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Annual Energy Outlook 2002

With Projections to 2020

December 2001

For Further Information . . .

The *Annual Energy Outlook 2002* (*AEO2002*) was prepared by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting, under the direction of Mary J. Hutzler (mhutzler@eia.doe.gov, 202/586-2222), Director, Office of Integrated Analysis and Forecasting; Scott Sitzer (ssitzer@eia.doe.gov, 202/586-2308), Director, Coal and Electric Power Division; Susan H. Holte (sholte@eia.doe.gov, 202/586-4838), Director, Demand and Integration 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
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FAX: 202/586-0727
TTY: 202/586-1181
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Specific questions about the information in this report may be directed to:

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 Cymbalsky (jcymbals@eia.doe.gov, 202/586-4815)
Commercial Demand	Erin 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 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	Albert Walgreen (awalgree@eia.doe.gov, 202/586-5877)
Coal Supply and Prices	Michael Mellish (mmellish@eia.doe.gov, 202/586-2136)
Emissions	Daniel Skelly (dskelly@eia.doe.gov, 202/586-1722)

AEO2002 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ by December 21, 2001. Assumptions underlying the projections and tables of regional and other detailed results will also be available on December 21, 2001, 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* are available at web site www.eia.doe.gov/bookshelf/docs.html.

Other contributors to the report include Joseph Benneche, Robert Eynon, Edward Flynn, Zia Haq, James Hewlett, Jeff Jones, Diane Kearney, Nasir Khilji, Paul Kondis, Matthew Lackey, Thomas Leckey, Han-Lin Lee, Thomas Lee, James Lockhart, Stacy MacIntyre, Phyllis Martin, Paul McArdle, Chris Namovicz, Chetha Phang, Anthony Radich, Eugene Reiser, Esmeralda Sanchez, Laurence Sanders, Kay Smith, Brian Unruh, Dana Van Wagener, Steven Wade, and Peggy Wells.

Preface

The *Annual Energy Outlook 2002* (*AEO2002*) presents midterm forecasts of energy supply, demand, and prices through 2020 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 *AEO2002* reference case. The next section, "Legislation and Regulations," discusses evolving legislative and regulatory issues. "Issues in Focus" discusses electricity and natural gas markets in California, oxygenates in gasoline, energy efficiency trends, and recent EIA analyses of proposed reductions in emissions from electricity generators. It is followed by the analysis of energy market trends.

The analysis in *AEO2002* 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 *AEO2002* assumptions, and the alternative cases.

The *AEO2002* projections are based on Federal, State, and local laws and regulations in effect on September 1, 2001. Pending legislation and sections of existing legislation requiring funds that have not been appropriated are not reflected in the forecasts. Historical data used for the *AEO2002* projections were the most current available as of July 31, 2001, when most 2000 data but only partial 2001 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 2001 and 2002 incorporate the short-term projections from EIA's October 2001 *Short-Term Energy Outlook*.

The *AEO2002* 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 *AEO2002* 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 *AEO2002* 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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Overview

Overview

Key Energy Issues to 2020

Over the past year, energy markets have been extremely volatile, with high prices for oil and natural gas and concerns for energy shortages earlier in the year giving way to an economic slowdown and lower prices following the September terrorist attacks in the United States. Those events are incorporated in the short-term projections for the *Annual Energy Outlook 2002* (*AEO2002*), but long-term volatility in energy markets is not expected to result from their impacts or from the impacts of such future events as supply disruptions or severe weather. *AEO2002* focuses on long-term events, including the supplies and prices of fossil fuels, the development of U.S. electricity markets, technology improvement, and the impact of economic growth on projected energy demand and carbon dioxide emissions through 2020.

The *AEO2002* projections assume a transition to full competitive pricing of electricity in States with specific deregulation plans. Other States are assumed to continue cost-of-service pricing. The projections include recent delays in restructuring plans in several States, as discussed in "Legislation and Regulations," pages 11-13. Problems in California have slowed the trend to restructuring, and retail access in the State has been suspended. The projections include the contracts entered into by California to guarantee electricity supplies in the State, leading to higher electricity prices than in the *Annual Energy Outlook 2001* (*AEO2001*). Increased competition in electricity markets is also represented through changes in the financial structure of the industry and efficiency and operating improvements.

World oil prices remained relatively high through most of 2001, largely due to actions by the Organization of Petroleum Exporting Countries (OPEC) and some non-OPEC countries to restrain oil production. U.S. natural gas prices achieved record levels in 2001 due to a cold winter and tight supplies caused by reduced drilling in response to low prices in 1998 and 1999. Electricity prices also reached record levels in California, as a result of restructuring difficulties, tight natural gas markets, low hydroelectric generation levels, and other generation problems. Energy prices began to decline later in 2001, however, in response to the slowing economy and more normal supply markets for natural gas and electricity.

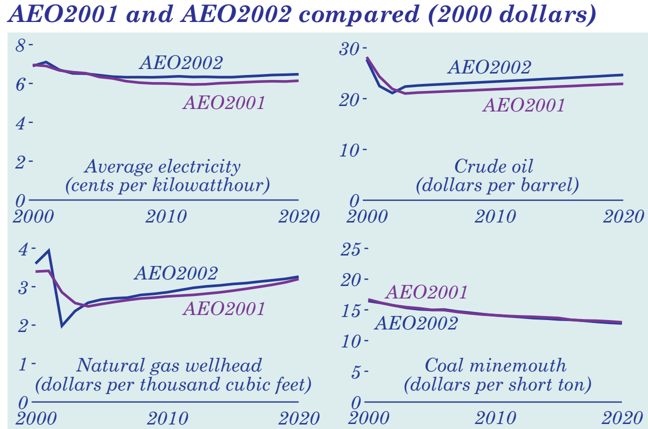
Economic Growth

Although there was an economic slowdown in the United States in 2001, in the long term 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 2000 to 2020, similar to the rate of 2.9 percent projected in *AEO2001* for the same period. Most of the determinants of economic growth are similar to those projected in *AEO2001*, but there are some differences. For example, commercial floorspace is expected to increase at an average annual rate of 1.7 percent through 2020, as compared with 1.2 percent in *AEO2001*. The *AEO2002* projection has a significant impact on energy demand in the forecast for that sector and is more consistent with recent historical trends.

Energy Prices

The average world oil price is projected to decline from $27.72 per barrel in 2000 (2000 dollars) to $22.48 per barrel in 2001, before beginning a gradual increase after 2002. In 2020, the projected price reaches $24.68 per barrel (Figure 1), as compared with $22.92 per barrel projected in *AEO2001*, largely due to higher projected world oil demand. Because of the effectiveness of OPEC in managing oil production and the generally slow response of non-OPEC supply to higher world oil prices, projected prices in the years following 2002 remain higher than in *AEO2001*.

Figure 1. Energy price projections, 2000-2020: AEO2001 and AEO2002 compared (2000 dollars)



World oil demand is projected to increase from 76.0 million barrels per day in 2000 to 118.9 million barrels per day in 2020, higher than the *AEO2001* projection of 117.4 million barrels per day, due to higher projected demand in the United States and developing countries, including the Pacific Rim and Central and South America. Growth in oil production in both OPEC and non-OPEC nations leads to the relatively slow growth of prices through 2020. OPEC oil production is expected to reach 57.5 million barrels per day in 2020, nearly double the 30.9 million barrels per day produced in 2000, assuming sufficient capital to expand production capacity.

Non-OPEC oil production is expected to increase from 45.7 to 61.1 million barrels per day between 2000 and 2020, 1.7 million barrels per day higher than projected in *AEO2001*, due to higher projected production in the Caspian Basin, offshore West Africa, and Brazil. Production from the Caspian Basin is expected to exceed 6.5 million barrels per day by 2020. By 2010, projected production in Brazil reaches nearly 2 million barrels per day and in the offshore regions of West Africa exceeds 2 million barrels per day. North Sea production is expected to peak in the middle of the current decade, reaching 7.5 million barrels per day, with a slower decline rate than earlier expected. By 2010, oil production in Mexico is expected to increase by 30 percent above current levels.

The average wellhead price of natural gas is projected to increase from $3.60 per thousand cubic feet in 2000 to nearly $4 per thousand cubic feet in 2001, then decline sharply in 2002. The price is expected to reach $3.26 per thousand cubic feet in 2020, slightly higher than the projection of $3.20 per thousand cubic feet in *AEO2001*. Although projected natural gas demand in 2020 is 1.0 trillion cubic feet lower than was projected in *AEO2001*, the price is expected to be higher due to a less optimistic assessment of natural gas reserves discovered by exploratory drilling. As the expected demand for natural gas increases over time, price increases are slowed by technological improvements in natural gas exploration and production. The transmission and distribution margins to electricity generators are projected to be higher than in *AEO2001*, under the assumption that generators will pay higher rates to guarantee deliverability, particularly as natural gas is expected to be used more for baseload and intermediate-load generation.

In *AEO2002*, the average minemouth price of coal is projected to decline from $16.45 per ton in 2000 to $12.79 per ton in 2020, slightly lower than the price of $12.99 per ton projected in *AEO2001*. Higher projected demand in *AEO2002* is met by increased production from lower cost western mines. Through 2020, the price is expected to decline with increasing productivity in mining, a shift to western production, and competitive pressures on labor costs.

Average electricity prices are projected to decline from 6.9 cents per kilowatthour in 2000 to 6.5 cents per kilowatthour in 2020, higher than the 6.1 cents per kilowatthour projected for 2020 in *AEO2001*, due to higher projections for natural gas prices, electricity demand, particularly in the commercial sector, and natural gas margins to electricity generators. Electricity industry restructuring contributes to declining projected prices through reductions in operating and maintenance costs, administrative costs, and other costs. Electricity prices are projected to decline to 6.3 cents per kilowatthour by 2006 then rise in the last 5 years of the forecast as natural gas prices rise. Federal Energy Regulatory Commission actions on open access and other changes for competitive markets enacted by some State public utility commissions are included in the projections, but because not all States have deregulated their electricity markets, the projections do not represent a fully restructured electricity market.

Energy Consumption

Total energy consumption is projected to increase from 99.3 to 130.9 quadrillion British thermal units (Btu) between 2000 and 2020, an average annual increase of 1.4 percent. In 2020, this forecast is nearly 4 quadrillion Btu higher than in *AEO2001*, primarily due to higher projected energy demand in the commercial and transportation sectors. The projections incorporate efficiency standards for new energy-using equipment in buildings and for motors mandated through 1994 by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992, including the new residential and commercial equipment standards.

Residential energy consumption is projected to grow at an average rate of 1.0 percent per year, with the most rapid growth for computers, electronic equipment, and appliances. In 2020, the projected residential demand is 24.3 quadrillion Btu, slightly lower than projected in *AEO2001*. Lower projected energy demand, particularly for natural gas, results from 2-percent lower housing starts in 2020, higher projected natural gas prices, and the new equipment efficiency standards announced in January 2001, as revised by the Bush Administration.

Commercial energy demand is projected to grow at an average annual rate of 1.7 percent, reaching 23.2 quadrillion Btu in 2020, 2.4 quadrillion Btu higher than in *AEO2001*. Commercial floorspace is projected to grow by an average of 1.7 percent per year, as compared with 1.2 percent per year in *AEO2001*, raising the demand for energy for many end uses in the commercial sector. The January 2001 equipment standards have a smaller impact in the commercial sector than in the residential sector. The most rapid increases in demand are projected for computers, office equipment, and telecommunications and other equipment.

Industrial energy demand is projected to increase at an average rate of 1.1 percent per year, reaching 43.8 quadrillion Btu in 2020, slightly higher than in the *AEO2001* forecast. Industrial gross output is projected to grow at an average annual rate of 2.6 percent; however, the growth is partially offset by an average projected decline in industrial energy intensity of 1.5 percent per year. Contributing to this decline is a continuing projected shift to less energy-intensive industries. The average annual growth in non-energy-intensive manufacturing is expected to be 3.3 percent, compared with 1.2 percent for energy-intensive manufacturing.

Transportation energy demand is projected to grow at an average annual rate of 1.9 percent, to 39.6 quadrillion Btu in 2020, 1.1 quadrillion Btu higher than in *AEO2001*. The projected energy demand for light-duty vehicles and heavy trucks is higher in *AEO2002*, because a reevaluation of recent trends in both travel and efficiency indicates more rapid growth in travel and slower growth in efficiency. In 2020, projected efficiency for new cars, new light trucks, and heavy trucks is lower by 0.8, 0.9, and 0.6 miles per gallon, respectively, than in *AEO2001*.

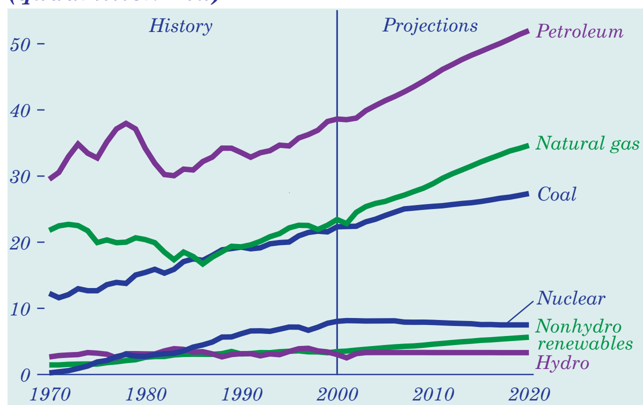
Electricity demand is projected to grow by 1.8 percent per year from 2000 through 2020, the same rate as in *AEO2001*; however, demand in 2020 is 2 percent higher than in *AEO2001*. The most rapid growth is expected for computers, office equipment, and a variety of residential and commercial appliances and equipment.

Demand for natural gas increases at an average annual rate of 2.0 percent (Figure 2), from 22.8 to 33.8 trillion cubic feet between 2000 and 2020, primarily due to rapid growth in demand for electricity generation. Total natural gas demand is projected to be 1.0 trillion cubic feet lower than in *AEO2001*, due to lower projected residential and electricity generation demand, offset in part by higher projected commercial demand.

In *AEO2002*, total coal consumption is projected to increase from 1,081 to 1,365 million tons between 2000 and 2020, an average increase of 1.2 percent per year. This projection is 68 million tons higher than the *AEO2001* projection due to higher projected demand for electricity generation, which constitutes about 90 percent of the domestic demand for coal.

Petroleum demand is projected to grow at an average annual rate of 1.5 percent through 2020, led by growth in the transportation sector, which is expected to account for more than 70 percent of petroleum demand in 2020. Projected demand in 2020 is higher than in *AEO2001* by 830 thousand barrels per day due to higher transportation demand.

Figure 2. Energy consumption by fuel, 1970-2020 (quadrillion Btu)



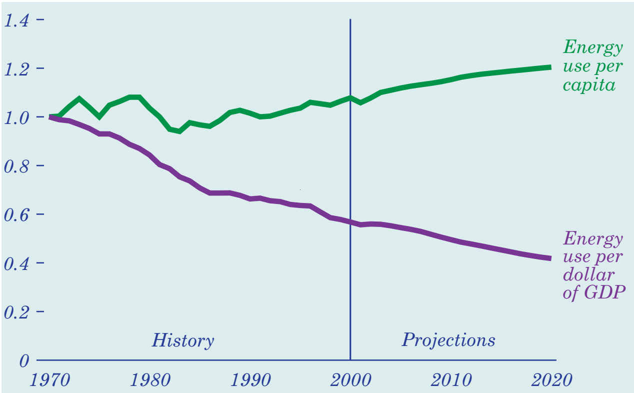
Renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.7 percent per year through 2020, primarily due to State mandates for renewable electricity generation. Nearly 55 percent of the projected demand for renewables in 2020 is for electricity generation and the rest for dispersed heating and cooling, industrial uses, including cogeneration, and fuel blending. The projected demand for renewable fuels in 2020 is 0.7 quadrillion Btu higher than in *AEO2001*, mainly due to higher use of biomass for industrial cogeneration and increased generation from geothermal and wind energy.

Energy Intensity

Between 1970 and 1986, energy intensity, measured as 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 and more efficient technologies in light of energy price increases (Figure 3). With slower price increases and growth of more energy-intensive industries, intensity declines moderated to an average of 1.5 percent per year between 1986 and 2000. Energy intensity is projected to continue to decline at an average annual rate of 1.5 percent through 2020, as continuing efficiency gains and structural shifts in the economy offset growth in demand for energy services.

Energy use per person generally declined from 1970 through the mid-1980s, increasing when energy prices declined. Per capita energy use increases slightly in the forecast, with efficiency gains only partially offsetting higher demand for energy services.

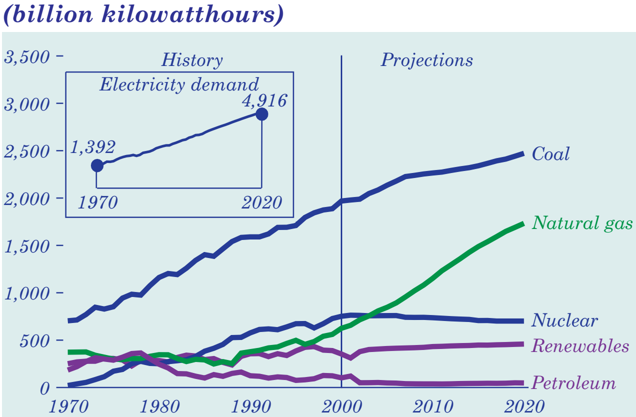
Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2020 (index, 1970 = 1)



Electricity Generation

Generation from natural gas, coal, and renewable fuels is projected to increase through 2020 to meet growing demand for electricity and offset the projected retirement of some existing fossil-fuel-fired and nuclear units (Figure 4). The projected levels of generation from power plants using coal, nuclear, and renewable fuels are higher than in *AEO2001* due to higher projected electricity demand, assumed improvements in the operating costs and performance of nuclear plants, and higher natural gas prices, which reduce natural-gas-fired generation relative to *AEO2001*. The share of generation from natural gas is projected to increase from 16 percent in 2000 to 32 percent in 2020, and the share from coal is projected to decline from 52 percent to 46 percent as a more competitive electricity industry invests in the less capital-intensive and more efficient natural gas generation technologies.

