4937**	**5252**	**5580**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.6	7.4	7.6	8.0	7.5	7.8	8.1	7.5	7.9	8.5
Commercial	7.9	6.5	6.7	7.1	6.9	7.2	7.3	7.0	7.3	7.8
Industrial	4.8	4.2	4.3	4.6	4.3	4.5	4.7	4.4	4.6	5.0
Transportation	7.5	6.3	6.5	6.8	6.1	6.3	6.4	5.9	6.1	6.5
All Sectors Average	**7.3**	**6.2**	**6.4**	**6.6**	**6.4**	**6.6**	**6.8**	**6.5**	**6.7**	**7.1**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	3.7	3.8	4.1	3.9	4.1	4.2	4.0	4.2	4.6
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.7
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	2.0	1.9	1.9	1.9

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Emissions										
Sulfur Dioxide (million tons)	10.63	9.50	9.57	9.67	8.95	8.95	8.95	8.95	8.95	8.95
Nitrogen Oxide (million tons)	4.75	3.88	3.92	3.97	4.01	4.06	4.12	4.05	4.12	4.19
Mercury (tons)	51.05	50.90	51.30	51.88	51.44	52.01	52.02	52.22	52.63	52.99

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run AEO2003.D110502C. **Projections**: EIA, AEO2003 National Energy Modeling System run LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.3	304.9	306.4	305.1	329.1	343.2	360.4	350.0	370.6	395.5
Other Fossil Steam[4]	133.8	81.5	83.4	85.5	72.7	77.2	76.9	72.0	76.2	75.9
Combined Cycle	43.6	140.3	145.0	154.4	209.6	228.3	251.3	244.1	270.4	297.3
Combustion Turbine/Diesel	98.1	126.2	128.2	132.6	149.8	152.7	158.7	163.8	173.9	183.9
Nuclear Power[5]	98.2	99.3	99.3	99.3	99.6	99.6	99.6	99.6	99.6	99.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.6	97.2	97.3	97.6	100.9	102.0	103.4	102.7	104.3	108.6
Distributed Generation[7]	0.0	1.6	1.7	2.0	9.6	10.1	12.0	13.9	15.8	19.1
Total	**789.4**	**871.5**	**881.8**	**897.0**	**991.7**	**1033.7**	**1082.7**	**1066.6**	**1131.2**	**1200.5**
Combined Heat and Power[8]										
Coal Steam	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Other Fossil Steam[4]	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Combined Cycle	22.6	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Combustion Turbine/Diesel	4.5	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**
Total Electric Power Industry	**823.1**	**914.3**	**924.7**	**939.9**	**1034.5**	**1076.5**	**1125.5**	**1109.4**	**1174.1**	**1243.3**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
Combustion Turbine/Diesel	0.0	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.4	6.4	6.4	6.5	6.5	6.5
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**96.2**	**96.2**	**96.2**	**97.9**	**97.9**	**97.9**	**98.0**	**98.0**	**98.0**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	5.7	6.8	5.5	31.7	45.5	62.6	53.7	74.0	98.8
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	41.3	46.1	55.4	110.6	129.3	152.3	145.1	171.4	198.3
Combustion Turbine/Diesel	0.0	11.7	12.3	14.3	38.7	40.0	43.6	53.1	61.9	71.2
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.3	1.4	1.7	3.4	4.5	5.9	5.1	6.7	11.1
Distributed Generation[7]	0.0	1.6	1.7	2.0	9.6	10.1	12.0	13.9	15.8	19.1
Total	**0.0**	**61.6**	**68.3**	**79.0**	**194.0**	**229.4**	**276.4**	**270.9**	**329.8**	**398.5**
Cumulative Total Additions	**0.0**	**157.8**	**164.5**	**175.2**	**291.8**	**327.3**	**374.2**	**368.9**	**427.8**	**496.5**
Cumulative Retirements[10]										
Coal Steam	0.0	6.1	5.8	5.8	7.9	7.6	7.6	9.0	8.7	8.7
Other Fossil Steam[4]	0.0	50.7	48.9	46.8	59.6	55.1	55.4	60.3	56.1	56.3
Combined Cycle	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Combustion Turbine/Diesel	0.0	10.8	9.4	7.0	14.3	12.6	10.2	14.7	13.4	12.6
Nuclear Power	0.0	1.8	1.8	1.8	2.8	2.8	2.8	2.8	2.8	2.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**70.1**	**66.5**	**62.0**	**85.2**	**78.7**	**76.6**	**87.4**	**81.7**	**81.1**

Table B9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	18.0	18.3	19.0	21.6	23.3	25.7	24.2	27.7	31.8
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3
Renewable Sources[6]	4.7	5.8	6.2	6.7	7.1	8.0	9.0	7.6	9.0	10.5
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.6**	**32.5**	**33.1**	**34.3**	**37.4**	**40.0**	**43.4**	**40.6**	**45.4**	**51.0**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.8	2.0	2.0	2.2
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.8	5.5	6.6	9.7	12.3	15.8	12.9	17.8	23.4
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.7	0.8	0.9	1.0

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[7]Primarily peak-load capacity fueled by natural gas
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table B17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Electricity Trade	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	142.7	102.9	102.9	102.9	0.0	0.0	0.0	0.0	0.0	0.0
Gross Domestic Economy Trade	176.8	198.9	199.8	198.6	181.1	180.0	161.2	185.6	177.9	176.4
Gross Domestic Trade	**319.5**	**301.8**	**302.8**	**301.5**	**181.1**	**180.0**	**161.2**	**185.6**	**177.9**	**176.4**
Gross Domestic Firm Power Sales (million 2001 dollars)	7047.1	5080.9	5080.9	5080.9	0.0	0.0	0.0	0.0	0.0	0.0
Gross Domestic Economy Sales (million 2001 dollars)	8240.1	5950.3	6203.2	6648.1	5923.6	6063.7	5505.1	6318.2	6238.5	6914.2
Gross Domestic Sales (million 2001 dollars)	**15287.3**	**11031.2**	**11284.1**	**11729.0**	**5923.6**	**6063.7**	**5505.1**	**6318.2**	**6238.5**	**6914.2**
International Electricity Trade										
Firm Power Imports From Canada and Mexico	12.1	5.8	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0
Economy Imports From Canada and Mexico	26.3	37.3	38.7	42.6	24.2	24.4	25.1	14.8	14.4	14.9
Gross Imports From Canada and Mexico	**38.5**	**43.1**	**44.5**	**48.4**	**24.2**	**24.4**	**25.1**	**14.8**	**14.4**	**14.9**
Firm Power Exports To Canada and Mexico	6.5	8.7	8.7	8.7	0.0	0.0	0.0	0.0	0.0	0.0
Economy Exports To Canada and Mexico	11.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**18.2**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Crude Oil										
Domestic Crude Production[1]	5.80	5.62	5.63	5.64	5.39	5.46	5.51	5.13	5.33	5.44
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 States	4.84	4.98	4.98	5.00	4.16	4.23	4.28	3.96	4.16	4.27
Net Imports	9.31	11.24	11.51	11.81	12.43	12.66	12.91	13.07	13.06	13.54
Gross Imports	9.33	11.30	11.58	11.87	12.48	12.72	12.97	13.12	13.11	13.60
Exports	0.02	0.06	0.06	0.06	0.05	0.06	0.06	0.04	0.05	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**16.86**	**17.14**	**17.45**	**17.82**	**18.12**	**18.42**	**18.20**	**18.39**	**18.99**
Natural Gas Plant Liquids	**1.87**	**2.18**	**2.23**	**2.30**	**2.47**	**2.53**	**2.62**	**2.49**	**2.63**	**2.75**
Other Inputs[3]	**0.30**	**0.44**	**0.44**	**0.45**	**0.43**	**0.44**	**0.45**	**0.45**	**0.45**	**0.46**
Refinery Processing Gain[4]	**0.90**	**0.90**	**0.91**	**0.92**	**0.95**	**0.96**	**0.97**	**0.95**	**0.96**	**0.98**
Net Product Imports[5]	**1.59**	**1.90**	**2.25**	**2.80**	**3.80**	**5.06**	**6.45**	**4.77**	**6.73**	**8.62**
Gross Refined Product Imports[6]	2.08	2.30	2.59	3.02	3.77	5.02	6.35	4.78	6.76	8.59
Unfinished Oil Imports	0.38	0.58	0.66	0.79	1.07	1.09	1.17	1.06	1.07	1.16
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	0.99	1.00	1.01	1.04	1.06	1.06	1.07	1.10	1.13
Total Primary Supply[7]	**19.80**	**22.26**	**22.97**	**23.92**	**25.48**	**27.11**	**28.92**	**26.86**	**29.16**	**31.79**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.40	10.69	11.01	12.08	12.78	13.45	12.87	13.77	14.65
Jet Fuel[9]	1.66	1.84	1.90	1.93	2.34	2.46	2.56	2.55	2.74	2.90
Distillate Fuel[10]	3.81	4.45	4.61	4.85	5.04	5.40	5.87	5.31	5.87	6.59
Residual Fuel	0.97	0.59	0.60	0.64	0.63	0.64	0.64	0.64	0.64	0.67
Other[11]	4.58	5.00	5.20	5.50	5.39	5.85	6.42	5.49	6.15	7.00
Total	**19.69**	**22.27**	**22.99**	**23.94**	**25.49**	**27.13**	**28.93**	**26.87**	**29.17**	**31.82**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.17	1.17	1.17	1.13	1.13	1.15	1.11	1.12	1.14
Industrial[12]	4.67	5.08	5.30	5.63	5.49	6.00	6.61	5.60	6.33	7.25
Transportation	13.27	15.85	16.33	16.90	18.64	19.79	20.98	19.91	21.48	23.15
Electric Generators[13]	0.55	0.18	0.19	0.23	0.23	0.20	0.19	0.25	0.23	0.28
Total	**19.69**	**22.27**	**22.99**	**23.94**	**25.49**	**27.13**	**28.93**	**26.87**	**29.17**	**31.82**
Discrepancy[14]	**0.10**	**-0.01**	**-0.01**	**-0.02**	**-0.01**	**-0.02**	**-0.02**	**-0.01**	**-0.02**	**-0.02**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.41**	**23.99**	**24.48**	**24.14**	**25.48**	**26.64**	**24.85**	**26.57**	**28.09**
Import Share of Product Supplied	**0.55**	**0.59**	**0.60**	**0.61**	**0.64**	**0.65**	**0.67**	**0.66**	**0.68**	**0.70**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**113.91**	**122.96**	**133.43**	**149.07**	**174.57**	**200.08**	**171.64**	**206.94**	**246.50**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.5**	**18.7**	**19.0**	**19.2**	**19.5**	**19.8**	**19.6**	**19.8**	**20.4**
Capacity Utilization Rate (percent)	**93.0**	**92.7**	**93.2**	**93.7**	**94.6**	**94.6**	**94.7**	**94.6**	**94.6**	**94.7**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B12. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (2001 dollars per barrel)	**22.01**	**23.41**	**23.99**	**24.48**	**24.14**	**25.48**	**26.64**	**24.85**	**26.57**	**28.09**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	109.1	110.4	112.9	114.7	121.0	123.9	119.7	123.8	126.9
Liquefied Petroleum Gas	127.3	116.9	120.2	121.4	121.3	124.5	127.2	123.0	127.3	131.1
Commercial										
Distillate Fuel	88.7	77.1	78.4	81.0	83.5	90.0	93.5	88.4	93.7	97.1
Residual Fuel	51.8	58.7	60.0	61.3	60.2	63.3	65.9	61.7	65.6	69.2
Residual Fuel (2001 dollars per barrel)	21.75	24.64	25.21	25.75	25.28	26.57	27.69	25.89	27.55	29.07
Industrial[1]										
Distillate Fuel	90.8	78.0	79.4	82.3	86.7	94.3	99.9	92.0	100.6	104.3
Liquefied Petroleum Gas	105.9	79.1	82.2	83.4	83.7	86.8	89.2	85.4	89.3	92.8
Residual Fuel	49.1	54.2	55.5	56.8	55.9	58.9	61.5	57.5	61.4	64.9
Residual Fuel (2001 dollars per barrel)	20.61	22.74	23.32	23.85	23.47	24.74	25.84	24.16	25.77	27.26
Transportation										
Diesel Fuel (distillate)[2]	139.4	138.7	141.7	144.6	131.6	140.9	150.2	135.3	145.9	153.6
Jet Fuel[3]	83.7	74.3	75.9	78.8	78.7	85.4	91.6	82.3	90.7	94.6
Motor Gasoline[4]	143.3	139.3	142.8	145.8	135.9	143.7	148.3	139.0	149.6	156.5
Liquid Petroleum Gas	145.2	126.5	130.5	132.4	128.9	133.0	136.1	129.0	134.1	139.2
Residual Fuel	58.4	51.9	53.2	54.4	53.4	56.4	59.1	54.9	58.9	62.5
Residual Fuel (2001 dollars per barrel)	24.52	21.78	22.35	22.83	22.41	23.71	24.83	23.07	24.75	26.23
Ethanol (E85)	158.4	189.5	190.7	191.2	203.0	204.4	203.7	207.1	209.6	210.9
Electric Generators[5]										
Distillate Fuel	86.0	69.7	71.1	74.0	77.0	84.0	89.4	80.2	85.7	88.2
Residual Fuel	67.4	58.2	59.4	59.9	59.5	62.9	65.8	61.1	65.9	69.0
Residual Fuel (2001 dollars per barrel)	28.30	24.43	24.94	25.16	24.97	26.44	27.66	25.66	27.67	28.98
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	124.5	127.2	130.1	122.1	131.3	139.8	126.4	136.3	143.2
Jet Fuel[3]	83.7	74.3	75.9	78.8	78.7	85.4	91.6	82.3	90.7	94.6
Liquefied Petroleum Gas	110.3	86.4	89.4	90.2	90.4	93.1	95.1	92.0	95.3	98.3
Motor Gasoline[4]	143.3	139.3	142.8	145.8	135.9	143.7	148.3	139.0	149.6	156.5
Residual Fuel	61.5	53.8	55.1	56.4	55.5	58.6	61.3	57.1	61.1	64.7
Residual Fuel (2001 dollars per barrel)	25.85	22.59	23.16	23.67	23.30	24.62	25.73	23.98	25.68	27.16
Average	**123.6**	**119.5**	**122.4**	**124.8**	**118.3**	**125.4**	**130.4**	**121.6**	**130.4**	**136.0**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Dry Gas Production[1]	19.45	21.35	21.88	22.59	24.48	25.07	26.60	24.58	26.75	27.97
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.65**	**4.55**	**4.78**	**5.14**	**5.40**	**6.66**	**7.58**	**6.78**	**7.76**	**9.09**
Canada	3.61	3.83	4.05	4.38	4.45	5.08	5.03	5.23	5.31	5.46
Mexico	-0.13	-0.27	-0.26	-0.23	-0.16	0.07	0.47	0.09	0.30	0.78
Liquefied Natural Gas	0.17	0.99	0.99	0.99	1.11	1.51	2.08	1.45	2.14	2.84
Total Supply	**23.17**	**25.99**	**26.76**	**27.83**	**29.98**	**31.82**	**34.27**	**31.45**	**34.60**	**37.15**
Consumption by Sector										
Residential	4.81	5.45	5.50	5.54	5.76	5.96	6.14	5.88	6.22	6.37
Commercial	3.24	3.66	3.69	3.70	4.03	4.17	4.32	4.18	4.43	4.58
Industrial[3]	7.53	8.58	8.88	9.36	9.30	10.10	11.27	9.64	10.91	12.38
Electric Generators[4]	5.30	6.47	6.80	7.29	8.76	9.39	10.12	9.58	10.56	11.21
Transportation[5]	0.01	0.06	0.06	0.06	0.09	0.10	0.11	0.10	0.11	0.12
Pipeline Fuel	0.61	0.74	0.76	0.79	0.85	0.88	0.97	0.87	1.00	1.05
Lease and Plant Fuel[6]	1.17	1.33	1.35	1.39	1.52	1.55	1.67	1.53	1.69	1.76
Total	**22.67**	**26.29**	**27.06**	**28.13**	**30.30**	**32.14**	**34.59**	**31.78**	**34.93**	**37.48**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.50**	**-0.30**	**-0.30**	**-0.30**	**-0.32**	**-0.32**	**-0.32**	**-0.33**	**-0.32**	**-0.33**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B14. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.17	3.29	3.59	3.58	3.69	3.63	3.83	3.90	4.50
Average Import Price	4.43	3.23	3.33	3.54	3.68	3.81	3.83	4.04	4.19	4.75
Average[2]	**4.17**	**3.19**	**3.30**	**3.58**	**3.60**	**3.72**	**3.68**	**3.87**	**3.97**	**4.56**
Delivered Prices										
Residential	9.68	7.55	7.68	8.01	7.87	7.96	7.88	8.23	8.22	8.76
Commercial	8.32	6.43	6.56	6.88	6.82	6.94	6.88	7.18	7.22	7.79
Industrial[3]	5.00	3.86	4.00	4.31	4.29	4.44	4.43	4.57	4.70	5.34
Electric Generators[4]	4.87	3.73	3.86	4.18	4.23	4.38	4.38	4.53	4.69	5.31
Transportation[5]	7.87	7.13	7.28	7.65	7.75	7.97	8.00	8.16	8.30	8.96
Average[6]	**6.57**	**5.06**	**5.17**	**5.44**	**5.39**	**5.50**	**5.43**	**5.69**	**5.75**	**6.31**
Transmission & Distribution Margins[7]										
Residential	5.50	4.37	4.38	4.44	4.26	4.24	4.21	4.36	4.25	4.20
Commercial	4.14	3.25	3.26	3.31	3.22	3.22	3.21	3.30	3.25	3.22
Industrial[3]	0.83	0.68	0.70	0.73	0.69	0.73	0.76	0.70	0.73	0.77
Electric Generators[4]	0.70	0.54	0.56	0.60	0.63	0.66	0.70	0.66	0.72	0.75
Transportation[5]	3.69	3.94	3.98	4.07	4.15	4.25	4.33	4.29	4.33	4.39
Average[6]	**2.40**	**1.88**	**1.87**	**1.87**	**1.79**	**1.78**	**1.76**	**1.81**	**1.78**	**1.74**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	23.82	24.12	24.57	24.56	25.26	25.84	25.64	26.44	26.77
Commercial	13.43	11.89	12.04	12.22	12.97	13.42	13.85	13.80	14.40	14.75
Industrial[3]	6.25	5.82	6.19	6.85	6.42	7.32	8.51	6.74	7.99	9.56
Electric Generators[4]	3.70	3.50	3.82	4.38	5.51	6.20	7.13	6.29	7.60	8.40
Transportation[5]	0.04	0.22	0.23	0.25	0.37	0.42	0.47	0.41	0.48	0.55
Total	**49.86**	**45.26**	**46.41**	**48.27**	**49.82**	**52.62**	**55.80**	**52.88**	**56.91**	**60.02**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections**: EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B15. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.24**	**23.90**	**24.34**	**23.51**	**24.89**	**26.08**	**24.29**	**26.12**	**27.64**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.62**	**5.63**	**5.64**	**5.39**	**5.46**	**5.51**	**5.13**	**5.33**	**5.44**
Lower 48 Onshore	3.13	2.50	2.51	2.52	2.10	2.12	2.13	1.96	1.98	1.99
Lower 48 Offshore	1.71	2.48	2.47	2.48	2.06	2.11	2.15	2.00	2.18	2.28
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.74**	**17.79**	**17.86**	**15.41**	**15.64**	**15.88**	**14.71**	**15.31**	**15.62**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.17**	**3.29**	**3.59**	**3.58**	**3.69**	**3.63**	**3.83**	**3.90**	**4.50**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.35**	**21.88**	**22.59**	**24.48**	**25.07**	**26.60**	**24.58**	**26.75**	**27.97**
Lower 48 Onshore	13.72	15.81	16.28	16.95	18.63	19.14	18.80	18.16	18.43	19.03
Associated-Dissolved[4]	1.77	1.37	1.38	1.38	1.21	1.21	1.22	1.15	1.15	1.16
Non-Associated	11.94	14.43	14.91	15.57	17.42	17.92	17.58	17.01	17.27	17.87
Conventional	6.54	7.85	7.98	8.17	8.21	8.24	8.12	7.53	7.75	8.02
Unconventional	5.40	6.58	6.93	7.40	9.21	9.68	9.46	9.48	9.53	9.84
Lower 48 Offshore	5.30	5.07	5.12	5.16	5.31	5.39	5.40	5.85	5.69	6.09
Associated-Dissolved[4]	1.08	0.79	0.79	0.80	0.75	0.77	0.78	0.86	0.91	0.88
Non-Associated	4.22	4.27	4.33	4.37	4.56	4.62	4.62	4.99	4.78	5.21
Alaska	0.43	0.48	0.48	0.48	0.54	0.55	2.39	0.57	2.64	2.85
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**177.37**	**178.39**	**179.49**	**190.48**	**193.42**	**194.72**	**190.77**	**189.88**	**189.81**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**24.62**	**25.83**	**27.12**	**25.98**	**27.37**	**26.95**	**28.98**	**28.41**	**29.72**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	443	414	422	425	391	419	449	393	431	471
Interior	147	160	158	157	148	150	157	155	159	167
West	548	642	651	659	775	790	807	828	850	882
East of the Mississippi	539	522	528	533	499	529	566	509	553	603
West of the Mississippi	599	694	703	708	815	829	846	867	887	917
Total	**1138**	**1216**	**1231**	**1241**	**1314**	**1359**	**1412**	**1376**	**1440**	**1520**
Net Imports										
Imports	20	20	20	20	25	25	25	28	28	28
Exports	49	35	35	35	28	29	29	26	26	26
Total	**-29**	**-15**	**-15**	**-15**	**-3**	**-4**	**-4**	**2**	**2**	**2**
Total Supply[2]	**1109**	**1201**	**1215**	**1226**	**1310**	**1355**	**1409**	**1377**	**1442**	**1521**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	65	66	69	66	69	73	67	71	77
of whidch: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	20	20	18	18	18
Electric Generators[4]	957	1110	1123	1132	1222	1263	1313	1290	1350	1424
Total	**1050**	**1204**	**1218**	**1229**	**1313**	**1358**	**1411**	**1381**	**1444**	**1524**
Discrepancy and Stock Change[5]	**59**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	14.95	14.99	15.11	14.06	14.38	14.79	13.99	14.36	14.93
(2001 dollars per million Btu)	0.83	0.73	0.73	0.73	0.69	0.71	0.72	0.69	0.71	0.73
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.83	29.83	29.97	30.30	27.84	28.40	29.16	27.22	27.92	28.87
Coke Plants	46.42	41.32	41.38	41.69	38.18	38.62	39.14	36.67	37.09	37.65
Electric Generators										
(2001 dollars per short ton)	25.06	23.45	23.61	23.93	21.85	22.45	23.20	21.43	22.17	23.13
(2001 dollars per million Btu)	1.25	1.16	1.17	1.18	1.10	1.12	1.15	1.08	1.10	1.15
Average	**26.06**	**24.15**	**24.31**	**24.64**	**22.41**	**23.00**	**23.74**	**21.91**	**22.64**	**23.59**
Exports[7]	36.97	32.74	32.88	33.05	31.52	31.89	32.33	30.49	30.85	31.36

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B17. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.36	78.92	78.92	78.92	78.92	78.92	78.92	78.92	78.92	78.92
Geothermal[2]	2.86	3.59	3.54	3.61	4.77	5.00	4.83	5.41	5.64	5.74
Municipal Solid Waste[3]	3.25	4.03	4.03	4.08	4.36	4.37	4.42	4.36	4.37	4.44
Wood and Other Biomass[4]	1.77	2.07	2.07	2.07	2.18	2.18	2.50	2.55	2.78	5.57
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.29	8.47	8.63	10.15	11.05	12.20	10.81	12.00	13.37
Total	**90.88**	**97.43**	**97.57**	**97.86**	**101.11**	**102.25**	**103.61**	**102.90**	**104.56**	**108.88**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	301.87	301.89	301.93	300.98	301.05	301.14	301.23	301.34	301.46
Geothermal[2]	13.81	20.22	19.81	20.43	29.91	31.78	30.40	34.98	36.92	37.67
Municipal Solid Waste[3]	19.55	28.85	28.88	29.26	31.30	31.34	31.76	31.39	31.49	32.07
Wood and Other Biomass[4]	9.38	20.59	21.27	21.83	21.19	21.88	24.18	21.82	24.66	33.94
Dedicated Plants	7.67	12.41	12.41	12.42	13.12	13.12	15.08	14.87	16.47	31.61
Cofiring	1.71	8.18	8.85	9.41	8.06	8.76	9.10	6.95	8.19	2.34
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.98	23.62	24.14	29.51	32.70	36.77	31.96	36.21	41.08
Total	**262.85**	**395.53**	**396.47**	**398.59**	**414.44**	**420.31**	**425.80**	**423.23**	**432.48**	**448.08**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.55	5.88	6.38	6.84	7.76	8.77	7.36	8.71	10.18
Total	**4.69**	**5.84**	**6.16**	**6.66**	**7.12**	**8.04**	**9.05**	**7.64**	**9.00**	**10.46**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.60	0.62	0.67	0.86	0.93	1.06
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.69**	**1.71**	**1.77**	**1.96**	**2.03**	**2.16**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	35.35	37.23	40.18	42.84	48.21	54.10	45.87	53.80	62.35
Total	**31.13**	**37.50**	**39.38**	**42.34**	**44.99**	**50.36**	**56.25**	**48.02**	**55.95**	**64.50**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.28	1.33	1.45	1.84	1.98	2.24
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.52**	**5.57**	**5.68**	**6.08**	**6.22**	**6.47**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.40**	**0.41**	**0.41**	**0.39**	**0.40**	**0.41**
Wood	0.39	0.41	0.41	0.41	0.40	0.41	0.41	0.39	0.40	0.41
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.13**	**2.22**	**2.37**	**2.52**	**2.77**	**3.07**	**2.68**	**3.05**	**3.49**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.08	2.17	2.32	2.47	2.72	3.03	2.63	3.01	3.45
Transportation	**0.15**	**0.26**	**0.26**	**0.27**	**0.30**	**0.31**	**0.33**	**0.31**	**0.34**	**0.35**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol used in Gasoline Blending	0.15	0.25	0.26	0.27	0.29	0.31	0.32	0.31	0.33	0.35
Electric Generators[5]	**3.02**	**4.50**	**4.50**	**4.53**	**4.90**	**5.00**	**5.02**	**5.08**	**5.21**	**5.37**
Conventional Hydroelectric	2.17	3.10	3.10	3.10	3.08	3.08	3.08	3.08	3.08	3.08
Geothermal	0.29	0.50	0.49	0.51	0.80	0.86	0.82	0.95	1.01	1.04
Municipal Solid Waste[6]	0.31	0.39	0.40	0.40	0.43	0.43	0.43	0.43	0.43	0.44
Biomass	0.15	0.26	0.26	0.27	0.27	0.27	0.29	0.27	0.30	0.37
Dedicated Plants	0.12	0.14	0.14	0.14	0.15	0.15	0.17	0.17	0.19	0.34
Cofiring	0.03	0.12	0.12	0.13	0.11	0.12	0.12	0.10	0.11	0.03
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	0.24	0.24	0.25	0.30	0.34	0.38	0.33	0.37	0.42
Total Marketed Renewable Energy	**5.47**	**7.39**	**7.49**	**7.69**	**8.22**	**8.59**	**8.94**	**8.57**	**9.11**	**9.73**
Sources of Ethanol										
From Corn	0.15	0.25	0.26	0.27	0.27	0.29	0.30	0.27	0.29	0.30
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.05	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.27**	**0.30**	**0.31**	**0.33**	**0.31**	**0.34**	**0.35**
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table B8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.7	25.7	25.9	24.8	25.1	25.4
Natural Gas	71.1	80.7	81.5	81.9	85.3	88.2	90.9	87.1	92.1	94.4
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Electricity	215.1	241.0	242.7	243.2	262.9	269.4	274.0	274.9	285.2	290.3
Total	**313.8**	**349.7**	**352.1**	**353.1**	**374.2**	**383.7**	**391.2**	**387.1**	**402.8**	**410.4**
Commercial										
Petroleum	14.0	13.1	13.1	13.2	13.5	13.4	13.6	13.5	13.5	13.8
Natural Gas	48.0	54.2	54.7	54.7	59.7	61.7	63.9	61.9	65.6	67.7
Coal	2.3	2.4	2.5	2.5	2.6	2.7	2.7	2.7	2.8	2.9
Electricity	214.5	244.7	247.0	247.8	290.2	298.4	306.1	315.6	328.0	338.3
Total	**278.8**	**314.4**	**317.2**	**318.1**	**365.9**	**376.2**	**386.3**	**393.7**	**409.9**	**422.7**
Industrial[1]										
Petroleum	97.9	95.2	98.6	103.6	100.1	106.5	114.3	101.5	110.4	123.2
Natural Gas[2]	123.4	144.2	149.0	156.4	157.3	169.4	188.1	162.5	183.4	205.5
Coal	52.1	54.9	56.2	58.5	53.6	56.1	60.0	52.5	56.1	62.0
Electricity	178.1	186.3	194.3	207.4	205.0	223.1	249.8	214.0	240.0	278.1
Total	**451.5**	**480.6**	**498.1**	**525.9**	**516.0**	**555.2**	**612.3**	**530.6**	**589.9**	**668.8**
Transportation										
Petroleum[3]	501.4	598.0	616.4	638.0	703.2	746.9	792.5	751.0	811.0	875.1
Natural Gas[4]	9.2	11.7	12.1	12.6	13.8	14.5	16.0	14.3	16.3	17.4
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.5	4.6	4.6	5.8	5.9	6.1	6.6	6.8	7.1
Total	**514.5**	**614.3**	**633.0**	**655.2**	**722.8**	**767.3**	**814.6**	**771.9**	**834.2**	**899.6**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	733.9	755.7	782.3	842.4	892.6	946.4	890.8	960.1	1037.6
Natural Gas	251.7	290.9	297.2	305.6	316.1	333.8	358.9	325.8	357.5	385.1
Coal	54.7	57.7	59.0	61.4	56.6	59.2	63.1	55.6	59.3	65.2
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	676.5	688.5	703.0	763.9	796.9	836.0	811.1	860.1	913.7
Total	**1558.6**	**1759.0**	**1800.5**	**1852.4**	**1979.0**	**2082.5**	**2204.4**	**2083.3**	**2236.9**	**2401.5**
Electric Generators[6]										
Petroleum	27.5	8.4	8.8	11.0	10.6	9.7	9.1	11.6	10.9	12.7
Natural Gas	77.7	94.9	99.9	107.0	128.5	137.8	148.5	140.6	155.0	164.5
Coal	506.4	573.1	579.9	585.0	624.8	649.5	678.5	659.0	694.2	736.4
Total	**611.6**	**676.5**	**688.5**	**703.0**	**763.9**	**796.9**	**836.0**	**811.1**	**860.1**	**913.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	742.3	764.5	793.3	853.1	902.2	955.4	902.4	971.0	1050.3
Natural Gas	329.4	385.9	397.1	412.6	444.6	471.6	507.4	466.3	512.5	549.6
Coal	561.1	630.8	638.9	646.4	681.3	708.7	741.6	714.6	753.4	801.6
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1759.0**	**1800.5**	**1852.4**	**1979.0**	**2082.5**	**2204.4**	**2083.3**	**2236.9**	**2401.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**6.0**	**6.1**	**6.3**	**6.4**	**6.5**	**6.5**	**6.6**	**6.8**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.374**	**1.313**	**1.221**	**1.922**	**1.708**	**1.515**	**2.291**	**1.981**	**1.692**
Real Gross Domestic Product	**9215**	**11754**	**12258**	**12941**	**14914**	**16450**	**17946**	**16589**	**18917**	**21,155**
Real Consumption	6377	8117	8412	8769	10349	11351	12097	11507	13012	14186
Real Investment	1575	2307	2499	2748	3126	3755	4276	3447	4492	5296
Real Government Spending	1640	1808	1895	1945	2014	2212	2339	2172	2429	2613
Real Exports	1076	1691	1784	1927	2945	3360	3838	3888	4695	5501
Real Imports	1492	2144	2301	2378	3367	4059	4294	4179	5398	5837
Real Disposable Personal Income	**6748**	**8336**	**8637**	**9004**	**10830**	**11713**	**12545**	**12246**	**13435**	**14,587**
AA Utility Bond Rate (percent)	**7.43**	**8.03**	**7.24**	**6.66**	**10.96**	**9.18**	**7.76**	**12.83**	**9.63**	**7.64**
Real Yield on Government 10 Year Bonds (percent)	**3.51**	**4.97**	**5.26**	**5.62**	**7.21**	**6.56**	**5.99**	**9.70**	**6.76**	**5.77**
Real Utility Bond Rate (percent)	**5.45**	**5.41**	**5.35**	**5.39**	**7.41**	**6.32**	**5.58**	**9.25**	**6.56**	**5.37**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.97	6.87	6.73	6.19	5.94	5.81	5.83	5.55	5.38
Total Energy	10.57	9.42	9.24	9.02	8.30	7.92	7.68	7.81	7.36	7.06
Consumer Price Index (1982-84=1.00)	**1.77**	**2.30**	**2.19**	**2.04**	**3.35**	**2.93**	**2.60**	**4.12**	**3.47**	**2.96**
Unemployment Rate (percent)	**4.79**	**4.80**	**4.41**	**3.65**	**6.95**	**5.89**	**5.77**	**6.96**	**5.77**	**5.46**
Housing Starts (millions)	**1.80**	**1.91**	**2.17**	**2.45**	**1.56**	**1.92**	**2.16**	**1.58**	**2.02**	**2.31**
Single-Family	1.27	1.16	1.34	1.51	0.87	1.12	1.26	0.83	1.12	1.29
Multifamily	0.33	0.40	0.47	0.56	0.40	0.48	0.58	0.46	0.57	0.70
Mobile Home Shipments	0.19	0.35	0.37	0.38	0.30	0.32	0.32	0.29	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**80.6**	**81.8**	**82.9**	**91.1**	**94.6**	**98.1**	**95.9**	**101.1**	**105.9**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6666	6959	7470	8236	8963	10118	9011	10126	11833
Nonmanufacturing	1346	1427	1505	1604	1562	1743	1922	1599	1869	2119
Manufacturing	4079	5238	5453	5867	6674	7220	8196	7411	8257	9714
Energy-Intensive Manufacturing	1086	1207	1256	1325	1330	1446	1578	1369	1532	1718
Non-Energy-Intensive Manufacturing	2993	4031	4197	4542	5344	5774	6619	6042	6725	7996
Unit Sales of Light-Duty Vehicles (millions)	**17.11**	**17.33**	**18.27**	**19.32**	**17.90**	**19.91**	**22.01**	**16.88**	**19.97**	**23.40**
Population (millions)										
Population with Armed Forces Overseas)	278.2	294.6	300.2	305.9	312.6	325.3	338.1	321.9	338.2	354.6
Population (aged 16 and over)	215.4	232.5	236.6	240.7	247.2	256.5	265.8	254.5	266.6	278.7
Employment, Non-Agriculture	131.7	144.0	147.1	152.2	150.3	159.2	166.9	153.1	165.9	177.4
Employment, Manufacturing	17.5	17.4	17.9	18.9	16.3	17.3	18.8	16.9	18.4	20.5
Labor Force	141.8	153.3	156.5	160.6	162.2	169.8	177.5	167.3	177.4	187.9

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price[1] (2001 dollars per barrel)	**22.01**	**23.41**	**23.99**	**24.48**	**24.14**	**25.48**	**26.64**	**24.85**	**26.57**	**28.09**
Production[2] (Conventional)										
Industrialized Countries										
U.S. (50 states)	8.88	9.13	9.20	9.31	9.25	9.39	9.55	9.02	9.36	9.63
Canada	2.09	1.93	1.93	1.94	1.61	1.62	1.63	1.53	1.54	1.55
Mexico	3.59	4.25	4.26	4.26	4.40	4.42	4.44	4.54	4.57	4.59
Western Europe[3]	6.92	6.32	6.33	6.33	5.43	5.45	5.45	4.98	5.00	5.01
Japan	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.06	0.07	0.07
Australia and New Zealand	0.80	0.84	0.84	0.84	0.79	0.79	0.79	0.78	0.78	0.78
Total Industrialized	**22.35**	**22.54**	**22.64**	**22.75**	**21.55**	**21.74**	**21.94**	**20.91**	**21.32**	**21.63**
Eurasia										
Former Soviet Union										
Russia	7.24	9.15	9.17	9.18	10.22	10.26	10.30	10.36	10.42	10.46
Caspian Area[4]	1.59	3.59	3.60	3.60	4.68	4.70	4.71	4.98	5.01	5.03
Eastern Europe[5]	0.22	0.28	0.28	0.28	0.38	0.38	0.38	0.42	0.42	0.42
Total Eurasia	**9.05**	**13.02**	**13.04**	**13.05**	**15.27**	**15.34**	**15.40**	**15.75**	**15.84**	**15.91**
Developing Countries										
OPEC[6]										
Asia	1.48	1.44	1.44	1.45	1.45	1.45	1.46	1.46	1.46	1.47
Middle East	19.42	22.06	22.43	23.04	33.30	33.82	34.65	41.48	42.02	43.22
North Africa	3.06	4.60	4.60	4.61	5.62	5.62	5.63	6.43	6.44	6.45
West Africa	2.23	3.23	3.23	3.23	4.64	4.64	4.65	5.45	5.45	5.46
South America	2.92	3.86	3.87	3.87	4.25	4.26	4.27	4.75	4.75	4.76
Non-OPEC										
China	3.30	3.44	3.44	3.45	3.32	3.33	3.35	3.26	3.28	3.29
Other Asia	2.38	2.53	2.54	2.54	2.54	2.55	2.56	2.52	2.53	2.54
Middle East[7]	1.99	2.25	2.25	2.26	2.44	2.45	2.46	2.60	2.61	2.63
Africa	2.70	4.46	4.47	4.48	6.57	6.60	6.62	6.81	6.85	6.89
South and Central America	3.72	4.58	4.59	4.59	6.07	6.10	6.12	6.28	6.31	6.34
Total Developing Countries	**43.20**	**52.46**	**52.86**	**53.52**	**70.20**	**70.83**	**71.76**	**81.03**	**81.72**	**83.05**
Total Production (Conventional)	**74.61**	**88.02**	**88.54**	**89.33**	**107.03**	**107.92**	**109.10**	**117.70**	**118.88**	**120.60**
Production[8] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other North America	0.72	1.52	1.52	1.52	2.07	2.07	2.07	2.22	2.22	2.22
Western Europe	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Asia	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Middle East[7]	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Africa	0.15	0.19	0.19	0.19	0.25	0.25	0.25	0.28	0.28	0.28
South and Central America	0.49	0.85	0.85	0.85	1.42	1.42	1.42	1.45	1.45	1.45
Total Production (Nonconventional)	**1.42**	**2.64**	**2.64**	**2.64**	**3.83**	**3.83**	**3.83**	**4.05**	**4.05**	**4.05**
Total Production	**76.02**	**90.66**	**91.18**	**91.97**	**110.87**	**111.75**	**112.93**	**121.75**	**122.93**	**124.65**

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2025 Low Economic Growth	2025 Reference	2025 High Economic Growth
Consumption[9]										
Industrialized Countries										
U.S. (50 states)	19.69	22.27	22.99	23.94	25.49	27.13	28.93	26.87	29.17	31.82
U.S. Territories	0.35	0.44	0.44	0.44	0.50	0.49	0.48	0.55	0.54	0.53
Canada	1.91	2.24	2.22	2.21	2.45	2.41	2.38	2.56	2.50	2.46
Mexico	1.94	2.79	2.78	2.77	4.01	3.94	3.87	4.60	4.47	4.36
Western Europe[3]	13.87	14.99	14.95	14.92	15.77	15.65	15.56	16.09	15.93	15.80
Japan	5.42	6.06	6.03	6.00	6.34	6.21	6.10	6.46	6.27	6.12
Australia and New Zealand	1.01	1.25	1.25	1.25	1.61	1.60	1.59	1.77	1.75	1.74
Total Industrialized	**44.19**	**50.06**	**50.66**	**51.53**	**56.17**	**57.42**	**58.91**	**58.90**	**60.64**	**62.82**
Eurasia										
Former Soviet Union	3.63	4.68	4.67	4.66	5.53	5.50	5.47	5.83	5.78	5.75
Eastern Europe[5]	1.37	1.61	1.61	1.61	2.09	2.08	2.07	2.35	2.33	2.33
Total Eurasia	**5.00**	**6.29**	**6.28**	**6.27**	**7.62**	**7.58**	**7.54**	**8.18**	**8.12**	**8.07**
Developing Countries										
China	4.82	6.58	6.55	6.53	10.16	10.05	9.96	12.36	12.20	12.06
India	2.00	3.20	3.19	3.18	4.97	4.92	4.88	6.22	6.12	6.05
South Korea	2.22	2.87	2.86	2.85	3.14	3.10	3.07	3.23	3.18	3.13
Other Asia	5.34	7.00	6.98	6.97	9.03	8.98	8.94	10.20	10.13	10.08
Middle East[7]	5.13	6.18	6.17	6.16	8.23	8.20	8.18	9.43	9.40	9.37
Africa	2.46	3.20	3.19	3.19	4.03	4.01	3.99	4.50	4.46	4.44
South and Central America	4.87	5.60	5.59	5.59	7.82	7.78	7.75	9.03	8.98	8.93
Total Developing Countries	**26.84**	**34.62**	**34.54**	**34.47**	**47.37**	**47.05**	**46.78**	**54.97**	**54.47**	**54.06**
Total Consumption	**76.03**	**90.96**	**91.48**	**92.27**	**111.16**	**112.04**	**113.23**	**122.05**	**123.23**	**124.96**
OPEC Production[10]	29.48	35.84	36.22	36.86	50.35	50.88	51.73	60.69	61.24	62.47
Non-OPEC Production[10]	46.54	54.82	54.96	55.11	60.52	60.86	61.19	61.07	61.69	62.18
Net Eurasia Exports	4.07	6.74	6.78	6.80	7.67	7.78	7.87	7.59	7.74	7.86
OPEC Market Share	0.39	0.40	0.40	0.40	0.45	0.46	0.46	0.50	0.50	0.50

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs LM2003.D110502C, AEO2003.D110502C, and HM2003.D110502C.

Oil Price Case Comparisons

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Crude Oil and Lease Condensate	12.29	11.72	11.91	12.29	11.04	11.56	12.25	10.42	11.29	12.08
Natural Gas Plant Liquids	2.65	3.15	3.16	3.21	3.55	3.59	3.66	3.70	3.76	3.83
Dry Natural Gas	19.97	22.35	22.47	22.76	25.70	25.75	26.28	26.99	27.47	27.99
Coal	23.97	25.12	25.30	25.36	27.53	27.69	27.69	29.18	29.29	29.74
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.24	7.23	7.23	8.29	8.28	8.26	8.82	8.78	8.76
Other[2]	0.57	0.86	0.84	0.83	0.80	0.80	0.79	0.81	0.80	0.82
Total	**72.81**	**78.79**	**79.27**	**80.03**	**85.34**	**86.10**	**87.36**	**88.36**	**89.83**	**91.66**
Imports										
Crude Oil[3]	20.26	25.32	25.13	24.47	29.02	27.61	26.42	30.58	28.47	27.34
Petroleum Products[4]	5.04	6.96	6.41	5.59	12.37	11.97	10.61	16.00	15.17	13.03
Natural Gas	4.10	5.51	5.52	5.54	7.04	7.22	7.23	8.01	8.30	8.38
Other Imports[5]	0.73	0.91	0.90	0.90	0.94	0.96	0.97	0.94	0.94	0.94
Total	**30.13**	**38.70**	**37.96**	**36.50**	**49.37**	**47.76**	**45.23**	**55.52**	**52.88**	**49.70**
Exports										
Petroleum[6]	2.01	2.24	2.24	2.23	2.37	2.34	2.36	2.52	2.41	2.40
Natural Gas	0.37	0.62	0.62	0.61	0.42	0.41	0.42	0.38	0.37	0.37
Coal	1.27	0.89	0.91	0.89	0.74	0.74	0.74	0.67	0.67	0.67
Total	**3.64**	**3.75**	**3.76**	**3.74**	**3.53**	**3.49**	**3.52**	**3.57**	**3.45**	**3.45**
Discrepancy[7]	**1.99**	**0.17**	**0.21**	**0.18**	**0.15**	**0.25**	**0.30**	**0.07**	**0.19**	**0.34**
Consumption										
Petroleum Products[8]	38.46	45.24	44.65	43.61	53.91	52.60	50.96	58.57	56.56	54.65
Natural Gas	23.26	27.62	27.75	28.06	32.72	32.96	33.25	35.03	35.81	35.98
Coal	22.02	24.81	24.98	25.06	27.53	27.68	27.68	29.32	29.42	29.67
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.24	7.23	7.23	8.29	8.28	8.26	8.82	8.78	8.76
Other[9]	0.21	0.30	0.29	0.29	0.16	0.17	0.18	0.07	0.07	0.07
Total	**97.30**	**113.57**	**113.26**	**112.61**	**131.03**	**130.12**	**128.78**	**140.24**	**139.07**	**137.57**
Net Imports - Petroleum	**23.29**	**30.05**	**29.31**	**27.83**	**39.02**	**37.24**	**34.67**	**44.06**	**41.23**	**37.97**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	19.04	23.99	32.51	19.04	25.48	33.02	19.04	26.57	33.05
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.29	3.29	3.34	3.56	3.69	3.67	3.87	3.90	3.92
Coal Minemouth Price (dollars per ton)	17.59	15.01	14.99	15.14	14.20	14.38	14.57	14.17	14.36	14.59
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.4	6.4	6.6	6.6	6.6	6.6	6.7	6.7

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.93	0.91	0.86	0.88	0.83	0.77	0.86	0.81	0.75
Kerosene	0.10	0.08	0.08	0.07	0.07	0.06	0.06	0.06	0.06	0.05
Liquefied Petroleum Gas	0.50	0.48	0.47	0.45	0.49	0.47	0.45	0.50	0.48	0.46
Petroleum Subtotal	1.50	1.49	1.46	1.39	1.43	1.37	1.28	1.42	1.34	1.25
Natural Gas	4.94	5.66	5.66	5.65	6.14	6.12	6.13	6.43	6.40	6.42
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.41	0.40	0.41	0.40	0.40
Electricity	4.10	4.93	4.93	4.92	5.61	5.59	5.58	5.96	5.94	5.94
Delivered Energy	**10.94**	**12.51**	**12.47**	**12.38**	**13.60**	**13.51**	**13.41**	**14.23**	**14.10**	**14.04**
Electricity Related Losses	9.15	10.32	10.28	10.26	10.99	10.96	10.94	11.37	11.33	11.27
Total	**20.09**	**22.82**	**22.75**	**22.64**	**24.58**	**24.47**	**24.35**	**25.60**	**25.43**	**25.31**
Commercial										
Distillate Fuel	0.46	0.51	0.48	0.44	0.57	0.49	0.43	0.60	0.49	0.42
Residual Fuel	0.09	0.05	0.04	0.04	0.05	0.05	0.04	0.05	0.05	0.04
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.67	0.62	0.78	0.69	0.62	0.81	0.70	0.62
Natural Gas	3.33	3.79	3.80	3.80	4.25	4.29	4.32	4.51	4.56	4.62
Coal	0.09	0.10	0.10	0.09	0.11	0.10	0.10	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.09	5.03	5.02	5.00	6.21	6.20	6.19	6.86	6.83	6.84
Delivered Energy	**8.32**	**9.72**	**9.69**	**9.63**	**11.45**	**11.38**	**11.34**	**12.40**	**12.30**	**12.30**
Electricity Related Losses	9.12	10.51	10.46	10.44	12.17	12.14	12.12	13.08	13.03	12.98
Total	**17.44**	**20.22**	**20.15**	**20.06**	**23.62**	**23.52**	**23.46**	**25.48**	**25.33**	**25.27**
Industrial[4]										
Distillate Fuel	1.13	1.23	1.21	1.19	1.38	1.36	1.32	1.48	1.45	1.40
Liquefied Petroleum Gas	2.10	2.57	2.55	2.50	3.14	3.10	3.02	3.40	3.33	3.27
Petrochemical Feedstock	1.14	1.44	1.43	1.42	1.71	1.69	1.67	1.84	1.82	1.79
Residual Fuel	0.23	0.20	0.19	0.17	0.21	0.20	0.18	0.22	0.20	0.19
Motor Gasoline[2]	0.15	0.17	0.17	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.35	4.31	4.04	4.63	4.49	4.35	4.77	4.60	4.50
Petroleum Subtotal	8.79	9.95	9.86	9.49	11.26	11.02	10.74	11.92	11.59	11.35
Natural Gas	7.74	9.05	9.13	9.42	10.34	10.38	10.54	11.11	11.22	11.30
Lease and Plant Fuel[6]	1.20	1.39	1.39	1.41	1.61	1.59	1.62	1.71	1.74	1.77
Natural Gas Subtotal	8.94	10.43	10.52	10.83	11.95	11.97	12.16	12.82	12.96	13.07
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.42	1.44	1.44	1.44	1.50	1.50	1.50	1.53	1.53	1.73
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.16	2.22	2.22	2.22	2.21	2.21	2.21	2.21	2.21	2.41
Renewable Energy[7]	1.82	2.22	2.22	2.21	2.78	2.77	2.77	3.06	3.05	3.05
Electricity	3.39	3.96	3.95	3.95	4.64	4.63	4.63	5.01	5.00	4.99
Delivered Energy	**25.10**	**28.78**	**28.76**	**28.71**	**32.85**	**32.61**	**32.51**	**35.03**	**34.81**	**34.87**
Electricity Related Losses	7.57	8.27	8.23	8.24	9.10	9.08	9.07	9.56	9.54	9.47
Total	**32.67**	**37.05**	**36.99**	**36.95**	**41.94**	**41.69**	**41.58**	**44.59**	**44.35**	**44.34**

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

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Transportation										
Distillate Fuell[8]	5.44	7.07	7.08	7.07	8.69	8.70	8.68	9.55	9.58	9.57
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.10	5.09	5.02	5.69	5.66	5.58
Motor Gasoline[2]	16.26	20.23	20.09	19.71	24.47	24.04	23.07	26.53	25.90	24.67
Residual Fuel	0.84	0.83	0.83	0.83	0.85	0.85	0.86	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.09	0.10
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	32.36	32.24	31.82	39.49	39.06	38.00	43.04	42.41	41.10
Pipeline Fuel Natural Gas	0.63	0.77	0.78	0.78	0.92	0.91	0.91	1.00	1.02	1.01
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Delivered Energy	**26.94**	**33.29**	**33.17**	**32.76**	**40.64**	**40.20**	**39.14**	**44.30**	**43.70**	**42.38**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.24	0.24	0.24	0.27	0.27	0.27
Total	**27.10**	**33.49**	**33.36**	**32.95**	**40.88**	**40.44**	**39.38**	**44.58**	**43.97**	**42.64**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.73	9.69	9.56	11.52	11.38	11.20	12.49	12.32	12.14
Kerosene	0.15	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.10	5.09	5.02	5.69	5.66	5.58
Liquefied Petroleum Gas	2.70	3.20	3.16	3.10	3.80	3.74	3.65	4.08	3.99	3.92
Motor Gasoline[2]	16.46	20.42	20.29	19.91	24.69	24.26	23.29	26.76	26.13	24.90
Petrochemical Feedstock	1.14	1.44	1.43	1.42	1.71	1.69	1.67	1.84	1.82	1.79
Residual Fuel	1.15	1.08	1.06	1.04	1.12	1.10	1.08	1.14	1.12	1.10
Other Petroleum[12]	4.24	4.58	4.54	4.27	4.91	4.76	4.63	5.07	4.89	4.79
Petroleum Subtotal	37.21	44.51	44.23	43.32	52.96	52.14	50.64	57.19	56.03	54.32
Natural Gas	16.02	18.55	18.65	18.93	20.83	20.89	21.09	22.17	22.29	22.46
Lease and Plant Fuel[6]	1.20	1.39	1.39	1.41	1.61	1.59	1.62	1.71	1.74	1.77
Pipeline Natural Gas	0.63	0.77	0.78	0.78	0.92	0.91	0.91	1.00	1.02	1.01
Natural Gas Subtotal	17.86	20.71	20.82	21.12	23.36	23.39	23.62	24.87	25.05	25.24
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.53	1.55	1.55	1.55	1.62	1.62	1.62	1.65	1.65	1.85
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.27	2.33	2.33	2.33	2.33	2.33	2.33	2.34	2.34	2.53
Renewable Energy[13]	2.31	2.74	2.74	2.73	3.30	3.29	3.28	3.58	3.57	3.56
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	14.01	13.99	13.97	16.59	16.55	16.52	17.98	17.92	17.92
Delivered Energy	**71.29**	**84.29**	**84.10**	**83.47**	**98.53**	**97.70**	**96.40**	**105.96**	**104.91**	**103.58**
Electricity Related Losses	26.01	29.28	29.16	29.14	32.50	32.42	32.37	34.28	34.17	33.99
Total	**97.30**	**113.57**	**113.26**	**112.61**	**131.03**	**130.12**	**128.78**	**140.24**	**139.07**	**137.57**
Electric Power[14]										
Distillate Fuel	0.17	0.19	0.11	0.08	0.32	0.10	0.08	0.77	0.17	0.08
Residual Fuel	1.08	0.54	0.31	0.21	0.62	0.36	0.24	0.62	0.36	0.25
Petroleum Subtotal	1.25	0.73	0.42	0.29	0.95	0.46	0.32	1.39	0.52	0.33
Natural Gas	5.40	6.92	6.93	6.94	9.36	9.57	9.63	10.15	10.76	10.74
Steam Coal	19.75	22.49	22.65	22.73	25.19	25.35	25.36	26.98	27.09	27.14
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[15]	3.02	4.50	4.50	4.50	4.99	5.00	4.98	5.24	5.21	5.20
Electricity Imports	0.21	0.30	0.29	0.29	0.16	0.17	0.18	0.06	0.07	0.07
Total	**37.66**	**43.29**	**43.15**	**43.11**	**49.09**	**48.97**	**48.90**	**52.26**	**52.09**	**51.91**

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

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Energy Consumption										
Distillate Fuel	8.11	9.91	9.80	9.64	11.84	11.48	11.28	13.26	12.49	12.22
Kerosene	0.15	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.10	5.09	5.02	5.69	5.66	5.58
Liquefied Petroleum Gas	2.70	3.20	3.16	3.10	3.80	3.74	3.65	4.08	3.99	3.92
Motor Gasoline[2]	16.46	20.42	20.29	19.91	24.69	24.26	23.29	26.76	26.13	24.90
Petrochemical Feedstock	1.14	1.44	1.43	1.42	1.71	1.69	1.67	1.84	1.82	1.79
Residual Fuel	2.23	1.62	1.37	1.25	1.74	1.46	1.32	1.76	1.47	1.35
Other Petroleum[12]	4.24	4.58	4.54	4.27	4.91	4.76	4.63	5.07	4.89	4.79
Petroleum Subtotal	38.46	45.24	44.65	43.61	53.91	52.60	50.96	58.57	56.56	54.65
Natural Gas	21.42	25.47	25.58	25.87	30.19	30.46	30.72	32.32	33.05	33.20
Lease and Plant Fuel[6]	1.20	1.39	1.39	1.41	1.61	1.59	1.62	1.71	1.74	1.77
Pipeline Natural Gas	0.63	0.77	0.78	0.78	0.92	0.91	0.91	1.00	1.02	1.01
Natural Gas Subtotal	23.26	27.62	27.75	28.06	32.72	32.96	33.25	35.03	35.81	35.98
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	21.28	24.04	24.21	24.29	26.82	26.97	26.97	28.64	28.74	28.99
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	22.02	24.81	24.98	25.06	27.53	27.68	27.68	29.32	29.42	29.67
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[16]	5.33	7.24	7.23	7.23	8.29	8.28	8.26	8.82	8.78	8.76
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.30	0.29	0.29	0.16	0.17	0.18	0.06	0.07	0.07
Total	**97.30**	**113.57**	**113.26**	**112.61**	**131.03**	**130.12**	**128.78**	**140.24**	**139.07**	**137.57**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	84.29	84.10	83.47	98.53	97.70	96.40	105.96	104.91	103.58
Total Energy Use	97.30	113.57	113.26	112.61	131.03	130.12	128.78	140.24	139.07	137.57
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12271	12258	12239	16484	16450	16408	18972	18917	18875
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1805.6	1800.5	1788.0	2099.7	2082.5	2057.0	2260.9	2236.9	2211.1

[1]Includes wood used for residential heating. See Table C18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C3. Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential	**15.80**	**13.72**	**13.84**	**14.11**	**14.25**	**14.53**	**14.68**	**14.57**	**14.82**	**14.89**
Primary Energy[1]	9.73	7.80	7.96	8.29	7.94	8.27	8.49	8.19	8.50	8.66
Petroleum Products[2]	10.85	9.10	9.90	11.46	9.50	10.70	12.18	9.58	11.01	12.34
Distillate Fuel	8.99	7.30	7.96	9.44	7.53	8.72	10.23	7.57	8.93	10.41
Liquefied Petroleum Gas	14.84	12.91	14.01	15.63	13.38	14.52	15.84	13.38	14.84	15.78
Natural Gas	9.41	7.47	7.48	7.52	7.59	7.74	7.73	7.90	7.99	7.96
Electricity	25.35	22.32	22.34	22.45	22.80	22.93	22.90	22.99	23.07	22.94
Commercial	**15.47**	**13.25**	**13.35**	**13.59**	**14.25**	**14.55**	**14.66**	**14.69**	**15.00**	**15.02**
Primary Energy[1]	7.81	6.22	6.34	6.60	6.43	6.74	6.92	6.73	7.01	7.14
Petroleum Products[2]	7.27	6.01	6.78	8.38	6.18	7.50	9.09	6.23	7.78	9.24
Distillate Fuel	6.40	4.99	5.66	7.16	5.28	6.49	8.00	5.39	6.75	8.19
Residual Fuel	3.46	3.27	4.01	5.33	3.26	4.23	5.39	3.24	4.38	5.38
Natural Gas	8.09	6.38	6.38	6.43	6.60	6.75	6.74	6.94	7.02	7.00
Electricity	23.22	19.67	19.73	19.89	20.72	20.96	20.98	20.99	21.26	21.18
Industrial[3]	**7.10**	**5.93**	**6.26**	**6.82**	**6.39**	**6.88**	**7.36**	**6.57**	**7.15**	**7.49**
Primary Energy	5.83	4.68	5.07	5.71	5.07	5.62	6.19	5.23	5.88	6.30
Petroleum Products[2]	7.72	6.09	6.94	8.44	6.54	7.63	8.96	6.57	7.94	9.02
Distillate Fuel	6.55	5.07	5.73	7.28	5.57	6.80	8.32	5.83	7.25	8.53
Liquefied Petroleum Gas	12.34	8.52	9.59	11.13	9.01	10.12	11.37	8.99	10.40	11.32
Residual Fuel	3.28	2.97	3.71	5.02	2.97	3.94	5.10	2.96	4.10	5.10
Natural Gas[4]	4.87	3.88	3.89	3.91	4.20	4.32	4.30	4.51	4.57	4.56
Metallurgical Coal	1.69	1.50	1.51	1.53	1.39	1.41	1.42	1.35	1.35	1.36
Steam Coal	1.46	1.37	1.38	1.40	1.30	1.31	1.33	1.28	1.29	1.30
Electricity	14.10	12.64	12.64	12.75	13.11	13.25	13.29	13.29	13.46	13.40
Transportation	**10.28**	**9.54**	**10.28**	**11.85**	**9.01**	**10.39**	**12.14**	**8.98**	**10.81**	**12.34**
Primary Energy	10.25	9.51	10.25	11.83	8.98	10.37	12.12	8.95	10.79	12.32
Petroleum Products[2]	10.25	9.51	10.26	11.84	8.99	10.37	12.13	8.95	10.80	12.33
Distillate Fuel[5]	10.05	9.31	10.22	11.83	9.03	10.16	11.87	9.12	10.52	12.08
Jet Fuel[6]	6.20	4.95	5.62	7.17	5.15	6.33	7.89	5.35	6.72	8.14
Motor Gasoline[7]	11.57	10.82	11.53	13.12	10.04	11.60	13.49	9.92	12.08	13.71
Residual Fuel	3.90	2.78	3.55	4.91	2.75	3.77	4.97	2.74	3.94	4.97
Liquefied Petroleum Gas[8]	16.93	14.05	15.21	16.78	14.26	15.50	16.76	14.04	15.63	16.27
Natural Gas[9]	7.65	7.06	7.08	7.13	7.49	7.75	7.73	7.81	8.07	8.02
Ethanol (E85)[10]	17.72	20.88	21.32	22.34	22.16	22.87	23.66	22.47	23.44	24.06
Electricity	21.84	18.96	18.99	19.10	18.18	18.37	18.39	17.65	17.82	17.78
Average End-Use Energy	**10.74**	**9.49**	**9.92**	**10.81**	**9.60**	**10.42**	**11.34**	**9.74**	**10.78**	**11.54**
Primary Energy	8.52	7.53	8.05	9.08	7.49	8.43	9.53	7.59	8.80	9.72
Electricity	21.30	18.61	18.65	18.77	19.27	19.45	19.45	19.48	19.66	19.57
Electric Power[11]										
Fossil Fuel Average	2.14	1.82	1.82	1.84	1.98	2.02	2.03	2.10	2.14	2.13
Petroleum Products	4.73	3.44	4.27	5.78	3.65	4.60	6.03	4.05	4.98	6.10
Distillate Fuel	6.20	4.50	5.13	6.67	4.71	6.06	7.59	4.81	6.18	7.78
Residual Fuel	4.50	3.09	3.97	5.46	3.09	4.21	5.53	3.10	4.40	5.56
Natural Gas	4.78	3.78	3.79	3.83	4.17	4.30	4.28	4.50	4.60	4.56
Steam Coal	1.25	1.16	1.17	1.18	1.11	1.12	1.13	1.09	1.10	1.12