Figure 4. Electricity generation by fuel, 1970-2020 (billion kilowatthours)



Nuclear generating capacity is projected to decline from 2000 to 2020, but a reevaluation of the aging-related costs for nuclear plants and the expectation of higher natural gas prices lead to a higher projection than in *AEO2001*. Nuclear plant retirements in the forecast are based on the cost of maintaining operation compared with the cost of new capacity. Of the 98 gigawatts of nuclear capacity available in 2000, 10 gigawatts are projected to be retired by 2020, as compared with 26 gigawatts of retirements in *AEO2001*. No new nuclear plants are expected to be constructed by 2020 in the reference case, based on the relative economics of alternative technologies.

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. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, contribute to the growth of renewables. With higher expected levels of industrial cogeneration and wind and geothermal generation, total renewable generation, including cogenerators, is projected to increase by 1.3 percent per year to a 2020 level that is slightly higher than in *AEO2001*.

Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy production through 2020. 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 at an average annual rate of 0.2 percent from 2000 to 2020, to 5.6 million barrels per day. Production is projected to increase in the latter half of the forecast and is 0.6 million barrels per day higher in 2020 than in *AEO2001*, due to production from more fields in the National Petroleum Reserve-Alaska, which is expected to begin in 2010. As a result of projected increases in natural gas plant liquids production, total petroleum production is expected to increase through 2020 (Figure 6). Increasing demand for petroleum is projected to raise the share of demand met by net imports from 53 percent in 2000 to 62 percent in 2020 (lower than the 64-percent share in *AEO2001*, due to higher domestic production).

As demand for natural gas increases in the forecast, production is expected to increase from 19.1 to 28.5 trillion cubic feet between 2000 and 2020, an average annual rate of 2.0 percent. Projected production in 2020 is 0.6 trillion cubic feet lower than in *AEO2001*, because the projected rate of growth in demand is lower in *AEO2002*. Net imports, primarily from Canada, are projected to increase from 3.5 to 5.5 trillion cubic feet between 2000 and 2020. Net imports of liquefied natural gas (LNG) are projected to increase to 0.8 trillion cubic feet by 2020. The remaining two of the four existing U.S. LNG import facilities have announced plans to reopen, and three of the four have announced capacity expansion plans.

Figure 5. Total energy production and consumption, 1970-2020 (quadrillion Btu)

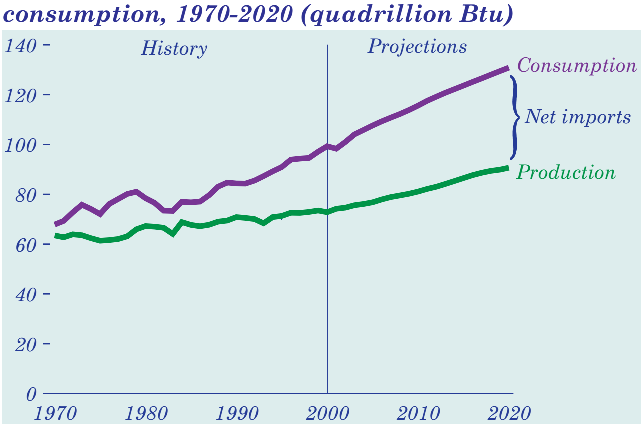
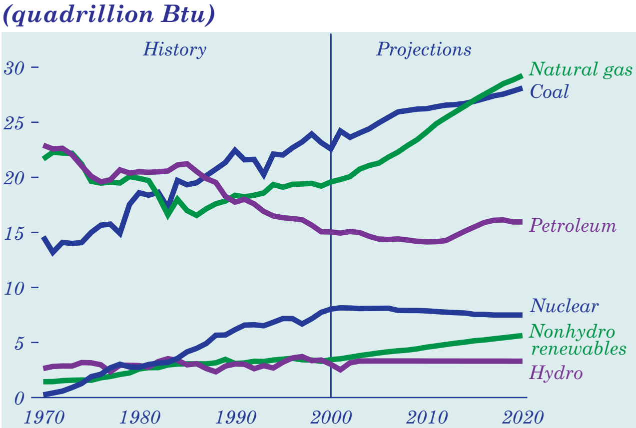


Figure 6. Energy production by fuel, 1970-2020 (quadrillion Btu)



U.S. coal production is projected to increase at an average annual rate of 1.3 percent, from 1,084 million tons in 2000 to 1,397 million tons in 2020, as domestic demand grows. Projected production in 2020 is 66 million tons higher than in *AEO2001*. Coal exports are projected to decline slightly through 2020, as European demand for imports declines as a result of environmental concerns and competition from other producers.

Renewable energy production is projected to increase from 6.5 to 8.9 quadrillion Btu between 2000 and 2020, with growth in industrial biomass, ethanol, and all sources of renewable electricity generation, with the exception of solar. Renewable energy production in 2020 is 0.6 quadrillion Btu higher than projected in *AEO2001*, due to higher expected levels of industrial cogeneration and generation from geothermal and wind energy.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase at an average rate of 1.5 percent per year, from 1,562 million metric tons carbon equivalent in 2000 to 2,088 million in 2020 (Figure 7). Projected emissions in 2020 are higher by 47 million metric tons carbon equivalent than in *AEO2001*, due to higher projected energy demand in the commercial and transportation sectors and more coal-fired electricity generation than in *AEO2001*. The higher projection for nuclear generation in *AEO2002* offsets some of the increase that would otherwise be expected to result from new fossil-fired capacity, but carbon dioxide emissions still are expected to increase more rapidly than total energy consumption, as a result of increasing use of fossil fuels, a slight decline in nuclear generation, and slow growth in renewable generation.

The projections do not include future actions that might be taken to reduce carbon dioxide emissions but do include voluntary actions to reduce energy demand and emissions. Carbon dioxide emissions and international negotiations for emissions reductions are discussed on pages 22-25. Special analyses of emissions reductions, including carbon dioxide, are summarized on pages 37-50.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020 (million metric tons carbon equivalent)

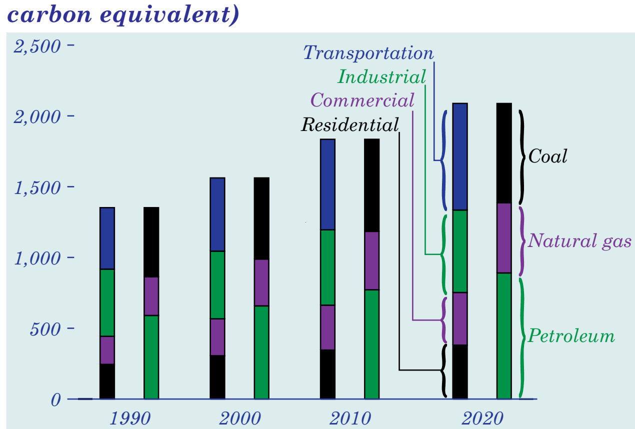


Table 1. Summary of results for five cases

Sensitivity Factors	1999	2000	2020 Reference	2020 Low Economic Growth	2020 High Economic Growth	2020 Low World Oil Price	2020 High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	15.06	15.04	15.95	15.52	16.39	14.40	17.73
Natural Gas	19.20	19.59	29.25	27.98	29.72	28.54	30.03
Coal	23.15	22.58	28.11	26.88	30.08	27.58	29.04
Nuclear Power	7.74	8.03	7.49	7.38	7.49	7.31	7.58
Renewable Energy	6.69	6.46	8.93	8.59	9.37	8.90	8.97
Other	1.66	1.10	0.93	0.91	0.73	0.40	1.06
Total Primary Production	**73.50**	**72.80**	**90.66**	**87.26**	**93.79**	**87.13**	**94.40**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	21.19	22.28	35.04	32.39	38.25	38.65	31.51
Natural Gas	3.50	3.60	5.64	5.12	6.40	5.90	5.17
Coal/Other (- indicates export)	-0.96	-0.77	-0.29	-0.38	-0.15	-0.31	-0.29
Total Net Imports	**23.73**	**25.11**	**40.39**	**37.13**	**44.49**	**44.25**	**36.40**
Discrepancy	0.13	-1.37	0.20	0.25	0.04	-0.04	0.51
Consumption (quadrillion Btu)							
Petroleum Products	38.25	38.63	51.99	48.84	55.60	53.78	50.96
Natural Gas	22.57	23.43	34.63	32.84	35.87	34.17	34.04
Coal	21.56	22.34	27.35	26.08	29.41	26.83	28.27
Nuclear Power	7.74	8.03	7.49	7.38	7.49	7.31	7.58
Renewable Energy	6.70	6.48	8.94	8.59	9.38	8.91	8.98
Other	0.28	0.38	0.44	0.40	0.48	0.42	0.46
Total Consumption	**97.10**	**99.29**	**130.85**	**124.13**	**138.24**	**131.42**	**130.29**
Prices (2000 dollars)							
World Oil Price (dollars per barrel)	17.60	27.72	24.68	23.45	25.81	17.64	30.58
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	2.27	3.60	3.26	2.94	3.65	3.07	3.40
Domestic Coal at Minemouth (dollars per short ton)	17.01	16.45	12.79	12.56	13.23	12.67	12.95
Average Electricity Price (cents per kilowatthour)	6.7	6.9	6.5	6.2	6.8	6.4	6.5
Economic Indicators							
Real Gross Domestic Product							
(billion 1996 dollars)	8,857	9,224	16,525	14,901	18,102	16,561	16,496
(annual change, 2000-2020)	—	—	3.0%	2.4%	3.4%	3.0%	2.9%
GDP Chain-Type Price Index							
(index, 1996=1.00)	1.047	1.070	1.826	2.067	1.608	1.797	1.859
(annual change, 2000-2020)	—	—	2.7%	3.3%	2.1%	2.6%	2.8%
Real Disposable Personal Income							
(billion 1996 dollars)	6,320	6,539	11,698	10,791	12,541	11,685	11,723
(annual change, 2000-2020)	—	—	3.0%	2.5%	3.3%	2.9%	3.0%
Gross Manufacturing Output							
(billion 1992 dollars)	3,804	4,022	7,003	6,473	8,023	7,026	6,977
(annual change, 2000-2020)	—	—	2.8%	2.4%	3.5%	2.8%	2.8%
Energy Intensity							
(thousand Btu per 1996 dollar of GDP)	10.97	10.77	7.92	8.34	7.64	7.94	7.90
(annual change, 2000-2020)	—	—	-1.5%	-1.3%	-1.7%	-1.5%	-1.5%
Carbon Dioxide Emissions							
(million metric tons carbon equivalent)	1,517	1,562	2,088	1,980	2,215	2,103	2,083
(annual change, 2000-2020)	—	—	1.5%	1.2%	1.8%	1.5%	1.5%

Notes: Specific assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections beginning on page 56. 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

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 2002* (*AEO2002*) are based on Federal, State, and local laws and regulations in effect on September 1, 2001. 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.

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 [*1*]; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; 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; and the new standards for energy-consuming equipment that were announced in 2001. *AEO2002* assumes the continuation of the ethanol tax incentive through 2020. *AEO2002* also 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 2000 levels in nominal terms. Although the above tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2002* assumes their continuation throughout the forecast.

AEO2002 also incorporates 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, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of July 1, 2001, 24 States and the District of Columbia had passed legislation or promulgated regulations to restructure their electricity markets. The projections include recently announced delays in restructuring in several States. In California, retail competition has been suspended.

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. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions; the forecast includes NO_x caps for States where they have been finalized. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 100).

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. A discussion of the status of efficiency standards is included later in this section.

Energy combustion is the primary source of anthropogenic (human-caused) carbon dioxide emissions. *AEO2002* 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 *AEO2002* 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. CCAP was formulated as a result of the Framework Convention on Climate Change, which was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992. As part of the Framework Convention, the economically developed signatories, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels. 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.

Although CCAP did not achieve the goal of reducing greenhouse gas emissions to 1990 levels by 2000 and no longer exists as a unified program, most of the individual programs, which are generally voluntary, remain. The impacts of those programs are included in the projections. 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 Kyoto Protocol, for which the Bush Administration has announced it will not seek ratification, and the status of international negotiations on climate change are discussed later in this section.

Electricity Markets: State Restructuring and the California Energy Crisis

Some States Step Back from Restructuring Plans

California formally ended competition (direct access) in its retail electricity market in September 2001, after a year and a half of very high wholesale prices exposed market design failures, forced competitive suppliers from the market, raised retail prices, and caused the bankruptcy of the State's largest utility [*2*]. California's energy crisis has led some States that were in the process of implementing electricity market restructuring legislation to postpone implementation and has forced other States in the process of negotiating the terms of restructuring legislation to rethink their priorities. The biggest fear among the States is that inadequate supply will allow a few suppliers to assert market power and raise prices beyond acceptable levels. States are also considering whether their transmission capacity is adequate to ensure a viable marketplace, and how to give electricity consumers more options for responding to price signals.

In March 2001, Nevada, New Mexico and Arkansas delayed the opening of their retail electricity markets to competition. Nevada's Governor halted the implementation of electric utility deregulation indefinitely—until such time as "the market stabilizes, adequate consumer protections are in place, and supply is at an acceptable level." New legislation in Nevada has re-regulated the State's utilities, delaying the sale of their power plants. At the same time, large customers with time-of-use meters (to be installed by the utility at the cost of the provider or customer) will be allowed to choose their suppliers and residential customers with renewable distributed generators will be offered net metering [*3*].

New Mexico enacted new legislation to delay the opening of its retail electricity market to competition until 2007. The law also delays Public Service of New Mexico's unbundling of its distribution business from its generation and marketing businesses and allows the utility to proceed with plans to build new generation capacity and form a holding company.

Arkansas put off the start of deregulation from January 2002 to October 2003. The Arkansas Public Service Commission (PSC) is also authorized to initiate further delays based on the adequacy of the State's transmission system and generating capacity to support a competitive market. The PSC issued a request for utilities to provide an analysis of prices customers may pay for electric generation service under open access as compared with continued regulation, and to provide the information needed to evaluate the readiness of both retail and wholesale markets for implementation of retail open access.

Legislation was enacted to revise Oregon's restructuring law in August 2001, delaying the date for implementing retail access for large customers from October 2001 to March 2002. Most other provisions of Oregon's plans for restructuring were also delayed for 6 months to March 2002, including allowing residents to choose from a portfolio of retail options.

In June 2001, Oklahoma delayed retail competition. New legislation established a nine-member task force to study the effects of deregulation. Competition, originally scheduled to be phased in from January 2002 to January 2004, will be put off until (1) the task force issues its final report, not later than December 2002, and (2) the legislature enacts enabling restructuring legislation.

In November 2000, the Montana Public Service Commission delayed the date for instituting complete retail access for all consumers from July 2002 to July 2004, because the State does not have a competitive power supply market in place. Most rural electric cooperatives have opted not to restructure or offer retail choice. Also, Montana Power customers have not been switching to retail choice in large numbers.

In light of the low cost of electricity in West Virginia and the price spikes that occurred this past summer in other States that have restructured retail markets, legislation was passed in October 2000 to require the 2001 West Virginia Legislature to pass a resolution before the provisions of the restructuring law can take effect. Consumer choice was to have started in January 2001. As of October 2001, no resolution had been passed.

North Carolina's legislation study panel decided in January 2001 that more study of restructuring issues was needed before recommending that the legislature open the State to competition by 2005, as previously recommended. The studies will focus on consumer protections and ways to encourage power plant construction in the State. In December 2000, the North Carolina Public Utilities Commission (PUC) staff recommended a limited deregulation plan to a legislative panel. In light of California's experience, the PUC recommended that restructuring in North Carolina proceed slowly and with caution.

In Other States, Restructuring Moves Ahead

Although many States delayed restructuring plans, others forged ahead by implementing restructuring on time or improving market designs to increase the competitiveness of their markets. Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island had full or partial competitive retail markets in place before 2001 and are proceeding as scheduled with full implementation of their restructuring plans.

Both the District of Columbia and Ohio began allowing customers direct access to competitive electricity suppliers on January 1, 2001, as mandated by restructuring legislation. Also in January 2001, the New Hampshire Supreme Court upheld New Hampshire's restructuring plan, clearing the way for competition to begin for the majority of consumers in April 2001.

Texas was still set to start full retail competition by January 2002, although pilot programs got started two months late. In September 2001, utilities in Texas began the process of auctioning part of their generating capacity. Restructuring legislation requires each generation company affiliated with a former monopoly utility to sell at least 15 percent of its installed generation capacity at least 60 days before full retail competition begins.

Pennsylvania amended its restructuring rules to allow competitive suppliers to bid for default customers, in order to ensure that more suppliers will stay in the market. In January 2001, as required under the Philadelphia Electric Company (PECO) restructuring plan, 300,000 residential customers who had not chosen a competitive supplier were randomly chosen and switched to The New Power Company, which was chosen by PECO to provide "Competitive Discount Service" from March 2001 through January 2004. Customers may opt out of the program or choose another electricity supplier without penalty.

In March 2001, Virginia passed legislation allowing competitive suppliers to bid to supply "last resort" customers—those customers without access to other competitive retail options. In July 2001, the Virginia State Corporation Commission adopted rules to advance a competitive energy supply market and protect customers who shop for alternative electricity suppliers when the retail market opens—on time—in January 2002.

The New York PSC spent 2001 fine-tuning its competitive market design. In March, the bill credit (shopping credit) a customer could receive for switching to a lower cost supplier was increased to encourage more suppliers to enter the market. The new shopping credit is tied to the going market price to make it easier for suppliers to deal with fluctuating wholesale prices. It also includes a small amount to cover administrative costs. The old shopping credit, which had been set below market prices, discouraged suppliers from entering the market. In June, the PSC approved standards governing the electronic exchange of routine business information and data among electricity and natural gas service providers in New York. The PSC also issued an order in June to establish uniform retail access billing and payment processing practices that will facilitate a single-bill option for customers who buy power and/or natural gas from energy service companies. The orders are designed to facilitate retail energy competition in New York and provide for efficient single-billing options for all New York electricity and natural gas customers.