Table C3. Energy Prices by Sector and Source (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Average Price to All Users[12]										
Petroleum Products[2]	9.54	8.67	9.48	11.07	8.42	9.78	11.45	8.39	10.18	11.63
Distillate Fuel	9.16	8.29	9.17	10.80	8.21	9.46	11.17	8.24	9.83	11.41
Jet Fuel	6.20	4.95	5.62	7.17	5.15	6.33	7.89	5.35	6.72	8.14
Liquefied Petroleum Gas	12.85	9.36	10.42	11.96	9.75	10.85	12.11	9.69	11.11	12.02
Motor Gasoline[7]	11.57	10.82	11.53	13.12	10.04	11.60	13.49	9.92	12.08	13.71
Residual Fuel	4.11	2.92	3.68	5.03	2.92	3.92	5.10	2.91	4.08	5.11
Natural Gas	6.40	5.03	5.03	5.06	5.23	5.35	5.33	5.53	5.60	5.57
Coal	1.26	1.18	1.18	1.20	1.12	1.13	1.14	1.10	1.12	1.15
Ethanol (E85)[13]	17.72	20.88	21.32	22.34	22.16	22.87	23.66	22.47	23.44	24.06
Electricity	21.30	18.61	18.65	18.77	19.27	19.45	19.45	19.48	19.66	19.57
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.69	165.99	166.98	168.87	188.02	190.35	190.89	201.49	202.99	202.98
Commercial	127.06	127.38	127.99	129.35	161.74	164.11	164.68	180.48	182.88	183.12
Industrial	135.20	129.20	135.28	146.32	158.88	169.19	179.03	175.59	188.45	195.96
Transportation	270.40	310.10	332.93	378.84	357.91	408.34	464.16	388.89	461.42	510.30
Total Non-Renewable Expenditures	699.35	732.67	763.18	823.39	866.56	932.00	998.78	946.46	1035.75	1092.36
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.09	0.10	0.11	0.12	0.13	0.14
Total Expenditures	**699.36**	**732.72**	**763.22**	**823.44**	**866.65**	**932.10**	**998.88**	**946.58**	**1035.88**	**1092.50**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 pm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Households (millions)										
Single-Family	77.50	85.82	85.79	85.70	93.88	93.77	93.57	97.45	97.27	96.97
Multifamily	22.19	24.14	24.12	24.09	27.08	27.05	27.02	28.84	28.78	28.73
Mobile Homes	6.57	7.33	7.33	7.33	8.02	8.01	8.01	8.24	8.23	8.23
Total	**106.27**	**117.29**	**117.24**	**117.12**	**128.98**	**128.84**	**128.60**	**134.53**	**134.28**	**133.94**
Average House Square Footage	**1685**	**1737**	**1737**	**1737**	**1780**	**1780**	**1779**	**1797**	**1797**	**1795**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	106.6	106.4	105.7	105.4	104.8	104.3	105.8	105.0	104.8
Total Energy Consumption	189.0	194.6	194.1	193.3	190.6	189.9	189.4	190.3	189.4	189.0
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	61.4	61.3	60.9	59.2	58.9	58.6	58.9	58.4	58.4
Total Energy Consumption	112.2	112.0	111.7	111.3	107.1	106.7	106.4	105.9	105.4	105.3
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.46	0.51	0.51	0.50	0.52	0.52	0.52
Space Cooling	0.52	0.60	0.60	0.60	0.65	0.65	0.65	0.68	0.68	0.68
Water Heating	0.45	0.47	0.47	0.47	0.44	0.44	0.44	0.44	0.44	0.44
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.22	0.25	0.25	0.25	0.27	0.27	0.27	0.28	0.28	0.28
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.94	0.93	0.93	1.03	1.03	1.03	1.07	1.07	1.07
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.20	0.25	0.25	0.25	0.27	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[2]	0.83	1.26	1.26	1.26	1.66	1.66	1.66	1.87	1.87	1.87
Delivered Energy	**4.10**	**4.93**	**4.93**	**4.92**	**5.61**	**5.59**	**5.58**	**5.96**	**5.94**	**5.94**
Natural Gas										
Space Heating	3.13	3.72	3.73	3.72	4.13	4.12	4.12	4.35	4.32	4.34
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.56	1.56	1.55	1.59	1.59	1.59	1.65	1.64	1.65
Cooking	0.20	0.22	0.22	0.22	0.25	0.25	0.25	0.26	0.25	0.25
Clothes Dryers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Delivered Energy	**4.94**	**5.66**	**5.66**	**5.65**	**6.14**	**6.12**	**6.13**	**6.43**	**6.40**	**6.42**
Distillate										
Space Heating	0.74	0.78	0.76	0.72	0.74	0.71	0.65	0.73	0.69	0.63
Water Heating	0.16	0.15	0.14	0.14	0.13	0.12	0.11	0.12	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.93**	**0.91**	**0.86**	**0.88**	**0.83**	**0.77**	**0.86**	**0.81**	**0.75**
Liquefied Petroleum Gas										
Space Heating	0.26	0.26	0.25	0.24	0.26	0.25	0.23	0.27	0.25	0.24
Water Heating	0.09	0.07	0.07	0.07	0.07	0.06	0.06	0.07	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.12	0.14	0.14	0.13	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.48**	**0.47**	**0.45**	**0.49**	**0.47**	**0.45**	**0.50**	**0.48**	**0.46**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.41	0.41	0.40	0.41	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.07	0.07	0.07	0.07

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.72	5.70	5.63	6.13	6.06	5.99	6.35	6.26	6.20
Space Cooling	0.52	0.60	0.60	0.60	0.65	0.65	0.65	0.68	0.68	0.68
Water Heating	2.19	2.25	2.24	2.23	2.23	2.21	2.20	2.28	2.26	2.25
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.40	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.33	0.36	0.36	0.36	0.38	0.38	0.38
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.94	0.93	0.93	1.03	1.03	1.03	1.07	1.07	1.07
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.20	0.25	0.25	0.25	0.27	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[7]	1.01	1.46	1.46	1.45	1.88	1.87	1.87	2.10	2.09	2.09
Delivered Energy	**10.94**	**12.51**	**12.47**	**12.38**	**13.60**	**13.51**	**13.41**	**14.23**	**14.10**	**14.04**
Electricity Related Losses	**9.15**	**10.32**	**10.28**	**10.26**	**10.99**	**10.96**	**10.94**	**11.37**	**11.33**	**11.27**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.69	6.66	6.59	7.12	7.05	6.98	7.34	7.25	7.19
Space Cooling	1.68	1.85	1.85	1.84	1.93	1.93	1.92	1.99	1.98	1.97
Water Heating	3.20	3.23	3.22	3.21	3.09	3.08	3.07	3.11	3.09	3.09
Refrigeration	1.36	1.05	1.05	1.05	0.95	0.95	0.95	0.96	0.96	0.96
Cooking	0.55	0.59	0.59	0.59	0.63	0.63	0.63	0.65	0.64	0.64
Clothes Dryers	0.78	0.85	0.85	0.84	0.88	0.88	0.88	0.91	0.91	0.90
Freezers	0.36	0.27	0.27	0.27	0.26	0.26	0.26	0.27	0.27	0.26
Lighting	2.40	2.89	2.88	2.88	3.06	3.04	3.04	3.12	3.10	3.10
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.60	0.60	0.60	0.75	0.75	0.75	0.78	0.77	0.77
Personal Computers	0.19	0.25	0.25	0.25	0.31	0.31	0.30	0.33	0.33	0.33
Furnace Fans	0.23	0.27	0.27	0.27	0.30	0.30	0.29	0.31	0.31	0.31
Other Uses[7]	2.86	4.10	4.08	4.07	5.14	5.12	5.11	5.67	5.65	5.63
Total	**20.09**	**22.82**	**22.75**	**22.64**	**24.58**	**24.47**	**24.35**	**25.60**	**25.43**	**25.31**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	78.7	78.7	78.5	91.4	91.2	91.1	97.8	97.6	97.5
New Additions	3.6	3.1	3.1	3.1	3.4	3.4	3.4	3.5	3.5	3.5
Total	**70.2**	**81.8**	**81.8**	**81.6**	**94.8**	**94.6**	**94.5**	**101.3**	**101.1**	**101.0**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	118.7	118.5	118.0	120.8	120.3	120.0	122.4	121.6	121.7
Electricity Related Losses	129.9	128.4	127.9	128.0	128.4	128.3	128.3	129.2	128.9	128.5
Total Energy Consumption	248.3	247.1	246.4	245.9	249.2	248.6	248.2	251.5	250.5	250.1
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Space Cooling[1]	0.43	0.44	0.44	0.44	0.47	0.47	0.47	0.48	0.48	0.48
Water Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.15	0.16
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.02	1.21	1.21	1.20	1.31	1.31	1.30	1.35	1.34	1.35
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.32	0.32	0.36	0.36	0.36
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.75	0.75	0.93	0.93	0.93
Other Uses[2]	1.46	1.90	1.90	1.90	2.57	2.57	2.56	2.93	2.93	2.93
Delivered Energy	**4.09**	**5.03**	**5.02**	**5.00**	**6.21**	**6.20**	**6.19**	**6.86**	**6.83**	**6.84**
Natural Gas										
Space Heating[1]	1.32	1.57	1.58	1.59	1.66	1.70	1.73	1.71	1.76	1.81
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Water Heating[1]	0.57	0.70	0.70	0.70	0.81	0.82	0.82	0.86	0.87	0.87
Cooking	0.25	0.31	0.30	0.30	0.35	0.35	0.35	0.37	0.37	0.37
Other Uses[3]	1.17	1.20	1.20	1.19	1.40	1.39	1.39	1.53	1.52	1.53
Delivered Energy	**3.33**	**3.79**	**3.80**	**3.80**	**4.25**	**4.29**	**4.32**	**4.51**	**4.56**	**4.62**
Distillate										
Space Heating[1]	0.17	0.22	0.20	0.17	0.28	0.22	0.17	0.30	0.22	0.17
Water Heating[1]	0.07	0.08	0.07	0.07	0.09	0.07	0.07	0.09	0.07	0.07
Other Uses[4]	0.22	0.21	0.20	0.19	0.21	0.20	0.19	0.21	0.20	0.19
Delivered Energy	**0.46**	**0.51**	**0.48**	**0.44**	**0.57**	**0.49**	**0.43**	**0.60**	**0.49**	**0.42**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.28**	**0.31**	**0.30**	**0.30**	**0.32**	**0.31**	**0.31**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.94	1.94	1.92	2.09	2.07	2.06	2.16	2.13	2.13
Space Cooling[1]	0.44	0.46	0.46	0.46	0.50	0.50	0.50	0.52	0.52	0.52
Water Heating[1]	0.79	0.93	0.93	0.92	1.06	1.05	1.04	1.11	1.10	1.10
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Cooking	0.29	0.34	0.34	0.34	0.38	0.38	0.38	0.40	0.40	0.40
Lighting	1.02	1.21	1.21	1.20	1.31	1.31	1.30	1.35	1.34	1.35
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.32	0.32	0.36	0.36	0.36
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.75	0.75	0.93	0.93	0.93
Other Uses[6]	3.30	3.70	3.69	3.66	4.59	4.57	4.55	5.10	5.07	5.06
Delivered Energy	**8.32**	**9.72**	**9.69**	**9.63**	**11.45**	**11.38**	**11.34**	**12.40**	**12.30**	**12.30**

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electricity Related Losses	**9.12**	**10.51**	**10.46**	**10.44**	**12.17**	**12.14**	**12.12**	**13.08**	**13.03**	**12.98**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.27	2.26	2.24	2.39	2.37	2.36	2.45	2.42	2.41
Space Cooling[1]	1.39	1.37	1.37	1.36	1.42	1.41	1.41	1.44	1.43	1.43
Water Heating[1]	1.12	1.26	1.26	1.25	1.36	1.35	1.35	1.41	1.39	1.39
Ventilation	0.55	0.56	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57
Cooking	0.37	0.41	0.41	0.41	0.44	0.44	0.44	0.46	0.45	0.46
Lighting	3.31	3.74	3.73	3.71	3.88	3.87	3.86	3.92	3.89	3.90
Refrigeration	0.69	0.74	0.73	0.73	0.77	0.77	0.77	0.79	0.78	0.78
Office Equipment (PC)	0.52	0.75	0.74	0.74	0.95	0.95	0.95	1.05	1.05	1.05
Office Equipment (non-PC)	0.99	1.45	1.44	1.44	2.21	2.21	2.20	2.70	2.69	2.68
Other Uses[6]	6.56	7.68	7.65	7.62	9.63	9.60	9.57	10.70	10.65	10.61
Total	**17.44**	**20.22**	**20.15**	**20.06**	**23.62**	**23.52**	**23.46**	**25.48**	**25.33**	**25.27**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5464	5,453	5445	7240	7220	7197	8297	8257	8222
Nonmanufacturing	1346	1507	1505	1503	1747	1743	1738	1875	1869	1865
Total	**5425**	**6970**	**6959**	**6948**	**8986**	**8963**	**8935**	**10172**	**10126**	**10087**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.10	12.64	12.64	12.75	13.11	13.25	13.29	13.29	13.46	13.40
Natural Gas	4.87	3.88	3.89	3.91	4.20	4.32	4.30	4.51	4.57	4.56
Steam Coal	1.46	1.37	1.38	1.40	1.30	1.31	1.33	1.28	1.29	1.30
Residual Oil	3.28	2.97	3.71	5.02	2.97	3.94	5.10	2.96	4.10	5.10
Distillate Oil	6.55	5.07	5.73	7.28	5.57	6.80	8.32	5.83	7.25	8.53
Liquefied Petroleum Gas	12.34	8.52	9.59	11.13	9.01	10.12	11.37	8.99	10.40	11.32
Motor Gasoline	11.57	10.78	11.49	13.08	9.99	11.56	13.46	9.87	12.07	13.71
Metallurgical Coal	1.69	1.50	1.51	1.53	1.39	1.41	1.42	1.35	1.35	1.36
Energy Consumption[1]										
Purchased Electricity	3.39	3.96	3.95	3.95	4.64	4.63	4.63	5.01	5.00	4.99
Natural Gas	7.74	9.05	9.13	9.42	10.34	10.38	10.54	11.11	11.22	11.30
Lease and Plant Fuel[2]	1.20	1.39	1.39	1.41	1.61	1.59	1.62	1.71	1.74	1.77
Natural Gas Subtotal	8.94	10.43	10.52	10.83	11.95	11.97	12.16	12.82	12.96	13.07
Steam Coal	1.42	1.44	1.44	1.44	1.50	1.50	1.50	1.53	1.53	1.73
Metallurgical Coal and Coke[3]	0.74	0.77	0.77	0.77	0.71	0.71	0.71	0.68	0.68	0.68
Residual Fuel	0.23	0.20	0.19	0.17	0.21	0.20	0.18	0.22	0.20	0.19
Distillate	1.13	1.23	1.21	1.19	1.38	1.36	1.32	1.48	1.45	1.40
Liquefied Petroleum Gas	2.10	2.57	2.55	2.50	3.14	3.10	3.02	3.40	3.33	3.27
Petrochemical Feedstocks	1.14	1.44	1.43	1.42	1.71	1.69	1.67	1.84	1.82	1.79
Other Petroleum[4]	4.18	4.51	4.47	4.20	4.82	4.67	4.54	4.97	4.79	4.69
Renewables[5]	1.82	2.22	2.22	2.21	2.78	2.77	2.77	3.06	3.05	3.05
Delivered Energy	**25.10**	**28.78**	**28.76**	**28.71**	**32.85**	**32.61**	**32.51**	**35.03**	**34.81**	**34.87**
Electricity Related Losses	7.57	8.27	8.23	8.24	9.10	9.08	9.07	9.56	9.54	9.47
Total	**32.67**	**37.05**	**36.99**	**36.95**	**41.94**	**41.69**	**41.58**	**44.59**	**44.35**	**44.34**
Energy Consumption per dollar of Shipment[1] (thousand Btu per 1996 dollars)										
Purchased Electricity	0.63	0.57	0.57	0.57	0.52	0.52	0.52	0.49	0.49	0.50
Natural Gas	1.43	1.30	1.31	1.36	1.15	1.16	1.18	1.09	1.11	1.12
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.20	0.18	0.18	0.18	0.17	0.17	0.18
Natural Gas Subtotal	1.65	1.50	1.51	1.56	1.33	1.34	1.36	1.26	1.28	1.30
Steam Coal	0.26	0.21	0.21	0.21	0.17	0.17	0.17	0.15	0.15	0.17
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.11	0.08	0.08	0.08	0.07	0.07	0.07
Residual Fuel	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Distillate	0.21	0.18	0.17	0.17	0.15	0.15	0.15	0.15	0.14	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.36	0.35	0.35	0.34	0.33	0.33	0.32
Petrochemical Feedstocks	0.21	0.21	0.21	0.20	0.19	0.19	0.19	0.18	0.18	0.18
Other Petroleum[4]	0.77	0.65	0.64	0.60	0.54	0.52	0.51	0.49	0.47	0.47
Renewables[5]	0.33	0.32	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.30
Delivered Energy	**4.63**	**4.13**	**4.13**	**4.13**	**3.66**	**3.64**	**3.64**	**3.44**	**3.44**	**3.46**
Electricity Related Losses	1.40	1.19	1.18	1.19	1.01	1.01	1.02	0.94	0.94	0.94
Total	**6.02**	**5.31**	**5.32**	**5.32**	**4.67**	**4.65**	**4.65**	**4.38**	**4.38**	**4.40**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Represents natural gas used in the field gathering and processing plant machinery.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	3015	3004	2965	3774	3753	3673	4158	4132	4039
Commercial Light Trucks (VMT)[1]	66	84	84	83	107	107	106	120	120	119
Freight Trucks >10,000 pounds (VMT)	206	264	263	263	339	338	337	382	380	379
Air (seat miles available)	1109	1357	1355	1350	1944	1942	1939	2260	2256	2248
Rail (ton miles traveled)	1448	1665	1669	1669	1991	1991	1986	2158	2155	2162
Domestic Shipping (ton miles traveled)	788	871	874	879	1003	1009	1017	1075	1087	1098
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	24.1	24.3	24.7	25.2	25.6	26.3	25.5	26.1	26.8
New Car (miles per gallon)[2]	28.1	28.3	28.5	28.9	29.4	29.8	30.4	29.6	30.1	30.8
New Light Truck (miles per gallon)[2]	20.7	20.9	21.0	21.5	22.0	22.5	23.1	22.4	23.0	23.8
Light-Duty Fleet (miles per gallon)[3]	19.8	19.3	19.3	19.4	19.6	19.8	20.2	19.9	20.2	20.6
New Commercial Light Truck (MPG)[1]	13.8	13.8	13.9	14.2	14.6	14.8	15.3	14.8	15.2	15.7
Stock Commercial Light Truck (MPG)[1]	13.7	13.8	13.8	13.9	14.2	14.4	14.7	14.5	14.8	15.2
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	54.6	58.4	58.6	59.4	60.4	60.7	61.5
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.3	6.3	6.4	6.4	6.5	6.5
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	19.48	19.36	19.01	23.82	23.47	22.56	25.88	25.36	24.22
Commercial Light Trucks[1]	0.60	0.76	0.76	0.75	0.94	0.93	0.90	1.04	1.02	0.98
Freight Trucks[4]	4.68	5.90	5.89	5.87	7.13	7.09	7.04	7.85	7.79	7.74
Air[5]	3.47	3.98	3.97	3.94	5.16	5.14	5.07	5.75	5.72	5.64
Rail[6]	0.63	0.68	0.68	0.68	0.75	0.75	0.74	0.78	0.78	0.78
Marine[7]	1.45	1.49	1.49	1.49	1.59	1.59	1.59	1.64	1.64	1.64
Pipeline Fuel	0.63	0.77	0.78	0.78	0.92	0.91	0.91	1.00	1.02	1.01
Lubricants	0.19	0.22	0.22	0.21	0.26	0.26	0.26	0.28	0.28	0.27
Total	**26.94**	**33.29**	**33.17**	**32.76**	**40.64**	**40.20**	**39.14**	**44.30**	**43.70**	**42.38**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	10.29	10.23	10.04	12.57	12.38	11.90	13.65	13.37	12.77
Commercial Light Trucks[1]	0.32	0.40	0.40	0.39	0.50	0.49	0.47	0.55	0.54	0.51
Freight Trucks	2.05	2.60	2.60	2.59	3.17	3.15	3.13	3.50	3.48	3.46
Railroad	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.28	0.28	0.28
Domestic Shipping	0.16	0.17	0.17	0.17	0.19	0.20	0.20	0.21	0.21	0.21
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.65	1.65	1.64	2.19	2.18	2.15	2.46	2.45	2.41
Military Use	0.30	0.34	0.34	0.34	0.37	0.38	0.38	0.40	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.32	0.39	0.39	0.40	0.47	0.46	0.46	0.50	0.52	0.51
Total	**13.64**	**16.90**	**16.84**	**16.62**	**20.61**	**20.38**	**19.82**	**22.45**	**22.13**	**21.44**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C

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

Supply, Disposition, and Prices	2001	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2170	2189	2199	2484	2497	2497	2698	2703	2712
Petroleum	113	70	39	25	95	43	29	154	52	29
Natural Gas[3]	411	695	708	707	1117	1143	1151	1257	1335	1333
Nuclear Power	769	800	800	800	807	807	807	807	807	807
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	393	393	416	416	416	429	429	428
Distributed Generation (Natural Gas)	0	1	1	1	5	5	5	8	7	7
Non-Utility Generation for Own Use	-21	-24	-24	-24	-24	-24	-24	-24	-24	-24
Total	**3370**	**4104**	**4105**	**4101**	**4901**	**4887**	**4881**	**5328**	**5309**	**5293**
Combined Heat and Power[5]										
Coal	33	33	33	33	33	33	33	33	33	33
Petroleum	7	5	4	3	5	3	3	6	3	3
Natural Gas	124	171	167	166	146	150	149	140	146	143
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-18	-18	-18	-18
Total	**162**	**195**	**190**	**188**	**170**	**173**	**171**	**166**	**169**	**166**
Net Available to the Grid	**3532**	**4299**	**4295**	**4289**	**5071**	**5059**	**5052**	**5494**	**5478**	**5459**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	41
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	83	115	115	115	152	151	151	185	183	183
Other Gaseous Fuels[7]	6	7	7	7	8	7	7	8	8	8
Renewable Sources[4]	31	39	39	39	51	50	50	56	56	56
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	159	202	202	202	251	249	248	290	287	305
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	6
Generation for Own Use	-137	-160	-160	-159	-188	-188	-187	-213	-212	-212
Total Sales to the Grid	**27**	**48**	**48**	**47**	**68**	**67**	**67**	**83**	**82**	**99**
Net Imports	20	29	28	28	15	17	18	6	7	7
Electricity Sales by Sector										
Residential	1201	1446	1445	1442	1643	1640	1637	1748	1742	1742
Commercial	1197	1473	1471	1467	1821	1816	1813	2011	2003	2005
Industrial	994	1159	1157	1158	1361	1358	1358	1469	1466	1464
Transportation	22	27	27	27	36	36	36	42	42	41
Total	**3414**	**4106**	**4101**	**4095**	**4861**	**4850**	**4843**	**5269**	**5252**	**5252**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.6	7.6	7.6	7.7	7.8	7.8	7.8	7.8	7.9	7.8
Commercial	7.9	6.7	6.7	6.8	7.1	7.2	7.2	7.2	7.3	7.2
Industrial	4.8	4.3	4.3	4.4	4.5	4.5	4.5	4.5	4.6	4.6
Transportation	7.5	6.5	6.5	6.5	6.2	6.3	6.3	6.0	6.1	6.1
All Sectors Average	**7.3**	**6.4**	**6.4**	**6.4**	**6.6**	**6.6**	**6.6**	**6.6**	**6.7**	**6.7**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	3.8	3.8	3.9	4.0	4.1	4.1	4.1	4.2	4.2
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Emissions										
Sulfur Dioxide (million tons)	10.63	9.78	9.57	9.57	8.94	8.95	8.95	8.95	8.95	8.95
Nitrogen Oxide (million tons)	4.75	3.93	3.92	3.91	4.05	4.06	4.06	4.12	4.12	4.11
Mercury (tons)	51.05	51.49	51.30	51.27	51.67	52.01	51.74	52.59	52.63	52.64

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run AEO2003.D110502C. **Projections:** AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	302.6	306.4	307.8	341.4	343.2	343.1	369.7	370.6	372.5
Other Fossil Steam[4]	133.8	87.1	83.4	83.1	77.1	77.2	76.8	76.2	76.2	76.0
Combined Cycle	43.6	138.1	145.0	144.4	226.2	228.3	230.3	271.0	270.4	271.7
Combustion Turbine/Diesel	98.1	136.2	128.2	125.3	158.2	152.7	148.4	180.8	173.9	167.7
Nuclear Power[5]	98.2	99.3	99.3	99.3	99.6	99.6	99.6	99.6	99.6	99.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.6	97.2	97.3	97.4	101.8	102.0	102.1	104.4	104.3	104.3
Distributed Generation[7]	0.0	2.1	1.7	1.6	11.1	10.1	10.3	17.2	15.8	15.9
Total	**789.4**	**883.0**	**881.8**	**879.4**	**1035.9**	**1033.7**	**1031.1**	**1139.4**	**1131.2**	**1128.2**
Combined Heat and Power[8]										
Coal Steam	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Other Fossil Steam[4]	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Combined Cycle	22.6	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Combustion Turbine/Diesel	4.5	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**	**42.8**
Total Electric Power Industry	**823.1**	**925.8**	**924.7**	**922.2**	**1078.7**	**1076.5**	**1073.9**	**1182.2**	**1174.1**	**1171.0**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
Combustion Turbine/Diesel	0.0	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.4	6.4	6.4	6.5	6.5	6.5
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**96.2**	**96.2**	**96.2**	**97.9**	**97.9**	**97.9**	**98.0**	**98.0**	**98.0**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	4.1	6.8	8.3	44.8	45.5	45.4	74.1	74.0	75.8
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	39.3	46.1	45.5	127.5	129.3	131.3	172.3	171.4	172.7
Combustion Turbine/Diesel	0.0	20.0	12.3	9.0	46.7	40.0	34.9	70.3	61.9	55.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.3	1.4	1.5	4.3	4.5	4.6	6.8	6.7	6.7
Distributed Generation[7]	0.0	2.1	1.7	1.6	11.1	10.1	10.3	17.2	15.8	15.9
Total	**0.0**	**66.9**	**68.3**	**65.8**	**234.4**	**229.4**	**226.5**	**340.7**	**329.8**	**326.8**
Cumulative Total Additions	**0.0**	**163.1**	**164.5**	**162.0**	**332.2**	**327.3**	**324.3**	**438.7**	**427.8**	**424.8**
Cumulative Retirements[10]										
Coal Steam	0.0	6.9	5.8	5.8	8.7	7.6	7.6	9.8	8.7	8.7
Other Fossil Steam[4]	0.0	45.2	48.9	49.2	55.2	55.1	55.5	56.1	56.1	56.3
Combined Cycle	0.0	0.8	0.5	0.5	0.8	0.5	0.5	0.8	0.5	0.5
Combustion Turbine/Diesel	0.0	9.1	9.4	9.0	13.8	12.6	11.8	14.8	13.4	13.3
Nuclear Power	0.0	1.8	1.8	1.8	2.8	2.8	2.8	2.8	2.8	2.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**63.9**	**66.5**	**66.4**	**81.5**	**78.7**	**78.4**	**84.5**	**81.7**	**81.8**

Table C9. Electricity Generating Capcity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	7.0
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	18.3	18.3	18.3	23.4	23.3	23.2	27.9	27.7	27.7
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Renewable Sources[6]	4.7	6.2	6.2	6.1	8.1	8.0	8.0	9.0	9.0	9.0
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.6**	**33.1**	**33.1**	**33.1**	**40.1**	**40.0**	**39.8**	**45.7**	**45.4**	**47.6**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.7	2.0	2.0	2.0
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	5.5	5.5	5.4	12.5	12.3	12.2	18.1	17.8	20.0
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.6	0.9	0.9	0.9

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[7]Primarily peak-load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table C17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capacity for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Electricity Trade	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	142.7	102.9	102.9	102.9	0.0	0.0	0.0	0.0	0.0	0.0
Gross Domestic Economy Trade	176.8	187.1	199.8	206.9	167.4	180.0	187.9	160.6	177.9	186.0
Gross Domestic Trade	**319.5**	**290.0**	**302.8**	**309.9**	**167.4**	**180.0**	**187.9**	**160.6**	**177.9**	**186.0**
Gross Domestic Firm Power Sales (million 2001 dollars)	7047.1	5080.9	5080.9	5080.9	0.0	0.0	0.0	0.0	0.0	0.0
Gross Domestic Economy Sales (million 2001 dollars)	8240.1	5771.5	6203.2	6614.6	5421.4	6063.7	6459.5	5381.0	6238.5	6536.0
Gross Domestic Sales (million 2001 dollars)	**15287.3**	**10852.4**	**11284.1**	**11695.5**	**5421.4**	**6063.7**	**6459.5**	**5381.0**	**6238.5**	**6536.0**
International Electricity Trade										
Firm Power Imports From Canada & Mexico	12.1	5.8	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0
Economy Imports From Canada and Mexico	26.3	39.7	38.7	38.9	23.1	24.4	25.3	14.0	14.4	14.7
Gross Imports From Canada and Mexico	**38.5**	**45.5**	**44.5**	**44.8**	**23.1**	**24.4**	**25.3**	**14.0**	**14.4**	**14.7**
Firm Power Exports To Canada and Mexico	6.5	8.7	8.7	8.7	0.0	0.0	0.0	0.0	0.0	0.0
Economy Exports To Canada and Mexico	11.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**18.2**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.80	5.53	5.63	5.80	5.22	5.46	5.79	4.92	5.33	5.71
Alaska	0.97	0.63	0.64	0.65	1.22	1.23	1.24	1.16	1.17	1.18
Lower 48 States	4.84	4.91	4.98	5.15	4.00	4.23	4.54	3.76	4.16	4.52
Net Imports	9.31	11.61	11.51	11.20	13.32	12.66	12.10	14.05	13.06	12.53
Gross Imports	9.33	11.66	11.58	11.27	13.37	12.72	12.17	14.09	13.11	12.59
Exports	0.02	0.06	0.06	0.07	0.05	0.06	0.07	0.03	0.05	0.07
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.14**	**17.14**	**17.00**	**18.54**	**18.12**	**17.89**	**18.98**	**18.39**	**18.24**
Natural Gas Plant Liquids	**1.87**	**2.22**	**2.23**	**2.26**	**2.49**	**2.53**	**2.58**	**2.59**	**2.63**	**2.68**
Other Inputs[3]	**0.30**	**0.45**	**0.44**	**0.44**	**0.44**	**0.44**	**0.51**	**0.45**	**0.45**	**0.67**
Refinery Processing Gain[4]	**0.90**	**0.94**	**0.91**	**0.89**	**1.03**	**0.96**	**0.94**	**1.06**	**0.96**	**0.95**
Net Product Imports[5]	**1.59**	**2.50**	**2.25**	**1.87**	**5.25**	**5.06**	**4.37**	**7.06**	**6.73**	**5.66**
Gross Refined Product Imports[6]	2.08	2.60	2.59	2.31	5.13	5.02	4.34	6.96	6.76	5.67
Unfinished Oil Imports	0.38	0.90	0.66	0.54	1.20	1.09	1.08	1.27	1.07	1.07
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	1.00	1.00	0.99	1.08	1.06	1.05	1.17	1.10	1.08
Total Primary Supply[7]	**19.80**	**23.26**	**22.97**	**22.46**	**27.75**	**27.11**	**26.28**	**30.15**	**29.16**	**28.19**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.76	10.69	10.48	13.00	12.78	12.27	14.10	13.77	13.12
Jet Fuel[9]	1.66	1.90	1.90	1.88	2.47	2.46	2.42	2.75	2.74	2.70
Distillate Fuel[10]	3.81	4.66	4.61	4.53	5.57	5.40	5.30	6.23	5.87	5.75
Residual Fuel	0.97	0.71	0.60	0.55	0.76	0.64	0.58	0.77	0.64	0.59
Other[11]	4.58	5.25	5.20	5.02	5.97	5.85	5.71	6.32	6.15	6.04
Total	**19.69**	**23.28**	**22.99**	**22.46**	**27.77**	**27.13**	**26.28**	**30.17**	**29.17**	**28.19**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.20	1.17	1.10	1.21	1.13	1.05	1.22	1.12	1.04
Industrial[12]	4.67	5.35	5.30	5.12	6.13	6.00	5.85	6.51	6.33	6.21
Transportation	13.27	16.40	16.33	16.11	20.01	19.79	19.23	21.81	21.48	20.79
Electric Generators[13]	0.55	0.32	0.19	0.13	0.42	0.20	0.14	0.63	0.23	0.14
Total	**19.69**	**23.28**	**22.99**	**22.46**	**27.77**	**27.13**	**26.28**	**30.17**	**29.17**	**28.19**
Discrepancy[14]	**0.10**	**-0.02**	**-0.01**	**0.00**	**-0.02**	**-0.02**	**0.00**	**-0.02**	**-0.02**	**0.00**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**19.04**	**23.99**	**32.51**	**19.04**	**25.48**	**33.02**	**19.04**	**26.57**	**33.05**
Import Share of Product Supplied	**0.55**	**0.61**	**0.60**	**0.58**	**0.67**	**0.65**	**0.63**	**0.70**	**0.68**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**102.20**	**122.96**	**154.71**	**140.01**	**174.57**	**204.04**	**163.31**	**206.94**	**229.81**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.8**	**18.7**	**18.6**	**19.9**	**19.5**	**19.2**	**20.4**	**19.8**	**19.6**
Capacity Utilization Rate (percent)	**93.0**	**93.0**	**93.2**	**92.9**	**94.7**	**94.6**	**94.6**	**94.7**	**94.6**	**94.6**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C12. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price (2001 dollars per barrel)	**22.01**	**19.04**	**23.99**	**32.51**	**19.04**	**25.48**	**33.02**	**19.04**	**26.57**	**33.05**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	101.2	110.4	131.0	104.4	121.0	141.9	105.0	123.8	144.3
Liquefied Petroleum Gas	127.3	110.8	120.2	134.1	114.8	124.5	135.9	114.8	127.3	135.4
Commercial										
Distillate Fuel	88.7	69.2	78.4	99.3	73.2	90.0	111.0	74.7	93.7	113.5
Residual Fuel	51.8	49.0	60.0	79.7	48.7	63.3	80.6	48.5	65.6	80.5
Residual Fuel (2001 dollars per barrel)	21.75	20.58	25.21	33.49	20.47	26.57	33.87	20.36	27.55	33.81
Industrial[1]										
Distillate Fuel	90.8	70.3	79.4	101.0	77.3	94.3	115.4	80.8	100.6	118.3
Liquefied Petroleum Gas	105.9	73.1	82.2	95.5	77.3	86.8	97.5	77.1	89.3	97.1
Residual Fuel	49.1	44.5	55.5	75.1	44.4	58.9	76.3	44.3	61.4	76.3
Residual Fuel (2001 dollars per barrel)	20.61	18.70	23.32	31.55	18.66	24.74	32.03	18.61	25.77	32.04
Transportation										
Diesel Fuel (distillate)[2]	139.4	129.1	141.7	164.1	125.2	140.9	164.7	126.5	145.9	167.5
Jet Fuel[3]	83.7	66.8	75.9	96.8	69.6	85.4	106.5	72.3	90.7	109.9
Motor Gasoline[4]	143.3	134.0	142.8	162.6	124.3	143.7	167.1	122.8	149.6	169.8
Liquid Petroleum Gas	145.2	120.5	130.5	143.9	122.3	133.0	143.8	120.4	134.1	139.6
Residual Fuel	58.4	41.5	53.2	73.5	41.2	56.4	74.4	41.0	58.9	74.3
Residual Fuel (2001 dollars per barrel)	24.52	17.45	22.35	30.87	17.30	23.71	31.25	17.23	24.75	31.22
Ethanol (E85)	158.4	186.7	190.7	199.7	198.1	204.4	211.6	200.9	209.6	215.1
Electric Generators[5]										
Distillate Fuel	86.0	62.4	71.1	92.5	65.4	84.0	105.3	66.7	85.7	107.9
Residual Fuel	67.4	46.2	59.4	81.7	46.3	62.9	82.7	46.4	65.9	83.2
Residual Fuel (2001 dollars per barrel)	28.30	19.40	24.94	34.31	19.45	26.44	34.74	19.50	27.67	34.94
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	114.9	127.2	149.8	113.9	131.3	154.9	114.2	136.3	158.2
Jet Fuel[3]	83.7	66.8	75.9	96.8	69.6	85.4	106.5	72.3	90.7	109.9
Liquefied Petroleum Gas	110.3	80.3	89.4	102.6	83.6	93.1	103.9	83.2	95.3	103.1
Motor Gasoline[4]	143.3	134.0	142.8	162.6	124.3	143.7	167.1	122.8	149.6	169.8
Residual Fuel	61.5	43.7	55.1	75.3	43.6	58.6	76.4	43.6	61.1	76.4
Residual Fuel (2001 dollars per barrel)	25.85	18.35	23.16	31.63	18.33	24.62	32.08	18.29	25.68	32.10
Average	**123.6**	**112.3**	**122.4**	**142.3**	**108.0**	**125.4**	**146.8**	**107.6**	**130.4**	**149.0**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Dry Gas Production[1]	19.45	21.76	21.88	22.16	25.02	25.07	25.59	26.28	26.75	27.26
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.65**	**4.78**	**4.78**	**4.81**	**6.47**	**6.66**	**6.66**	**7.46**	**7.76**	**7.84**
Canada	3.61	4.04	4.05	4.07	4.90	5.08	5.06	5.24	5.31	5.23
Mexico	-0.13	-0.26	-0.26	-0.25	0.07	0.07	0.07	0.27	0.30	0.47
Liquefied Natural Gas	0.17	0.99	0.99	0.99	1.51	1.51	1.54	1.95	2.14	2.14
Total Supply	**23.17**	**26.63**	**26.76**	**27.06**	**31.59**	**31.82**	**32.34**	**33.84**	**34.60**	**35.19**
Consumption by Sector										
Residential	4.81	5.50	5.50	5.49	5.97	5.96	5.96	6.26	6.22	6.25
Commercial	3.24	3.68	3.69	3.70	4.14	4.17	4.20	4.39	4.43	4.49
Industrial[3]	7.53	8.80	8.88	9.17	10.06	10.10	10.26	10.81	10.91	11.00
Electric Generators[4]	5.30	6.79	6.80	6.81	9.19	9.39	9.45	9.96	10.56	10.54
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.61	0.75	0.76	0.76	0.90	0.88	0.89	0.97	1.00	0.99
Lease and Plant Fuel[6]	1.17	1.35	1.35	1.37	1.56	1.55	1.58	1.66	1.69	1.72
Total	**22.67**	**26.93**	**27.06**	**27.36**	**31.91**	**32.14**	**32.43**	**34.16**	**34.93**	**35.09**
Natural Gas to Liquids	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.23**	**0.00**	**0.00**	**0.43**
Discrepancy[7]	**0.50**	**-0.30**	**-0.30**	**-0.30**	**-0.32**	**-0.32**	**-0.32**	**-0.32**	**-0.32**	**-0.33**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C14. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.29	3.29	3.34	3.56	3.69	3.67	3.87	3.90	3.92
Average Import Price	4.43	3.32	3.33	3.36	3.70	3.81	3.80	4.06	4.19	4.10
Average[2]	**4.17**	**3.29**	**3.30**	**3.34**	**3.59**	**3.72**	**3.70**	**3.92**	**3.97**	**3.96**
Delivered Prices										
Residential	9.68	7.68	7.68	7.74	7.80	7.96	7.95	8.12	8.22	8.19
Commercial	8.32	6.56	6.56	6.61	6.79	6.94	6.93	7.14	7.22	7.19
Industrial[3]	5.00	3.99	4.00	4.02	4.32	4.44	4.42	4.64	4.70	4.69
Electric Generators[4]	4.87	3.85	3.86	3.90	4.25	4.38	4.36	4.59	4.69	4.64
Transportation[5]	7.87	7.26	7.28	7.33	7.70	7.97	7.95	8.03	8.30	8.24
Average[6]	**6.57**	**5.16**	**5.17**	**5.19**	**5.37**	**5.50**	**5.48**	**5.68**	**5.75**	**5.72**
Transmission and Distribution Margins[7]										
Residential	5.50	4.38	4.38	4.39	4.21	4.24	4.25	4.20	4.25	4.23
Commercial	4.14	3.26	3.26	3.27	3.20	3.22	3.23	3.22	3.25	3.23
Industrial[3]	0.83	0.69	0.70	0.68	0.73	0.73	0.72	0.72	0.73	0.73
Electric Generators[4]	0.70	0.56	0.56	0.56	0.66	0.66	0.66	0.67	0.72	0.69
Transportation[5]	3.69	3.97	3.98	3.99	4.11	4.25	4.25	4.11	4.33	4.28
Average[6]	**2.40**	**1.87**	**1.87**	**1.85**	**1.78**	**1.78**	**1.78**	**1.77**	**1.78**	**1.76**
Transmission and Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.12	24.12	24.14	25.13	25.26	25.33	26.31	26.44	26.42
Commercial	13.43	12.02	12.04	12.09	13.23	13.42	13.56	14.13	14.40	14.52
Industrial[3]	6.25	6.10	6.19	6.21	7.33	7.32	7.35	7.79	7.99	8.04
Electric Generators[4]	3.70	3.78	3.82	3.83	6.07	6.20	6.24	6.68	7.60	7.22
Transportation[5]	0.04	0.23	0.23	0.23	0.40	0.42	0.42	0.45	0.48	0.48
Total	**49.86**	**46.26**	**46.41**	**46.50**	**52.16**	**52.62**	**52.91**	**55.35**	**56.91**	**56.67**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, Office of Integrated Analysis and Forecasting AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C15. Oil and Gas Supply

Production and Supply	2001	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**20.06**	**23.90**	**32.41**	**18.54**	**24.89**	**32.44**	**18.62**	**26.12**	**32.59**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.53**	**5.63**	**5.80**	**5.22**	**5.46**	**5.79**	**4.92**	**5.33**	**5.71**
Lower 48 Onshore	3.13	2.46	2.51	2.60	2.04	2.12	2.20	1.90	1.98	2.02
Lower 48 Offshore	1.71	2.45	2.47	2.55	1.96	2.11	2.35	1.86	2.18	2.50
Alaska	0.97	0.63	0.64	0.65	1.22	1.23	1.24	1.16	1.17	1.18
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.46**	**17.79**	**18.57**	**14.80**	**15.64**	**16.80**	**14.03**	**15.31**	**16.30**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.29**	**3.29**	**3.34**	**3.56**	**3.69**	**3.67**	**3.87**	**3.90**	**3.92**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.76**	**21.88**	**22.16**	**25.03**	**25.07**	**25.59**	**26.29**	**26.75**	**27.26**
Lower 48 Onshore	13.72	16.22	16.28	16.48	18.37	19.14	19.06	18.37	18.43	18.62
Associated-Dissolved[4]	1.77	1.36	1.38	1.41	1.19	1.21	1.24	1.13	1.15	1.16
Non-Associated	11.94	14.86	14.91	15.07	17.18	17.92	17.82	17.24	17.27	17.46
Conventional	6.54	7.94	7.98	8.15	7.92	8.24	8.26	7.79	7.75	7.85
Unconventional	5.40	6.91	6.93	6.91	9.26	9.68	9.56	9.45	9.53	9.61
Lower 48 Offshore	5.30	5.07	5.12	5.21	5.19	5.39	5.74	5.49	5.69	5.75
Associated-Dissolved[4]	1.08	0.79	0.79	0.81	0.72	0.77	0.85	0.74	0.91	0.97
Non-Associated	4.22	4.28	4.33	4.40	4.47	4.62	4.89	4.75	4.78	4.78
Alaska	0.43	0.48	0.48	0.48	1.47	0.55	0.79	2.42	2.64	2.89
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**177.47**	**178.39**	**180.81**	**190.95**	**193.42**	**196.67**	**188.09**	**189.88**	**192.95**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**24.92**	**25.83**	**28.14**	**25.47**	**27.37**	**28.46**	**26.86**	**28.41**	**28.98**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production[1]										
Appalachia	443	419	422	423	412	419	419	427	431	434
Interior	147	161	158	161	147	150	155	156	159	174
West	548	642	651	650	794	790	783	852	850	854
East of the Mississippi	539	526	528	529	522	529	533	549	553	567
West of the Mississippi	599	695	703	705	830	829	824	887	887	895
Total	**1138**	**1221**	**1231**	**1234**	**1353**	**1359**	**1357**	**1436**	**1440**	**1462**
Net Imports										
Imports	20	20	20	20	25	25	25	28	28	28
Exports	49	34	35	35	29	29	29	26	26	26
Total	**-29**	**-15**	**-15**	**-15**	**-4**	**-4**	**-4**	**2**	**2**	**2**
Total Supply[2]	**1109**	**1207**	**1215**	**1219**	**1349**	**1355**	**1354**	**1437**	**1442**	**1464**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	67	66	66	69	69	69	71	71	90
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	19
Coke Plants	26	24	24	24	20	20	20	18	18	18
Electric Generators[4]	957	1114	1123	1127	1257	1263	1262	1346	1350	1353
Total	**1050**	**1210**	**1218**	**1222**	**1352**	**1358**	**1356**	**1440**	**1444**	**1467**
Discrepancy and Stock Change[5]	**59**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.01	14.99	15.14	14.20	14.38	14.57	14.17	14.36	14.59
(2001 dollars per million Btu)	0.83	0.73	0.73	0.74	0.70	0.71	0.71	0.70	0.71	0.72
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.83	29.77	29.97	30.38	28.08	28.40	28.76	27.54	27.92	26.46
Coke Plants	46.42	41.25	41.38	41.83	38.25	38.62	38.88	36.92	37.09	37.29
Electric Generators										
(2001 dollars per short ton)	25.06	23.46	23.61	23.89	22.17	22.45	22.71	21.84	22.17	22.45
(2001 dollars per million Btu)	1.25	1.16	1.17	1.18	1.11	1.12	1.13	1.09	1.10	1.12
Average	**26.06**	**24.16**	**24.31**	**24.60**	**22.71**	**23.00**	**23.26**	**22.32**	**22.64**	**22.88**
Exports[7]	36.97	32.69	32.88	33.14	31.61	31.89	32.11	30.65	30.85	31.04

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.36	78.92	78.92	78.92	78.92	78.92	78.92	78.92	78.92	78.92
Geothermal[2]	2.86	3.59	3.54	3.54	5.02	5.00	4.91	5.81	5.64	5.60
Municipal Solid Waste[3]	3.25	4.01	4.03	4.03	4.34	4.37	4.36	4.35	4.37	4.37
Wood and Other Biomass[4]	1.77	2.07	2.07	2.07	2.21	2.18	2.18	2.93	2.78	2.87
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.32	8.47	8.52	10.80	11.05	11.20	11.76	12.00	11.96
Total	**90.88**	**97.45**	**97.57**	**97.61**	**102.02**	**102.25**	**102.31**	**104.61**	**104.56**	**104.57**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	301.89	301.89	301.89	301.05	301.05	301.05	301.34	301.34	301.35
Geothermal[2]	13.81	20.20	19.81	19.78	31.92	31.78	31.02	38.26	36.92	36.55
Municipal Solid Waste[3]	19.55	28.70	28.88	28.87	31.16	31.34	31.34	31.31	31.49	31.49
Wood and Other Biomass[4]	9.38	21.45	21.27	21.48	22.32	21.88	22.20	24.67	24.66	24.78
Dedicated Plants	7.67	12.41	12.41	12.42	13.36	13.12	13.12	17.13	16.47	16.77
Cofiring	1.71	9.04	8.85	9.06	8.96	8.76	9.07	7.54	8.19	8.01
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	23.10	23.62	23.74	31.79	32.70	33.23	35.34	36.21	36.06
Total	**262.85**	**396.36**	**396.47**	**396.79**	**419.79**	**420.31**	**420.40**	**432.77**	**432.48**	**432.09**
End-Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.89	5.88	5.86	7.78	7.76	7.73	8.75	8.71	8.69
Total	**4.69**	**6.17**	**6.16**	**6.14**	**8.07**	**8.04**	**8.01**	**9.03**	**9.00**	**8.97**
Other End-Use Generators[7]										
Contentional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.62	0.62	0.62	0.93	0.93	0.93
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.71**	**1.71**	**2.02**	**2.03**	**2.02**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.31	37.23	37.11	48.37	48.21	48.05	54.02	53.80	53.65
Total	**31.13**	**39.46**	**39.38**	**39.26**	**50.53**	**50.36**	**50.20**	**56.17**	**55.95**	**55.81**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.32	1.33	1.32	1.97	1.98	1.98
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.56**	**5.57**	**5.56**	**6.20**	**6.22**	**6.21**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Sector and Source	2001	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.41**	**0.41**	**0.40**	**0.41**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.41	0.41	0.41	0.40	0.41	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.22**	**2.22**	**2.21**	**2.78**	**2.77**	**2.77**	**3.06**	**3.05**	**3.05**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.17	2.17	2.17	2.73	2.72	2.72	3.02	3.01	3.00
Transportation	**0.15**	**0.26**	**0.26**	**0.26**	**0.32**	**0.31**	**0.30**	**0.34**	**0.34**	**0.32**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.26	0.31	0.31	0.30	0.34	0.33	0.32
Electric Generators[5]	**3.02**	**4.50**	**4.50**	**4.50**	**4.99**	**5.00**	**4.98**	**5.24**	**5.21**	**5.20**
Conventional Hydroelectric	2.17	3.10	3.10	3.10	3.08	3.08	3.08	3.08	3.08	3.08
Geothermal	0.29	0.50	0.49	0.49	0.87	0.86	0.84	1.06	1.01	1.00
Municipal Solid Waste[6]	0.31	0.39	0.40	0.40	0.43	0.43	0.43	0.43	0.43	0.43
Biomass	0.15	0.26	0.26	0.27	0.28	0.27	0.28	0.29	0.30	0.30
Dedicated Plants	0.12	0.14	0.14	0.14	0.15	0.15	0.15	0.20	0.19	0.19
Cofiring	0.03	0.12	0.12	0.13	0.12	0.12	0.13	0.10	0.11	0.11
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	0.24	0.24	0.24	0.33	0.34	0.34	0.36	0.37	0.37
Total Marketed Renewable Energy	**5.47**	**7.51**	**7.49**	**7.49**	**8.60**	**8.59**	**8.56**	**9.16**	**9.11**	**9.08**
Sources of Ethanol										
From Corn	0.15	0.26	0.26	0.26	0.29	0.29	0.27	0.29	0.29	0.27
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.05	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.26**	**0.32**	**0.31**	**0.30**	**0.34**	**0.34**	**0.32**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table C8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

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

Sector and Source	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential										
Petroleum	27.2	28.2	27.6	26.2	27.0	25.7	24.1	26.7	25.1	23.5
Natural Gas	71.1	81.4	81.5	81.3	88.4	88.2	88.2	92.6	92.1	92.5
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Electricity	215.1	243.2	242.7	242.3	270.5	269.4	268.6	287.3	285.2	284.2
Total	**313.8**	**353.2**	**352.1**	**350.1**	**386.2**	**383.7**	**381.3**	**406.9**	**402.8**	**400.6**
Commercial										
Petroleum	14.0	13.7	13.1	12.1	15.2	13.4	12.0	15.8	13.5	12.1
Natural Gas	48.0	54.5	54.7	54.7	61.2	61.7	62.2	64.9	65.6	66.5
Coal	2.3	2.5	2.5	2.4	2.7	2.7	2.7	2.8	2.8	2.8
Electricity	214.5	247.7	247.0	246.4	299.7	298.4	297.6	330.5	328.0	327.2
Total	**278.8**	**318.4**	**317.2**	**315.6**	**378.8**	**376.2**	**374.5**	**414.0**	**409.9**	**408.6**
Industrial[1]										
Petroleum	97.9	99.9	98.6	92.8	110.0	106.5	102.8	115.1	110.4	107.8
Natural Gas[2]	123.4	147.7	149.0	153.4	169.0	169.4	172.2	181.4	183.4	185.0
Coal	52.1	56.2	56.2	56.2	56.1	56.1	56.0	56.1	56.1	61.1
Electricity	178.1	195.0	194.3	194.6	224.0	223.1	222.8	241.5	240.0	238.8
Total	**451.5**	**498.7**	**498.1**	**497.0**	**559.2**	**555.2**	**553.9**	**594.2**	**589.9**	**592.7**
Transportation										
Petroleum[3]	501.4	618.8	616.4	608.5	754.9	746.9	726.8	822.9	811.0	786.2
Natural Gas[4]	9.2	12.0	12.1	12.2	14.7	14.5	14.6	16.0	16.3	16.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.6	4.6	4.6	6.0	5.9	5.9	6.9	6.8	6.7
Total	**514.5**	**635.4**	**633.0**	**625.2**	**775.6**	**767.3**	**747.3**	**845.8**	**834.2**	**809.1**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	760.5	755.7	739.5	907.1	892.6	865.8	980.5	960.1	929.6
Natural Gas	251.7	295.6	297.2	301.7	333.3	333.8	337.3	354.9	357.5	360.3
Coal	54.7	59.0	59.0	59.0	59.1	59.2	59.1	59.3	59.3	64.2
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	690.4	688.5	687.8	800.1	796.9	794.9	866.1	860.1	857.0
Total	**1558.6**	**1805.6**	**1800.5**	**1788.0**	**2099.7**	**2082.5**	**2057.0**	**2260.9**	**2236.9**	**2211.1**
Electric Generators[6]										
Petroleum	27.5	15.3	8.8	6.0	19.6	9.7	6.7	28.3	10.9	6.8
Natural Gas	77.7	99.6	99.9	99.9	134.8	137.8	138.7	146.2	155.0	154.6
Coal	506.4	575.6	579.9	581.9	645.7	649.5	649.6	691.6	694.2	695.6
Total	**611.6**	**690.4**	**688.5**	**687.8**	**800.1**	**796.9**	**794.9**	**866.1**	**860.1**	**857.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	775.8	764.5	745.5	926.7	902.2	872.4	1008.8	971.0	936.4
Natural Gas	329.4	395.2	397.1	401.6	468.1	471.6	475.9	501.2	512.5	514.9
Coal	561.1	634.6	638.9	640.9	704.8	708.7	708.6	750.9	753.4	759.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1805.6**	**1800.5**	**1788.0**	**2099.7**	**2082.5**	**2057.0**	**2260.9**	**2236.9**	**2211.1**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**6.0**	**6.0**	**6.5**	**6.4**	**6.3**	**6.7**	**6.6**	**6.5**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.313**	**1.313**	**1.316**	**1.697**	**1.708**	**1.729**	**1.957**	**1.981**	**2.018**
Real Gross Domestic Product	**9215**	**12271**	**12258**	**12239**	**16484**	**16450**	**16408**	**18972**	**18917**	**18875**
Real Consumption	6377	8438	8412	8366	11405	11351	11288	13078	13012	12975
Real Investment	1575	2506	2499	2487	3778	3755	3721	4530	4492	4449
Real Government Spending	1640	1897	1895	1892	2215	2212	2208	2434	2429	2426
Real Exports	1076	1781	1784	1792	3351	3360	3366	4699	4695	4675
Real Imports	1492	2328	2301	2256	4129	4059	3974	5498	5398	5313
Real Disposable Personal Income	**6748**	**8657**	**8637**	**8604**	**11740**	**11713**	**11702**	**13451**	**13435**	**13480**
AA Utility Bond Rate (percent)	**7.43**	**7.18**	**7.24**	**7.38**	**8.90**	**9.18**	**9.62**	**9.17**	**9.63**	**10.30**
Real Yield on Government 10 Year Bonds (percent)	**3.51**	**5.22**	**5.26**	**5.39**	**6.36**	**6.56**	**6.90**	**6.41**	**6.76**	**7.32**
Real Utility Bond Rate (percent)	**5.45**	**5.31**	**5.35**	**5.47**	**6.15**	**6.32**	**6.61**	**6.22**	**6.56**	**7.12**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.87	6.87	6.83	5.98	5.94	5.88	5.59	5.55	5.49
Total Energy	10.57	9.26	9.24	9.21	7.95	7.92	7.85	7.40	7.36	7.29
Consumer Price Index (1982-84=1.00)	**1.77**	**2.18**	**2.19**	**2.20**	**2.90**	**2.93**	**2.97**	**3.41**	**3.47**	**3.54**
Unemployment Rate (percent)	**4.79**	**4.38**	**4.41**	**4.44**	**5.87**	**5.89**	**5.89**	**5.74**	**5.77**	**5.70**
Housing Starts (millions)	**1.80**	**2.18**	**2.17**	**2.16**	**1.94**	**1.92**	**1.90**	**2.04**	**2.02**	**2.00**
Single-Family	1.27	1.34	1.34	1.33	1.13	1.12	1.10	1.14	1.12	1.10
Multifamily	0.33	0.47	0.47	0.47	0.49	0.48	0.48	0.57	0.57	0.57
Mobile Home Shipments	0.19	0.37	0.37	0.37	0.32	0.32	0.32	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**81.8**	**81.8**	**81.6**	**94.8**	**94.6**	**94.5**	**101.3**	**101.1**	**101.0**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6970	6959	6948	8986	8963	8935	10172	10126	10087
Nonmanufacturing	1346	1507	1505	1503	1747	1743	1738	1875	1869	1865
Manufacturing	4079	5464	5453	5445	7240	7220	7197	8297	8257	8222
Energy-Intensive Manufacturing	1086	1260	1256	1251	1455	1446	1439	1546	1532	1528
Non-Energy-Intensive Manufacturing	2993	4203	4197	4194	5785	5774	5758	6751	6725	6694
Unit Sales of Light-Duty Vehicles (millions)	**17.11**	**18.40**	**18.27**	**18.11**	**20.18**	**19.91**	**19.49**	**20.43**	**19.97**	**19.61**
Population (millions)										
Population with Armed Forces Overseas)	278.2	300.2	300.2	300.2	325.3	325.3	325.3	338.2	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	236.6	256.5	256.5	256.5	266.6	266.6	266.6
Employment, Non-Agriculture	131.7	147.2	147.1	147.0	159.2	159.2	159.2	166.0	165.9	166.2
Employment, Manufacturing	17.5	17.9	17.9	18.0	17.2	17.3	17.5	18.3	18.4	18.7
Labor Force	141.8	156.5	156.5	156.5	169.8	169.8	169.7	177.5	177.4	177.4