In Washington State, a May 2001 agreement between Puget Sound and its six largest industrial customers allows them to buy power from any source. In January 2001, the Florida PSC issued a draft restructuring plan that would allow large industrial customers retail choice starting in January 2003. In March 2001, the legislatively mandated Energy 2020 Study Commission released an interim report, *Proposal for Restructuring Florida's Wholesale Market for Electricity*. The report made recommendations to the 2001 legislature that would result in the development of a competitive wholesale electricity market in Florida. Proposals included removing barriers to entry for merchant generation plants, requiring investor-owned load-serving utilities to acquire energy resources through a competitive acquisition process, and allowing utility affiliate companies to assume ownership of existing generation assets and to build new ones.

In January 2001, the Louisiana PSC issued a draft restructuring plan that would allow large industrial customers in Louisiana retail choice starting in January 2003. In March 2001, the staff of the PSC issued its final report, *Final Response of the Commission Staff to Comments on Proposed Competitive Transition Plan*. The report recommends some changes to the transition plan issued in January, including allowing open access to competitive service providers only for large industrial customers with loads averaging 5 megawatts or more rather than the original 2-megawatt load. Although the PSC ruled 2 years ago that open access was not in the State's best interest, study of the issue has continued in light of concerns about economic development. The report recommends another study, due in 2005, to determine whether competition would benefit all classes of customers.

Changes to the *AEO2002* projections as a result of State legislation and regulation were minor, with the exception of California. The changes that have resulted from California's legislative and regulatory developments throughout 2001 and their effects on the *AEO2002* forecasts are discussed in "Issues in Focus," pages 28-35.

Appliance Efficiency Standards

Since 1988, the U.S. Department of Energy (DOE) has promulgated numerous efficiency standards requiring the manufacture of appliances that meet or exceed minimum levels of efficiency as set forth by DOE test procedures. In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which permitted DOE to establish test procedures and efficiency standards for 13 consumer products. Under the auspices of NAECA, DOE is responsible for revising the test procedures and efficiency levels as technology and economic conditions evolve over time.

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 2. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. As a result of the moratorium, no standards were promulgated from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

Table 2. Effective dates of appliance efficiency standards, 1988-2007

Product	*1988*	*1990*	*1992*	*1993*	*1994*	*1995*	*2000*	*2001*	*2003*	*2004*	*2005*	*2006*	*2007*
Clothes dryers	X				X								
Clothes washers	X				X					X			X
Dishwashers	X				X								
Refrigerators and freezers		X		X				X					
Kitchen ranges and ovens		X											
Room air conditioners		X					X						
Direct heating equipment		X											
Fluorescent lamp ballasts		X									X		
Water heaters		X								X			
Pool heaters		X											
Central air conditioners and heat pumps			X									X	
Furnaces													
Central (>45,000 Btu per hour)			X										
Small (<45,000 Btu per hour)			X										
Mobile home		X											
Boilers			X										
Fluorescent lamps, 8 foot					X								
Fluorescent lamps, 2 and 4 foot (U tube)						X							
Commercial water-cooled air conditioners									X				
Commercial natural gas furnaces									X				
Commercial natural gas water heaters									X				

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among such disparate concerns as the natural gas and electric power industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric power and natural gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

In January 2001, DOE published final rules for several residential and commercial appliances, including residential water heaters, clothes washers, and central air conditioners and heat pumps, as well as commercial water-cooled cooling equipment and natural-gas-fired water heaters and furnaces. In July, however, DOE issued a Notice of Proposed Rulemaking (NOPR) withdrawing the final rulemaking for central air conditioners and heat pumps. The NOPR, which invited public comment through the end of September 2001, essentially replaced the 13 seasonal energy efficiency ratio (SEER) standard issued in January with a 12 SEER standard. The decision to lower the standard has brought legal action from the Natural Resources Defense Council (NRDC) and 3 States, which have sued DOE over the legality of withdrawing the original 13 SEER standard. For *AEO2002*, it is assumed that the 12 SEER standard will prevail in 2006, when it is scheduled to become effective.

Currently, DOE is evaluating standards for distribution transformers and residential furnaces and boilers. Because the *AEO2002* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, these efficiency standards are not included in the projections.

Production Tax Credit for Renewables

As part of EPACT, Congress established a tax credit of 1.5 cents per kilowatthour for electricity produced from new renewable generators using wind or closed-loop biomass energy sources. (Closed-loop biomass plants use feedstocks derived from "energy crops" grown specifically for energy production.) The credit is applicable for 10 years after a qualifying facility has been placed in service. Originally set to expire in 1999, the credit was extended by Congress to cover new units entering service by December 31, 2001. The tax credit was indexed to inflation and currently is worth 1.7 cents per kilowatthour.

In August 2001, the U.S. House of Representatives passed the Securing America's Future Energy Act of 2001 (SAFE Act of 2001, currently bill H.R. 4). The SAFE Act would extend the renewable electricity production tax credit (PTC) for another 5 years, for new facilities on line through December 31, 2006, and would expand eligibility to open-loop biomass and landfill gas facilities. (Open-loop biomass plants use feedstocks derived as waste from other activities, such as agricultural residue, yard trimmings, and commercial wood waste.) Other similar proposals before Congress would extend the credit for various durations and expand it to different renewable generating technologies.

Because the legislation is still pending, it is not incorporated in the *AEO2002* reference case. Additional analysis indicates that the PTC provisions of H.R. 4 could have a significant effect on the targeted industries. By 2020, the tax credit could result in an additional 4 gigawatts of wind capacity (13 gigawatts with the PTC extension, compared with 9 gigawatts without), an additional 2 gigawatts of dedicated biomass capacity (4 gigawatts with the extension and expansion, compared with 2 gigawatts without), and an additional 1 gigawatt of landfill gas capacity (5 gigawatts with the extension and expansion, compared with 4 gigawatts without). If all the potential new renewable capacity were built, the nonhydroelectric renewable share of total U.S. electricity generation in 2020 could increase to 3.4 percent, as compared with 2.9 percent projected in the *AEO2002* reference case.

Heavy-Duty Vehicle Emissions and Diesel Fuel Quality Standards

In December 2000, the EPA finalized new regulations on heavy-duty engine and vehicle standards and highway diesel fuel sulfur control requirements [*4*]. The engine and vehicle standards will affect new heavy-duty vehicles sold in model years 2004, 2007, and 2010. In 2004, the standard requires that all new heavy-duty vehicles achieve a 40-percent reduction in emissions of nitrogen oxides (NO_x) and hydrocarbons (HC). In 2007, the rule requires 50 percent of new heavy-duty vehicles sold to meet significantly more stringent emissions standards. The 2007 standards require a 92-percent reduction in NO_X emissions and an 89-percent reduction in HC emissions from the 2004 standard. For model years 2007 through 2009, the EPA allows engine manufacturers flexibility in meeting the NO_X and HC standards, in that they are given the option to produce 100 percent of their engines to meet an average of the 2004 and 2007 NO_X and HC emissions standards. In 1998, the EPA signed consent decrees with several manufacturers of heavy-duty diesel engines, stating that they would produce engines to meet the 2004 emissions standards by October 2002. New standards for heavy-duty gasoline engines and vehicles will reduce both NO_X and HC emissions for all vehicles above 8,500 pounds gross vehicle weight not covered in the Tier 2 standards, beginning in 2004.

The new rule requires refiners and importers to produce highway diesel fuel meeting a 15 parts per million (ppm) maximum requirement, starting June 1, 2006; however, pipelines are expected to require refiners to provide diesel fuel with an even lower sulfur content, somewhat below 10 ppm, in order to compensate for contamination from higher sulfur products in the system and to provide a tolerance for testing. Diesel fuel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010; the remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

Analysis included in an EIA study conducted at the request of the EPA, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*, released in May 2001, indicated the possibility of a tight diesel market at the onset of the new 15-ppm sulfur maximum in June 2006 [*5*]. Given the EPA's assumptions for refinery equipment costs and return on investment, the EIA analysis concluded that increases in highway diesel costs of between 5.4 and 6.8 cents per gallon could be expected in the short run in Petroleum Administration for Defense Districts (PADDs) I through IV, and even higher increases would be expected if a shortfall in diesel supply occurred. The EPA has taken steps to monitor the ultra-low-sulfur diesel fuel (ULSD) supply situation. The EPA's Final Rulemaking requires refiners and importers expecting to produce highway diesel in 2006 to register with the EPA by December 31, 2001, and to provide annual updates of expected ULSD production capacity beginning in 2003.

EIA's study also included a longer term analysis of increases in the average annual end-use price of highway diesel, based on a range of different assumptions. Using a set of assumptions similar to those used by the EPA in its Regulatory Impact Analysis of the diesel rule, EIA estimated increases in the average U.S. end-use price ranging from 6.5 to 7.0 cents per gallon between 2007 and 2010. When a set of assumptions more consistent with previous industry analyses was used, price differentials ranged from 8.4 to 8.8 cents per gallon. The additional costs associated with complying with the new diesel regulation are included in the *AEO2002* reference case, based on the specific assumptions discussed in Appendix G.

In addition to the new highway diesel regulation, the EPA is in the early planning stages of new standards for diesel fuel used for other purposes, or "non-road" diesel. Since the specifics of the non-road standards have yet to be proposed by EPA, no changes in non-road diesel quality are reflected in the *AEO2002* reference case.

Relaxed Standard for Reformulated Gasoline in the Midwest

In June 2001, the EPA decided to modify the volatile organic compound (VOC) emissions standard for Federal reformulated gasoline (RFG) blended with ethanol. The EPA recognized that ethanol-blended RFG provides additional reductions in carbon monoxide emissions, which in turn reduce ground-level ozone formation. Because the VOC standards are also intended to reduce ground-level ozone formation, the standard for RFG with ethanol could be relaxed by the equivalent of 0.3 pounds per square inch (psi) Reid vapor pressure (Rvp) while maintaining the air quality benefits of the RFG program.

The EPA is moving cautiously, so far having granted the VOC waiver only to the Chicago-Milwaukee RFG market, which is the only market that requires RFG to be blended with ethanol. Both cities have had gasoline supply problems, due in part to the difficulty of refining the low-volatility blendstocks needed to blend RFG with ethanol. The EPA expects the VOC adjustment to increase gasoline supply in Chicago and Milwaukee.

Extension of the Rvp waiver for ethanol blending with RFG has been suggested before. In order to encourage the use of ethanol, conventional gasoline blended with ethanol is allowed by CAAA90 to have Rvp 1 psi higher than that of conventional gasoline. CAAA90 limited conventional gasoline volatility to 9 psi during the summer months, when ground-level ozone concentrations are most often at unhealthy levels. It also authorized the Administrator of the EPA to impose tighter Rvp standards in current or former nonattainment areas. An Rvp limit of 7.8 psi was imposed on many such areas, mainly those in warmer climates or at higher elevations. CAAA90 allows ethanol blends to exceed the applicable limit by 1 psi, provided that the gasoline blendstock complies with applicable limits and provided that the ethanol blend will not adversely affect emissions from vehicles certified to 1975 or later standards.

In February 1994, the EPA considered extending to RFG the 1-psi waiver for ethanol blends when it finalized standards for RFG. It noted that the VOC emission standards adopted for RFG might have the effect of excluding ethanol from the RFG oxygenate market. Forcing ethanol out of the RFG market might have increased dependence on foreign crude oil, which would be contrary to the Nation's energy policy. But the proposed waiver was expected to have little effect on petroleum imports as a result of the loss of energy content per gallon of gasoline that occurs when hydrocarbons are replaced with ethanol.

Of greater concern to the EPA was the potential for loss of air quality benefits if ethanol RFG blended under the waiver was mixed with non-ethanol RFG during automobile refueling. The EPA, estimating that such mixing could negate 40 to 50 percent of the VOC performance improvement associated with the RFG program, declined to extend the waiver to RFG at the time. The ethanol waiver decision was revisited after the emergence of supply shortages and price spikes in the Chicago-Milwaukee RFG market in the spring of 2000.

New Rule on Airborne Benzene

In March 2001, the EPA established its Mobile Source Air Toxics (MSAT) regulatory program. Twenty-one substances were placed on the MSAT list for future regulatory action. All MSAT substances are known or suspected to cause cancer or other serious illness. Benzene, formaldehyde, 1,3-butadiene, acetaldehyde, diesel particulate matter, and diesel exhaust organic gases are of the most concern. The EPA did not explicitly tighten emission standards for any of the MSAT substances, but it did put in place a regulation ensuring that future fuels will be at least as clean as today's fuels, according to emissions forecast from the EPA's Complex Model.

The new rule sets an allowable level of emissions (as predicted by the Complex Model) for each refiner's gasolines that is equal to the average predicted emissions of its output between 1998 and 2000. By 2020, the MSAT program is expected to reduce highway emissions of benzene, formaldehyde, 1,3-butadiene, and acetaldehyde by 67 to 76 percent relative to 1990 levels. Diesel particulate matter is projected to be reduced by 90 percent relative to 1990 levels.

One goal of the new rule is to prevent “backsliding” on airborne benzene. Benzene is emitted by evaporation of gasoline from vehicle fuel tanks and by incomplete combustion of gasoline. The RFG program gave refiners a choice of two benzene standards: an average of 0.95 percent by volume with an upper limit of 1.3 percent by volume, or an upper limit of 1.0 percent by volume with no average requirement. Benzene in conventional gasoline was regulated indirectly by the RFG program's anti-dumping toxic standards. Toxic standards for each refiner were set to the average emissions (as predicted by the Complex Model) for each batch of gasoline produced by that refiner in 1990. Under the new rule, conventional gasoline could average 1.3 percent benzene by volume.

In practice, refiners overcomplied with their limits. The new MSAT regulations aim to maintain current overcompliance levels of benzene in gasoline while forcing improvements in other emissions. Accordingly, refiners are now limited by the average emissions, as predicted by the Complex Model, of conventional gasoline and RFG that each produced between 1998 and 2000. A default baseline will also be available for refiners that did not produce gasoline for the U.S. market for 12 consecutive months between 1998 and 2000.

Low-Emission Vehicle Program

The Low-Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could opt in to the California program and achieve lower emissions levels than required by CAAA90. Both New York and Massachusetts chose to opt in to the LEVP, implementing the same mandates as California.

The LEVP was an emissions-based policy, setting sales mandates for three categories of low-emission vehicles according to their relative emissions of air pollutants: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resources Board (CARB) were dedicated electric vehicles [*6*].

The LEVP was originally scheduled to begin in 1998, with a requirement that 2 percent of the State's vehicle sales be ZEVs, increasing to 5 percent in 2001 and 10 percent in 2003. On November 5, 1998, the CARB amended the original LEVP to include ZEV credits for advanced technology vehicles. According to the CARB, qualifying advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range" [*7*]. There are three components in calculating the ZEV credit, which vary by vehicle technology: (1) a baseline ZEV allowance, (2) a zero-emission vehicle-miles traveled (VMT) allowance, and (3) a low fuel-cycle emission allowance.

Further modifications proposed for the ZEV mandate in September 2000 were finalized in January 2001 [*8*]. The proposal was designed to maintain progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. The CARB proposal removed ZEV sales requirements before 2003 but maintained the 2003 required ZEV sales goal of 10 percent and required a gradual increase of ZEV sales to 16 percent by 2018. The number of vehicles included in the estimation of required ZEV sales was also increased, to include small light-duty trucks.

The proposal also provides manufacturers flexibility in meeting the goal through increased vehicle credits and greater allowances for partial ZEVs (PZEVs) and advanced technology ZEVs (AT-PZEVs). ZEVs will earn 1.25 credits per vehicle before 2006, and PZEVs will receive a phase-in multiplier credit of 4, 2, and 1.3 per vehicle for 2004, 2005, and 2006, respectively. Extra credits will also be allowed for ZEVs with extended range and/or reduced fueling times.

The baseline PZEV allowance potentially can provide up to 0.2 credit if the advanced technology vehicle meets the following standards: (1) super-ultra-low-emission vehicle (SULEV) standards, which approximate the emissions from power plants associated with recharging electric vehicles; (2) on-board diagnostics (OBD) requirements for indicators on the dashboard that light up when vehicles are out of emissions compliance levels; (3) a 150,000-mile warranty on emission control equipment; and (4) evaporative emissions requirements in California, which prevent emissions during refueling. The modifications allow a maximum of 6 percentage points of the ZEV mandate sales requirement to be met by PZEVs.

The AT-PZEV allowance will allow a maximum 0.6 credit if the vehicle is capable of some all-electric operation (to a range of at least 20 miles), or if the vehicle has ZEV-like equipment on board, such as regenerative braking, advanced batteries, or an advanced electric drive train. AT-PZEVs can satisfy up to 50 percent of the pure ZEV sales requirement. The remaining mandated ZEV sales must be electric vehicles or hydrogen fuel cell vehicles.

An emission allowance was also made for vehicle fuels with low fuel-cycle emissions used in advanced technology vehicles. A maximum of 0.2 credit is provided for vehicles that use fuels which emit no more than 0.01 gram of nonmethane organic gases per mile, based on the grams per gallon and the fuel efficiency of the vehicle.

AEO2002 assumes that Massachusetts, New York, Maine, and Vermont will also adopt the California LEVP mandates.

Proposed Energy Legislation

Comprehensive energy-related legislation has been proposed in both the House and the Senate. H.R. 4, Securing America's Energy Future Act of 2001 (Tauzin), which largely parallels the National Energy Policy Plan (NEPP) [*9*], was passed in the House of Representatives in August 2001. The proposed Republican bill in the Senate, S. 388, the National Energy Security Act of 2001 (Murkowski), is similar to H.R. 4; however, the principal Senate bill, S. 597, the Comprehensive and Balanced Energy Policy Act of 2001 (Bingaman), differs from the NEPP and H.R. 4 in several respects. Perhaps the most notable difference is that the NEPP and H.R. 4 permit oil and natural gas drilling in Alaska's

Arctic National Wildlife Refuge (ANWR), whereas S. 597 does not. Neither proposal requires changes to vehicle fuel economy standards, although H.R. 4 requires the Secretary of Transportation to prescribe standards for light trucks manufactured from 2004 to 2010.