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price[1] (2001 dollars per barrel)	**22.01**	**19.04**	**23.99**	**32.51**	**19.04**	**25.48**	**33.02**	**19.04**	**26.57**	**33.05**
Production[2] (Conventional)										
Industrialized Countries										
U.S. (50 states)	8.88	9.14	9.20	9.40	9.18	9.39	9.63	9.03	9.36	9.48
Canada	2.09	2.04	1.93	2.12	1.67	1.62	1.87	1.51	1.54	1.69
Mexico	3.59	4.19	4.26	4.78	4.27	4.42	5.18	4.39	4.57	5.36
Western Europe[3]	6.92	6.28	6.33	6.70	5.36	5.45	5.88	4.91	5.00	5.40
Japan	0.08	0.07	0.08	0.12	0.06	0.07	0.18	0.05	0.07	0.19
Australia and New Zealand	0.80	0.83	0.84	0.94	0.76	0.79	0.93	0.75	0.78	0.92
Total Industrialized	**22.35**	**22.55**	**22.64**	**24.06**	**21.30**	**21.74**	**23.67**	**20.64**	**21.32**	**23.03**
Eurasia										
Former Soviet Union										
Russia	7.24	9.03	9.17	10.30	9.92	10.26	12.02	10.02	10.42	12.21
Caspian Area[4]	1.59	3.54	3.60	4.04	4.54	4.70	5.50	4.81	5.01	5.87
Eastern Europe[5]	0.22	0.27	0.28	0.31	0.37	0.38	0.45	0.40	0.42	0.49
Total Eurasia	**9.05**	**12.84**	**13.04**	**14.65**	**14.82**	**15.34**	**17.98**	**15.24**	**15.84**	**18.58**
Developing Countries										
OPEC[6]										
Asia	1.48	1.46	1.44	1.38	1.49	1.45	1.38	1.50	1.46	1.40
Middle East	19.42	25.24	22.43	14.06	40.93	33.82	20.12	51.40	42.02	27.59
North Africa	3.06	4.64	4.60	4.51	5.68	5.62	5.51	6.51	6.44	6.33
West Africa	2.23	3.25	3.23	3.16	4.69	4.64	4.55	5.51	5.45	5.37
South America	2.92	3.95	3.87	3.64	4.51	4.26	3.75	5.07	4.75	4.14
Non-OPEC										
China	3.30	3.39	3.44	3.87	3.22	3.33	3.91	3.15	3.28	3.84
Other Asia	2.38	2.50	2.54	2.85	2.47	2.55	2.99	2.44	2.53	2.96
Middle East[7]	1.99	2.22	2.25	2.53	2.37	2.45	2.87	2.51	2.61	3.07
Africa	2.70	4.43	4.47	5.01	6.45	6.60	7.68	6.71	6.85	7.95
South and Central America	3.72	4.53	4.59	5.14	5.94	6.10	7.08	6.14	6.31	7.30
Total Developing Countries	**43.20**	**55.61**	**52.86**	**46.14**	**77.76**	**70.83**	**59.84**	**90.94**	**81.72**	**69.96**
Total Production (Conventional)	**74.61**	**91.01**	**88.54**	**84.85**	**113.89**	**107.92**	**101.48**	**126.82**	**118.88**	**111.56**
Production[8] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.31
Other North America	0.72	1.38	1.52	1.57	1.95	2.07	2.22	2.16	2.22	2.49
Western Europe	0.04	0.04	0.04	0.05	0.03	0.04	0.06	0.03	0.04	0.06
Asia	0.02	0.02	0.03	0.04	0.02	0.03	0.05	0.02	0.03	0.05
Middle East[7]	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.01	0.03	0.04
Africa	0.15	0.16	0.19	0.23	0.16	0.25	0.34	0.15	0.28	0.41
South and Central America	0.49	0.78	0.85	1.02	1.16	1.42	1.94	1.11	1.45	2.13
Total Production[3] (Nonconventional)	**1.42**	**2.40**	**2.64**	**2.93**	**3.34**	**3.83**	**4.75**	**3.49**	**4.05**	**5.49**
Total Production	**76.02**	**93.40**	**91.18**	**87.78**	**117.22**	**111.75**	**106.23**	**130.31**	**122.93**	**117.05**

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Consumption[9]										
Industrialized Countries										
U.S. (50 states)	19.69	23.28	22.99	22.46	27.77	27.13	26.28	30.17	29.17	28.19
U.S. Territories	0.35	0.47	0.44	0.40	0.55	0.49	0.44	0.61	0.54	0.49
Canada	1.91	2.34	2.22	2.05	2.66	2.41	2.18	2.80	2.50	2.29
Mexico	1.94	2.91	2.78	2.59	4.51	3.94	3.35	5.36	4.47	3.70
Western Europe[3]	13.87	15.34	14.95	14.38	16.37	15.65	14.97	16.77	15.93	15.32
Japan	5.42	6.37	6.03	5.52	7.13	6.21	5.30	7.46	6.27	5.34
Australia and New Zealand	1.01	1.28	1.25	1.21	1.66	1.60	1.53	1.83	1.75	1.69
Total Industrialized	**44.19**	**51.98**	**50.66**	**48.60**	**60.65**	**57.42**	**54.06**	**65.01**	**60.64**	**57.02**
Eurasia										
Former Soviet Union	3.63	4.77	4.67	4.52	5.70	5.50	5.31	6.02	5.78	5.61
Eastern Europe[5]	1.37	1.63	1.61	1.57	2.13	2.08	2.04	2.40	2.33	2.29
Total Eurasia	**5.00**	**6.40**	**6.28**	**6.10**	**7.82**	**7.58**	**7.35**	**8.42**	**8.12**	**7.90**
Developing Countries										
China	4.82	6.79	6.55	6.20	10.69	10.05	9.46	13.08	12.20	11.57
India	2.00	3.28	3.19	3.04	5.26	4.92	4.57	6.64	6.12	5.70
South Korea	2.22	2.97	2.86	2.70	3.35	3.10	2.87	3.47	3.18	2.95
Other Asia	5.34	7.10	6.98	6.80	9.26	8.98	8.71	10.49	10.13	9.86
Middle East[7]	5.13	6.24	6.17	6.07	8.35	8.20	8.07	9.59	9.40	9.26
Africa	2.46	3.24	3.19	3.12	4.14	4.01	3.86	4.65	4.46	4.31
South and Central America	4.87	5.68	5.59	5.46	7.99	7.78	7.59	9.25	8.98	8.78
Total Developing Countries	**26.84**	**35.31**	**34.54**	**33.38**	**49.04**	**47.05**	**45.13**	**57.17**	**54.47**	**52.43**
Total Consumption	**76.03**	**93.69**	**91.48**	**88.08**	**117.51**	**112.04**	**106.53**	**130.60**	**123.23**	**117.35**
OPEC Production[10]	29.48	39.14	36.22	27.53	58.19	50.88	36.80	70.84	61.24	46.46
NonOPEC Production[10]	46.54	54.26	54.96	60.26	59.03	60.86	69.44	59.47	61.69	70.59
Net Eurasia Exports	4.07	6.45	6.78	8.57	7.01	7.78	10.65	6.83	7.74	10.70
OPEC Market Share	0.39	0.42	0.40	0.31	0.50	0.46	0.35	0.54	0.50	0.40

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs LW2003.D110502C, AEO2003.D110502C, and HW2003.D110502C.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Summary
(Million Barrels per Day Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Production								
Crude Oil and Lease Condensate	5.87	5.80	5.58	5.63	5.25	5.46	5.33	-0.4%
Natural Gas Plant Liquids	1.28	1.25	1.39	1.49	1.61	1.70	1.78	1.5%
Dry Natural Gas	9.19	9.43	9.77	10.61	11.56	12.13	12.98	1.3%
Coal	10.64	11.32	11.02	11.95	12.45	13.04	13.84	0.8%
Nuclear Power	3.71	3.79	3.91	3.95	3.97	3.97	3.98	0.2%
Renewable Energy[1]	2.81	2.52	3.17	3.42	3.66	3.90	4.15	2.1%
Other[2]	0.51	0.27	0.39	0.40	0.35	0.38	0.38	1.4%
Total	**34.01**	**34.39**	**35.24**	**37.44**	**38.85**	**40.58**	**42.43**	**0.9%**
Imports								
Crude Oil[3]	9.07	9.33	10.29	11.58	12.41	12.72	13.11	1.4%
Petroleum Products[4]	2.24	2.38	2.01	3.03	4.53	5.65	7.17	4.7%
Natural Gas	1.82	1.94	2.15	2.61	2.80	3.40	3.92	3.0%
Other Imports[5]	0.33	0.34	0.38	0.42	0.46	0.45	0.44	1.1%
Total	**13.45**	**13.99**	**14.83**	**17.64**	**20.20**	**22.23**	**24.64**	**2.4%**
Exports								
Petroleum[6]	1.02	0.95	0.97	1.06	1.07	1.10	1.14	0.8%
Natural Gas	0.12	0.17	0.28	0.29	0.26	0.20	0.17	0.1%
Coal	0.72	0.60	0.47	0.43	0.35	0.35	0.32	-2.6%
Total	**1.85**	**1.72**	**1.72**	**1.78**	**1.68**	**1.65**	**1.63**	**-0.2%**
Discrepancy[7]	**1.18**	**-0.72**	**0.36**	**0.14**	**0.14**	**0.06**	**0.16**	**N/A**
Consumption								
Petroleum Products[8]	18.15	18.17	18.80	21.09	23.11	24.78	26.72	1.6%
Natural Gas	11.34	10.99	11.92	13.11	14.29	15.52	16.91	1.8%
Coal	10.63	10.39	10.75	11.75	12.35	12.96	13.81	1.2%
Nuclear Power	3.71	3.79	3.91	3.95	3.97	3.97	3.98	0.2%
Renewable Energy[1]	2.81	2.52	3.17	3.42	3.66	3.90	4.15	2.1%
Other[9]	0.15	0.10	0.15	0.14	0.13	0.08	0.03	-4.4%
Total	**46.79**	**45.95**	**48.70**	**53.45**	**57.51**	**61.22**	**65.61**	**1.5%**
Net Imports - Petroleum	**10.49**	**11.00**	**11.59**	**13.84**	**16.18**	**17.54**	**19.48**	**2.4%**
Prices (2001 dollars per unit)								
World Oil Price (dollars per barrel)[10]	28.35	22.01	23.27	23.99	24.72	25.48	26.57	0.8%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.83	4.12	2.88	3.29	3.55	3.69	3.90	-0.2%
Coal Minemouth Price (dollars per ton)	17.18	17.59	16.50	14.99	14.67	14.38	14.36	-0.8%
Average Electricity Price (cents per kilowatthour)	6.9	7.3	6.5	6.4	6.5	6.6	6.7	-0.3%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001). 2001 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2000 coal minemouth prices: EIA, *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). 2000 petroleum supply values: EIA *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2000 and 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002).
Projections: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Crude Oil Equivalency Summary

Table D2. Total Energy Supply and Disposition Summary
(Million Tons of Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2001-2025 (percent)
	2000	2001	2005	2010	2015	2020	2025	
Production								
Crude Oil and Lease Condensate	313.37	309.66	297.85	300.17	279.90	291.41	284.38	-0.4%
Natural Gas Plant Liquids	68.27	66.73	74.29	79.69	86.11	90.44	94.81	1.5%
Dry Natural Gas	491.38	503.32	521.07	566.14	616.67	648.84	692.32	1.3%
Coal	569.02	604.04	587.93	637.53	664.44	697.67	738.20	0.8%
Nuclear Power	198.38	202.31	208.63	210.56	211.81	212.45	212.48	0.2%
Renewable Energy[1]	150.24	134.22	169.14	182.26	195.24	208.73	221.29	2.1%
Other[2]	27.41	14.45	20.94	21.18	18.63	20.10	20.24	1.4%
Total	**1818.07**	**1834.74**	**1879.83**	**1997.53**	**2072.81**	**2169.65**	**2263.73**	**0.9%**
Imports								
Crude Oil[3]	496.22	510.44	562.96	633.34	678.68	695.72	717.32	1.4%
Petroleum Products[4]	119.31	127.09	107.06	161.61	241.56	301.67	382.32	4.7%
Natural Gas	97.39	103.30	114.48	139.10	149.61	182.03	209.23	3.0%
Other Imports[5]	17.43	18.36	20.44	22.63	24.62	24.15	23.68	1.1%
Total	**730.35**	**759.20**	**804.94**	**956.68**	**1094.47**	**1203.58**	**1332.56**	**2.4%**
Exports								
Petroleum[6]	54.18	50.55	51.67	56.40	56.91	58.86	60.62	0.8%
Natural Gas	6.18	9.20	14.93	15.62	13.77	10.43	9.33	0.1%
Coal	38.51	32.03	25.19	22.85	18.68	18.66	16.98	-2.6%
Total	**98.86**	**91.78**	**91.80**	**94.87**	**89.37**	**87.96**	**86.93**	**-0.2%**
Discrepancy[7]	**-54.87**	**50.27**	**-6.72**	**5.27**	**5.86**	**6.24**	**4.70**	**-9.4%**
Consumption								
Petroleum Products[8]	970.89	969.20	1002.71	1125.17	1233.13	1325.49	1425.26	1.6%
Natural Gas	606.45	586.07	636.06	699.29	762.39	830.47	902.38	1.8%
Coal	570.55	554.82	574.97	629.51	662.71	697.51	741.44	1.2%
Nuclear Power	198.38	202.31	208.63	210.56	211.81	212.45	212.48	0.2%
Renewable Energy[1]	150.25	134.23	169.14	182.27	195.26	208.75	221.32	2.1%
Other[9]	7.91	5.26	8.19	7.29	6.75	4.35	1.79	-4.4%
Total	**2504.43**	**2451.89**	**2599.70**	**2854.08**	**3072.05**	**3279.02**	**3504.66**	**1.5%**
Net Imports - Petroleum	**561.35**	**586.99**	**618.34**	**738.55**	**863.32**	**938.53**	**1039.02**	**2.4%**
Prices (2001 dollars per unit)								
World Oil Price (dollars per barrel)[10]	28.35	22.01	23.27	23.99	24.72	25.48	26.57	0.8%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.83	4.12	2.88	3.29	3.55	3.69	3.90	-0.2%
Coal Minemouth Price (dollars per ton)	17.18	17.59	16.50	14.99	14.67	14.38	14.36	-0.8%
Average Electricity Price (cents per kilowatthour)	6.9	7.3	6.5	6.4	6.5	6.6	6.7	-0.3%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.

[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

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

[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.

[5]Includes coal, coal coke (net), and electricity (net).

[6]Includes crude oil and petroleum products.

[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.

[9]Includes net electricity imports, methanol, and liquid hydrogen.

[10]Average refiner acquisition cost for imported crude oil.

[11]Represents lower 48 onshore and offshore supplies.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2000 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001). 2001 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2000 coal minemouth prices: EIA, *Coal Industry Annual 2000*, DOE/EIA-0584(2000) (Washington, DC, January 2002). 2000 petroleum supply values: EIA *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2000 and 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002).
Projections: EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Household Expenditures

Table E1. 2000 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2911.33**	**1392.10**	**915.34**	**386.40**	**90.36**	**1519.23**
Households by Income Quintile						
1st	1703.47	1041.51	655.28	305.39	80.84	661.95
2nd	2451.98	1189.96	807.73	321.69	60.54	1262.02
3rd	2857.96	1337.50	878.72	363.50	95.29	1520.46
4th	3215.65	1446.36	954.27	413.53	78.55	1769.30
5th	3917.81	1780.23	1170.69	488.12	121.42	2137.59
Households by Census Division						
New England	3245.12	1656.61	805.21	312.69	538.72	1588.50
Middle Atlantic	2985.58	1710.16	842.92	513.83	353.40	1275.43
South Atlantic	3089.30	1378.97	736.41	618.21	24.34	1710.33
East North Central	3254.01	1361.28	826.49	500.01	34.78	1892.73
East South Central	2800.23	1361.97	1111.94	220.37	29.66	1438.26
West North Central	2867.97	1420.52	1204.75	213.55	2.22	1447.45
West South Central	2956.38	1544.33	1211.60	332.74	0.00	1412.05
Mountain	2680.37	1123.82	754.82	363.16	5.84	1556.55
Pacific	2598.20	1069.94	745.31	315.87	8.76	1528.26

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table E2. 2005 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2783.98**	**1342.94**	**897.74**	**369.03**	**76.17**	**1441.04**
Households by Income Quintile						
1st	1639.89	1006.10	648.54	289.81	67.76	633.79
2nd	2354.59	1151.06	794.65	305.25	51.15	1203.53
3rd	2734.40	1289.09	861.02	347.56	80.50	1445.31
4th	3069.10	1395.47	935.13	394.24	66.10	1673.63
5th	3727.68	1712.69	1141.91	468.40	102.38	2015.00
Households by Census Division						
New England	3079.90	1574.93	792.56	295.93	486.43	1504.98
Middle Atlantic	2798.22	1583.45	764.12	514.62	304.71	1214.77
South Atlantic	2924.46	1342.83	730.79	591.39	20.65	1581.63
East North Central	3106.66	1319.50	826.69	462.66	30.15	1787.16
East South Central	2680.25	1340.46	1112.99	204.60	22.87	1339.78
West North Central	2726.66	1341.32	1143.87	195.66	1.79	1385.35
West South Central	2842.49	1477.53	1168.61	308.92	0.00	1364.95
Mountain	2646.20	1142.99	762.12	376.03	4.84	1503.21
Pacific	2547.23	1057.52	745.20	305.18	7.14	1489.71

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table E3. 2010 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2919.70**	**1341.91**	**900.60**	**370.62**	**70.69**	**1577.79**
Households by Income Quintile						
1st	1704.31	1007.14	656.32	289.00	61.82	697.17
2nd	2471.03	1151.52	798.42	305.67	47.44	1319.50
3rd	2870.70	1287.67	863.41	349.55	74.71	1583.03
4th	3223.98	1392.83	937.08	394.25	61.50	1831.15
5th	3917.63	1711.90	1142.65	473.46	95.79	2205.73
Households by Census Division						
New England	3248.45	1593.02	815.56	294.30	483.16	1655.43
Middle Atlantic	2896.56	1571.06	768.54	514.85	287.68	1325.49
South Atlantic	3052.19	1345.25	730.75	595.04	19.46	1706.94
East North Central	3272.67	1319.62	829.48	461.53	28.60	1953.06
East South Central	2776.27	1330.15	1097.23	212.52	20.40	1446.12
West North Central	2787.18	1288.19	1094.28	192.34	1.57	1498.99
West South Central	2955.76	1464.06	1158.08	305.98	0.00	1491.70
Mountain	2877.82	1198.79	801.59	393.09	4.11	1679.02
Pacific	2767.77	1084.41	765.63	311.89	6.89	1683.36

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table E4. 2015 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2991.17**	**1362.56**	**920.97**	**374.67**	**66.92**	**1628.60**
Households by Income Quintile						
1st	1744.14	1023.02	675.69	289.96	57.37	721.12
2nd	2531.90	1168.24	815.29	307.99	44.96	1363.65
3rd	2942.61	1307.06	882.24	353.94	70.87	1635.55
4th	3300.48	1411.99	955.99	397.62	58.38	1888.50
5th	4020.49	1742.30	1169.40	481.56	91.34	2278.20
Households by Census Division						
New England	3368.16	1637.43	852.79	297.48	487.16	1730.73
Middle Atlantic	2986.22	1611.64	813.36	522.61	275.67	1374.58
South Atlantic	3108.78	1377.10	755.42	602.85	18.84	1731.68
East North Central	3323.76	1330.73	832.15	469.42	29.16	1993.02
East South Central	2834.50	1353.75	1116.43	219.00	18.31	1480.75
West North Central	2802.45	1283.69	1095.29	187.03	1.36	1518.77
West South Central	3044.67	1506.09	1200.64	305.45	0.00	1538.58
Mountain	2993.27	1225.89	807.46	414.98	3.45	1767.38
Pacific	2851.34	1070.42	749.54	314.49	6.39	1780.92

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table E5. 2020 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3118.06**	**1393.55**	**949.85**	**379.43**	**64.28**	**1724.51**
Households by Income Quintile						
1st	1811.98	1046.53	700.40	292.04	54.09	765.45
2nd	2643.70	1195.02	840.32	311.41	43.30	1448.67
3rd	3069.87	1337.07	909.72	359.07	68.28	1732.79
4th	3439.44	1442.29	984.62	401.51	56.16	1997.15
5th	4196.92	1784.39	1206.29	489.85	88.26	2412.53
Households by Census Division						
New England	3485.90	1688.94	894.38	299.42	495.13	1796.96
Middle Atlantic	3055.41	1633.23	836.30	529.38	267.55	1422.18
South Atlantic	3229.83	1421.21	791.91	611.26	18.04	1808.63
East North Central	3455.17	1356.96	852.14	474.25	30.58	2098.20
East South Central	2955.19	1380.42	1137.42	226.61	16.40	1574.76
West North Central	2895.13	1301.22	1115.68	184.42	1.12	1593.91
West South Central	3209.80	1573.42	1260.28	313.14	0.00	1636.38
Mountain	3196.57	1277.20	844.10	430.33	2.78	1919.37
Pacific	2995.59	1073.21	752.09	315.30	5.82	1922.38

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table E6. 2025 Average Household Expenditures for Energy by Household Characteristic
(2001 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3280.15**	**1426.56**	**971.89**	**393.37**	**61.30**	**1853.59**
Households by Income Quintile						
1st	1892.80	1071.54	720.94	300.01	50.59	821.26
2nd	2783.37	1224.03	860.35	322.25	41.43	1559.34
3rd	3234.58	1368.69	930.53	372.82	65.34	1865.89
4th	3621.04	1475.83	1006.05	416.20	53.57	2145.22
5th	4426.90	1829.38	1233.99	510.67	84.72	2597.53
Households by Census Division						
New England	3630.36	1713.24	903.70	311.77	497.77	1917.12
Middle Atlantic	3172.98	1654.37	850.58	545.67	258.12	1518.61
South Atlantic	3375.38	1450.18	799.41	633.75	17.02	1925.20
East North Central	3665.66	1412.53	881.32	499.09	32.13	2253.13
East South Central	3113.72	1404.30	1157.64	232.57	14.08	1709.42
West North Central	3015.27	1304.79	1123.55	180.38	0.86	1710.47
West South Central	3396.27	1623.75	1303.45	320.30	0.00	1772.51
Mountain	3462.72	1340.56	872.71	465.74	2.11	2122.16
Pacific	3148.74	1116.50	775.80	335.34	5.36	2032.24

Source: Energy Information Administration, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Results from Side Cases

Table F1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2001	2010				2015			
		2003 Technology	Reference Case	High Technology	Best Available Technology	2003 Technology	Reference Case	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.91	0.92	0.91	0.90	0.87	0.88	0.87	0.85	0.80
Kerosene	0.10	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.06
Liquefied Petroleum Gas	0.50	0.48	0.47	0.47	0.45	0.48	0.47	0.46	0.43
Petroleum Subtotal	1.50	1.47	1.46	1.45	1.39	1.43	1.41	1.39	1.29
Natural Gas	4.94	5.69	5.66	5.63	4.76	5.93	5.85	5.82	4.54
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy	0.39	0.41	0.41	0.40	0.40	0.41	0.41	0.40	0.40
Electricity	4.10	4.98	4.93	4.83	4.45	5.34	5.25	5.04	4.46
Delivered Energy	**10.94**	**12.57**	**12.47**	**12.32**	**11.00**	**13.14**	**12.93**	**12.67**	**10.70**
Electricity Related Losses	9.15	10.38	10.28	10.06	9.27	10.72	10.54	10.12	8.96
Total	**20.09**	**22.95**	**22.75**	**22.38**	**20.27**	**23.86**	**23.47**	**22.79**	**19.66**
Delivered Energy Consumption per Household (million Btu per household)	**102.9**	**107.2**	**106.4**	**105.1**	**93.8**	**106.4**	**104.7**	**102.6**	**86.7**
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.04**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.46	0.49	0.48	0.48	0.48	0.50	0.49	0.48	0.48
Residual Fuel	0.09	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline	0.05	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.71	0.68	0.67	0.67	0.67	0.70	0.68	0.68	0.67
Natural Gas	3.33	3.81	3.80	3.78	3.66	4.02	4.00	3.98	3.81
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.09	5.07	5.02	4.93	4.46	5.71	5.59	5.44	4.79
Delivered Energy	**8.32**	**9.77**	**9.69**	**9.58**	**8.99**	**10.64**	**10.49**	**10.30**	**9.48**
Electricity Related Losses	9.12	10.57	10.46	10.28	9.29	11.47	11.23	10.92	9.62
Total	**17.44**	**20.34**	**20.15**	**19.87**	**18.28**	**22.11**	**21.72**	**21.23**	**19.10**
Delivered Energy Consumption per Square Foot (thousand Btu per square foot)	**118.4**	**119.4**	**118.5**	**117.2**	**109.9**	**120.7**	**118.9**	**116.8**	**107.5**
Net Summer Capacity (megawatts)									
Natural Gas	609	618	628	628	628	630	746	744	746
Solar Photovoltaic	16	252	252	268	278	278	305	443	513
Generation (billion kilowatthours)									
Natural Gas	4.26	4.33	4.40	4.40	4.40	4.41	5.25	5.24	5.25
Solar Photovoltaic	0.03	0.54	0.54	0.58	0.60	0.60	0.66	0.94	1.08
Non-Marketed Renewables (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2003 National Energy Modeling System, runs BLDFRZN.D110602A, AEO2003.D110502C, BLDHIGH.D110602A, and BLDBEST.D110602A

2020				2025				Annual Growth 2001-2025			
2003 Technology	Reference Case	High Technology	Best Available Technology	2003 Technology	Reference Case	High Technology	Best Available Technology	2003 Technology	Reference Case	High Technology	Best Available Technology
0.86	0.83	0.81	0.74	0.84	0.81	0.78	0.69	-0.3%	-0.5%	-0.6%	-1.1%
0.07	0.06	0.06	0.05	0.06	0.06	0.05	0.05	-2.0%	-2.2%	-2.3%	-3.0%
0.49	0.47	0.46	0.43	0.50	0.48	0.46	0.43	0.0%	-0.2%	-0.3%	-0.6%
1.41	1.37	1.34	1.22	1.39	1.34	1.30	1.17	-0.3%	-0.5%	-0.6%	-1.0%
6.25	6.12	6.03	4.56	6.57	6.40	6.24	4.68	1.2%	1.1%	1.0%	-0.2%
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.6%	0.4%	0.3%	0.1%
0.42	0.41	0.39	0.39	0.42	0.40	0.39	0.38	0.4%	0.2%	0.0%	-0.1%
5.72	5.59	5.27	4.57	6.09	5.94	5.55	4.80	1.7%	1.6%	1.3%	0.7%
13.81	**13.51**	**13.04**	**10.76**	**14.48**	**14.10**	**13.49**	**11.04**	**1.2%**	**1.1%**	**0.9%**	**0.0%**
11.20	10.96	10.32	8.96	11.60	11.33	10.58	9.16	1.0%	0.9%	0.6%	0.0%
25.01	**24.47**	**23.36**	**19.72**	**26.08**	**25.43**	**24.07**	**20.20**	**1.1%**	**1.0%**	**0.8%**	**0.0%**
107.2	**104.8**	**101.2**	**83.5**	**107.8**	**105.0**	**100.5**	**82.2**	**0.2%**	**0.1%**	**-0.1%**	**-0.9%**
0.05	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.05**	**2.2%**	**2.3%**	**2.4%**	**2.0%**
0.51	0.49	0.48	0.48	0.51	0.49	0.48	0.48	0.5%	0.3%	0.2%	0.2%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-2.5%	-2.5%	-2.5%	-2.5%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.7%	-0.7%	-0.7%	-0.7%
0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.4%	0.4%	0.4%	0.4%
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-1.1%	-1.1%	-1.1%	-1.1%
0.71	0.69	0.68	0.68	0.72	0.70	0.68	0.68	0.1%	-0.1%	-0.1%	-0.1%
4.29	4.29	4.26	4.06	4.53	4.56	4.55	4.34	1.3%	1.3%	1.3%	1.1%
0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.7%	0.7%	0.7%	0.7%
0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%	0.0%	0.0%	0.0%
6.41	6.20	5.96	5.19	7.16	6.83	6.48	5.61	2.4%	2.2%	1.9%	1.3%
11.63	**11.38**	**11.12**	**10.14**	**12.63**	**12.30**	**11.93**	**10.85**	**1.8%**	**1.6%**	**1.5%**	**1.1%**
12.57	12.14	11.68	10.16	13.66	13.03	12.36	10.70	1.7%	1.5%	1.3%	0.7%
24.19	**23.52**	**22.80**	**20.30**	**26.29**	**25.33**	**24.29**	**21.54**	**1.7%**	**1.6%**	**1.4%**	**0.9%**
122.8	**120.3**	**117.5**	**107.1**	**124.9**	**121.6**	**118.0**	**107.3**	**0.2%**	**0.1%**	**-0.0%**	**-0.4%**
663	1307	1429	1546	720	2238	2837	3323	0.7%	5.6%	6.6%	7.3%
307	471	751	846	337	773	1107	1236	13.5%	17.5%	19.3%	19.8%
4.64	9.29	10.17	11.02	5.05	16.00	20.33	23.84	0.7%	5.7%	6.7%	7.4%
0.66	1.01	1.57	1.76	0.73	1.63	2.30	2.56	13.6%	17.5%	19.2%	19.7%
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**1.1%**	**1.3%**	**1.5%**	**1.6%**

Table F2. Key Results for Industrial Sector Technology Cases

Consumption	2001	2010			2020			2025		
		2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.13	1.25	1.21	1.20	1.42	1.36	1.31	1.52	1.45	1.39
Liquefied Petroleum Gas	2.10	2.60	2.55	2.52	3.19	3.10	3.03	3.43	3.33	3.25
Petrochemical Feedstocks	1.14	1.46	1.43	1.42	1.74	1.69	1.67	1.87	1.82	1.78
Residual Fuel	0.23	0.20	0.19	0.18	0.22	0.20	0.18	0.23	0.20	0.18
Motor Gasoline	0.15	0.17	0.17	0.16	0.19	0.18	0.18	0.20	0.19	0.19
Other Petroleum	4.03	4.39	4.31	4.27	4.64	4.49	4.37	4.78	4.60	4.46
Petroleum Subtotal	8.79	10.06	9.86	9.75	11.40	11.02	10.74	12.03	11.59	11.25
Natural Gas	7.74	9.59	9.13	8.96	11.23	10.38	9.75	12.16	11.22	10.35
Lease and Plant Fuel	1.20	1.39	1.39	1.39	1.59	1.59	1.59	1.74	1.74	1.74
Natural Gas Subtotal	8.94	10.98	10.52	10.35	12.82	11.97	11.33	13.90	12.96	12.09
Metallurgical Coal[1]	0.74	0.82	0.77	0.69	0.81	0.71	0.54	0.80	0.68	0.49
Steam Coal	1.42	1.47	1.44	1.42	1.56	1.50	1.44	1.61	1.53	1.45
Coal Subtotal	2.16	2.29	2.22	2.11	2.37	2.21	1.99	2.41	2.21	1.94
Renewable Energy	1.82	2.18	2.22	2.34	2.66	2.77	3.17	2.90	3.05	3.63
Electricity	3.39	4.08	3.95	3.81	4.99	4.63	4.32	5.49	5.00	4.61
Delivered Energy	**25.10**	**29.59**	**28.76**	**28.36**	**34.25**	**32.61**	**31.55**	**36.73**	**34.81**	**33.52**
Electricity Related Losses	7.57	8.50	8.23	7.93	9.77	9.08	8.47	10.47	9.54	8.78
Total	**32.67**	**38.09**	**36.99**	**36.29**	**44.02**	**41.69**	**40.02**	**47.20**	**44.35**	**42.31**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 1996 dollar)	**4.63**	**4.25**	**4.13**	**4.08**	**3.82**	**3.64**	**3.52**	**3.63**	**3.44**	**3.31**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	22.02	27.25	27.45	30.07	32.39	33.44	38.44	35.43	37.66	43.40
Generation (billion kilowatthours)	125.40	162.20	163.34	181.16	197.58	204.42	236.60	218.77	233.76	269.15

[1]Includes net coal coke imports.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs INDFRZN.D110602A, AEO2003.D110502C, and INDHIGH.D110602A.