While S. 597 and H.R. 4 have dozens of provisions that are similar, they differ greatly in emphasis. H.R. 4 contains numerous tax incentives for energy production; S. 597 does not. Also, S. 597 contains numerous provisions on electricity deregulation that do not appear in H.R. 4. As of mid-November 2001, it appeared unlikely that there would be a vote on the Senate bill before the end of 2001. Consequently, the *AEO2002* forecasts do not include any of the provisions of the proposed legislation. A number of the proposals contained in S. 597, H.R. 4, and the NEPP, as described in the summaries of the bills and in the NEPP, are listed below. Many of the NEPP proposals would require new legislation, and others would depend on budget authority.

S. 597

- Establishes a National Commission on Energy and Climate Change and an Interagency Working Group on Clean Energy Technology Transfer
- Authorizes the States to develop regional coordination of energy infrastructure
- Mandates periodic reviews of regulations to identify barriers to market entry for emerging energy technologies
- Amends the Federal Power Act to establish the Electric Reliability Organization
- Establishes a Public Benefits Fund
- Amends the Rural Electrification Act of 1936 to authorize electrification grants for rural and remote communities
- Amends the Energy Policy Act of 1992 to mandate a comprehensive Indian energy program and amends the Department of Energy Organization Act to establish an Office of Indian Energy Policy and Programs
- Directs the Federal Trade Commission to prescribe disclosure requirements regarding energy sources used to generate electricity and specified consumer protections and privacy
- Amends the Federal Power Act to require the FERC to establish a wholesale electricity market data information system and wholesale electric energy rates in the Western energy market
- Prescribes guidelines governing renewable energy resources, distributed generation facilities, and hydroelectric relicensing
- Directs the Secretary of Energy to assess cost and performance goals for a national coal-based technology development and applications program and to implement a power plant improvement initiative program
- Amends the Atomic Energy Act of 1954 to revise indemnification and liability guidelines (the Price-Anderson Amendments Act of 2001)
- Sets a deadline for a specified Outer Continental Shelf oil and gas lease sale. Mandates an accelerated research and development program regarding pipeline integrity for natural gas and hazardous liquids
- Prescribes guidelines for statutory mechanisms that increase vehicle fuel efficiency or provide vehicle alternatives in order to limit demand for petroleum products by light-duty vehicles
- Amends the Energy Policy and Conservation Act to revise alternative fuel requirements for Federal fleets
- Establishes a Federal Energy Bank and a High Performance Schools Program
- Delineates goals for enhanced research and development programs that target energy efficiency, renewable energy, fossil energy, nuclear energy, and fundamental energy science (Energy Science and Technology Enhancement Act)
- Directs the Secretary of Energy to establish national energy research and development advisory boards; monitor workforce trends pertaining to skilled technical personnel supporting energy technology industries; establish traineeship grant programs for technically skilled personnel; and develop employee training guidelines to support electric supply system reliability and safety.

H.R. 4

- Reauthorizes Federal energy conservation programs with respect to Federal energy savings performance contracts, automobile fuel economy, nuclear energy, high ozone season reformulated gasoline and gasoline blendstock requirements, MTBE contamination from underground storage tanks, oil and gas pipeline routes, the burning of post-consumer carpet in cement kilns as an alternative energy source, and other specified matters

- Sets goals for energy research, development, and commercial application programs (Comprehensive Energy Research and Technology Act of 2001)
- Directs the Secretary of Energy to establish a competitive grant pilot program for State and local governments and metropolitan transportation authorities to implement an alternative fuel vehicle acquisition program (Alternative Fuel Vehicle Acceleration Act of 2001)
- Directs the Secretary of Energy to establish grant and cooperative agreement programs for alternative fuel, ultra-low-sulfur diesel, and fuel-cell-powered school buses (Clean Green School Bus Act of 2001)
- Authorizes the Secretary of Energy to establish the Next Generation Lighting Initiative (Next Generation Lighting Initiative Act)
- Earmarks funds for the U.S. EPA's Office of Air and Radiation (Environmental Protection Agency Office of Air and Radiation Authorization Act of 2001)
- Amends the Spark M. Matsunaga Hydrogen Research, Development, and Demonstration Act of 1990 to direct the Secretary of Energy to conduct a hydrogen technology transfer program to increase the global market for hydrogen technologies (Robert S. Walker and George E. Brown, Jr. Hydrogen Energy Act of 2001)
- Authorizes appropriations for bioenergy research and development programs and biofuels energy systems (Bioenergy Act of 2001)
- Directs the Secretary of Energy to support or conduct a program to maintain the Nation's human resource investment and infrastructure in nuclear sciences and engineering; an advanced fuel recycling technology research and development program to promote the availability of proliferation-resistant fuel recycling technologies; a Nuclear Energy Research Initiative; and a Nuclear Energy Plant Optimization research and development program (Department of Energy University Nuclear Science and Engineering Act)
- Directs the Secretary of Energy to implement research and development programs pertaining to unconventional and ultra-deepwater natural gas and petroleum exploration and production technologies in areas currently available for Outer Continental Shelf leasing (Natural Gas and Other Petroleum Research, Development, and Demonstration Act of 2001)
- Directs the Secretary of Energy to develop a plan for U.S. construction of a magnetic fusion burning plasma experiment and a Fusion Energy Sciences Program
- Authorizes appropriations for the "Spallation Neutron Source" at Oak Ridge National Laboratory
- Amends the Internal Revenue Code with respect to specified energy conservation credits and deductions (Energy Tax Policy Act of 2001)
- Directs the Secretary of Energy to implement a prescribed program of cost and performance goals for specified 5-year periods, entailing research, development, demonstration, and commercial application of clean coal technologies (Clean Coal Power Initiative Act of 2001)
- Mandates Federal agency reports on whether rights-of-way for transportation across Federal lands of energy supplies or transmission of electricity can be authorized for new or additional capacity; and an inventory review of the wind, solar, coal, and geothermal power production potential of Federal lands (Energy Security Act)
- Mandates use of a specified bidding system for certain oil and gas lease sales located in the Western and Central Planning Area of the Gulf of Mexico (Royalty Relief Extension Act of 2001)
- Amends the Outer Continental Shelf Lands Act to prescribe guidelines for the payment in kind of oil and gas royalties to the United States and for royalty rate reductions for production declines at certain oil and gas wells, in order to spur marginal well production (Federal Oil and Gas Lease Management Improvement Demonstration Program Act of 2001)
- Amends the Geothermal Steam Act of 1970 to prescribe royalty reductions and to waive royalty requirements for certain geothermal energy leases
- Directs the Secretary of the Interior to establish a competitive oil and gas leasing program for the exploration and production of oil and gas resources of the Arctic Coastal Plain (Arctic Coastal Plain Domestic Energy Security Act of 2001).

Legislation and Regulations

NEPP

- Increases funding for energy efficiency programs, encouraging the development of fuel-efficient vehicles, creating tax credits to encourage consumer conservation, and expanding DOE conservation programs
- Expedites permitting for infrastructure improvements, expands research on reliable energy transmission, and removes regulatory barriers
- Expands the use of alternative and renewable energy such as wind, solar, biomass, and geothermal energy and provides for the safe expansion of cheap, clean, and safe nuclear energy
- Increases funding for clean coal research
- Directs DOE to undertake a review of existing energy efficiency and alternative and renewable energy research and development programs to assure that future program budget allocations are performance-based and modeled as public-private partnerships
- Provides $285 million for energy efficiency and renewable energy research and development
- Increases the industry cost share beyond the current average 50-percent share for some DOE programs, especially as research and development projects move closer to commercialization
- Enacts a new tax credit for investments in combined heat and power systems or shortens the depreciation life for combined heat and power projects
- Provides temporary income tax credits for the purchase of new hybrid and fuel cell vehicles, which would be available for all qualifying light vehicles, including cars, minivans, sport utility vehicles, and light trucks
- Proposes pipeline safety legislation that would significantly strengthen the enforcement of pipeline safety laws
- Directs the Secretaries of Energy and State to coordinate with the Secretary of the Interior and the FERC to work closely with Canada, the State of Alaska, Congress, and other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 States, including proposing to Congress any modifications to the Alaska Natural Gas Transportation Act of 1976 that may be necessary
- Proposes the development of legislation to implement electricity restructuring that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act
- Proposes the development of legislation to grant authority to obtain rights-of-way for electricity transmission lines only when absolutely necessary, with the goal of creating a reliable national transmission grid
- Provides several tax incentives to help increase the contribution that alternative and renewable energy makes to the Nation’s energy supply and extends the present 1.7 cents per kilowatthour tax credit for electricity produced from wind
- Expands tax credits for electricity produced using renewable technology, such as biomass; extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and other specified sources (for existing biomass facilities, the credit for electricity produced from the new sources is 1.0 cent per kilowatthour for 3 years of production, 2002-2004); and proposes a tax credit for electricity produced from co-firing biomass from new sources of 0.5 cent per kilowatthour for 3 years of production, 2002-2004
- Proposes a new 15-percent tax credit for individuals who purchase photovoltaic equipment or solar water heating equipment for use in an individual residence, up to a maximum credit of $2,000 for each type of equipment, which would be available for 2002-2007 for photovoltaic equipment and 2002-2005 for solar water heating equipment
- Proposes to extend the excise tax exemption for gasohol (ethanol mixed with motor fuels) and the income tax credit for ethanol used as fuel beyond 2007, when they are scheduled to expire
- Proposes to encourage an alternative source of energy near population centers by providing tax credits for energy produced from landfill gas, which would be available for energy produced from methane from regulated landfills that are required by the EPA to collect and flare methane and for unregulated landfills

- Supports reauthorization of the Hydrogen Energy Act
- Supports legislative or administrative reform of the hydropower licensing process to make the hydropower licensing process more clear and efficient, while preserving environmental goals
- Proposes that Congress authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR; and that any legislation should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment
- Urges Congress to pass legislation to use an estimated $1.2 billion of bid bonuses from leasing of ANWR for additional funding of research on alternative and renewable energy resources, including wind, solar, geothermal, and biomass
- Allows taxpayers (other than regulated utilities) to make deductible contributions to a nuclear decommissioning fund and permits nuclear decommissioning funds to accumulate the full amount needed for decommissioning
- Reauthorizes the Price-Anderson Act
- Directs the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power plants generators; propose mandatory reduction targets for emissions of sulfur dioxide, nitrogen oxides, and mercury; phase in the reductions over a reasonable period of time, similar to the successful acid rain reduction program established by CAAA90; provide regulatory certainty to encourage utilities to install newer, cleaner, more efficient systems; and provide market-based incentives, such as emissions trading credits, to help achieve the required results
- Directs the Secretary of the Interior to work with Congress to create a Royalties Conservation Fund that would earmark royalties from new oil and gas production in ANWR to fund land conservation efforts and would be used to eliminate the maintenance and improvements backlog on Federal lands
- Requests a fiscal year 2002 budget of $1.7 billion for the Low-Income Home Energy Assistance Program (LIHEAP), which would be an increase of $300 million from last year's non-emergency appropriation
- Proposes $1.2 billion in additional funding for the weatherization program over 10 years, roughly double the current level of spending.

Renewal of the Price-Anderson Act

The Price-Anderson Act, first passed in 1957 as an amendment to the Atomic Energy Act of 1954 and renewed three times since, will expire on August 1, 2002. The Act provides for payment of public liability claims in the event of a nuclear incident. Several bills have been introduced in the Senate to provide a 10-year extension to the Price-Anderson Act, including S. 388, the National Energy Security Act of 2001; S. 472, Nuclear Energy Electricity Supply Assurance Act of 2001; and S. 597, the Comprehensive and Balanced Energy Policy Act of 2001.

The goals of the Price-Anderson Act were to ensure that adequate funds would be available to the public to satisfy liability claims in the event of a nuclear accident and to permit private sector participation in nuclear energy by removing the threat of potentially enormous liability. Each nuclear reactor is required to be covered by the maximum liability insurance available from private insurers (currently $200 million). In addition, for each reactor, payment of up to $88 million into a supplemental insurance pool may be required if it is needed to cover damages in excess of the insurance coverage. Today, the total protection available in the event of a nuclear accident is over $9 billion. The Price-Anderson Act covers all currently licensed reactors throughout their lifetimes; however, new units will not be covered after August 1, 2002, unless Congress approves a renewal of the Act.

Analysis of North American Natural Gas Markets

On April 25, 2001, the Secretary of Energy, Spencer Abraham, asked EIA to conduct two studies of the North American natural gas market due to public concern about "tight supplies, volatile prices, and regional price disparities" during the winter of 2000-2001. The first study, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, released in May 2001 [*10*], examined the causes for high natural gas prices in the 2000-2001 winter, based on data available in the spring of 2001 and the prospects for the future as forecast in EIA's April 2001 *Short-Term Energy Outlook*. The study concluded that the high natural gas prices were caused by higher than normal demand; low natural gas prices in prior years, which resulted in a scarcity of wellhead gas production capacity relative to the high demand; a low level of working gas in storage at the beginning of the winter; and regional constraints on natural gas transmission.

The second study, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, released in December 2001 [*11*], updated the first analysis using more recent market data and provided a more detailed examination of the future prospects for U.S. natural gas markets. Four topics were specifically requested for consideration in the second study: the impact of drilling on wellhead gas supply, the potential for future imports of liquefied natural gas (LNG), the impact of removing access limitations to Federal lands and offshore areas on future natural gas supply, and improvements in data collection that would support a better understanding of natural gas markets.

Natural gas prices have declined since the winter of 2000-2001 due to lower demand and an increase in new wellhead supplies stimulated by the earlier high prices. The price reductions and record storage additions during 2001 indicate that the U.S. natural gas market has the self-correcting mechanisms associated with well-functioning markets, which bodes well for the market outlook, as domestic resources are expected to be substantial. The potential for foreign supplies is limited by U.S. capacity to import them. U.S. import capacity is expandable, given favorable economics.

Short-term price cycles are likely to be inevitable in a competitive market. When the industry operates at close to full capacity, small changes in supply and/or demand can cause significant market pressures that result in substantial price changes. The market experience in 2000-2001 shows that natural gas prices are vulnerable to short-term fluctuations in market conditions.

Large and unpredictable swings in natural gas prices impose considerable risk on investments in natural gas supply and consumption. An unpredictable price environment would shift the mix of natural gas supply investments away from long-term investments, such as LNG terminals and the Alaskan pipeline, toward short-term investments, such as conventional onshore drilling for natural gas. Such price behavior could also favor coal-fired facilities over natural-gas-fired facilities.

The construction of new LNG terminals and increased access to restricted areas would make more natural gas supply available, which could moderate future price increases. Increased access to Federal lands would increase the exploitable resource base in the Rocky Mountains by 29 trillion cubic feet and reduce the costs and development time for exploiting an additional 59 trillion cubic feet of Rocky Mountain resources. In the Outer Continental Shelf region, increased access would expand exploitable offshore resources by 58 trillion cubic feet. Under a high natural gas demand scenario, such as meeting a carbon dioxide emissions target, increased access to restricted areas is projected to increase domestic production in 2020 by about 1.1 trillion cubic feet over the reference case projection, while reducing wellhead natural gas prices by 15 cents per thousand cubic feet. When reference case assumptions are combined with alternative LNG costs in the cases with carbon dioxide emissions limits, LNG is projected to provide an incremental 0.9 trillion cubic feet of natural gas supply in 2020 at an average price that is 9 cents per thousand cubic feet lower than projected in the reference case.

With respect to natural gas data collection, EIA faces a number of challenges with regard to both the scope and quality of current natural gas data series. The collection of natural gas production and wellhead price data involves a challenge of timeliness, because monthly data submitted by the States and by the Minerals Management Service of the U.S. Department of Interior undergo numerous revisions before being finalized by the reporting agencies. The collection of natural gas consumption and end-use price data involves the challenge of completeness, because the restructuring of the natural gas industry, which began in the mid-1980s, expanded the number of market participants and changed business practices so that the current respondents sometimes do not know either the final use of the natural gas or its burnertip price. Efforts to correct these data inadequacies, which are crucial to serving the public need for timely, accurate, and complete natural gas data, are underway.

International Negotiations on Greenhouse Gas Reductions

The Framework Convention on Climate Change

As a result of increasing warnings by members of the climatological and scientific community about the possible harmful effects of rising greenhouse gas concentrations in the Earth's atmosphere, the Intergovernmental Panel on Climate Change was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. A series of international conferences followed, and in 1990 the United Nations established the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change. After a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992.

The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." All signatories agreed to implement measures to mitigate climate change and prepare periodic emissions inventories. In addition, the developed country signatories agreed to adopt national policies with a goal of returning anthropogenic emissions of greenhouse gases to 1990 levels. The Convention excludes chlorofluorocarbons and hydrochlorofluorocarbons, which are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

In response to the Framework Convention, the United States issued the Climate Change Action Plan (CCAP) [*12*], published in October 1993, which consisted of a series of 44 actions to reduce greenhouse gas emissions. The actions included voluntary programs, industry partnerships, government incentives, research and development, regulatory programs including energy efficiency standards, and forestry actions. Greenhouse gases affected by the CCAP actions included carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons. At the time the CCAP was developed, the Clinton Administration estimated that the actions it enumerated would reduce total net emissions of these greenhouse gases in the United States to 1990 levels by 2000 [*13*]. That reduction was not achieved, however, and net U.S. greenhouse gas emissions increased from 1990 to 2000. Although the CCAP no longer stands as a unified program, some of its individual programs remain in effect.

The Conference of the Parties and the Kyoto Protocol

The Framework Convention established the Conference of the Parties (COP) to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." Moving beyond the 2000 target in the Convention, the first Conference of the Parties (COP-1) met in Berlin in 1995 and issued the Berlin mandate, an agreement to "begin a process to enable it to take appropriate action for the period beyond 2000." COP-2, held in Geneva in July 1996, called for negotiations on quantified limitations and reductions of greenhouse gas emissions and policies and measures for COP-3. From December 1 through 11, 1997, representatives from more than 160 countries met at COP-3 in Kyoto, Japan. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries—relative to their emissions levels in 1990 [*14*].

The Kyoto Protocol targets are to be achieved, on average, from 2008 through 2012, the first commitment period. The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. The reduction target for the United States is 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. As of October 26, 2001, 43 countries had ratified or acceded to the Protocol [*15*]; however, only one Annex I nation, Romania, has ratified the Protocol at this point.

Energy use is a natural focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,678 million metric tons carbon equivalent, of which carbon dioxide emissions from the combustion of fossil fuels accounted for 1,352 million metric tons carbon equivalent, or 81 percent [*16*]. By 2000, total U.S. greenhouse gas emissions had risen to 1,906 million metric tons carbon equivalent, with 1,562 million metric tons carbon equivalent, or 82 percent, from fuel combustion. Because energy-related carbon dioxide emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance. Reductions in other greenhouse gases—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—can offset carbon dioxide emissions [*17*]. “Sinks” that absorb carbon dioxide—forests, other vegetation, and soils—may also be used to offset emissions.

Emissions trading among the Annex I countries is also permitted under the Protocol, and groups of Annex I countries may jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint Implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance sinks in other Annex I countries; however, it is indicated in the Protocol that trading and Joint Implementation are supplemental to domestic actions. The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries if the projects lead to measurable, long-term emissions benefits.

The targets specified in the Protocol can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking—carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

In November 1998 at COP-4 in Buenos Aires, Argentina, a plan of action was adopted to finalize a number of the implementation issues at COP-6, held in the Netherlands on November 13 through 24, 2000, at The Hague. Negotiations at COP-5 in Bonn, Germany, from October 25 through November 5, 1999, focused on developing rules and guidelines for emissions trading, joint implementation, and the CDM; negotiating the definition and use of forestry activities and additional sinks; and understanding the basics of a compliance system, with an effort to complete the work at COP-6 [*18*].

The major goals of the COP-6 negotiations held in fall 2000 were to develop the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force and to encourage significant action by the non-Annex I countries to meet the objectives of the Framework Convention [*19*]. The COP-6 negotiations focused on a range of technical issues, including emissions reporting and review, communications by non-Annex I countries, technology transfer, and assessments of capacity needs for developing countries and countries with economies in transition.

The COP-6 negotiations were suspended in November 2000, however, without agreement on a number of issues, including the appropriate amount of credit for carbon sinks, such as forests and farmlands, and the use of flexible mechanisms, such as international emissions trading and the CDM, to reduce the cost of meeting the global emissions targets [*20*]. COP-6 was rescheduled to resume in 2001 in Bonn, Germany [*21*].

COP-6 negotiations (Part 2) resumed in Bonn, Germany, on July 16, 2001, again focusing on developing the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force. On July 23, 2001, 178 member nations of the United Nations Framework Convention on Climate Change reached an agreement, known as the Bonn Agreement, on the operational rulebook for the Kyoto Protocol.

The Bonn Agreement creates a Special Climate Change Fund and a Protocol Adaptation Fund to help developing countries adapt to climate change impacts, obtain clean technologies, and limit the growth in their emissions; allows developed nations to use carbon sinks to comply, in part, with their Kyoto emission reduction commitments; and establishes rules for the CDM, emissions trading, and Joint Implementation projects. The Bonn Agreement also emphasizes that domestic actions shall constitute a significant element of emission reduction efforts made by each Party, and establishes a Compliance Committee with a facilitative branch and an enforcement branch. In terms of compliance, for every ton of gas that a country emits over its target, it will be required to reduce an additional 1.3 tons during the Protocol’s second commitment period, which starts in 2013.

The Bonn Agreement was forwarded for official adoption at COP-7, which was held in Marrakech, Morocco, from October 29 to November 9, 2001. On November 9, 2001, 165 nations reached agreement on a number of implementation rules for the Bonn Agreement and the Kyoto Protocol. The agreement, referred to as the "Marrakech Accords," covered a number of issues, including rules for international emissions trading; a compliance regime to enforce emissions targets, with the issue of legally binding targets deferred to a future Conference of the Parties; fungible accounting rules that allow emissions trading among Annex I countries, CDM and Joint Implementation mechanisms; and a new emission unit for carbon "sinks" that cannot be banked for future commitment periods [*22*]. COP-8 is scheduled for October 23 to November 1, 2002, with India as a possible location [*23*]. COP-8 will, among other things, review the adequacy of commitments under the Kyoto Protocol, including those of developing countries, with the intent of framing the issue for discussion at COP-9.

The Bush Administration has indicated that it has no objection to the participation of other countries in the Kyoto Protocol, even without U.S. participation, and has indicated that it intends to develop U.S. alternatives to the Kyoto Protocol, including the National Climate Change Technology Initiative [*24*]. As noted above, the Protocol can enter into force with ratification by enough Annex I nations to account for 55 percent of total Annex I carbon dioxide emissions in 1990. Because the United States accounted for about 35 percent of 1990 Annex I carbon dioxide emissions, the Protocol can enter into force without ratification by the United States.

Issues in Focus

The California Energy Crisis: Implications for Electricity Market Restructuring

Insufficient electricity supply, transmission constraints, limited natural gas supplies, heat waves, and prolonged drought in the West that greatly restricted hydroelectricity supplies contributed to blackouts and brownouts in California in 2001, huge electricity price spikes throughout the West, and the bankruptcy and near bankruptcy of California's largest utilities. Many are blaming California's attempt at deregulating the electricity industry as a major contributing factor to California's energy woes. The resulting political fallout, as well as a genuine need to take a closer look at their markets, has caused those States that have not restructured their electricity markets to scale back efforts toward that goal. Some States that have passed, but not yet implemented, restructuring legislation have postponed implementation dates.

On September 20, 2001, California abandoned its retail choice program altogether. Proponents for regulation and proponents for competition in the electricity industry are gathering evidence from the California crisis to support their positions in a debate that has been ongoing since the first power companies were formed.

Arguments For and Against Competition in Electricity Markets

A basic tenet of market economics is that true competition will afford customers the lowest prices and best service possible and will spur technology development that will create even lower prices and better services. In order for a market to come close to true competition, supply and demand must be able to respond quickly to each other through price signals. Each supplier has a minimum acceptable price to supply a given amount of commodity or service, and each customer has a maximum acceptable price to acquire a certain quantity of good. In a perfectly competitive market, where there are many buyers and sellers, the prices and quantities of products supplied and bought are determined by the level at which the marginal cost to produce the product [*25*] equals the marginal benefits to consumers [*26*]. When there is a shortage of a product with no or few substitutes the equilibrium price will rise. When more resources are introduced into the market or affordable substitutes become available, the equilibrium price will fall.

Advocates for and against a competitive electricity market generally agree that reliable electricity at reasonable prices is vital to maintaining the health and welfare of the economy and the public at large. Those who support regulation believe that events in California illustrate that system reliability and price stability cannot be incorporated into a competitive system. In their opinion, it is not in the interest of suppliers to hold or build more generation than they are certain they can sell. Therefore, in situations of unexpected demand increases, system reliability will be compromised.

Proponents of regulation also believe that supply cannot be built nor shut off fast enough to respond to demand in an economically feasible way [*27*]. Therefore, they assert, the resulting price spikes in times of unexpected high demand will persist for the long period of time needed for supply to adjust; and thus, a competitive market cannot guarantee stable or affordable electricity prices for all. They contend that the resulting system unreliability and price instability can damage the health and vitality of the nation, citing the amount of money lost by businesses during the California blackouts, the danger of electricity surges and outages to people at home dependent on life-support systems, and the deaths of people without power during extreme weather conditions.

Competition advocates believe that competition ultimately will produce lower electricity prices and better services as competitive suppliers seek to increase and retain a customer base. For instance, technically it now takes as little as 18 months to build new natural-gas-fired combined-cycle plants. Competition advocates also assert that more than ever, there are reasonably priced distributed generation alternatives to grid-based generation, such as reciprocating engines and gas combustion and microturbine units [*28*]. Additionally, there are energy management options to lower energy usage as needed in times of scarcity and price increases as well as during the most expensive peak periods.

Supporters of competition believe that a market that is set up properly will encourage efficiency and technological developments that will increase the responsiveness of market demand and supply to price signals by increasing the availability of affordable substitutes to grid generation, by increasing the ease of demand response to price (for example, through use of the internet), and by encouraging improved electricity transmission infrastructure through price signals. They contrast California's market design to restructured market designs in other States or regions that have been performing much better.

California's Restructured Market Design

The Retail Market

California was one of the first States to restructure its retail electric power markets. In 1996 (when California passed deregulation legislation), the average price of electricity in California was 9.48 cents per kilowatthour, the 10th highest among the 50 States and the District of Columbia. The U.S. average price was 6.86 cents per kilowatthour. Under California's restructuring plan, which started on March 31, 1998, customers of California's three investor-owned utilities (IOUs) were allowed to shop for alternative sources of power. The IOUs were allowed to recover investments (stranded costs) made with the approval or mandate of their regulator—the California Public Utilities Commission (CPUC)—that they would not be able to recover within the new competitive market structure [*29*]. Regulators assumed there would be a period of transition until the market became truly competitive and these stranded costs would be paid off.

Regulators also assumed that prices would be lower under a competitive market structure, with the need to retain and win customers producing incentives to provide electricity at lower cost. Operating under this assumption, legislators froze electricity prices for IOU customers at June 1996 levels and mandated a 10-percent rate reduction for residential and small commercial customers for the transition period so that customers would see immediate benefits of the new market, even with the stranded costs they were paying [*30*]. To protect customers during the transition period, utilities were required to supply electricity to all default customers—customers who did not want, or were not given the opportunity, to switch to a competitive supplier—as well as to serve as the suppliers of last resort for customers who were dropped or abandoned by their competitive suppliers.

The Wholesale Market

As California attempted to create a competitive supply market, regulators required utilities to divest most of their generation assets and buy power through a Power Exchange (PX) at spot market prices. Consequently, the percentage of IOU ownership of generating capacity in the State of California dropped from 55 percent to 15 percent after the implementation of competition in 1998 [*31*]. The nonutility share of generating assets increased from 19 percent to 54 percent after competition was implemented [*32*]. (The remaining third of California's generating assets are owned by public utilities).

In addition to the energy needed to power machinery and appliances, electricity generators also must provide extra power, such as reactive power needed to balance the electricity system, as well as reserves in case more than expected energy or reactive power is needed. California was the only State that set up separate markets for energy and for the "extra" power needed to provide transmission operating and reliability services. Until recently, the PX operated multiple energy markets, the most important of which were the day-ahead and hour-ahead markets. The California Independent Systems Operator (CAISO) operates multiple transmission product markets for the different types of capacity reserves and ancillary services (spinning and non-spinning reserves, regulation, etc.) needed to keep the transmission system operating reliably on a day-ahead, hourly, and real-time basis. CAISO also dispatches power plants and operates the transmission grid. If adequate bids are not received, CAISO can offer above-market (out-of-market) prices to obtain sufficient resources. If above-market prices still fail to garner sufficient resources, emergency measures are triggered, resulting in Stage 1-3 alerts [*33*, *34*].

Problems with California's Market Design

Design flaws in California's competitive electricity market have surfaced throughout its short history. For one, although a substantial $89 million customer education campaign was launched, it was hard to persuade unregulated retail competitors to enter and stay in the market. Only a small percentage of customers left utility suppliers (Figure 8). With utilities forced to sell at low rates and customers making high payments for stranded costs on the distribution portion of their bills (regardless of the generation supplier), it was difficult for competitive suppliers to offer rates low enough to provide the incentive needed to persuade consumers to risk switching to unfamiliar retail electricity companies.

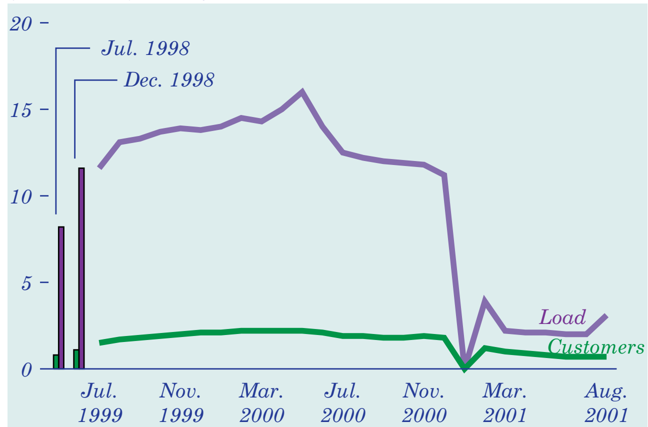
In contrast, Pennsylvania—which provided more room between utility and competitive rates through "shopping credits" [*35*]—has seen up to 24 percent of its electricity load switch to competitive suppliers. Maine, which allowed competitive suppliers to bid for default customers, has seen up to 35 percent of its load switch to competitive suppliers. Recently, Pennsylvania has also opened its default customer load to competitive bids.

Most of the customers in California who chose competitive suppliers did so to support the emerging "green energy" market. Although green energy prices were higher than other electricity products, the California Energy Commission (CEC) offered a renewable energy customer credit ranging from 1.5 cents per kilowatthour at the start of retail choice to 1 cent per kilowatthour by the end. The proportion of customers receiving the credit relative to total direct access customers increased steadily to the point where those purchasing renewable energy comprised nearly all of the direct access market. By June 2000, the total number of direct access customers in all customer classes had increased to 209,000, with 199,000 (95 percent) of them receiving the renewable energy customer credit. Virtually all residential direct access customers were receiving the customer credit by then [*36*].

Meanwhile, electricity demand in California started to rise more rapidly than had been predicted. From 1990 through 1999, overall electricity demand in California increased by 11.3 percent, largely as a result of rapid growth in the high-tech sector and population growth in the latter part of the decade [*37*]. Strong economic growth increased demand for energy in all customer classes. According to the CEC, this trend is expected to continue [*38*]. The CEC is projecting large increases in electricity demand through 2010 as a result of: (1) expected population growth of approximately 15 percent from 2000 to 2010; (2) stronger expected population growth in hotter inland areas (26 percent) than in coastal areas (11 percent), which is expected to lead to more demand for air conditioning, exacerbated by an increase in telecommuting; and (3) a standard of living fueled by high-tech industries, which demand a resilient electricity system that provides reliable and high-quality power [*39*].

While electricity demand increased in California, net generating capacity decreased by 1.7 percent from 1990 to 1999 [*40*]. Consequently, the State's reliance on power imports increased. California currently relies on about 11,000 megawatts of out-of-State capacity [*41*]. However, demand has also been increasing more rapidly than expected in neighboring States. Census Bureau figures show that, in the past 10 years, Washington, Oregon, Arizona, and Nevada have been rapidly growing in population [*42*]. Unsure of receiving adequate compensation

Figure 8. Direct access customers in California's retail electricity market, 1998-2001 (percent of total)



under the emerging competitive structure, California's utilities took no action to build new plants. Long and expensive siting and permitting procedures to build new generation, several years of high water levels—yielding an abundance of cheap hydroelectric imports—and low price caps on wholesale energy (before 2001) also discouraged new capacity additions.

Other regions—including States in the Northeast Power Coordinating Council, the Mid-Atlantic Area Council, and Texas—have faced similar demand increases but have been much more successful in promoting new capacity additions and expansions. Simpler siting and permitting procedures, higher or no price caps, and other regulatory procedures in place in each State and region have influenced how much needed capacity has been or is being built.

Price spikes hit California's wholesale markets in the first year of operation. In the summer of 1998, the California ISO experienced price spikes and bid insufficiencies in its newly established ancillary services markets. As a result, the Federal Energy Regulatory Commission (FERC) approved a purchase price cap for those markets. Stressing that the cap was not to remain in place for long, FERC directed the ISO to facilitate a comprehensive stakeholder process to redesign the ancillary services markets and to file a redesign proposal no later than March 1, 1999. In general, however, during the first 3 years of operation, a convergence of favorable fuel prices, temperatures and hydropower conditions resulted in such low spot market prices that the IOUs were able to write off substantial amounts of stranded costs.

By 2000, extreme winter and summer weather conditions created sudden high peaks in energy demand. At the same time, the West was experiencing a drought, reducing the amount of water available for hydroelectric power generation. To make matters worse, producers of natural gas, which fuels roughly one-half of California's electricity generators, had been curtailing production in response to all-time low prices [*43*]. Extreme wholesale price spikes resulted as peak demand surpassed available supply. Older plants, called on to run more than usual, caused California to surpass emissions standards. The high costs of meeting California's power plant emissions requirements also contributed to the increase in wholesale electricity prices [*44*]. Additionally, overuse of older plants caused them to break down, further exacerbating the supply problem.

As electricity supply tightened, problems with the design of California's wholesale electricity market structure came to light. A major problem was the two-tiered structure of California's energy and ancillary service markets. Because both markets require generators to provide or set aside the same amount of output regardless of which product or service the output is providing, power suppliers naturally bid into the market that offered the opportunity to receive the highest prices. A strict balance must be maintained between all the electricity services to maintain a reliable system. Thus, mass migration to one market will cause prices in the other markets to rise. The CAISO was often forced to buy electricity at out-of-market prices in order to balance and maintain a reliable energy flow.

Another problem cropped up with California's congestion management system [*45*]. Congestion charges were averaged over zones instead of being charged to generators according to the actual cost of the congestion they caused. The CAISO contended that this promoted "gaming" of the congestion system, because generators with market power on the export side of a constraint could overschedule in the day-ahead market and then submit very low or negative decremental bids to alleviate the congestion it created. Generators thus created artificial scarcity in order to create congestion revenues that would be paid to them [*46*].

Critics asserted that when pricing does not conform to the operating conditions, substantial operating restrictions must be imposed to preserve system reliability. Customer flexibility and choice require efficient pricing; inefficient pricing necessarily limits market flexibility [*47*]. In California's case, however, the CAISO had an even tougher job trying to maintain system reliability and control congestion by coordinating the two markets in the two-tiered market structure as suppliers jumped among the markets. In January 2000, the FERC called for an overhaul or replacement of California's congestion management approach.