Table F3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2001	2010			2020			2025		
		2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology
Energy Consumption										
(quadrillion Btu)										
Distillate Fuel	5.44	7.14	7.08	6.98	9.26	8.70	8.31	10.41	9.58	9.04
Jet Fuel	3.43	3.95	3.93	3.88	5.26	5.09	4.82	5.96	5.66	5.21
Motor Gasoline	16.26	20.18	20.09	19.64	25.07	24.04	22.58	27.60	25.90	24.04
Residual Fuel	0.84	0.83	0.83	0.83	0.86	0.85	0.84	0.88	0.87	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.08	0.08	0.07	0.10	0.09	0.08
Other Petroleum	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	32.41	32.24	31.64	40.84	39.06	36.93	45.27	42.41	39.55
Pipeline Fuel Natural Gas	0.63	0.78	0.78	0.78	0.91	0.91	0.91	1.02	1.02	1.02
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.12	0.11	0.11
Renewables (E85)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.03
Electricity	0.07	0.09	0.09	0.09	0.11	0.12	0.12	0.12	0.14	0.13
Delivered Energy	**26.94**	**33.34**	**33.17**	**32.58**	**41.97**	**40.20**	**38.07**	**46.53**	**43.70**	**40.85**
Electricity Related Losses	0.17	0.18	0.19	0.20	0.21	0.24	0.24	0.23	0.27	0.26
Total	**27.10**	**33.52**	**33.36**	**32.77**	**42.18**	**40.44**	**38.31**	**46.76**	**43.97**	**41.10**
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[1]	24.1	23.8	24.3	25.8	23.7	25.6	28.1	23.7	26.1	28.7
New Car (miles per gallon)[1]	28.1	27.6	28.5	30.7	27.6	29.8	32.6	27.5	30.1	32.9
New Light Truck (miles per gallon)[1]	20.7	20.8	21.0	22.2	20.7	22.5	24.8	20.8	23.0	25.3
Light-Duty Fleet (miles per gallon)[2]	19.8	19.2	19.3	19.8	19.0	19.8	21.2	18.9	20.2	21.9
New Commercial Light Truck (MPG)[3]	13.8	13.7	13.9	14.7	13.6	14.8	16.4	13.6	15.2	16.8
Stock Commercial Light Truck (MPG)[3]	13.7	13.8	13.8	14.2	13.6	14.4	15.5	13.6	14.8	16.2
Aircraft Efficiency (seat miles per gallon)	51.2	54.0	54.3	55.0	56.4	58.6	62.3	57.3	60.7	66.7
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.1	6.0	6.3	6.5	6.0	6.5	6.7
Rail Efficiency (ton miles per thousand Btu)	2.8	2.9	3.1	3.2	2.9	3.4	3.8	2.9	3.6	4.1
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.3	2.4	2.5	2.3	2.4	2.6
Light-Duty Vehicles Less Than 8500 Pounds (vehicle miles traveled)	**2409**	**3004**	**3004**	**3007**	**3747**	**3753**	**3761**	**4124**	**4132**	**4143**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
Btu = British thermal unit.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs TRNFROZ.D110602A, AEO2003.D110502C, and TRNHIGH.D110602A.

Table F4. Key Results for Integrated Technology Cases

Consumption and Emissions	2001	2010			2020			2025		
		2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology	2003 Technology	Reference Case	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	20.1	22.9	22.8	22.4	25.3	24.5	23.3	26.3	25.4	23.8
Commercial	17.4	20.3	20.2	19.9	24.5	23.5	22.7	26.6	25.3	23.9
Industrial	32.7	38.1	37.0	36.2	44.6	41.7	39.6	47.8	44.3	41.4
Transportation	27.1	33.5	33.4	32.8	42.3	40.4	38.3	46.6	44.0	41.0
Total	**97.3**	**114.9**	**113.3**	**111.3**	**136.7**	**130.1**	**123.8**	**147.3**	**139.1**	**130.1**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	38.5	45.1	44.6	43.8	54.9	52.6	50.0	59.9	56.6	53.2
Natural Gas	23.3	28.3	27.7	27.0	33.5	33.0	30.5	35.5	35.8	32.3
Coal	22.0	25.6	25.0	24.4	31.5	27.7	25.6	34.7	29.4	26.3
Nuclear Power	8.0	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Renewable Energy	5.3	7.2	7.2	7.5	8.2	8.3	9.1	8.6	8.8	9.8
Other	0.2	0.3	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1
Total	**97.3**	**114.9**	**113.3**	**111.3**	**136.7**	**130.1**	**123.8**	**147.3**	**139.1**	**130.1**
Energy Intensity (thousand Btu per 1996 dollar of GDP)	**10.6**	**9.4**	**9.2**	**9.1**	**8.3**	**7.9**	**7.5**	**7.8**	**7.4**	**6.9**
Carbon Dioxide Emissions by Sector (million metric tons carbon equivalent)										
Residential	313.8	356.2	352.1	345.1	408.1	383.7	357.8	432.9	402.8	366.8
Commercial	278.8	321.5	317.2	311.3	405.2	376.2	354.1	450.4	409.9	375.0
Industrial	451.5	517.3	498.1	481.4	611.1	555.2	509.0	660.3	589.9	525.9
Transportation	514.5	636.4	633.0	621.4	803.4	767.3	726.0	885.1	834.2	778.0
Total	**1558.6**	**1831.3**	**1800.5**	**1759.2**	**2227.8**	**2082.5**	**1946.8**	**2428.7**	**2236.9**	**2045.7**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons carbon equivalent)										
Petroleum	640.5	761.9	755.7	741.9	933.4	892.6	847.5	1020.0	960.1	901.0
Natural Gas	251.7	303.7	297.2	294.1	355.3	333.8	322.8	374.5	357.5	335.9
Coal	54.7	61.0	59.0	56.2	63.0	59.2	53.4	64.3	59.3	52.3
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	704.8	688.5	667.0	876.0	796.9	723.1	970.0	860.1	756.5
Total	**1558.6**	**1831.3**	**1800.5**	**1759.2**	**2227.8**	**2082.5**	**1946.8**	**2428.7**	**2236.9**	**2045.7**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)										
Petroleum	27.5	10.7	8.8	7.6	9.4	9.7	7.2	12.2	10.9	8.0
Natural Gas	77.7	100.7	99.9	91.9	124.4	137.8	113.5	133.7	155.0	126.7
Coal	506.4	593.5	579.9	567.4	742.3	649.5	602.4	824.1	694.2	621.7
Total	**611.6**	**704.8**	**688.5**	**667.0**	**876.0**	**796.9**	**723.1**	**970.0**	**860.1**	**756.5**
Carbon Dioxide Emissions by Primary Fuel (million metric tons carbon equivalent)										
Petroleum	668.0	772.5	764.5	749.5	942.8	902.2	854.7	1032.2	971.0	909.0
Natural Gas	329.4	404.4	397.1	386.0	479.7	471.6	436.3	508.2	512.5	462.6
Coal	561.1	654.4	638.9	623.7	805.3	708.7	655.8	888.4	753.4	674.1
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1831.3**	**1800.5**	**1759.2**	**2227.8**	**2082.5**	**1946.8**	**2428.7**	**2236.9**	**2045.7**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2003 National Energy Modeling System runs LTRKITEN.D110702A, AEO2003.D110502C, and HTRKITEN.D110602A.

Table F5. Key Results for Advanced Nuclear Cost Case
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2001	Projections							
		2010		2015		2020		2025	
		Reference	Advanced Nuclear	Reference	Advanced Nuclear	Reference	Advanced Nuclear	Reference	Advanced Nuclear
Capacity									
Coal Steam	310.5	311.5	311.6	328.1	328.1	348.4	346.7	375.8	367.7
Other Fossil Steam	135.0	84.6	84.6	79.5	79.5	78.3	78.3	77.3	77.0
Combined Cycle	66.2	176.1	176.0	228.8	229.7	259.3	259.0	301.4	299.2
Combustion Turbine/Diesel	102.6	133.5	133.3	144.9	144.0	157.9	157.4	179.1	176.8
Nuclear Power	98.2	99.3	99.3	99.5	99.5	99.6	101.3	99.6	113.9
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources	90.9	97.6	97.7	100.1	100.1	102.2	102.3	104.6	104.3
Distributed Generation (Natural Gas)	0.0	1.7	1.7	4.9	5.0	10.1	10.0	15.8	15.5
Combined Heat and Power[1]	28.8	34.6	34.6	37.6	37.6	41.7	41.7	47.4	47.6
Total	**851.9**	**959.3**	**959.1**	**1043.9**	**1044.0**	**1118.2**	**1117.2**	**1221.5**	**1222.5**
Cumulative Additions									
Coal Steam	0.0	6.8	6.9	23.9	23.9	45.5	43.8	74.0	65.9
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	109.2	109.2	161.9	162.8	192.5	192.1	234.5	232.3
Combustion Turbine/Diesel	0.0	40.1	39.7	52.6	51.6	67.7	67.2	89.7	87.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	14.3
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources	0.0	6.3	6.4	8.8	8.9	11.0	11.0	13.3	13.1
Distributed Generation	0.0	1.7	1.7	4.9	5.0	10.1	10.0	15.8	15.5
Combined Heat and Power[1]	0.0	5.8	5.8	8.8	8.8	12.9	12.9	18.7	18.8
Total	**0.0**	**170.3**	**170.1**	**261.5**	**261.4**	**340.2**	**339.2**	**446.4**	**447.5**
Cumulative Retirements	**0.0**	**66.5**	**66.3**	**74.1**	**74.0**	**78.7**	**78.8**	**81.7**	**81.6**
Generation by Fuel (billion kilowatthours)									
Coal	1881	2222	2223	2368	2368	2530	2517	2736	2670
Petroleum	120	43	42	47	47	46	46	55	51
Natural Gas	535	875	874	1087	1086	1293	1292	1481	1445
Nuclear Power	769	800	800	805	805	807	818	807	920
Pumped Power	-9	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources	263	396	397	409	409	420	421	432	432
Distributed Generation	0	1	1	3	3	5	5	7	7
Combined Heat and Power[1]	164	207	207	227	227	255	255	294	295
Total	**3723**	**4544**	**4544**	**4944**	**4944**	**5355**	**5354**	**5813**	**5819**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	27.5	8.8	8.7	9.8	9.9	9.7	9.8	10.9	10.3
Natural Gas	77.7	99.9	99.7	117.5	117.3	137.8	137.7	155.0	151.4
Coal	506.4	579.9	580.0	613.3	613.3	649.5	646.9	694.2	679.6
Total	**611.6**	**688.5**	**688.5**	**740.6**	**740.4**	**796.9**	**794.3**	**860.1**	**841.2**
Prices to Electric Generators (2001 dollars per million Btu)									
Petroleum	4.73	4.27	4.27	4.43	4.42	4.60	4.61	4.98	4.98
Natural Gas	4.78	3.79	3.79	4.14	4.14	4.30	4.30	4.60	4.43
Coal	1.25	1.17	1.17	1.15	1.15	1.12	1.12	1.10	1.10

[1] Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2] Excludes combined heat and power and other generators

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with electric utility capacity estimates.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs AEO2003.D110502C, and ADVNUC03.D110602A.

Table F6. Key Results for High Electricity Demand Case

Net Summer Capacity, Generation, Consumption, Emissions, and Prices	2001	2010		2020		2025		Annual Growth 2001-2025	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	**3414**	**4101**	**4353**	**4850**	**5503**	**5252**	**6163**	**1.8%**	**2.5%**
Electricity Prices (2001 cents per kilowatthour)	**7.3**	**6.4**	**6.6**	**6.6**	**6.8**	**6.7**	**7.0**	**-0.3%**	**-0.2%**
Capacity (gigawatts)									
Coal Steam	310.5	311.5	319.9	348.4	411.7	375.8	472.9	0.8%	1.8%
Other Fossil Steam	135.0	84.6	90.5	78.3	84.5	77.3	80.0	-2.3%	-2.2%
Combined Cycle	66.2	176.1	202.7	259.3	299.1	301.4	350.4	6.5%	7.2%
Combustion Turbine/Diesel	102.6	133.5	150.2	157.9	183.2	179.1	226.2	2.3%	3.3%
Nuclear Power	98.2	99.3	99.3	99.6	99.6	99.6	99.6	0.1%	0.1%
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2	33.2%	33.2%
Renewable Sources/Pumped Storage	110.7	117.9	118.1	122.6	124.4	124.9	128.3	0.5%	0.6%
Distributed Generation	0.0	1.7	2.4	10.1	14.4	15.8	23.6	N/A	N/A
Combined Heat and Power[1]	28.8	34.6	34.6	41.7	41.7	47.4	47.4	2.1%	2.1%
Total	**851.9**	**959.3**	**1017.8**	**1118.2**	**1258.7**	**1221.5**	**1428.7**	**1.5%**	**2.2%**
Cumulative Additions (gigawatts)									
Coal Steam	0.0	6.8	15.2	45.5	108.8	74.0	171.1	N/A	N/A
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Combined Cycle	0.0	109.2	135.9	192.5	232.2	234.5	283.5	N/A	N/A
Combustion Turbine/Diesel	0.0	40.1	56.4	67.7	94.9	89.7	141.9	N/A	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2	N/A	N/A
Renewable Sources/Pumped Storage	0.0	6.6	6.8	11.3	13.1	13.6	17.0	N/A	N/A
Distributed Generation	0.0	1.7	2.4	10.1	14.4	15.8	23.6	N/A	N/A
Combined Heat and Power[1]	0.0	5.8	5.8	12.9	12.9	18.7	18.7	N/A	N/A
Total	**0.0**	**170.3**	**222.6**	**340.2**	**476.5**	**446.4**	**656.0**	**N/A**	**N/A**
Generation by Fuel (billion kilowatthours)									
Coal	1881	2222	2311	2530	2991	2736	3447	1.6%	2.6%
Petroleum	120	43	59	46	48	55	81	-3.2%	-1.6%
Natural Gas	535	875	1027	1293	1510	1481	1684	4.3%	4.9%
Nuclear Power	769	800	800	807	807	807	807	0.2%	0.2%
Renewable Sources/Pumped Storage	254	396	398	419	427	432	445	2.2%	2.4%
Distributed Generation	0	1	2	5	7	7	11	N/A	N/A
Combined Heat and Power[1]	164	207	207	255	255	294	294	2.5%	2.6%
Total	**3723**	**4544**	**4804**	**5355**	**6044**	**5813**	**6770**	**1.9%**	**2.5%**
Fossil Fuel Consumption by Electric Generators (quadrillion Btu)[2]									
Petroleum	1.25	0.42	0.58	0.46	0.47	0.52	0.75	-3.6%	-2.1%
Natural Gas	5.40	6.93	7.98	9.57	11.11	10.76	12.15	2.9%	3.4%
Coal	19.75	22.65	23.49	25.35	29.08	27.09	32.50	1.3%	2.1%
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	27.5	8.8	12.1	9.7	9.9	10.9	15.5	-3.8%	-2.4%
Natural Gas	77.7	99.9	114.9	137.8	160.0	155.0	174.9	2.9%	3.4%
Coal	506.4	579.9	601.1	649.5	744.9	694.2	832.3	1.3%	2.1%
Total	**611.6**	**688.5**	**728.2**	**796.9**	**914.8**	**860.1**	**1022.7**	**1.4%**	**2.2%**
Prices to Electric Generators (2001 dollars per million Btu)									
Petroleum	4.73	4.27	4.23	4.60	4.66	4.98	5.05	0.2%	0.3%
Natural Gas	4.78	3.79	4.10	4.30	4.11	4.60	5.14	-0.2%	0.3%
Coal	1.25	1.17	1.18	1.12	1.16	1.10	1.17	-0.5%	-0.3%

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2] Excludes combined heat and power and other generators.

Btu = British thermal unit.

N/A = not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas. Side case was run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs AEO2003.D110502C, and HDEM03.D110602A.

Table F7. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2001	2010			2020			2025		
		Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil
Capacity										
Pulverized Coal	310.0	314.6	310.8	305.5	382.2	344.2	303.6	424.0	368.6	302.5
Coal Gasification Combined-Cycle	0.5	0.7	0.8	8.7	1.3	4.1	58.1	1.3	7.1	94.3
Conventional Natural Gas Combined-Cycle	66.2	152.7	133.7	130.7	187.9	134.0	130.7	210.3	134.0	130.2
Advanced Natural Gas Combined-Cycle	0.0	17.3	42.4	47.5	21.1	125.3	159.6	22.1	167.4	204.7
Conventional Combustion Turbine	102.6	131.0	128.2	126.3	156.4	127.7	118.5	172.2	128.6	117.0
Advanced Combustion Turbine	0.0	2.5	5.3	3.3	5.6	30.2	13.8	7.3	50.5	22.7
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Nuclear	98.2	99.3	99.3	99.3	99.6	99.6	99.6	99.6	99.6	99.6
Oil and Gas Steam	135.0	85.7	84.6	85.0	81.2	78.3	72.5	80.4	77.3	68.5
Renewable Sources/Pumped Storage	110.7	118.1	117.9	117.7	125.3	122.6	119.9	134.2	124.9	120.5
Distributed Generation	0.0	2.3	1.7	1.3	15.0	10.1	5.1	23.7	15.8	8.8
Combined Heat and Power[1]	28.8	34.6	34.6	34.6	41.7	41.7	41.7	47.4	47.4	47.4
Total	**851.9**	**958.9**	**959.3**	**960.0**	**1117.6**	**1118.2**	**1123.2**	**1222.7**	**1221.5**	**1216.5**
Cumulative Additions										
Pulverized Coal	0.0	10.4	6.6	1.6	79.8	41.9	1.6	122.7	67.4	1.6
Coal Gasification Combined-Cycle	0.0	0.2	0.3	8.2	0.8	3.6	57.6	0.8	6.6	93.8
Conventional Natural Gas Combined-Cycle	0.0	85.9	66.8	63.8	121.0	67.1	63.8	143.4	67.1	63.8
Advanced Natural Gas Combined-Cycle	0.0	17.3	42.4	47.5	21.1	125.3	159.6	22.1	167.4	204.7
Conventional Combustion Turbine	0.0	37.2	34.8	32.2	65.9	37.5	32.9	82.1	39.2	33.9
Advanced Combustion Turbine	0.0	2.5	5.3	3.3	5.6	30.2	13.8	7.3	50.5	22.7
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	6.8	6.6	6.4	14.0	11.3	8.6	22.9	13.6	9.2
Distributed Generation	0.0	2.3	1.7	1.3	15.0	10.1	5.1	23.7	15.8	8.8
Combined Heat and Power[1]	0.0	5.8	5.8	5.8	12.9	12.9	12.9	18.7	18.7	18.7
Total	**0.0**	**168.5**	**170.3**	**170.3**	**336.4**	**340.2**	**356.1**	**443.8**	**446.4**	**457.5**
Cumulative Retirements	**0.0**	**65.0**	**66.5**	**65.7**	**75.5**	**78.7**	**89.6**	**77.8**	**81.7**	**97.7**
Generation by Fuel (billion kilowatthours)										
Coal	1881	2247	2222	2237	2757	2530	2600	3066	2736	2864
Petroleum	120	44	43	40	48	46	39	64	55	52
Natural Gas	535	848	875	866	1052	1293	1252	1093	1481	1386
Nuclear Power	769	800	800	800	807	807	807	807	807	807
Renewable Sources/Pumped Storage	254	397	396	395	428	419	406	474	432	411
Distributed Generation	0	2	1	1	7	5	2	11	7	4
Combined Heat and Power[1]	164	207	207	207	255	255	255	294	294	294
Total	**3723**	**4544**	**4544**	**4546**	**5354**	**5355**	**5361**	**5810**	**5813**	**5817**
Fuel Consumption by Electric Generators (quadrillion Btu)[2]										
Coal	19.75	22.87	22.65	22.67	27.26	25.35	24.96	29.92	27.09	26.45
Petroleum	1.25	0.43	0.42	0.40	0.48	0.46	0.39	0.64	0.52	0.48
Natural Gas	5.40	6.86	6.93	6.69	8.44	9.57	8.13	8.74	10.76	8.66
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Sources	3.02	4.52	4.50	4.50	5.08	5.00	4.72	5.60	5.21	4.85
Total	**37.45**	**43.04**	**42.86**	**42.61**	**49.69**	**48.80**	**46.63**	**53.33**	**52.02**	**48.87**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]										
Petroleum	27.5	9.1	8.8	8.3	10.1	9.7	8.1	13.4	10.9	10.0
Natural Gas	77.7	98.8	99.9	96.4	121.6	137.8	117.1	125.8	155.0	124.7
Coal	506.4	585.4	579.9	580.2	698.4	649.5	639.4	766.3	694.2	677.7
Total	**611.6**	**693.2**	**688.5**	**684.8**	**830.0**	**796.9**	**764.6**	**905.5**	**860.1**	**812.3**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2] Excludes combined heat and power and other generators.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with electric utility capacity estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2003 National Energy Modeling System runs LFOSS03.D110602A, AEO2003.D110502C, and HFOSS03.D110602A.

Table F8. Key Results for High Renewable Energy Case

Capacity, Generation, and Emissions	2001	2010		2020		2025	
		Reference	High Renewables	Reference	High Renewables	Reference	High Renewables
Renewable Capacity (gigawatts)							
Net Summer Capacity							
Electric Generators[1]							
Conventional Hydropower	78.36	78.92	78.92	78.92	78.92	78.92	78.92
Geothermal[2]	2.86	3.54	4.12	5.00	6.82	5.64	7.51
Municipal Solid Waste[3]	3.25	4.03	4.03	4.37	4.37	4.37	4.37
Wood and Other Biomass[4]	1.77	2.07	2.07	2.18	3.30	2.78	5.00
Solar Thermal	0.33	0.44	0.44	0.48	0.48	0.50	0.50
Solar Photovoltaic	0.02	0.10	0.10	0.27	0.27	0.36	0.36
Wind	4.29	8.47	11.68	11.05	36.91	12.00	39.12
Total	**90.88**	**97.57**	**101.36**	**102.25**	**131.05**	**104.56**	**135.77**
Combined Heat and Power[5]							
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Wood and Other Biomass	4.41	5.88	6.35	7.76	9.23	8.71	10.84
Total	**4.69**	**6.16**	**6.63**	**8.04**	**9.51**	**9.00**	**11.13**
Other End-Use Generators[6]							
Conventional Hydropower	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.41	0.62	1.38	0.93	2.49
Total	**1.12**	**1.47**	**1.50**	**1.71**	**2.48**	**2.03**	**3.58**
Generation (billion kilowatthours)							
Electric Generators							
Coal	1881	2222	2208	2530	2440	2736	2616
Petroleum	120	43	42	46	47	55	53
Natural Gas	535	875	869	1293	1255	1481	1462
Total Fossil	**2536**	**3140**	**3119**	**3869**	**3742**	**4273**	**4131**
Conventional Hydropower	213.82	301.89	301.89	301.05	301.05	301.34	301.34
Geothermal	13.81	19.81	24.43	31.78	46.52	36.92	52.32
Municipal Solid Waste[3]	19.55	28.88	28.88	31.34	31.34	31.49	31.49
Wood and Other Biomass[4]	9.38	21.27	21.54	21.88	26.80	24.66	33.34
Dedicated Plants	7.67	12.41	12.42	13.12	20.16	16.47	30.38
Cofiring	1.71	8.85	9.12	8.76	6.64	8.19	2.96
Solar Thermal	0.49	0.77	0.86	0.90	1.08	0.97	1.21
Solar Photovoltaic	0.00	0.24	0.24	0.66	0.66	0.88	0.88
Wind	5.78	23.62	35.34	32.70	131.76	36.21	139.59
Total Renewable	**262.85**	**396.47**	**413.18**	**420.31**	**539.21**	**432.48**	**560.18**
Combined Heat and Power[5]							
Total Fossil	**111**	**144**	**144**	**180**	**181**	**212**	**213**
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15
Wood and Other Biomass	28.67	37.23	40.00	48.21	56.80	53.80	66.23
Total Renewables	**31.13**	**39.38**	**42.15**	**50.36**	**58.95**	**55.95**	**68.38**
Other End-Use Generators[6]							
Conventional Hydropower[7]	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.87	1.33	2.90	1.98	5.17
Total	**4.25**	**5.05**	**5.11**	**5.57**	**7.14**	**6.22**	**9.41**
Sources of Ethanol							
From Corn	0.15	0.26	0.25	0.29	0.26	0.29	0.24
From Cellulose	0.00	0.00	0.01	0.02	0.05	0.05	0.10
Total	**0.15**	**0.26**	**0.26**	**0.31**	**0.31**	**0.34**	**0.34**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[8]							
Petroleum	27.5	8.8	8.7	9.7	9.8	10.9	10.5
Natural Gas	77.7	99.9	99.5	137.8	134.0	155.0	153.1
Coal	506.4	579.9	576.6	649.5	629.1	694.2	667.9
Total	**611.6**	**688.5**	**684.8**	**796.9**	**772.9**	**860.1**	**831.5**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
[8]Excludes combined heat and power and other generators.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2003 National Energy Modeling System runs AEO2003.D110502C, and HIRENEW03.D110602B.

Table F9. Total Energy Supply and Disposition Summary, Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Production										
Crude Oil and Lease Condensate	12.29	11.81	11.91	11.98	11.26	11.56	11.83	10.71	11.29	11.75
Natural Gas Plant Liquids	2.65	3.12	3.16	3.19	3.46	3.59	3.75	3.54	3.76	3.98
Dry Natural Gas	19.97	22.17	22.47	22.67	25.28	25.75	26.89	25.80	27.47	29.07
Coal	23.97	25.50	25.30	25.17	28.14	27.69	27.02	29.69	29.29	28.79
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.23	7.23	7.24	8.28	8.28	8.18	8.82	8.78	8.69
Other[2]	0.57	0.85	0.84	0.84	0.80	0.80	0.80	0.81	0.80	0.80
Total	**72.81**	**79.03**	**79.27**	**79.45**	**85.64**	**86.10**	**86.91**	**87.80**	**89.83**	**91.52**
Imports										
Crude Oil[3]	20.26	25.16	25.13	25.06	27.72	27.61	27.34	29.07	28.47	28.18
Petroleum Products[4]	5.04	6.61	6.41	6.32	12.30	11.97	11.84	15.54	15.17	14.60
Natural Gas	4.10	5.41	5.52	5.60	7.28	7.22	6.84	9.17	8.30	7.72
Other Imports[5]	0.73	0.90	0.90	0.89	0.95	0.96	0.97	0.94	0.94	0.94
Total	**30.13**	**38.08**	**37.96**	**37.87**	**48.26**	**47.76**	**46.98**	**54.71**	**52.88**	**51.44**
Exports										
Petroleum[6]	2.01	2.24	2.24	2.24	2.34	2.34	2.35	2.39	2.41	2.39
Natural Gas	0.37	0.60	0.62	0.64	0.37	0.41	0.50	0.36	0.37	0.36
Coal	1.27	0.91	0.91	0.89	0.74	0.74	0.74	0.67	0.67	0.67
Total	**3.64**	**3.75**	**3.76**	**3.77**	**3.45**	**3.49**	**3.59**	**3.43**	**3.45**	**3.43**
Consumption										
Petroleum Products[7]	38.46	44.74	44.65	44.59	52.65	52.60	52.61	56.73	56.56	56.40
Natural Gas	23.26	27.37	27.75	28.02	32.59	32.96	33.63	35.02	35.81	36.83
Coal	22.02	25.18	24.98	24.86	28.13	27.68	27.02	29.82	29.42	28.93
Nuclear Power	8.03	8.36	8.36	8.36	8.43	8.43	8.43	8.43	8.43	8.43
Renewable Energy[1]	5.33	7.23	7.23	7.24	8.28	8.28	8.18	8.82	8.78	8.69
Other[8]	0.21	0.29	0.29	0.28	0.17	0.17	0.18	0.07	0.07	0.06
Total	**97.30**	**113.15**	**113.26**	**113.34**	**130.25**	**130.12**	**130.05**	**138.89**	**139.07**	**139.34**
Net Imports - Petroleum	**23.29**	**29.53**	**29.31**	**29.15**	**37.69**	**37.24**	**36.82**	**42.21**	**41.23**	**40.39**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[9]	22.01	23.99	23.99	23.99	25.48	25.48	25.48	26.57	26.57	26.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[10]	4.12	3.46	3.29	3.13	3.52	3.69	3.72	4.35	3.90	3.38
Coal Minemouth Price (dollars per ton)	17.59	15.05	14.99	15.03	14.42	14.38	14.31	14.42	14.36	14.20
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.4	6.3	6.6	6.6	6.7	6.8	6.7	6.6
Carbon Dioxide Emissions (million metric tons carbon equivalent)	**1558.6**	**1801.8**	**1800.5**	**1800.0**	**2089.6**	**2082.5**	**2075.6**	**2239.0**	**2236.9**	**2235.8**

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[8]Includes net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA,*Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA,*Quarterly Coal Report, October-December 2001, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002)*. **Projections:** EIA, AEO2003 National Energy Modeling System runs OGLTEC03.D110602C, AEO2003.D110502C, and OGHTEC03.D110602C.