A series of price caps, implemented in lieu of effective market controls, dampened hourly price spikes but may have contributed to an increase in average prices. Throughout the summer of 2000, an investigation by FERC staff [*48*] found that specific decreases in the CAISO price cap led to increased exports from California to other areas within the Western Systems Coordinating Council (WSCC), which operates the Western grid. Overall, this may have led to higher average prices as energy supplies within California became even more constrained.

Transmission constraints between northern and southern California topped off the bad situation, resulting in rolling blackouts and brownouts as well as substantial wholesale price spikes that continued well into 2001. With such high prices, most of the competitive retail suppliers left the market, and their customers defaulted to the utilities (Figures 9 and 10). The requirement to buy generation through the PX had hindered California's IOUs from hedging against volatile spot market prices by entering into bilateral contracts with generators. Because the IOUs were not allowed to pass on the huge costs of wholesale power, which on average were 8 times higher than prices at the start of competition in 1998, they lost billions of dollars and their credit ratings.

The governor and the CPUC concluded that suppliers were exercising market power by playing one tier of the market against the other. They urged the FERC to exercise control over suppliers and order them to return the billions of dollars lost by the utilities. In March 2001, the FERC ordered public utility power suppliers to reimburse the CAISO and the PX $69 million for January 2001 overcharges. The utilities, to date, have not been compensated for the large losses they experienced. California's largest utility, Pacific Gas and Electric, filed for Chapter 11 bankruptcy protection in April 2001. Southern California Edison, the second largest utility, was teetering on the edge of declaring bankruptcy but reached an agreement with the State in October 2001 to allow it to pay off its debts by significantly raising rates for the next 2 years.

From November 2000 through 2001, the FERC ordered remedies for California's wholesale power markets. Among other things, the FERC ordered the elimination of the mandatory requirement that the three IOUs sell and buy all their power through the California PX. The FERC also terminated the wholesale rate schedule that enabled the PX to continue operating, and in January 2001 the PX ceased operations [*49*]. Congestion management procedures and pricing were ordered to be redesigned, demand response procedures were to be considered, and market monitoring procedures were to be strengthened.

Re-Regulation

California's governor, regulators, and legislators, under pressure from the State's utilities and consumers, have not been willing to wait and see whether a FERC-ordered market redesign will allow the market to function satisfactorily. With the IOUs unable to recover the high costs of wholesale power through reimbursements from customers, suppliers, or the government, they were unable to make payments on much of their power purchases, and power generators refused to sell them more power. As a result, the State took over the job of buying power. On February 1, 2001, the California Department of Water Resources (DWR) was authorized to buy power for the utilities.

The DWR negotiated long-term contracts, many through 2010 and some through 2020, for more than one-half of California's projected energy needs through 2010. Although the long-term contracts have stabilized prices, they were negotiated at much higher average costs than are projected for the State's spot market.

The California legislature has guaranteed the DWR reimbursement of the revenue requirements for its electricity purchases through large ratepayer surcharges (increasing electricity prices by up to 46 percent for some consumers) and bond issues. In addition, the PUC formally ended California's retail access program, in order to ensure that the costs to the DWR would be shared by the roughly three-quarters of California's electricity load located within the jurisdiction of the three IOUs. These actions are expected to keep California's electricity prices from falling to the levels anticipated in its initial effort at deregulation.

In May 2001, Governor Gray Davis signed a bill creating the California Consumer Power and Conservation Financing Authority, which will have broad powers to construct, own, and operate electric power facilities and finance energy conservation projects. He also signed an emergency bill to shorten the times for reviewing applications for new and upgraded power plants. The bill also allows new owners to pay emission mitigation fees in lieu of obtaining emission offsets when such offsets are unavailable.

Implications of the Failure of California's Experiment with Competition

The failure of California to maintain a workable competitive electricity market has highlighted the difficulties of designing a competitive electricity market structure that works. The political need to ensure consumers short-term benefits, in the form of lower prices, may inhibit formation of market designs that would create cheaper electricity, better service, and a cleaner environment in the long term.

Figure 9. Direct access customer load in California's retail electricity market, 1998-2000 (percent of total)

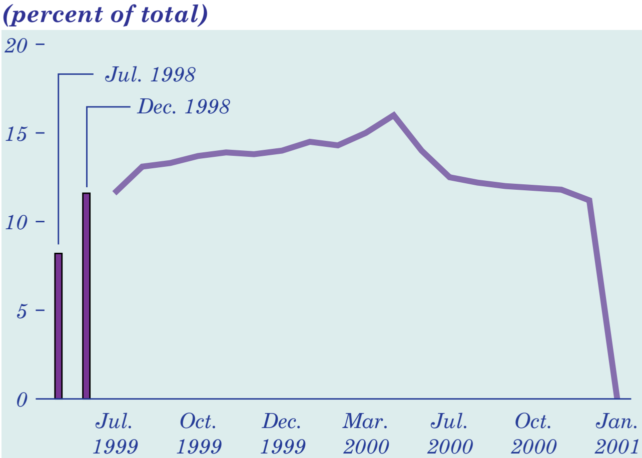
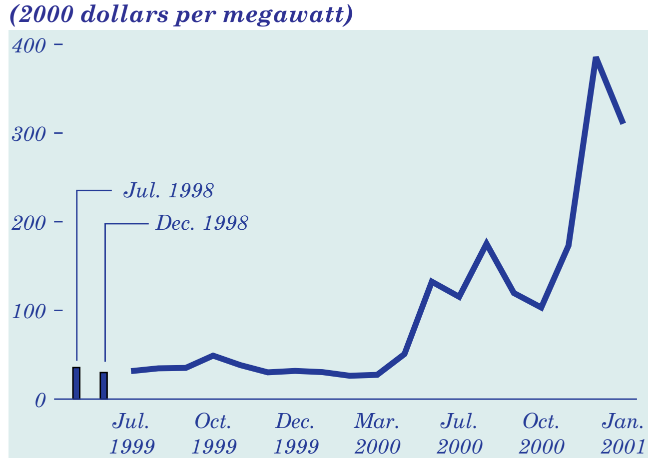


Figure 10. California's Power Exchange (PX) energy price, 1998-2000 (2000 dollars per megawatt)



It may be too early to judge whether competition will work better than regulation in other regions. So far, some other regions faced with the same challenges as California have been more successful in changing regulations, implementing transmission improvements, and redesigning market infrastructure when necessary. The FERC has approved market design changes for the PJM, New England, and New York ISOs as they work to improve transmission service and the functioning of their wholesale markets. In addition, various States have revised restructuring legislation to make the retail electricity market more competitive by streamlining plant siting and construction procedures, allowing competitive suppliers to bid for default customers, and adjusting shopping credits, among other changes.

ISOs, States, and competitive suppliers are currently looking into improving demand response options, including procedures for adding advanced metering devices and services, incorporating net metering regulations for customers who generate their own electricity, making it easier to connect distributed generators to the grid, and offering energy management services. Some States have pushed back retail competition start dates until supply is deemed adequate to forestall the threat of market power abuse by a few suppliers.

Under Order No. 2000, issued in December 1999, the FERC called for the voluntary formation of Regional Transmission Organizations (RTOs), stating that RTOs would broaden the market for electric power transactions and help ensure comparability of service for users, reliability for consumers, and efficient economic transactions for customers. The FERC has recently become more adamant in its encouragement of the formation of large RTOs—as few in number as possible in order to improve market performance—with a stated preference for one Western RTO consisting of all the States connected to the Western grid. Aware that the failure of competition in California could dampen support for competition, and under pressure to formulate stricter guidelines for RTO formation [*50*], FERC Chairman Pat Wood has stated his intention to formulate protocols for the RTO organizations, beginning with a series of Commissioner-led workshops in mid-October 2001 on the core subject areas (congestion management, cost recovery, market monitoring, transmission planning, business and reliability standards, nature of transmission rights, etc.) [*51*].

The Role of Natural Gas Prices

Natural-gas-fired generating plants provide approximately one-half of California's electricity. In the State's competitive wholesale market, the electricity price for a given period represents the price paid to the last generator dispatched to the grid. Because petroleum- and natural-gas-fired generators usually have higher fuel costs than hydroelectric, nuclear, or coal-fired generators, petroleum and natural gas units are typically dispatched last to serve intermediate and peak loads. Thus, gas-fired generators often set the wholesale electricity price, and the cost of the natural gas used for electricity generation plays an important role in determining California's wholesale electricity prices.

Natural gas wellhead prices increased significantly during the second half of 2000, after drilling was curtailed in response to low prices in 1998 and 1999. Because there is a 6- to 18-month lag between increased drilling investments and natural gas production increases, producers could not respond to California's sudden demand for natural gas for electricity generation. The resulting supply shortage led to higher natural gas prices, which coincided with California's electricity supply problems and subsequent increases in wholesale electricity prices. Some have blamed the high natural gas prices on high electricity prices; others have noted the contribution of high natural gas prices to high electricity prices. After September 2000, the delivered price of natural gas in California became decoupled from those elsewhere in North America.

California typically relies on out-of-State sources to supply approximately 83 percent of the natural gas it consumes. Reliance on out-of-State supplies has integrated California into the North American natural gas market through gas transmission facilities, which bring supplies into California from Canada, Wyoming, New Mexico, and Texas. The extensive North American transmission system works to equilibrate natural gas prices across the continent, with differences in regional wholesale prices largely attributable to the regional availability of spare transmission capacity and the cost of transporting gas from one region to another.

California's relationship to the North American supply market is quantified by the price differential between the prices for natural gas delivered to California and the spot prices posted at the Henry Hub in

Louisiana. The Henry Hub is the largest and most prominent "market center" for natural gas in North America [*52*]. The NYMEX futures trading contract specifies the Henry Hub as that contract's physical delivery point, because this market center provides the most flexibility to buyers and sellers in terms of transmission receipt and delivery points. Consequently, the Henry Hub spot price best reflects the overall supply and demand situation for the North American natural gas market.

A comparison of Henry Hub spot prices and delivered prices to California electric utilities shows that the annual price differential varied between approximately 40 and 70 cents per thousand cubic feet from 1997 through 1999. As natural gas prices at the Henry Hub rose during 2000, so too did the price of gas delivered to California utilities. During the first half of 2000, the price differential between the Henry Hub price and the delivered California price stayed within the bounds of the historic price differentials. In the latter part of the year, however, the difference between the Henry Hub price and delivered California gas price increased substantially. By December 2000 the average monthly price difference was over $10.00 per thousand cubic feet, and on some days the differences were much larger.

The huge price disparity between delivered California gas prices and the Henry Hub spot prices can only be explained by supply and demand conditions unique to California. In the neighboring States of Arizona and Nevada there was no significant divergence from historical patterns. Something unique occurred in the California market that caused natural gas prices in the State to become decoupled from the North American natural gas market.

The principal reason for the skewing of California's natural gas prices was a lack of sufficient pipeline capacity in the State. As noted above, about 83 percent of the natural gas consumed in California is transported from outside the State. Insufficient transmission capacity to move natural gas from the California border caused prices in California to rise well above those in the rest of the U.S. natural gas market.

Temporary constraints on interstate pipelines delivering natural gas into California also appear to have played a role in raising the price of natural gas in the State. For example, on August 19, 2000, there was a rupture in the El Paso Pipeline outside Carlsbad, New Mexico, reducing gas transmission capacity throughout the remainder of the 2000-2001 winter season. The damaged pipeline segment was carrying 1.2 billion cubic feet per day at the time of the rupture. After the rupture, the Henry Hub/California price differentials for September and October rose to 86 cents per thousand cubic feet and 94 cents per thousand cubic feet, respectively, from 38 cents per thousand cubic feet in August.

Interstate transmission capacity to deliver natural gas at the California border exceeds the "take-away capacity" of California's intrastate pipeline system by approximately 300 to 590 million cubic feet per day. Inadequate pipeline capacity constrained gas supplies from entering California and moderating delivered gas prices to a level more commensurate with historical price differentials.

California electricity and natural gas prices reached unusually high levels as a result of rigidities in both markets, which impeded market efforts to bring supply and demand into balance. In the electricity market, fixed retail prices prevented the consumption adjustments necessary to mitigate the deficit of hydroelectric generation and the lack of sufficient transmission capacity. In the natural gas market, inadequate transmission capacity impeded market efforts to increase gas supplies in response to the greater demand for natural gas resulting from the electricity market's attempts to substitute natural-gas-fired generation for inadequate hydroelectric generation. If either of these market rigidities had not been present, it is likely that prices would not have reached the unusually high levels they did.

Changes in the AEO2002 Forecast for Electricity Prices in the California Region

The National Energy Modeling System (NEMS) has been modified to take into consideration the prices of long-term power contracts for projections of electricity prices for the California region, as well as the fact that competition in the retail market has been terminated. As a result, the *AEO2002* projected electricity prices in California are higher than the *AEO2001* projected prices through the end of the forecast period [*53*]. In the *AEO2001* forecast, California electricity prices reached a projected high of 10.6 cents per kilowatthour in 2000, fell to a low of 7.0 cents per kilowatthour in 2012, and rose slightly to 7.3 cents per kilowatthour by 2020 [*54*]. In the *AEO2002* forecast, average electricity prices in California are projected to reach a high of 13.5 cents per kilowatthour in 2001—a direct result of the surcharge imposed by recent State legislation, as described above—but are expected to decline as the average long-term contract price declines and the amount of generation bought on the spot market increases. Prices are expected to be 8.8 cents per kilowatthour in 2020, 1.5 cents per kilowatthour higher than projected in *AEO2001*, as a result of changes in California's market structure.

Phasing Out MTBE in Gasoline

Methyl tertiary butyl ether (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 2000. 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, the use of MTBE has become a source of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels.

MTBE is an important blending component for RFG because it adds oxygen, extends the volume of the gasoline, and boosts octane, all at the same time. In order to meet the 2-percent (by weight) oxygen requirement for Federal RFG, MTBE is blended at approximately 11 percent by volume, thus extending the volume of the gasoline. When MTBE is added to a gasoline blend pool, it has an important dilution effect, reducing the fraction of undesirable compounds such as benzene and aromatics. The dilution effect is even more valuable in light of a ruling by the U.S. Environmental Protection Agency (EPA) that will require the sulfur content of gasoline to be reduced substantially by 2004 and its Mobile Source Air Toxics (MSAT) regulatory program, which will maintain benzene at 1998-2000 levels (see "Legislation and Regulations"). In addition, MTBE is a valuable octane enhancer. Its high octane helps offset the Federal limitations on other high-octane components, such as aromatics and benzene. If the use of MTBE is reduced or banned, refiners must find other measures to maintain the octane level of gasoline and still meet all Federal requirements.

MTBE is the oxygenate that is 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 traditional 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 have many of the same characteristics as MTBE and may lead to similar problems that affect the water supply.

Ethanol currently receives a Federal excise tax exemption of 53 cents per gallon, which is scheduled to decline to 52 cents in 2003 and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007, but because the exemption has been renewed several times since it was initiated in 1978, the *AEO2002* reference case assumes that it will be extended at the 51-cent (nominal) level through 2020. Blending with ethanol, which is primarily produced from corn, is also encouraged by tax incentives in 17 States to help bolster agricultural markets. Some of the characteristics of ethanol have made it less attractive to refiners than MTBE as an oxygenate. Ethanol results in higher emissions of smog-forming volatile organic compounds (VOCs) than MTBE. Its higher volatility makes it more difficult to meet emissions standards, especially in the summertime, when RFG must meet VOC emissions standards. Ethanol's volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to balance the addition of ethanol.

In addition to being more volatile than MTBE, ethanol contains more oxygen. As a result, only about half as much ethanol is needed to produce the same oxygen level in gasoline that is provided by MTBE. The result is a volume loss, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. Ethanol is slightly higher in octane than MTBE is, but because only one-half as much ethanol is blended, a net loss in octane occurs when ethanol is used to replace MTBE. Blending with ethanol also results in a slight increase in emissions of toxics, which must be compensated by other blending changes in order to comply with "antibacksliding" regulations.

The prospect of increased use of ethanol also poses some logistical problems. Unlike gasoline blended with MTBE and other ethers, gasoline blended with ethanol cannot be shipped in multi-fuel pipelines in the United States, because moisture in pipelines and storage tanks causes ethanol to separate from gasoline. When gasoline is blended with ethanol, the petroleum-based gasoline components are shipped separately to a terminal and then blended with the ethanol when the product is loaded into trucks. Thus, changes in the current fuel distribution infrastructure would be needed to accommodate growth in "terminal blending" of ethanol with gasoline. Alternatively, changes in pipeline and storage procedures would be needed to allow ethanol-blended gasoline to be transported from refineries to distributors.

Ethanol supply is another significant issue, because current ethanol production capacity would not be adequate to replace MTBE nationwide. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents per gallon for transportation [*55*]. If the demand for ethanol increased as a result of a ban on MTBE, higher prices could make new ethanol facilities economically viable, and sufficient capacity could be in place depending on the timing of the MTBE ban.

Because the *AEO2002* projections reflect only current laws and regulations, they incorporate MTBE restrictions in the States where they have been passed but do not include any proposed State or Federal actions. The *AEO2002* reference case assumes that the RFG oxygen requirement will be maintained and incorporates MTBE ban or reduction legislation that has been passed in 13 States: Arizona, California, Colorado, Connecticut, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington [*56*]. As a result, the amount of MTBE used by domestic refiners is projected to be cut in half by 2004, from 247 thousand barrels per day in 2000 to 123 thousand barrels per day. Nearly three-quarters of the projected decline in MTBE consumption results from a ban on MTBE in California, which is currently scheduled to begin at the end of 2002. The need to maintain oxygen and octane levels and to offset some of the volume loss associated with MTBE removal results in a projected national increase in ethanol blending of 60 thousand barrels per day in 2004 from the 2000 level of 106 thousand barrels per day.

Although 13 States have passed legislation to restrict the use of MTBE, growing concerns about the supply and price impacts of the restrictions have heightened uncertainty about when the laws will be enforced. The failure of California to obtain approval from the EPA for a waiver of the Federal 2-percent oxygen requirement in RFG has prompted discussions about delaying the MTBE ban because of concerns about the availability and price of ethanol in 2003, the first year of the State's scheduled ban on MTBE. The same concerns apply to other States that are scheduled to restrict MTBE.

On the other hand, the political impetus for more widespread restrictions on MTBE is evident. Numerous legislative proposals in the U.S. Congress have focused on an MTBE ban in all States [*57*]. Because of supply and price concerns, the ban is sometimes linked to a waiver of the oxygen requirement for RFG, which in turn is often linked to a renewable fuels mandate which would ensure that renewable fuels (ethanol) represent a certain percentage of the gasoline pool.

Although it was not possible to analyze all the variations of MTBE ban legislation that have been proposed, *AEO2002* includes a "Federal MTBE ban case" that can be considered the most severe scenario in terms of gasoline supply, because no oxygen waiver is assumed. This case was analyzed through 2010 and assumes that MTBE and other ethers cannot be blended into gasoline after 2005. In the Federal ban case it is projected that the remaining 118 to 128 thousand barrels per day of MTBE blended in gasoline between 2006 and 2010 would be eliminated, with an associated increase of 79 to 89 thousand barrels per day in ethanol consumption.

Previous analysis indicates that ethanol blending would increase even if the oxygen requirement on RFG were waived, because ethanol is a good option for replacing the volume and octane loss resulting from MTBE removal [*58*]. The extent to which ethanol would be used to replace octane and volume depends on the availability of other quality blendstocks, such as alkylate and iso-octane. As compared with the reference case projections, the national average pump price of gasoline is about 3 cents per gallon higher in the Federal ban case, with RFG prices 9 to 10 cents per gallon higher between 2006 and 2010. As a result of the higher prices, gasoline consumption between 2006 and 2010 is projected to be 60 to 80 thousand barrels per day lower in the Federal ban case than in the reference case.

The *AEO2002* projections are developed from a regional model, which captures the effects of limitations on MTBE in individual States through adjustments to assumptions about regional supplies of gasoline. The adjustments are made to reflect shifts in oxygenate selection and gasoline characteristics and changes in average gasoline prices in specific regions. Because the regional price changes are projected only on an annual basis, however, localized price spikes that might occur as a result of State MTBE bans are not reflected in the model results.

Multiple Emissions Controls in Electricity Markets

Background

Electric power plant operators may face new requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in current regulations. They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. At present neither the future reductions nor the timing for compliance is known for any of these airborne emissions. Given these uncertainties, compliance planning is difficult for plant owners.

Until recently, each of these environmental issues was addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, CAAA90 required operators of electric power plants to reduce emissions of SO_2 and NO_x. Phase II of the SO_2 reduction program—lowering allowable SO_2 emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000 [*59*]. More stringent NO_x emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. For example, in 1997 the EPA issued new standards for particulate matter and ozone. The ozone standard was tightened from 0.12 parts per million measured over 1 hour to 0.08 parts per million measured over 8 hours. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, States could require that these emissions be reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in NO_x and SO_2.

To reduce ozone formation, the EPA has promulgated a multi-State summer season cap on power plant NO_x emissions that will take effect in 2004. Emissions that lead to fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are associated with power plant emissions of NO_x and SO_2, and further reductions in NO_x and SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations will be developed over the next 3 years, possibly as part of a multi-emissions reduction strategy. Further, if the United States decides that emissions of greenhouse gases need to be mitigated, it is likely that energy-related CO_2 emissions will also have to be reduced.

Because the timing and levels of emission reduction requirements under the new standards are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions.

The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO_2 and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO_2 and NO_x today may not be the optimal choice in the future if Hg and CO_2 emissions must also be reduced.

Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that reduces SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence. Aware of these difficulties, both the previous and current Congresses have proposed legislation that would require simultaneous reductions of multiple emissions.

Congressional Requests

There have been three Congressional requests to the Energy Information Administration (EIA) for analyses of proposed legislation for reductions of multiple emissions. The Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform [*60*] asked EIA to "analyze the potential costs of various multi-emissions strategies to reduce the air emissions from electric power plants." The Subcommittee requested that EIA examine cases with alternative NO_x, SO_2, CO_2, and

Hg emission reductions, with and without a renewable portfolio standard (RPS) requiring a specified portion of all electricity sales to come from generators that use nonhydroelectric renewable fuels.

In the cases specified by the Subcommittee, emissions of NO_x and SO_2 were to be reduced to 75 percent below 1997 levels beginning in 2002 and reaching compliance by 2008. CO_2 emissions were required to be reduced to 1990 levels by 2008 and 7 percent below 1990 levels by 2012. Hg emissions were to be reduced by 90 percent from 1997 levels by 2008. The RPS was targeted to reach 20 percent by 2020. The analysis examined the impacts of these requirements both for individual emissions and for all emissions taken together [*61*].

In a second study, requested by Senators Bob Smith, George Voinovich, and Sam Brownback, EIA was asked to examine the costs of different multi-emissions reduction strategies for NO_x, SO_2, and Hg. The Senators also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008. The request called for 50- to 75-percent reductions in NO_x below 1997 levels, 50- to 75-percent reduction in SO_2 emissions below full implementation of CAAA90 Title IV, and 50- to 75-percent reductions in Hg emissions below 1999 levels, with half the reductions to be achieved by 2007 and the full reductions to occur by 2012. The emissions reduction programs, covering all electricity generators other than cogenerators producing both electricity and useful thermal output, were patterned after the SO_2 allowance program created in the CAAA90. One-half of the reductions in Hg emissions were to come from site-specific reductions [*62*].

A third analysis, requested by Senators James M. Jeffords and Joseph I. Lieberman, was to examine the potential impacts of limits on SO_2, NO_x, CO_2, and Hg emissions from electricity generators [*63*]. Using 2002 as a start date for emissions reductions, the request specified that, by 2007, NO_x emissions from electricity generators were to be reduced to 75 percent below 1997 levels, SO_2 emissions to 75 percent below the full implementation of the Phase II requirements under CAAA90 Title IV, Hg emissions to 90 percent below 1999 levels, and CO_2 emissions to 1990 levels. It was assumed that these emissions limits would be applied to all electricity generators, excluding cogenerators. This analysis examined the impacts of this set of limits on electricity-sector emissions of SO_2, NO_x, Hg, and CO_2 under four scenarios with different assumptions about technology cost and performance, energy policies, and consumer behavior.

Modeling Approach

The analyses for the House and Senate requests were prepared using NEMS. NEMS simulates the energy investment and utilization decisions of the various sectors of the U.S. economy including households, commercial establishments, industrial facilities, and energy suppliers. When power sector emission caps are imposed, NEMS simulates the decision process in each economic sector to determine an appropriate compliance strategy.

Each of the emission caps imposed was assumed to be implemented under a "cap and trade" system patterned after the SO_2 CAAA90 allowance program [*64*]. All electricity generators, excluding cogenerators, were assumed to be covered by the emissions caps. Electricity generators were assumed to behave competitively, incorporating the costs of emissions allowances in their electricity bid prices [*65*]. The cases included all energy laws and regulations in effect as of July 1, 2000, including the NO_x and SO_2 regulations established in the CAAA90, plus the new appliance efficiency standards announced in January 2001, as modified by the Bush Administration.

Uncertainties Related to Emissions Control Equipment

Considerable uncertainty exists about the ability of various types of emissions control equipment to remove Hg and, to a lesser extent, NO_x. Many factors affect the level of Hg emissions from a particular power plant, including the Hg content (by speciation—elemental Hg versus various Hg-containing compounds), chlorine content, and other chemical constituents of the coal used; the rank of the coal (i.e., bituminous or subbituminous); the boiler temperature and firing type and the flue gas temperature; and the types of existing control equipment for NO_x, SO_2, and particulates. In recent years data collection and analysis efforts have focused on these factors so that better estimates of current power sector Hg emissions could be developed; however, substantial uncertainty remains. As additional tests are performed, factors currently unaccounted for may turn out to be important.

The Hg removal rates for the various coal plant configurations also showed significant variation. The 1999 data show that, on average, a cold-side electrostatic precipitator (CSE)—a particulate removal device—removes 31 percent of the Hg that passes through it. However, the variation among plants with CSEs was large, ranging between 0 percent and 87 percent removal. The situation was similar for facilities with fabric filters—another type of particulate removal device. On average they removed 69 percent of the Hg passing through them, but, after excluding plants that actually reported increases in Hg after passing flue gas through the fabric filter, the removal rate ranged between 54 percent and nearly 100 percent.

In addition, there is very little information on the impact of new NO_x control devices—selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment—on Hg emissions. Although many plant owners plan to add them in the near future, only a few are using them now. With respect to NO_x, SCRs are assumed to reduce emissions by 75 to 80 percent on average; however, because so few plants have SCRs today, the true cost and performance of the technology are not known at this time. With respect to Hg, this study assumes that, when combined with an SO_2 scrubber, an SCR enhances Hg removal with an emissions modification factor of 0.65 (increases Hg removal by 35 percent); however, no additional removal is assumed for plant configurations that have an SCR but do not have an SO_2 scrubber. Some pilot-scale tests suggest that SCRs would increase Hg removal for some system configurations, but the magnitude of the impact is not known at this time.

Analysis for House Request

The analysis cases examine the impacts of each emission cap and the RPS singly and in various combinations. The emission caps are applied only to the electricity generation sector, excluding cogenerators, and are assumed to cover emissions from both utility-owned and independent electric power plants. Cogenerators are treated as industrial facilities in this analysis. Because no requirements to reduce emissions in the residential, commercial, industrial, and transportation sectors are assumed, the results of this analysis are not directly comparable with the results of studies that have examined the impacts of complying with the Kyoto Protocol across all sectors of the economy.

In all cases it is assumed that emission caps for NO_x, SO_2, and CO_2 would be phased in beginning in 2002 and fully implemented by 2008. The cap on Hg emissions is assumed to begin in the compliance year (2008). For the cases that require that CO_2 emissions to average 7 percent below the 1990 level over the 2008 to 2012 period, the cap is constructed so that emissions are slightly above the 1990-7% level in the first year or two of the period and slightly below it in the later years. After 2012, the cap is held at 7 percent below the 1990 level through the remainder of the projections. In addition, it is assumed that the emission reduction programs will be operated as market-based emission cap and trade programs patterned after the SO_2 allowance program, and the emission allowance prices are included in the operating costs of plants that produce one or more of the emissions.

In many parts of the country the methodology used to price electricity—especially in the wholesale market—is currently changing. Historically, power prices have been based on embedded costs. In other words, all the costs associated with building and operating electric power plants were summed and divided by expected sales to determine the price per kilowatthour. As the generation market becomes more competitive, however, power prices are increasingly being set by the costs of the most expensive generator operating at any point in time—what economists refer to as the “marginal cost.” This change could have significant impacts on the way in which emission allowance prices affect electricity prices and the resource costs of meeting the emission caps.

In competitive markets, allowance prices would become part of the operating costs of any generator producing the covered emission. Allowances are assumed to be given to generators at zero cost initially. After the initial allocation, however, additional allowances would have to be purchased in the marketplace. The allowance costs for the marginal generator are assumed to be included in the price of electricity in competitive markets.

Allowance prices may have a different impact on electricity prices in regulated markets, where prices are set according to cost of service. For example, if a company in a regulated region were allocated allowances at no cost, the regulatory authority would not include allowance prices when setting retail electricity prices. Conversely, if the regulated utility purchased allowances—from the government or from another utility—the cost of the allowances would likely be reflected in retail electricity prices. In the integrated cost of service CO_2 1990-7% 2008 case, it is assumed that allocated allowances will have zero cost in regions that have not deregulated. While this would lead to lower price impacts, the resource costs are likely to be higher, because consumers will not have the same incentive to reduce electricity consumption.

Recognizing the impact of natural gas supply and demand on electricity markets, an integrated high gas price CO_2 1990-7% 2008 case assumes that technologies associated with the finding, developing, and delivery of natural gas will not improve as rapidly as expected, and that additional Alaskan production and imports of liquefied natural gas projected in other cases with a CO_2 cap will not occur, resulting in higher natural gas prices.

Electricity Market Impacts in the House Analysis

When emission caps on NO_x, SO_2, CO_2, and Hg are assumed in various combinations, with and without an RPS, there are complex interactions among the compliance strategies and the resulting prices of emissions allowances and electricity prices (Table 3). When an RPS is assumed to be combined with NO_x, SO_2, CO_2, and Hg emissions caps, resource costs for generators complying with the caps are projected to be higher than when the RPS is not included. Although electricity prices are projected to be well above reference case levels when NO_x, SO_2, CO_2, and

Table 3. Key results for the electricity generation sector in the House analysis, 2010 and 2020

Projection	Reference case	CO_2 emissions capped at 1990 level: Without RPS	CO_2 emissions capped at 1990 level: With RPS	CO_2 emissions capped at 1990-7% level: Without RPS	CO_2 emissions capped at 1990-7% level: With RPS	Sensitivity cases[a]: Cost of service	Sensitivity cases[a]: High gas price
2010							
Generation by fuel, excluding cogenerators (billion kilowatthours)							
Coal	2,245	1,290	1,425	1,069	1,223	1,003	1,079
Natural gas	825	1,421	1,026	1,575	1,189	1,740	1,525
Renewable fuels	397	484	723	503	706	515	514
Nuclear	725	741	741	741	741	744	744
Emissions allowance prices							
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	84	84	120	124	117	125
NO_x (1999 dollars per ton)[b]	NA	0	0	0	0	0	0
SO_2 (1999 dollars per ton)	187	1	3	0	2	0	0
Hg (million 1999 dollars per ton)	NA	443	432	296	342	308	305
Electricity price (1999 cents per kilowatthour)	6.1	7.9	8.0	8.4	8.6	7.7	8.6
Electricity sales (billion kilowatthours)	4,147	3,896	3,882	3,851	3,830	3,956	3,838
Electricity industry revenue (billion 1999 dollars)	255	308	311	324	329	304	330
2020							
Generation by fuel, excluding cogenerators (billion kilowatthours)							
Coal	2,315	1,082	1,345	988	1,190	852	1,038
Natural gas	1,495	2,014	1,206	2,005	1,304	2,243	1,503
Renewable fuels	400	513	1,131	554	1,128	657	687
Nuclear	613	681	651	681	665	694	704
Emissions allowance prices							
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	135	71	150	90	162	169
NO_x (1999 dollars per ton)[b]	NA	0	1,304	0	1,118	0	0
SO_2 (1999 dollars per ton)	241	2	150	1	0	0	2
Hg (million 1999 dollars per ton)	NA	297	407	219	337	244	344
Electricity price (1999 cents per kilowatthour)	6.2	8.4	7.8	8.6	8.0	7.9	9.3
Electricity sales (billion kilowatthours)	4,788	4,309	4,354	4,257	4,313	4,453	4,188
Electricity industry revenue (billion 1999 dollars)	297	360	340	364	344	350	388
Cumulative resource costs, 2001-2020: difference from reference case (billion 1999 dollars)	NA	132	192	194	215	291	323

[a]The sensitivity cases shown require CO_2 emissions to be reduced to 7 percent below the 1990 level. They do not include a renewable portfolio standard.
[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

Hg emissions are capped either with or without an RPS, they are projected to be lower in the long term when the RPS is included [*66*], because increased dependence on renewable technologies rather than natural gas would lead to lower prices for natural gas and for CO_2 allowances, offsetting the effects of the higher costs of renewable fuels on consumer electricity prices [*67*]. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

When power sector CO_2 emissions caps are assumed, at the 1990 level or 7 percent lower, the effects of efforts to comply with the CO_2 caps far outweigh the effects of steps that would be taken to comply with the other emission caps. As in the case of a CO_2 cap alone, the primary compliance strategy is expected to be a major shift in the fuel mix used to produce electricity. Power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce electricity use in response to higher electricity prices, and cogeneration capacity is expected to be expanded in response to higher grid-based electricity prices. The role of renewable technologies is especially important when an RPS requirement is included.

When CO_2 emissions are capped at the 1990 level, coal-fired electricity generation in 2020 is projected to be approximately half the level projected in the reference case, and the projected share of electricity generation from natural gas is much larger. When an RPS is included, the expected increase in renewable electricity generation dampens the increase in natural-gas-fired generation and slightly reduces the need to limit coal-fired generation. The addition of carbon-free renewable technologies stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 cap. In contrast, when the cap on CO_2 emissions is tightened to 7 percent below the 1990 level, the projected reduction in coal-fired generation is even larger.

The combination of higher natural gas prices and CO_2 allowance prices is projected to lead to significant electricity price increases when a CO_2 cap is incorporated with other emission caps. As might be expected, when the CO_2 cap is set to 7 percent below the 1990 level, the projected impact on electricity prices is larger than when the CO_2 cap is set to the 1990 level. For example, the price of electricity in 2010 is projected to be 7.9 cents per kilowatthour when NO_x, SO_2, and Hg caps are combined with a CO_2 cap set to the 1990 level, but 8.4 cents per kilowatthour when they are combined with a cap set to 7 percent below the 1990 level—29 percent and 37 percent higher, respectively, than in the reference case. The higher electricity prices are projected to lead to increases of $146 and $192, respectively, in annual household electricity bills and $53 billion and $69 billion, respectively, in the Nation's total electricity bill.

When an RPS is included, the cumulative resource costs of compliance are projected to be $21 billion higher than they would be without the RPS with the CO_2 cap at 7 percent below the 1990 level. Electricity prices are projected to be higher in the early years of the forecast, when new renewable power plants are built rather than new natural-gas-fired plants. In the later years, however, the increased use of renewable fuels reduces natural gas consumption in the power sector, leading to a smaller projected increase in natural gas prices and lower CO_2 allowance prices and, in turn, a smaller increase in electricity prices.