Table F10. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Lower 48 Average Wellhead Price (2001 dollars per thousand cubic feet)	**4.12**	**3.46**	**3.29**	**3.13**	**3.52**	**3.69**	**3.72**	**4.35**	**3.90**	**3.38**
Dry Gas Production[1]										
U.S. Total	**19.45**	**21.59**	**21.88**	**22.08**	**24.61**	**25.07**	**26.19**	**25.12**	**26.75**	**28.31**
Lower 48 Onshore	13.72	16.16	16.28	16.43	17.08	19.14	19.99	17.67	18.43	19.98
Associated-Dissolved	1.77	1.37	1.38	1.38	1.20	1.21	1.23	1.13	1.15	1.18
Non-Associated	11.94	14.79	14.91	15.05	15.89	17.92	18.76	16.54	17.27	18.80
Conventional	6.54	7.92	7.98	8.02	7.55	8.24	8.62	7.54	7.75	7.85
Unconventional	5.40	6.87	6.93	7.03	8.33	9.68	10.13	9.00	9.53	10.95
Lower 48 Offshore	5.30	4.95	5.12	5.17	5.14	5.39	5.66	5.03	5.69	5.91
Associated-Dissolved	1.08	0.78	0.79	0.80	0.75	0.77	0.80	0.82	0.91	0.90
Non-Associated	4.22	4.17	4.33	4.37	4.39	4.62	4.86	4.20	4.78	5.01
Alaska	0.43	0.48	0.48	0.48	2.39	0.55	0.55	2.42	2.64	2.42
Supplemental Natural Gas[2]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Net Imports	**3.65**	**4.70**	**4.78**	**4.85**	**6.76**	**6.66**	**6.20**	**8.61**	**7.76**	**7.19**
Canada	3.61	3.94	4.05	4.13	4.46	5.08	5.15	5.16	5.31	5.10
Mexico	-0.13	-0.24	-0.26	-0.28	0.34	0.07	-0.14	0.71	0.30	0.17
Liquefied Natural Gas	0.17	0.99	0.99	0.99	1.96	1.51	1.19	2.75	2.14	1.92
Total Supply	**23.17**	**26.38**	**26.76**	**27.02**	**31.47**	**31.82**	**32.48**	**33.83**	**34.60**	**35.60**
Consumption by Sector										
Residential	4.81	5.47	5.50	5.54	5.96	5.96	5.96	6.17	6.22	6.33
Commercial	3.24	3.66	3.69	3.72	4.16	4.17	4.17	4.38	4.43	4.52
Industrial[3]	7.53	8.83	8.88	8.92	10.08	10.10	10.17	10.76	10.91	11.08
Electric Generators[4]	5.30	6.57	6.80	6.95	9.02	9.39	9.89	10.19	10.56	11.10
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.61	0.75	0.76	0.76	0.90	0.88	0.91	0.94	1.00	1.03
Lease and Plant Fuel[6]	1.17	1.34	1.35	1.36	1.57	1.55	1.60	1.61	1.69	1.76
Total	**22.67**	**26.68**	**27.06**	**27.32**	**31.78**	**32.14**	**32.80**	**34.16**	**34.93**	**35.92**
Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.50**	**-0.30**	**-0.30**	**-0.30**	**-0.32**	**-0.32**	**-0.32**	**-0.33**	**-0.32**	**-0.33**
Lower 48 End of Year Reserves	**174.04**	**173.61**	**178.39**	**183.38**	**183.92**	**193.42**	**202.36**	**174.83**	**189.88**	**212.43**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs OGLTEC03.D110602C, AEO2003.D110502C, and OGHTEC03.D110602C.

Table F11. Crude Oil Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
World Oil Price										
(2001 dollars per barrel)	**22.91**	**23.86**	**23.90**	**23.90**	**24.84**	**24.89**	**24.90**	**26.10**	**26.12**	**26.11**
Production[1]										
U.S. Total	**5.80**	**5.58**	**5.63**	**5.66**	**5.32**	**5.46**	**5.59**	**5.06**	**5.33**	**5.55**
Lower 48 Onshore	3.13	2.50	2.51	2.52	2.08	2.12	2.16	1.92	1.98	2.03
Lower 48 Offshore	1.71	2.46	2.47	2.48	2.04	2.11	2.17	1.99	2.18	2.32
Alaska	0.97	0.62	0.64	0.66	1.20	1.23	1.26	1.15	1.17	1.20
Net Crude Imports	**9.31**	**11.53**	**11.51**	**11.48**	**12.72**	**12.66**	**12.53**	**13.35**	**13.06**	**12.92**
Other Crude Supply	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total Crude Supply	**15.13**	**17.11**	**17.14**	**17.14**	**18.04**	**18.12**	**18.12**	**18.41**	**18.39**	**18.47**
Natural Gas Plant Liquids	**1.87**	**2.20**	**2.23**	**2.25**	**2.42**	**2.53**	**2.64**	**2.48**	**2.63**	**2.79**
Other Inputs[2]	**0.30**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.45**	**0.45**	**0.45**
Refinery Processing Gain[3]	**0.90**	**0.91**	**0.91**	**0.91**	**0.97**	**0.96**	**0.95**	**0.96**	**0.96**	**0.95**
Net Product Imports[4]	**1.59**	**2.35**	**2.25**	**2.21**	**5.27**	**5.06**	**4.97**	**6.94**	**6.73**	**6.43**
Total Primary Supply[5]	**19.80**	**23.01**	**22.97**	**22.95**	**27.13**	**27.11**	**27.12**	**29.24**	**29.16**	**29.08**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.17	1.17	1.17	1.14	1.13	1.13	1.13	1.12	1.12
Industrial[6]	4.67	5.31	5.30	5.29	6.00	6.00	5.99	6.37	6.33	6.31
Transportation	13.27	16.33	16.33	16.33	19.80	19.79	19.79	21.49	21.48	21.49
Electric Generators[7]	0.55	0.22	0.19	0.17	0.21	0.20	0.22	0.27	0.23	0.17
Total	**19.69**	**23.03**	**22.99**	**22.96**	**27.15**	**27.13**	**27.13**	**29.26**	**29.17**	**29.10**
Discrepancy[8]	**0.10**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**
Lower 48 End of Year Reserves										
(billion barrels)[1]	**19.48**	**17.76**	**17.79**	**17.77**	**15.68**	**15.64**	**15.78**	**14.89**	**15.31**	**15.44**

[1]Includes lease condensate.
[2]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[3]Represents volumetric gain in refinery distillation and cracking processes.
[4]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[5]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[6]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[7]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs OGLTEC03.D110602C, AEO2003.D110502C, and OGHTEC03.D110602C.

Table F12. Key Results for Coal Mining Cost Cases

Prices, Productivity, Wages, and Emissions	2001	2010			2020			2025		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (2001 dollars per short ton)	**17.59**	**13.86**	**14.99**	**16.25**	**12.56**	**14.38**	**16.61**	**11.96**	**14.36**	**17.24**
Delivered Price to Electric Generators (2001 dollars per million Btu)	**1.25**	**1.12**	**1.17**	**1.23**	**1.01**	**1.12**	**1.24**	**0.97**	**1.10**	**1.27**
Labor Productivity (short tons per miner per hour)	**6.85**	**9.79**	**8.47**	**7.33**	**12.62**	**9.60**	**7.31**	**14.28**	**9.97**	**7.08**
Labor Productivity (average annual growth from 2001)	**N/A**	**4.0**	**2.4**	**0.8**	**3.3**	**1.8**	**0.3**	**3.1**	**1.6**	**0.1**
Average Coal Miner Wage (2001 dollars per hour)	**18.94**	**18.11**	**18.94**	**19.81**	**17.22**	**18.94**	**20.82**	**16.80**	**18.94**	**21.35**
Average Coal Miner Wage (average annual growth from 2001)	**N/A**	**-0.50**	**0.00**	**0.50**	**-0.50**	**0.00**	**0.50**	**-0.50**	**0.00**	**0.50**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[1]										
Petroleum	27.5	8.6	8.8	9.1	9.8	9.7	9.7	11.4	10.9	11.9
Natural Gas	77.7	98.6	99.9	101.5	130.2	137.8	148.7	139.0	155.0	173.0
Coal	506.4	584.3	579.9	573.6	669.5	649.5	619.1	730.2	694.2	644.5
Total	**611.6**	**691.5**	**688.5**	**684.1**	**809.5**	**796.9**	**777.4**	**880.6**	**860.1**	**829.3**
Electric Generator Capability (gigawatts)	**789.4**	**919.4**	**922.5**	**924.3**	**1141.9**	**1148.8**	**1162.0**	**1267.2**	**1282.8**	**1316.7**

[1]Excludes combined heat and power and other generators.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2003 National Energy Modeling System runs LMCST03.D110602A, AEO2003.D110502C, and HMCST03.D110602A.

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2003* (*AEO2003*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years into the future. In order to represent the regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of September 1, 2002, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. In comparison with EIA's past energy data publications, the impact of the definition changes for the industrial sector is to reduce measured natural gas consumption. For example, the previously reported value for 2000 has been revised from 9.39 trillion cubic feet to 8.25 trillion cubic feet. In comparison with past energy data publications, the impact of the definition changes and new data sources for total energy use increases measured natural gas consumption. Total natural gas consumption in 2000 is 0.6 trillion cubic feet higher than was previously reported. The impact of the review on reported fuel values is discussed in "Issues in Focus," page 32. More detailed discussion is available in EIA's *Annual Energy Review 2001*, Appendix H, "Estimating and Presenting Power Sector Fuel Use in EIA Publications and Analyses," web site www.eia.doe.gov/emeu/aer/pdf/pages/sec_h.pdf.

Major Assumptions for the Forecasts

In general, the historical data used for the *AEO2003* projections were based on EIA's *Annual Energy Review 2001*, published in November 2002 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2002. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2001*, published in December 2002 [*2*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2003* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2003* projections for 2002 and 2003 incorporate short-term projections from EIA's September 2002 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*3*].

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module uses the following Global Insight (formerly DRI-WEFA) models: Macroeconomic Model of the U.S. Economy, National Industrial Shipments Model, National Employment Model, and Regional Model. In addition, EIA has constructed a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census Divisions.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Estimates of average expenditures for households are provided by income group and Census division.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, subject to delivered energy prices, availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, subject to delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and effects of both building shell and appliance standards. Both modules include a representation of distributed generation.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module. All CAAA90 compliance options are explicitly represented in the capacity expansion and dispatch decisions. New generating technologies for fossil fuels, nuclear, and renewables compete directly in the decisions.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Conventional hydroelectricity is represented in the Electricity Market Module (EMM).

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports, exports to Canada and Mexico, and liquefied natural gas imports and exports. Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and non-core markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions—Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2003* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, and Washington [*4*].

Because the *AEO2003* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a greatly reduced annual average sulfur content, 30 parts per million (ppm), between 2004 and 2007 is explicitly modeled. The new "ultra-low-sulfur diesel" regulation finalized in December 2000 is also explicitly modeled. The diesel regulation requires that 80 percent of the highway diesel produced between June 1, 2006, and May 31, 2010, have a maximum sulfur content of 15 ppm, and that all highway diesel fuel meet the same limit after June 1, 2010. Costs of the regulation include capacity expansion for refinery processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, State and Federal taxes, and environmental site costs. *AEO2003* assumes that refining capacity expansion may occur on the East Coast, West Coast, and Gulf Coast.

Coal Market Module

The Coal Market Module simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, fuel costs, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 13 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Major assumptions for the *Annual Energy Outlook 2003*

Table G1 provides a summary of the cases used to derive the *AEO2003* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions for domestic macroeconomic activity are presented in the "Market Trends" section. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

World oil market assumptions

World oil price. The world oil price is assumed to be the annual average acquisition cost of imported crude oils to U.S. refiners. The low, reference, and high price cases reflect alternative assumptions regarding the expansion of production capacity in the nations comprising the Organization of Petroleum Exporting Countries (OPEC), particularly those producers in the Persian Gulf region. The forecast of the world oil

Table G1. Summary of the *AEO2003* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Reference	Baseline economic growth, world oil price, and technology assumptions	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 51	—
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 51	—
Low World Oil Price	World oil prices are $19.04 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 52	—
High World Oil Price	World oil prices are $33.05 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 52	—
Residential: 2003 Technology	Future equipment purchases based on equipment available in 2003. Existing building shell efficiencies fixed at 2003 levels.	With commercial	p. 63	p. 233
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 12 percent from 1997 values by 2025.	With commercial	p. 63	p. 234
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 16 percent from 1997 values by 2025.	With commercial	p. 63	p. 234
Commercial: 2003 Technology	Future equipment purchases based on equipment available in 2003. Building shell efficiencies fixed at 2003 levels.	With residential	p. 64	p. 235
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential	p. 64	p. 235
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential	p. 64	p. 235
Industrial: 2003 Technology	Efficiency of plant and equipment fixed at 2003 levels.	Standalone	p. 65	p. 236
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 65	p. 236
Transportation: 2003 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2003 levels.	Standalone	p. 65	p. 237
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 65	p. 237
Integrated 2003 Technology	Combination of the residential, commercial, industrial, and transportation 2003 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2002 levels.	Fully integrated	p. 93	—

Table G1. Summary of the *AEO2003* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 93	—
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have both lower capital costs than in the reference case.	Partially integrated	p. 71	p. 240
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially integrated	p. 71	p. 240
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2003.	Partially integrated	p. 72	p. 240
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values.	Partially integrated	p. 72	p. 240
Renewables: High Renewables	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics, approximating U.S. Department of Energy goals for 2025. Includes greater improvements in residential and commercial photovoltaic systems, more rapid improvement in recovery of industrial biomass byproducts, and more rapid improvement in cellulosic ethanol production technology.	Fully integrated	p. 74	p. 242
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 15-percent slower improvement than in the reference case.	Fully integrated	p. 79, p. 81	p. 243
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 15-percent more rapid improvement than in the reference case.	Fully integrated	p. 79, p. 81	p. 243
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 87	p. 247
Coal: High Mining Cost	Productivity increases at an annual rate of 0.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs increase by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 87	p. 247

price in a given year is a function of OPEC production capacity utilization and the world oil price in the previous year. The three price cases do not assume any disruptions in petroleum supply.

World oil demand. Demand outside the United States is assumed to be for total petroleum with no specificity as to individual refined products or sectors of the economy. The forecast of petroleum demand within a region is a Koyck-lag formulation and is a function of world oil price and GDP. Estimates of regional GDPs are from EIA's *International Energy Outlook 2002*.

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* and represent country-level assessments as of January 1, 2002. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) and are part of its "Worldwide Petroleum Assessment 2002." Technology factors are derived from the DESTINY forecast software and are a part of the International Energy Services of Petroconsultants, Inc.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. The National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT), both of which are incorporated in *AEO2003*, contain provisions that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Federal mandates, such as Executive Order 13123, "Greening the Government Through Efficient Energy Management" (signed in June 1999) and Executive Order 13221, "Energy-Efficient Standby Power Devices" (signed in July 2001), are expected to affect future energy use in Federal buildings.

Residential assumptions. The NAECA minimum standards [*5*] for the major types of equipment in the residential sector are:

- Central air conditioners and heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992, increasing to 12.0 in 2006
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, increasing to 9.7 in 2003
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993 and to 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990, increasing to 0.90 in 2004
- Natural gas water heaters—a 0.54 energy factor in 1990, increasing to 0.59 in 2004.

The *AEO2003* version of the NEMS Residential Demand Module is based on EIA's Residential Energy Consumption Survey (RECS) [*6*]. This survey provides most of the housing stock characteristics, appliance stock information (equipment type and fuel), and energy consumption estimates used to initialize the residential module. The projected effects of equipment turnover and the choice of various levels of equipment energy efficiency are based on tradeoffs between normally higher equipment costs for the more efficient equipment versus lower annual energy costs. Equipment characterizations begin with the minimum efficiency standards that apply, recognizing the range of equipment available with even higher energy efficiency. These characterizations include equipment made available through various green programs, such as the U.S. Environmental Protection Agency (EPA) Energy Star Programs [*7*].

AEO2003 uses a combined heating, ventilation, and air conditioning (HVAC)/shell module to model building shells in new construction. The module combines specific heating and cooling equipment with appropriate levels of shell efficiency to model the least expensive ways to meet selected overall efficiency levels. The levels include:

- The current average new house
- The International Energy Conservation Code (IECC 2000)
- Energy Star Homes using upgraded HVAC equipment and/or shell integrity (combined energy requirements for HVAC must be 30 percent lower than IECC 2000)
- The PATH home (HUD and DOE's Partnership for Advancing Technology in Housing [*8*])
- A shell intermediate to Energy Star and PATH set to save 40 percent of HVAC energy.

Similar to the choice of end-use equipment, the choice of HVAC/shell efficiency level among the available alternatives is based on a tradeoff between estimated higher initial capital costs for the more efficient combinations and lower estimated annual energy costs.

In addition to the *AEO2003* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the residential sector:

- The *2003 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2003. Existing building shell efficiencies are assumed to be fixed at 2003 levels.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*9*]. Heating shell efficiency is projected to increase by 12 percent over 1997 levels by 2025.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 16 percent over 1997 levels by 2025.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*10*]. Minimum standards for representative equipment types are:

- Central air conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Natural-gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard (January 1994)
- Natural-gas-fired storage water heaters—a 0.80 thermal efficiency standard (October 2003)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and an 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994)
- Fluorescent lamp ballasts—a standard mandating electronic ballasts with a 1.17 ballast efficacy factor for 4-foot ballasts holding two F40T12 lamps and a 0.63 ballast efficacy for 8-foot ballasts holding two F96T12 lamps (April 2005 for new lighting systems, June 2010 for replacement ballasts).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to the efficiencies of existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 5 percent and 7 percent, respectively, by 2025 relative to the 1999 averages.

Among the energy efficiency programs recognized in the *AEO2003* reference case are the expansion of the EPA Energy Star Buildings program and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs that target particular end uses, the *AEO2003* version of the commercial module includes end-use-specific segmentation of discount rates. Federal buildings are assumed to participate in energy efficiency programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

The definition of the commercial sector for *AEO2003* is based on data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS) [*11*]. Parking garages and commercial buildings on multibuilding manufacturing sites, included in the previous CBECS, were eliminated from the target building population starting with the 1995 CBECS. In addition, the CBECS data are estimates based on reported data from representatives of a randomly chosen subset of the entire population of commercial buildings. As a result, the estimates always differ from the true population values and vary from survey to survey. Differences between the estimated values and the actual population values result from both nonsampling errors that would be expected to occur in all possible samples and sampling errors that occur because the survey estimate is calculated from a randomly chosen subset of the entire population [*12*].

Due to the variability caused by nonsampling and sampling errors, the estimates of commercial floorspace for the 1999 CBECS are higher than the 1995 CBECS estimates. For example, the 1999 CBECS reports 14 percent more commercial floorspace in the United States than was reported in the 1995 CBECS. The most notable effect on *AEO2003* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO2003* is significantly lower than in *AEO*s based on the 1995 CBECS, not because energy consumption is lower but because the 1999 floorspace estimates are higher. The variability between CBECS surveys also results in different estimates of the amount of each major fuel used to provide end-use services such as space heating, lighting, etc., affecting the *AEO2003* projections for fuel consumption within each end use. For example, the 1999 CBECS estimates for equipment replacement lead to lower end-use intensities for fuel used for heating and cooling than the end-use intensities based on the 1995 CBECS.

In addition to the *AEO2003* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the commercial sector:

- The *2003 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2003. Building shell efficiencies are assumed to be fixed at 2003 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*13*]. Building shell efficiencies are assumed to improve at a rate that is 50 percent faster than the rate of improvement in the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Building shell efficiencies are assumed to improve at a 50 percent faster rate than in the reference case.

Buildings renewable energy. The forecast for wood consumption in the residential sector is based on the RECS. The RECS data provide a benchmark for British thermal units (Btu) of wood energy use in 1997. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump energy consumption is also based on the latest RECS; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Residential and commercial solar thermal energy consumption for water heating is represented by displaced primary energy relative to an electric water heater. Residential and commercial solar photovoltaic systems are discussed in the distributed generation section that follows.

Buildings distributed generation. Distributed generation includes photovoltaics and fuel cells for both the residential and commercial sectors, as well as microturbines and conventional combined heat and power technologies for the commercial sector. The forecast of distributed generation is developed on the basis of economic returns projected for investments in distributed generation technologies. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration rates are estimated by Census division and building type and vary by building vintage (newly constructed versus existing floorspace).

For purchases not related to specific programs, penetration rates are determined by the number of years required for an investment to show a positive economic return: the more quickly costs are recovered, the higher the technology penetration rate. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a joint U.S. Department of Energy and Electric Power Research Institute report published in December 1997. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE and industry news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System. The program-driven installations incorporate some of the non-economic considerations and local incentives that are not captured in the cash flow model.

The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies [*14*]. The assumptions were used in the integrated high renewables case, which focuses on electricity generation.

Industrial sector assumptions

The manufacturing portion of the Industrial Demand Module is calibrated to EIA's 1998 Manufacturing Energy Consumption Survey [*15*]. The nonmanufacturing portion of the module is based on information from EIA, the U.S. Department of Agriculture, and the U.S. Census Bureau [*16*]. EPACT sets efficiency standards for coke ovens and for boilers, furnaces, and electric motors. CAAA90 sets emissions limits for criteria air pollutants. The electric motor standards in EPACT set minimum efficiency levels for all motors up to 200 horsepower purchased after 1998 [*17*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use. For *AEO2003*, a motor stock model was developed for the Food, Bulk Chemicals, Metal-Based Durables, and Balance of Manufacturing sectors. When new motors are purchased, either an EPACT minimum efficiency motor or a premium efficiency motor is installed, depending on prevailing electricity prices. Combined heat and power (CHP), the simultaneous generation of electricity and useful steam, has been a standard practice in the industrial sector for many years. A separate model within NEMS evaluates additions to natural-gas-fired CHP, based on technical potential and prevailing electricity and natural gas prices.

High technology, 2003 technology, and high renewables cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*18*]. The high technology case also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.2 percent per year in the reference case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, primary energy intensity falls by 1.5 percent annually in the high technology case. In the reference case, primary energy intensity falls by 1.3 percent annually between 2001 and 2025.

The *2003 technology case* holds the energy efficiency of plant and equipment constant at the 2003 level over the forecast. In this case, primary energy intensity falls by 1.1 percent annually. Because the level and composition of industrial output are the same in the reference, high technology, and 2003 technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

The *high renewables case* assumes the more rapid rate of improvement in the recovery of biomass byproducts from industrial processes contained in the high technology case (1.0 percent per year, as compared with 0.2 percent per year in the reference case). This assumption is incorporated in the integrated high renewables case, which focuses on electricity generation.

Transportation sector assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2003* projections assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard for automobiles and 20.7 miles per gallon for light trucks and sport utility vehicles. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., natural gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*19*]. The legislation requires that alternative-fuel vehicles make up 75 percent of Federal and State fleet purchases in 2002. *AEO2003* assumes that they remain at that level through 2005. The municipal and private business fleet mandates, which are proposed to begin in 2003 at 20 percent and scale up to 70 percent by 2005, are not included in *AEO2003*.

In addition to the above requirements, the sale of zero-emission vehicles (ZEVs) required by the State of California's Low Emission Vehicle Program (LEVP) are also included in the forecast. In 1998, California modified those requirements so that 60 percent of the ZEV mandate could be met by credits earned from the sales of advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate was to be achieved through the sales of "true ZEVs," which include only electric and hydrogen fuel cell vehicles [*20*]. In December 2001, further modifications were enacted that maintained progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. Those modifications removed ZEV sales requirements before 2003 but maintained the 2003 required sales goal of 10 percent and required a gradual increase in ZEV sales to 16 percent by 2018.

Additional sales credits were given for the sale of true ZEVs, and partial credits were allowed for advanced technology vehicles and certain alternative-fuel vehicles. The number of vehicles included in the estimation of required ZEV sales was also increased to include light-duty and medium-duty trucks. Auto manufacturers filed a Federal suit in California in 2002 arguing that the revisions to the ZEV program are preempted by the Federal fuel economy statute of the Energy Policy and Conservation Act of 1975. In June 2002, a Federal judge granted a preliminary injunction preventing the California Air Resources Board from enforcing the ZEV regulations for model year 2003 and 2004 vehicles. The projections currently assume that California, Massachusetts, New York, Maine, and Vermont will formally begin implementing the LEVP mandates in 2005.

Technology choice. Conventional light-duty vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 63 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*21*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; in the model, consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable. Technology choice captures the manufacturers' response to the market.

Consumers do not place a significant value on high-efficiency vehicles. This is reflected in the model by assuming a 3-year payback period, with the real discount rate remaining steady at 30 percent. Expected future fuel prices are calculated based on extrapolation of the growth rate between a 5-year moving average of fuel prices 3 years and 4 years before the present year. This assumption is based on a lead time of 3 to 4 years for significant modification of the vehicles offered by a manufacturer.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal improvement in fuel efficiency, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*22*]. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*23*].

Similar to freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*24*].

Travel. Projections for both personal travel [*25*] and freight travel [*26*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 68 percent by 2020 and remains constant thereafter; and the cost of driving.

Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*27*]. Both rail and ship travel are also based on projected coal production and distribution. Air travel is estimated for domestic travel (both personal and business), international travel, and dedicated air freight shipments by U.S. carriers. Depending on the market segment, the demand for air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel (expressed in revenue-passenger miles and revenue-ton miles) to seat-miles of demand, remain relatively constant over the forecast period.

2003 technology case. The *2003 technology case* assumes that new fuel efficiency levels are held constant at 2003 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements, technology introduction dates, and costs [*28*]. In the air travel sector, the high technology case assumes 40-percent efficiency improvement from new aircraft technologies by 2025. Based on an analysis by the Federal Aviation Administration, the high technology case also assumes an additional 5-percent fleet efficiency improvement from the Air Traffic Management program. In the freight truck sector, the high technology case assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*29*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices.

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. Fossil fuel, renewable, and nuclear technologies are represented and include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions per year by 2010. Utilities are assumed to comply with the limits on sulfur dioxide emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. The assumed cost for FGD equipment averages approximately $440 per kilowatt, in 2001 dollars, for units of all sizes. This includes some very small, possibly uneconomical, units. The average cost for large units (500 megawatts capacity or larger) is $182 per kilowatt, although there are wide variations across the regions. It is also assumed that the market for trading emissions allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

In *AEO2003*, emissions of sulfur dioxide (SO_2) from electricity generators are subject to a cap, as specified by CAAA90, which amounts to 9.48 million tons for the years 2001 through 2009 and 8.95 million tons per year thereafter. In the reference, high and low economic growth, and high and low world oil price cases, generators are projected to meet the annual SO_2 caps based solely on additions of 23 gigawatts of planned retrofits of flue gas desulfurization equipment (scrubbers) at existing coal-fired power plants, combined with the drawdown of banked SO_2 emission allowances amounting to 10.4 million tons at the end of 2000. Announced retrofits of scrubbers by Duke Power and Progress Energy in response to North Carolina's Clean Smokestacks Bill account for nearly one-half of the planned retrofits included. The remainder are based on other factors, including compliance strategies developed by generators in response to CAAA90, agreements that generators have reached with the U.S. Department of Justice in lawsuits related to New Source Review, and other State and local environmental issues.

The EPA has issued rules to limit emissions of nitrogen oxides, specifically calling for capping emissions during the summer season in 22 eastern and midwestern States. After an initial challenge, the rules have been upheld, and emissions limits have been finalized for 19 States, starting in 2004. In *AEO2003*, electricity generators in those 19 States must comply with the limits either by reducing their own emissions or by purchasing allowances from others.

The reference case assumes a transition to full competitive pricing in New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, the Southwest Power Pool, and the Rocky Mountain Power Area/Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. In California, a return to complete cost-of-service regulation is now assumed.

In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2003* includes such agreements in the electricity price forecast. In general, the transition period is assumed to be a 10-year period from the beginning of restructuring in each region, during which prices gradually shift to competitive prices. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. *AEO2003* assumes that the competitive price in deregulated regions is the marginal cost of generation.

Competitive cost of capital. The cost of capital is calculated as a weighted average of the costs of debt and equity. *AEO2003* assumes a ratio of 55 percent debt and 45 percent equity. The yield on debt represents that of a BBB corporate bond, and the cost of equity is calculated to be representative of unregulated industries similar to the electricity generation sector. It is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to reduce their greenhouse gas emissions voluntarily. These efforts cover a wide variety of programs, including increasing demand-side management investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out of service, planting trees, and purchasing emissions offsets from international sources.

To the degree possible, each of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they should be addressed separately. Programs such as tree planting and emissions offset purchasing are not addressed, but the other programs are, for the most part, captured in *AEO2003*. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, extend a plant's life, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Data for these programs are included in the *AEO2003* input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emissions savings, should be attributed to the Climate Challenge Program and which are the result of normal business operations.

Fossil steam and nuclear plant retirement assumptions. Fossil steam plants and nuclear plants are retired when it is no longer economical to run them. In each forecast year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue a plant receives is not sufficient to cover its forward costs (including fuel, operations and maintenance costs, and assumed annual capital additions) the plant is retired. Beyond age 30, the forward costs also include capital expenditures assumed to be needed to address aging-related issues. For fossil plants the aging-related costs are assumed to be $5 per kilowatt. For nuclear plants the aging-related costs are assumed to be $50 per kilowatt. Aging-related cost increases result from increased capital costs, decreases in performance, and/or increased maintenance expenditures to mitigate the effects of aging.

Nuclear power. There are no nuclear units actively under construction in the United States. In NEMS, new nuclear plants are competed against other options when new capacity is needed. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide.

The capital cost assumptions in the reference case are meant to represent the expense of building a new single-unit nuclear plant of approximately 1,000 megawatts at a new "greenfield" site. Because no new nuclear plants have been built in the United States in many years, there is a great deal of uncertainty about the true costs of a new unit. EIA accounts for that uncertainty by requiring that the capital cost estimates be symmetric in the sense that there is an equal probability that they could turn out to be either "too high" or "too low." For that reason, the estimate used for *AEO2003* is basically an average of the ones reviewed from various sources.

The average nuclear capacity factor in 2001 was 89 percent, the highest annual average ever in the United States. The average annual capacity factor generally increases throughout the forecast, reaching a national average of 92 percent by 2010. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

AEO2003 assumes that the Browns Ferry 1 nuclear unit will return to operation in 2007. The unit has been shut down since 1985 for safety issues but has retained an operating license. The Tennessee Valley Authority, owner and operator of the Browns Ferry plant, recently decided to make the investment required to return the plant to service, which is expected to take 5 years. The *AEO2003* nuclear power forecast also assumes capacity increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 22 applications for power uprates in 2001, and another 22 were approved or pending in 2002. *AEO2003* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 10 years, for a capacity increase of 4.2 gigawatts between 2002 and 2025.

For nuclear power plants, *an advanced nuclear cost case* analyzes the sensitivity of the projections to lower costs for new plants. The cost assumptions for the advanced nuclear cost case are consistent with goals endorsed by DOE's Office of Nuclear Energy and indicated as requirements for cost-competitiveness by the Office's Near-Term Deployment Working Group. The overnight capital cost of a new advanced nuclear unit is assumed to be $1,500 per kilowatt initially, declining to $1,200 per kilowatt by 2020 (in year 2001 dollars) and remaining constant thereafter—28 percent lower initially than assumed in the reference case and 36 percent lower in 2025. Cost and performance characteristics for all other technologies are as assumed in the reference case.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $230 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of its total output using biomass fuel, assuming sufficient fuel supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional biomass supply.

Distributed generation. *AEO2003* assumes the availability of two generic technologies for distributed electricity generation. To determine the levels of capacity and generation for distributed technologies projected to be used in the forecast, the model compares their costs with the "avoided costs" of electricity producers. The avoided costs are the costs electricity producers would incur if they added the least expensive conventional central-station generators rather than distributed generators, as well as the costs of additional transmission and distribution equipment that would be required if the distributed generators were not added. Because there are currently no reliable estimates of the transmission and distribution costs that can be avoided by adding distributed generators, regional estimates were developed for the transmission and distribution investments that would be needed for each kilowatt of central-station generating capacity added. It was then assumed that 75 percent of such "growth-related" transmission and distribution costs could be avoided by adding distributed generators.

International learning. Capital costs for all new fossil-fueled electricity generating technologies are assumed to decrease in response to foreign as well as domestic experience, to the extent that the new plants reflect technologies and firms competing in the United States. In its learning function, *AEO2003* includes 1,928 megawatts of advanced coal gasification combined-cycle capacity (including the 127-megawatt Fife plant that entered service in Scotland in 2001) and 5,244 megawatts of advanced combined-cycle natural gas capacity operating or under construction outside the United States from 2001 through 2003.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 2001 and 2025, compared with 1.8 percent in the reference case. No attempt was made to determine changes in the end-use sectors that would result in the stronger demand growth. The high electricity demand case is partially integrated, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2025 is 7.0 cents per kilowatthour in the high demand case, as compared with 6.7 cents in the reference case. Higher fuel prices, especially for natural gas, are the key factor leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. In the *high fossil technology case*, capital costs and/or heat rates for the advanced coal and gas technologies are assumed to be lower and decline faster than in the reference case. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. The values used in the high fossil technology case for capital costs and heat rates were based on the Vision 21 program for new generating technologies, developed by DOE's Office of Fossil Energy. In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 2002 values assumed in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in these assumptions are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Renewable fuels assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production tax credit (PTC) of 1.5 cents per kilowatthour (now adjusted for inflation to 1.8 cents) for new wind and some biomass plants originally expired on June 30, 1999. It was first extended through December 31, 2001, and then retroactively extended from December 31, 2001 through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147). *AEO2003* applies the credit to all wind plants built through 2003 but assumes the "closed loop" biomass plants eligible for the credit cannot be built until 2010.

Because the PTC displaces taxable income (project revenue) with non-taxable income (a tax credit), its actual value to the project owner is somewhat larger than the face value of the credit. Specifically, the 1.8-cent credit has a value of 2.8 cents, based on the assumed marginal income tax rate of 36 percent used to determine project revenue requirements for generating capacity expansion (that is, the actual value is equal to the face value divided by one minus the tax rate). This represents the additional taxable revenue the owner would have to derive from a project to compensate for the tax credit if it were not available. *AEO2003* does not project planned new wind units after 2003 for which construction is contingent on further extension of the PTC [*30*]. *AEO2003* assumes that the 10-percent investment tax credit for solar and geothermal technologies that generate electric power will be continued through 2025.

Renewable capacity additions. AEO2003 includes 6,680 megawatts of new central-station generating capacity using renewable resources, as announced by utilities and independent power producers or identified by EIA to be built from 2002 through 2020. No builds were identified after 2020. Of the total, 5,206 megawatts results from State mandates, State renewable portfolio standards (RPS), State goals, and other requirements, and 1,474 megawatts results from commercial builds and voluntary programs, such as green power programs and utility testing and demonstration projects using renewables.

For a number of reasons, *AEO2003* does not estimate all new renewable capacity implied by State RPS and other mandates; it includes only the requirement-induced capacity (generally, near term) about which the States and utilities are relatively certain. First, actual implementation for some States is proceeding more slowly than initially expected, suggesting caution in expectations for the near term. Further, States and utilities are sometimes unable to quantify new capacity that they expect to result from the RPS. Moreover, RPS implementation itself is often uncertain, given legal alternatives (such as fines and exemptions) and technology choices (such as conservation). Finally, even if the new capacity is eventually built, the technologies chosen, the year built, and the size and location are unclear.

Estimating supplemental additions of new renewable capacity for *AEO2003* is further complicated by reported transmission constraints thwarting wind development, by uncertainty about post-2003 extension of the PTC, by uncertain financial positions of utilities in the West that serve California markets, by uncertain demand for renewables in light of potential overbuilding of natural gas capacity, and by uncertainty about States' adherence to RPS mandates when economic growth is slow. As a result, the State RPS estimates should be considered relatively certain estimates of new capacity likely to be built in the near term and not as measures of the full potential consequences of the RPS over the entire forecast period.

Using publicly available information and working with State agencies, EIA confirms projections of mandated renewable energy capacity; however, limited resources preclude confirming the status of every new renewable energy plant.

The projection also includes minimum expectations for new central-station solar energy capacity assumed to be installed for reasons other than least-cost electricity supply. *AEO2003* estimates include 75.5 megawatts of central-station solar thermal-electric and 332.5 megawatts of central-station photovoltaic (PV) generating capacity to be installed from 2003 through 2025.

Renewable resources. Although conventional hydroelectricity is the largest source of renewable energy in U.S. electricity markets today, the lack of available new sites, environmental and other restrictions, and costs are assumed to halt the expansion of U.S. hydroelectric power. Solar, wind, and geothermal resources are theoretically very large, but economically accessible resources are much less available.

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*31*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low Btu content per weight of fuel.

The *AEO2003* reference case incorporates upward-sloping supply curves for geothermal and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind power costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences.

AEO2003 includes two revisions to the treatment of wind energy for capacity planning and dispatch. The first reflects the current trend in wind capacity markets toward level capital costs and improving capacity factors, resulting from the experience gained with increasing wind turbine builds. The second change reflects the additional costs imposed on the power grid by increasing levels of wind penetration. For *AEO2003*, the marginal capacity credit for wind decreases toward zero with increasing penetration, which ensures the availability of adequate firm capacity within a region to satisfy reliability requirements. Regional penetration of wind is limited to 20 percent, to reflect additional costs of very high penetration, such as the forced shutdown of wind resources during periods of potential excess generation.

High renewables case. For the *high renewables case*, greater improvements are assumed for central-station nonhydroelectric generating technologies using renewable resources (other than landfill gas) than in the reference case, including capital costs falling below reference case estimates, in order to approximate DOE's Office of Energy Efficiency and Renewable Energy December 1997 *Renewable Energy Technology Characterizations* [*32*]. The high renewables case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, and increased biomass supplies, as well as lower capital costs for residential and commercial distributed photovoltaic systems.

Because of the nature of geothermal sites, which require incremental development to assure that the resource is viable, annual limits are placed on development. The annual limits on builds at geothermal sites were raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years in *AEO2003*. Other generating technologies and forecast assumptions remain unchanged from those in the reference case. The rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed in the high renewables case, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market (using the Blackman market share equation), resulting in increased cellulosic ethanol supply compared with the reference case.

Integrated technology cases. The *integrated high technology case* uses the same assumptions as the high renewables case for central-station renewable energy technologies. The *integrated low technology case* assumes that capital costs for biomass, geothermal, wind, solar thermal, and central-station photovoltaic technologies remain fixed at 2002 values, and that the capacity factors for wind turbines in each wind class remain fixed at 2002 levels.

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2003* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS), the Minerals Management Service (MMS) of the Department of the Interior [*33*], and the National Petroleum Council (NPC), with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that drilling, success rates, and finding rates will improve and the effective cost of supply activities will be reduced. The assumed increase in recovery is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques.

Drilling, operating, and lease equipment costs are expected to decline due to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging roughly from 0.5 percent to 2.0 percent. The technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. Success rates are assumed to improve by 0.67 to 2.62 percent per year, and finding rates are expected to improve by 0.3 to 3.5 percent per year because of technological progress.

Rapid and slow technology cases. Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases, conventional oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates were adjusted by plus or minus 15 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 15 percent in the rapid and slow technology cases. Key Canadian supply parameters were adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential. All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2003*, which is available on the Internet at www.eia.doe.gov/oiaf/aeo/assumption/.

Leasing and drilling restrictions. The projections of crude oil and natural gas supply assume that current restrictions on leasing and drilling will continue to be enforced throughout the forecast period. At present, drilling is prohibited along the entire East Coast, the west coast of Florida, and the West Coast except for the area off Southern California. In Alaska, drilling is prohibited in a number of areas, including the Arctic National Wildlife Refuge. The projections also assume that coastal drilling activities will be reduced in response to the restrictions of CAAA90, which require that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska, MacKenzie Delta, and LNG imports. Due to relative economics, the assumption in the model is that a pipeline from the MacKenzie Delta to Alberta would be constructed first, followed by one from Alaska, with potential expansions following thereafter. The timing of both systems is based on estimates of the cost to bring the gas to market in the United States, relative to the average lower 48 wellhead price.

A natural gas pipeline from Alaska into Alberta, Canada, is assumed to carry an initial capitalization of $11.6 billion (2002 dollars) and be depreciated over 15 years. The corresponding cost for a pipeline from the MacKenzie Delta into Alberta is $3.6 billion. It is assumed that the pipeline will require 4 years to construct (3 years for the MacKenzie pipeline), will not be completed before 2009 (2007 for MacKenzie), will deliver 4.5 billion cubic feet per day once fully operational (1.5 billion for MacKenzie), and can be expanded by 23 percent, if economical. The wellhead price of natural gas from Alaska to be delivered through the pipeline is assumed to be $0.80 per thousand cubic feet in 2001 dollars ($1.00 for MacKenzie). Gas treatment and pipeline fuel costs are accounted for as well. A capital cost risk and market price risk premium totaling $0.56 per thousand cubic feet is assumed ($0.39 for MacKenzie), above and beyond the expected cost of delivery into Alberta and on to the lower 48 States. The resulting assumption is that an average price in the lower 48 States of around $3.50 (2001 dollars) per thousand cubic feet ($3.40 for MacKenzie) would need to be maintained on average over 3 years for construction to commence. An additional $0.08 per thousand cubic feet is assumed to be necessary for an expansion of either pipeline. Expansion of the MacKenzie Delta pipeline is assumed not to occur until the Alaska pipeline is built, and only then is the Alaska pipeline allowed to expand.

The liquefied natural gas (LNG) facilities at Everett, Massachusetts, Lake Charles, Louisiana, and Elba Island, Georgia (the only ones currently in operation) have a combined design capacity of 1,880 million cubic feet per day (687 billion cubic feet per year) and an assumed combined sustainable sendout of 487 billion cubic feet per year. The LNG facility at Cove Point, Maryland, with an assumed sustainable capacity of 292 billion cubic feet per year, is assumed to reopen in 2003. This, plus additional capacity of 396 billion cubic feet per year resulting from currently proposed expansions at the four facilities, brings the total U.S. sendout capacity to 1,175 billion cubic feet per year. An assumed maximum load factor of 90 percent effectively reduces the total available LNG from existing and proposed capacity to 1,057 billion cubic feet per year. This level of LNG is viable between 2005 and 2010, when regional prices at the tailgate range from $3.31 to $3.51 per thousand cubic feet.

Existing facilities are allowed to expand beyond what has been proposed if prices make it economical. Expansions could increase available LNG from existing terminals up to an assumed level of 1,470 billion cubic feet per year. The model also has a provision for the construction of new facilities in all U.S. coastal regions and in Baja California, Mexico, once existing facilities have expanded to their assumed limits. Construction in a region is triggered when the regional price of natural gas meets or exceeds the cost (per thousand cubic feet) of producing, liquefying, transporting, and regasifying the LNG (based on the cost of a new terminal in the region). Regional prices at the LNG tailgate, including relevant transportation charges, that trigger construction range from $3.72 to $4.53 per thousand cubic feet. An LNG facility in Baja California, Mexico, with expansion potential, is assumed to be constructed at a tailgate price of $3.40 per thousand cubic feet. This contributes to the shift of Mexico from being a net importer of U.S. natural gas to a net exporter by the end of the forecast.

Natural gas transmission and distribution assumptions. Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing ratebase. The rates based on cost of service are adjusted according to pipeline utilization, to reflect a more market-based approach. In determining interstate pipeline tariffs, potential future expenditures for pipeline safety necessary to comply with the pending Pipeline Safety Improvement Act of 2002 are not considered.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor. Markups to electricity generators are a direct function of changes in consumption levels alone. The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are based on historical differences between end-use and citygate prices from EIA's *Natural Gas Annual* plus Federal and State taxes on vehicle natural gas. The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed dispensing charge of $3 per thousand cubic feet (1987 dollars) plus taxes.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*34*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming that they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater share of the costs, because demand for light products is less price-responsive than that for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for cleaner burning gasoline and diesel fuels. The recent regulation requiring a reduction in gasoline sulfur content to an annual average of 30 ppm between 2004 and 2007 is also reflected. The additional costs are determined in the representation of refinery operations by incorporating specifications and demands for the fuels.

Demands for conventional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 2002 market shares in each Census division. The expected market shares for oxygenated gasoline assume continued wintertime participation of carbon monoxide nonattainment areas and State-wide participation in Minnesota. Oxygenated gasoline represents about 4 percent of gasoline demand in the forecast.

Fuel ethanol production is modeled in the Petroleum Market Module (PMM). Ethanol is produced in dedicated plants from corn or cellulose feedstocks. Most ethanol is produced from corn in the Midwest (Census Divisions 3 and 4). Commercial cellulosic ethanol production from corn stover is assumed in the Midwest. Cellulosic ethanol production from wood products is assumed in the Mid-Atlantic (Census Division 2), East North Central (Census Division 3), West North Central (Census Division 4), West South Central (Census Division 7), and Pacific (Census Division 9). Ethanol is blended into gasoline at up to 10 percent by volume to provide oxygen, octane, and gasoline volume. Blended with 15 percent gasoline, it is sold as E85. Ethanol can also be used to make ethyl tertiary butyl ether (ETBE), another potential gasoline oxygenate. The PMM is capable of modeling ETBE, but it is expected to cause water contamination problems similar to those caused by MTBE and is therefore not in widespread use.

Reformulated gasoline (RFG) is assumed to continue to be consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas that voluntarily opted into the program [*35*]. RFG projections also reflect a State-wide requirement in California and RFG required by State law in Phoenix, Arizona. In total, RFG is assumed to account for about 34 percent of annual gasoline sales throughout the *AEO2003* forecast.

RFG reflects the "Complex Model" definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. The RFG specifications used for the West Coast reflect the California Air Resources Board (CARB) State-wide gasoline requirements, first implemented in 1996, which will be tightened in 2004. The *AEO2003* projections also reflect legislation in 17 States, including California, that would restrict or ban the use of MTBE in gasoline around 2004 [*36*]. The EPA recently denied a request by California to waive the Federal oxygen requirement in Federal nonattainment areas, including Los Angeles, San Diego, Sacramento, and San Joaquin Valley. Because those areas make up about 80 percent of California's population, *AEO2003* assumes that 80 percent of RFG in the State will continue to require 2.0 percent oxygen by weight after MTBE is banned.

AEO2003 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased down to 30 ppm between 2004 and 2007. *AEO2003* assumes that RFG has an average annual sulfur content of 135 ppm in 2001 and will meet the 30-ppm requirement in 2004. The reduction in sulfur content between 2001 and 2004 is assumed to reflect incentives for "early reduction." The regional assumptions for phasing down the sulfur content of conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30-ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2003 also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. By definition, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The new regulation contains the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100-percent requirement for ULSD thereafter. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007, and the impact of the 100-percent requirement cannot be seen until 2011. Major assumptions related to the implementation of the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7 ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process.

- The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the onset of the program, declining to 4.4 percent at full implementation. The decline reflects an expectation that, with experience, the distribution system will become more efficient at handling ULSD.

- Demand for highway-grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total demand for distillate in the transportation sector. Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.
- ULSD production is modeled through improved distillate hydrotreating units as well as the Phillips S-Zorb process. Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production; the remaining refineries will build new units. The capital cost of a revamp is assumed to be 50 percent of the cost of adding a new unit.
- No change in the sulfur level of non-road diesel is assumed, because the EPA has not yet promulgated non-road diesel standards.

If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,500 per barrel of daily capacity (2001 dollars). Operating costs are assumed to be $3.99 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.75 to $4.45 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feed is assumed to cost $0.82 per thousand cubic feet (2001 dollars).

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic fuels per day and 696 megawatts of capacity for electricity cogeneration sold to the grid [*37*]. CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). CTL capacity is projected to be built only in the *AEO2003* high world oil price case.

State taxes on gasoline, diesel, jet fuel, M85, and E85 are assumed to increase with inflation, as has occurred historically. Federal taxes, which have increased sporadically in the past, are assumed to stay at 2001 nominal levels (a decline in real terms). Extension of the excise tax exemption for blending corn-based ethanol with gasoline, passed in the Federal Highway Bill of 1998, is incorporated in the projections. The bill extends the tax exemption through 2007 but reduces the current exemption of 53 cents per gallon by 1 cent per gallon in 2003 and 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2025 at the nominal level of 51 cents per gallon (a decline in real terms).

High renewables case. The *high renewables case* uses more optimistic assumptions about renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price than are available in the reference case.

Coal market assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue but to decline in magnitude over the forecast horizon. Different rates of improvement are developed, based on econometric estimates using historical data by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 1.6 percent per year over the *AEO2003* forecast period, declining from an estimated annual improvement rate of 2.4 percent between 2001 and 2010 to a rate of 1.1 percent between 2010 and 2025. By comparison, productivity in the U.S. coal industry improved at an average rate of 7.1 percent per year between 1980 and

1990 and by 5.4 percent per year between 1990 and 2001.

Coal transportation costs. Transportation rates are escalated or de-escalated over the forecast period to reflect projected changes in input factor costs. The escalators used to adjust the rates year by year are generated endogenously from a regression model based on the current-year diesel price, employee wage cost index, price index for transportation equipment, and a producer time trend.

Coal exports. Coal exports are modeled as part of a linear program that provides annual forecasts of U.S. steam and coking coal exports in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands.

Mining cost cases. Two alternative mining cost cases examine the impacts of different labor productivity, labor cost, and equipment cost assumptions. The annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity. The low and high mining cost cases were developed by adjusting the *AEO2003* reference case productivity path by one standard deviation, corresponding to adjustments in the annual growth rates of coal mine labor productivity by 2.0 percent for underground mines and 1.3 percent for surface mines. The resulting national average productivities in 2025 (in short tons per hour) were 14.28 in the *low mining cost case* and 7.08 in the *high mining cost case*, compared with 9.97 in the reference case. These are fully integrated cases, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

In the reference case, labor wage rates for coal mine production workers and equipment costs are assumed to remain constant in real terms over the forecast period. In the low and high mining cost cases, wages and equipment costs are assumed to decline and increase by 0.5 percent per year in real terms, respectively.

Notes

[*1*] Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002).

[*2*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002).

[*3*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html.

[*4*] Maine has passed legislation that provides a goal of phasing out MTBE.

[*5*] Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction*; and U.S. Department of Energy, Office of Codes and Standards.

[*6*] Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0321(97) (Washington, DC, 1999).

[*7*] For additional information on green programs see web site www.energystar.gov.

[*8*] For further information see web site www.pathnet.org/about/about.html.

[*9*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*10*] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[*11*] Energy Information Administration, 1999 CBECS Public Use Data Files (January 2002), web site www.eia.doe.gov/emeu/cbecs/ and preliminary 1999 CBECS energy consumption and expenditure data (August 2002).

[*12*] A detailed discussion of the nonsampling and sampling errors for CBECS is provided in Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures*, DOE/EIA-0625(95) (Washington, DC, October 1998), Appendix B, and at web site www.eia.doe.gov/emeu/cbecs/tech_errors_intro.html.

[*13*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*14*] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/power/pdfs/techchar.pdf.

[*15*] Energy Information Administration, *1998 Manufacturing Energy Consumption Survey*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*16*] The data sources and methodology used to develop the nonmanufacturing portion of the Industrial Demand Module are described in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy*

Modeling System, DOE/EIA-M064(2002) (Washington, DC, December 2001).

[*17*] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[*18*] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001).

[*19*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*20*] California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*21*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Truck* (Energy and Environmental Analysis, September 2002).

[*22*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*23*] S. Davis, *Transportation Energy Databook No. 21*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 2001).

[*24*] D. Greene, *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622 (Oak Ridge, TN: Oak Ridge National Laboratory, June 1990), and Oak Ridge National Laboratory, Air Transportation Energy Use Model.

[*25*] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[*26*] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[*27*] U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); Federal Highway Administration, *Highway Statistics 1998* (Washington, DC, November 1999); and S. Davis, *Transportation Energy Databook No. 19*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 1999).

[*28*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Truck* (Energy and Environmental Analysis, September 2002).

[*29*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*30*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916, and extended in Section 507 of the Tax Relief Extension Act of 1999 (Title V of the Ticket to Work and Work Incentives Improvement Act of 1999) and in the Job Creation and Worker Assistance Act of 2002, P.L. 107-147.

[*31*] Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 (August 1991); and M.N. Schwartz, O.L. Elliott, and G.L. Gower, *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992* (Seattle, WA, October 19-23, 1992).

[*32*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997), web site www.eren.doe.gov/power/techchar.html. Where projected cost or performance values for 2002 do not match EIA estimates for 2002, the EIA 2002 estimate is used, and the rate of cost decline through 2025 from the *Renewable Energy Technology Characterizations* is used to establish the 2025 target value.

[*33*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); U.S. Department of the Interior, Minerals Management Service, *2000 Assessment of the Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf, as of January 1, 1999*, OCS Report MMS 2001-087 (New Orleans, LA, October 2001); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (Washington, DC, December 1999).

[*34*] Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993). Excludes operations and maintenance base costs before 1997.

[*35*] Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, and Sacramento. Opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Massachusetts, Maryland, Missouri, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1997.

[*36*] Arizona, California, Colorado, Connecticut, Iowa, Illinois, Indiana, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, and Washington. The State of Maine has passed legislation that provides a goal of phasing out MTBE.

[*37*] Based on the methodology described in D. Gray and G. Tomlinson, *Coproduction: A Green Coal Technology*, Technical Report MP 2001-28 (Mitretek, March 2001).

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.072
Consumption	million Btu per short ton	20.828
Coke Plants	million Btu per short ton	27.426
Industrial	million Btu per short ton	22.433
Residential and Commercial	million Btu per short ton	25.020
Electric Utilities	million Btu per short ton	20.511
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.117
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.948
Petroleum Products		
Consumption[2]	million Btu per barrel	5.322
Motor Gasoline[2]	million Btu per barrel	5.202
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[2]	million Btu per barrel	3.603
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[2]	million Btu per barrel	5.545
Unfinished Oils	million Btu per barrel	5.825
Imports[2]	million Btu per barrel	5.311
Exports[2]	million Btu per barrel	5.782
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.883
Natural Gas		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
Non-electric Utilities	Btu per cubic foot	1,028
Electric Utilities	Btu per cubic foot	1,019
Imports	Btu per cubic foot	1,022
Exports	Btu per cubic foot	1,006
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.

[1]Coal conversion factors vary from year to year. Values correspond to those published by EIA for 2000 and may differ slightly from model results.

[2]Conversion factors vary from year to year. 2010 values are reported.

Sources: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and EIA, AEO2003 National Energy Modeling System run AEO2003.D110502C.

Table H2. Metric Conversion Factors

United States Unit	multiplied by	Conversion Factor	equals	Metric Unit
Mass				
Pounds (lb)	X	0.453 592 37	=	kilograms (kg)
Short Tons (2000 lb)	X	0.907 184 7	=	metric tons (t)
Length				
Miles	X	1.609 344	=	kilometers (km)
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules(J)
Quadrillion Btu	X	25.2	=	million tons of oil equivalent (Mtoe)
Kilowatthours (kWh)	X	3.6	=	megajoules(MJ)
Volume				
Barrels of Oil (bbl)	X	0.158 987 3	=	cubic meters (m^3)
Cubic Feet (ft^3)	X	0.028 316 85	=	cubic meters (m^3)
U.S. Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.
[a]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam, London, 1956.
Source: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002).

Table H3. Metric Prefixes

Unit Multiple	Prefix	Symbol
10^3	kilo	k
10^6	mega	M
10^9	giga	G
10^{12}	tera	T
10^{15}	peta	P
10^{18}	exa	E

Source: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), Table B2.

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The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook Conference

Renaissance, Washington, DC — ***March 18, 2003***

Morning Program

8:15 a.m. - 8:30	**Opening Remarks -** *Administrator*, Energy Information Administration
8:30 a.m. - 9:00	**Overview of the *Annual Energy Outlook 2003* - *Mary J. Hutzler,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:00 a.m. - 9:45	**Keynote Address: Analysis and Policy for Electricity Marketing - *Bill Hogan***, *Professor of Public Policy and Administration*, Harvard University
10:30 a.m. - 12:00	**Concurrent Sessions A** **1. Projecting Future Liquefied Natural Gas Imports** **2. Analyzing the Impacts of Multi-Pollutant Strategies** **3. Perspectives on World Energy Markets**
1:15 p.m. - 2:45	**Concurrent Sessions B** **1. The Challenges of Restructured Electric Transmission Markets** **2. Domestic Refining Capacity or Product Imports?** **3. Improving Mid-Term Energy Forecasts for Buildings**
3:00 p.m. - 4:30	**Concurrent Sessions C** **1. Challenges/Issues for Controlling Energy-Related Emissions in the Midterm** **2. Air Transportation Demand: Are There Constraints?** **3. Renewables: What Affects Their Penetration?**

Hotel

The conference will be held at the *Renaissance*, (202) 898-9000. The *Renaissance* is located at 999 Ninth Street, NW, Washington, DC 20001, near the Gallery Place Metro station. A block of rooms has been reserved at the *Renaissance* (202) 898-9000., in the name of the NEMS Conference. Please make reservations quickly; only a limited number of rooms were held.

Information

For information, contact Peggy Wells, Energy Information Administration, at (202) 586-0109, peggy.wells@eia.doe.gov.

Conference Handouts

Handouts provided in advance by the conference speakers will be posted online by March 7, 2003, at www.eia.doe.gov/oiaf/aeo/conf/handouts.html in lieu of being provided at the conference.

Conference Registration

Conference registration is free, but space is limited.
Please register by February 28, 2003.

Register online at www.eia.doe.gov/oiaf/aeo/conf/

Or mail or fax this form to:

Peggy Wells
Energy Information Administration, EI-84
1000 Independence Avenue, SW
Washington, DC 20585
Phone: (202) 586-0109
Fax: (202) 586-3045

Or register by e-mail to peggy.wells@eia.doe.gov.

Please provide the information requested below:

Name: ____________________

Title: ____________________

Organization: ____________________

Address: ____________________

____

Phone: ____________________

Fax: ____________________

E-mail: ____________________

Please indicate which sessions you will be attending:

❒ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

❒ Projecting Future Liquefied Natural Gas Imports
❒ Analyzing the Impacts of Multi-Pollutant Strategies
❒ Perspectives on World Energy Markets

Concurrent Sessions B

❒ The Challenges of Restructured Electric Transmission Markets
❒ Domestic Refining Capacity or Product Imports?
❒ Improving Mid-Term Energy Forecasts for Buildings

Concurrent Sessions C

❒ Challenges/Issues for Controlling Energy-Related Emissions in the Midterm
❒ Air Transportation Demand: Are There Constraints?
❒ Renewables: What Affects Their Penetration?

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