Smaller increases in electricity prices are also projected when it is assumed that prices in many regions of the country will continue to be based on cost of service pricing. Regulators in those regions could treat any emissions allowances allocated to the companies they regulate as having zero cost, so that they would not be added to the operating costs of electric power plants. With this assumption, the price of electricity in 2010 is projected to be 9 percent less than when the wholesale power market is assumed to behave competitively—still 25 percent higher than without the stringent emission caps. However, power suppliers would have to take additional actions to reduce emissions, because consumers would not be expected to reduce their electricity usage as much as they would if electricity prices reflected the full opportunity costs of emissions allowances. As a result, supplier resource costs would be higher.

Electricity prices could be substantially higher if natural gas prices turn out to be higher than expected. When the reference case technology assumptions for natural gas discovery and production are replaced with assumptions of less robust technology development, the projected price of electricity in 2020 with combined NO_x, SO_2, Hg, and CO_2 emission caps is 9.3 cents per kilowatthour, 49 percent above the reference case projection and 8 percent above the corresponding projection based on reference case natural gas technology assumptions. The higher natural gas prices would also lead to greater reliance on renewable fuels and more conservation by consumers. Of course, these same natural gas technology assumptions would lead to higher natural gas prices in the reference case, even without the imposition of new emissions caps.

Fuel Market Impacts in the House Analysis

Imposing a CO_2 emission cap, whether at the 1990 level or 7 percent below the 1990 level and with or without stringent NO_x, SO_2, and Hg emission caps, is expected to have a dramatic impact on coal use in the power sector. Because the carbon content of coal is the highest among the fossil fuels, power suppliers are expected to reduce their coal use to meet a CO_2 emission cap. For example, when a CO_2 cap set to 7 percent below the 1990 level is assumed, coal consumption for electricity generation in 2020 is expected to be 59 percent below the reference case level.

Reducing NO_x, SO_2, and Hg emissions is not projected to have large impacts on natural gas markets—generally increasing its use in the power sector by a small amount. More significant impacts are expected when Hg emissions are capped at 5 tons than when either an NO_x or SO_2 emission cap is assumed. For example, when Hg emissions are capped at 5 tons, electricity sector natural gas consumption is projected to be 0.8 trillion cubic feet (11 percent) higher in 2010 than in the reference case.

The impact on natural gas markets of capping power sector CO_2 emissions is projected to be much larger than the impacts of other emission caps. Power suppliers are expected to turn to natural gas if they are required to reduce CO_2 emissions. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, electricity sector natural gas consumption is projected to be 10.6 trillion cubic feet in 2010 and 13.4 trillion cubic feet in 2020, as compared with 6.8 trillion cubic feet and 11.2 trillion cubic feet projected for 2010 and 2020 in the reference case. The one exception is when a 20-percent RPS is included with the emission caps. In this case, the projected increase in generation from nonhydroelectric renewable fuels partially reduces the need to turn to natural gas.

To meet the increased demand for natural gas when CO_2 emission caps are assumed, both domestic production and imports of natural gas are expected to grow. Total U.S. gas supplies are projected to reach 38.5 trillion cubic feet in 2020 if stringent caps are placed on power sector NO_x, SO_2, Hg, and CO_2 emissions, approximately 3.2 trillion cubic feet above the reference case projection. Of the 3.2 trillion cubic feet projected to be added, 0.8 trillion cubic feet is expected to come from domestic resources and 2.3 trillion cubic feet from higher imports. The annual increases in production required between 2005 and 2010 would be near record levels, representing a serious challenge for the industry.

The projected increase in natural gas use for electricity generation when a cap on power sector CO_2 emissions is assumed is expected to lead to higher natural gas prices. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, the natural gas wellhead price is projected to be \$3.66 per thousand cubic feet in 2010 and \$3.74 per thousand cubic feet in 2020, as compared with \$2.87 and \$3.22 per thousand cubic feet in the reference case.

Renewable Fuels Market Impacts in the House Analysis

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed either one at a time or together, the projected impact on renewable fuel use for electricity generation is small. Because natural gas plants emit virtually no SO_2 or Hg emissions and very low NO_x emissions, they are expected to remain the most economical option when new electric power plants are needed. As a result, few new renewable power plants are projected to be built in response to stringent NO_x, SO_2, or Hg emissions caps.

Imposing a CO_2 emission cap on the power sector (especially one set to 7 percent below the 1990 level) is projected to have a significant impact on the development of renewable generating facilities. Although the primary compliance option for meeting a power sector CO_2 emission cap is expected to be increasing generation from natural-gas-fired power plants, the use of renewable fuels is also expected to grow, whether the CO_2 cap is assumed to be imposed alone or in concert with stringent caps on NO_x, SO_2, and Hg. The combination of higher natural gas prices as electricity suppliers consume more natural gas and the cost of CO_2 allowances begins to make new renewable plants economical.

For example, when a CO_2 cap of 7 percent below the 1990 level is assumed, nonhydroelectric renewable technologies are projected to provide 6.4 percent of U.S. electricity sales in 2020, up from 2.0 percent in

2000 and more than double the reference case projection of 2.8 percent in 2020. The key renewable energy technologies stimulated by a CO_2 cap are expected to be biomass (co-fired in coal plants and used in dedicated plants) and wind.

An RPS reaching 20 percent by 2020 is projected to have a larger impact on the use of renewable fuels for electricity generation than are power sector emissions caps on NO_x, SO_2, Hg, and/or CO_2. In general, meeting emissions reduction requirements by adding emissions control equipment and/or changing the mix of fossil fuels used for power production is projected to remain less costly than switching to more expensive renewable alternatives in the absence of an RPS. The renewable technologies expected to be stimulated by a 20-percent RPS are biomass, wind, and geothermal technologies. By 2020 the generation from qualifying nonhydroelectric renewable technologies is projected to reach 932 billion kilowatthours when a 20-percent RPS is assumed, as compared with 135 billion kilowatthours projected in 2020 in the reference case without an RPS.

Macroeconomic Impacts in the House Analysis

When stringent caps on power sector NO_x, SO_2, Hg, and CO_2 emissions are assumed, higher prices for electricity and natural gas are projected to have an impact on the U.S. economy. Higher energy prices would stimulate consumers to reduce their energy use and industries to shift to less energy-intensive production processes and products. The impact would be largest in the short term, when the economy first reacts to the higher prices. In the long run the economy is projected to recover and return to a more stable growth path.

When the four emission caps are first phased in, the unemployment rate is projected to be as much as 0.4 percentage points higher and real gross domestic product (GDP) as much as much as 0.9 percentage points lower in 2010 than projected in the reference case. By 2020, as the economy adjusts to the higher prices, real GDP is projected to be only 0.1 percent below the reference case level, and the unemployment rate is projected to be near the reference case level.

If, rather than a no-cost allocation of emission allowances, allowances were auctioned by the Federal Government, the economic impact could be different. The key question is what the Federal Government would do with the funds raised in the auction. If funds were returned to power suppliers, the effect would be the same as that of the no-cost allocation. If, on the other hand, they were given back to consumers in a lump-sum payment or through a cut in personal income taxes, the effect would be to help consumers maintain their level of overall consumption but reduce total investment. In the near term, this would be expected to reduce the impact on the economy, with GDP in 2010 projected to be 0.8 percent lower than in the reference case, as compared with 0.9 percent lower GDP with a no-cost allocation. In the longer term, the opposite would be the case: 0.4 percent lower GDP in 2020, as compared with 0.1 percent lower under the no-cost allocation scheme.

Analysis for Senators Smith, Voinovich, and Brownback (SVB)

In a second study, requested by Senators Smith, Voinovich, and Brownback, EIA examined the costs of different multi-emissions reduction targets. EIA was asked to analyze the impacts of three cases with alternative power sector emission caps on NO_x, SO_2, and Hg. The Senators also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008.

Specifically, EIA was asked to analyze three cases for reducing power sector emissions with and without holding CO_2 emissions to 2008 reference case levels. The first case reduces NO_x emissions by 75 percent below 1997 levels, SO_2 emissions 75 percent below full implementation of CAAA90 Title IV, and Hg emissions by 75 percent below 1999 levels. In the two other cases the reductions are less—65 percent and 50 percent, respectively.

The emission reduction programs are assumed to cover all electricity generators other than cogenerators [*68*] and to operate as cap and trade programs patterned after the SO_2 control program created in the CAAA90. It was requested that the analysis should assume that the programs would begin in 2002, achieving half the required reductions by 2007 and full compliance by 2012. At the request of the Senators, the existing summer season NO_x cap and trade program is assumed to be replaced by the annual programs established in each of the cases. For Hg, half the required reductions are to come from actual reductions at each unit, and the rest can be achieved through allowance trading among units.

In all cases, power suppliers are able to bank emissions for future use. In other words, power suppliers can chose to reduce their emissions below the number of allowances they have in some years and hold (bank) them for use in other years. Typically a power supplier would be expected to do this in the early phase of the emission reduction programs, when allowances are relatively inexpensive, so that they can reduce the number of allowances they might have to buy in the later phases, when allowances might be more expensive.

Electricity Market Impacts in the SVB Analysis

The key results of controlling NO_x, SO_2 and Hg emissions to the required levels include adding emissions control equipment as the dominant compliance option. Emission allowance costs and electricity prices are projected to increase as the caps on NO_x, SO_2, and Hg are tightened across the cases (Table 4). In 2020, the price of electricity is projected to be between 1 and 6 percent higher than in the reference case. The Nation's total electricity bill is projected to be 1 to 5 percent higher in 2020 (between \$3 and \$13 billion 1999 dollars), as compared with the reference case.

From 2001 to 2020, power supplier resource costs are projected to be between \$28 billion and \$89 billion higher than in the reference case. When it is assumed that power suppliers are required to purchase offsets for CO_2 emissions above the projected emissions level in 2008 in the reference case and that trading outside the power sector is not permitted, the CO_2 allowance price in 2020 is projected to range from \$33 per metric ton carbon equivalent in the 75-percent reduction case to \$54 per metric ton in the 50-percent reduction case (Table 5). The allowance price is higher in the 50-percent case than in the 75-percent case because more offsets are needed in the 50-percent case.

Fuel Market Impacts in the SVB Analysis

Decreased use of coal and increased use of natural gas in the electricity sector is projected when emission reductions at these levels are required. By 2020, coal-fired generation is projected to be between 4 and

Table 4. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis without holding carbon dioxide emissions to 2008 levels, 2010 and 2020

Projection	Reference case[a]	50-percent reduction case	65-percent reduction case	75-percent reduction case
		2010		
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,238	2,162	2,064	2,068
Natural gas	826	903	989	984
Renewable fuels	396	399	401	401
Nuclear	720	725	725	729
Emissions allowance prices				
SO_2 (1999 dollars per ton)	180	210	415	296
NO_x (1999 dollars per ton)[b]	NA	1,208	1,491	2,072
Hg (million 1999 dollars per ton)	NA	29	40	64
Electricity price (1999 cents per kilowatthour)	6.1	6.1	6.2	6.2
Electricity sales (billion kilowatthours)	4,133	4,135	4,122	4,120
Electricity industry revenue (billion 1999 dollars)	253	253	257	257
		2020		
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	2,221	2,135	2,083
Natural gas	1,488	1,551	1,626	1,661
Renewable fuels	399	407	409	411
Nuclear	610	613	613	613
Emissions allowance prices				
SO_2 (1999 dollars per ton)	200	719	1,390	1,737
NO_x (1999 dollars per ton)[b]	NA	1,108	1,457	2,825
Hg (million 1999 dollars per ton)	NA	42	82	170
Electricity price (1999 cents per kilowatthour)	6.1	6.2	6.3	6.5
Electricity sales (billion kilowatthours)	4,763	4,749	4,736	4,716
Electricity industry revenue (billion 1999 dollars)	292	295	301	305
Cumulative resource costs, 2001-2020: difference from reference case (billion 1999 dollars)	NA	28	66	89

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.
[b]Regional NO_x limits are included in the reference case, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

10 percent below reference case levels, and natural-gas-fired generation is projected to be between 4 and 10 percent higher than reference case levels.

The potential exists, however, for an increase in coal use and its associated emissions in other sectors of the economy (i.e., residential, commercial and industrial) not covered by emission cap programs. However, because coal plays such a small role in these sectors and because the projected reduction in coal prices is generally expected to be less than a few percent, the potential for emission "leakage" appears slight [*69*]. The increase in natural gas prices that is projected to occur because of increased use in the electricity sector appears to be more important, leading to lower overall fuel consumption and emissions in other sectors. Natural gas prices to all users in 2020 are projected to be $0.28 per million Btu higher in the 75-percent reduction case than in the reference case.

Analysis for Senators Jeffords and Lieberman (J/L)

For this analysis, Senators Jeffords and Lieberman requested that EIA consider the impacts of technology improvements and other market-based opportunities on the costs of emissions reductions from electricity generators. Using 2002 as a start date for emissions reductions, the request specifies that by 2007 NO_x emissions from electricity generators are to be reduced to 75 percent below 1997 levels, SO_2 emissions to 75 percent below the full implementation of the CAAA90 Phase II requirements, Hg emissions to 90 percent below 1999 levels, and CO_2 emissions to 1990 levels. These emissions limits are applied to all electricity generators, excluding cogenerators.

The impacts of emissions limits were analyzed using four cases with varying levels of energy demand and technology costs and different assumptions about energy policies: the reference case from the *Annual Energy Outlook 2001* (*AEO2001*), published in December 2000; an advanced technology case combining the high technology assumptions for end-use demand, supply, and generating technologies from *AEO2001*; and cases incorporating the moderate and advanced policies from *Scenarios for a Clean Energy Future* (*CEF*), a publication of an interlaboratory working group, published in November 2000 [*70*]. The policies in the *CEF* analysis included fiscal incentives, regulations, and increased research and development funding for advanced technologies. The advanced *CEF* case also included a domestic CO_2 trading system for all energy markets that was assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent, which would be announced in 2002 and implemented in 2005.

Electricity Market Impacts in the J/L Analysis

The *AEO2001* reference case included continuing development of energy-consuming and producing technologies, consistent with historical trends in research and development funding. The advanced technology assumptions in *AEO2001* were based on more optimistic technology development throughout

Table 5. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis holding carbon dioxide emissions to 2008 levels, 2020

Projection	Reference case[a]	50-percent reduction case	65-percent reduction case	75-percent reduction case
	2020			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	1,894	1,842	1,794
Natural gas	1,488	1,653	1,767	1,816
Renewable fuels	399	468	438	442
Nuclear	610	637	631	631
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	54	37	33
SO_2 (1999 dollars per ton)	200	527	2,009	2,812
NO_x (1999 dollars per ton)[b]	NA	0	931	432
Hg (million 1999 dollars per ton)	NA	15	53	98
Electricity price (1999 cents per kilowatthour)	6.1	7.1	7.0	7.1
Electricity sales (billion kilowatthours)	4,763	4,615	4,631	4,631
Electricity industry revenue (billion 1999 dollars)	292	328	324	329

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.
[b]Regional NO_x limits are included in the reference case, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

the energy system, consistent with more aggressive research and development programs. The costs to achieve these technology improvements were not quantified, because there is no analysis showing that funding levels for research and development can be tied directly to the successful development of new technologies.

The moderate and advanced cases in *CEF* included a number of policies to encourage the development and adoption of technologies that are more energy-efficient and with lower emissions. However, the success of these programs was based in part on assumed changes in consumer behavior that are not consistent with historical behavior patterns, research and development funding increases that have not occurred, and voluntary and information programs for which there is no analytical basis for evaluating the impacts. Also, some of the assumed *CEF* policies required legislative or regulatory actions that may not be enacted at all or may be enacted at later dates than assumed in *CEF*.

Future technology development cannot be known with certainty, and even the technology improvements assumed in the reference case are likely, but not certain. The more rapid technology development assumed in the advanced technology case and in the *CEF* cases is more uncertain and represents a higher level of risk for the ultimate success and timing of the technology improvement. Furthermore, the simultaneous success of a wide range of technology development projects is highly unlikely.

Because the reference case is based on historical levels of funding and technology development, the technology trends assumed in the reference case are considered to be the most likely trends. However, of the cases considered in this study, the reference case projects the highest costs for reducing emissions. Relative to the reference case, the advanced technology case and the cases with the *CEF* policies all reduce projected energy demand, energy prices, and related emissions. Total energy demand in 2020 is projected to be similar in the advanced technology case and the case incorporating the *CEF* moderate policies, with the lowest demand in the case incorporating the *CEF* advanced policies. Because the advanced technology case also includes more rapid technology development for fossil fuel supply, that case has the lowest projected energy prices. As a result of lower energy prices and demand, the advanced technology case and the *CEF* cases have lower projected energy expenditures than in the reference case.

Introducing the emissions limits in the reference case raises the projected average delivered price of electricity by 33 percent in 2020 relative to the reference case (Table 6). Electricity prices are higher because of the additional costs for emission control equipment, the costs of obtaining emissions permits, and higher fossil fuel prices to electricity generators. Overall, the higher electricity prices reduce the projected demand for electricity, although the impact is dampened by the higher projected natural gas price, which results from higher demand for natural gas. Coal-fired electricity generation is reduced with the imposition of the emissions limits, and due to the premature retirement of coal-fired generators, generation from natural gas, renewable, and existing nuclear technologies is higher, even with lower generation requirements. As a result of higher energy prices, energy expenditures are projected to be higher than in the reference case (without emissions limits).

The total cost of supplying electric power, which is called the resource cost, includes the cost of fuel, operations and maintenance costs, investments in plant and equipment, and costs of purchasing power. The resource cost does not include the costs of emissions allowances. Through 2020, the cumulative resource costs of electricity generation are projected to be $177 billion (undiscounted 1999 dollars), or 9 percent, higher with the emissions limits.

Imposing the emissions limits on the advanced technology case raises the projected average delivered price of electricity by 22 percent in 2020, less than the increase in the reference case. Lower projected demand for electricity and the use of less carbon-intensive fuels in the advanced technology case relative to the reference case reduce the effort needed to meet the emissions limits. Among the four emissions that have limits in these cases, CO_2 emissions tend to be the most costly to reduce, largely through the premature retirement of existing coal plants and increased use of natural gas and renewable technologies. CO_2 sequestration is included in NEMS, but currently there are no economical technologies to sequester CO_2 emissions from generation plants, unlike the technologies available for the removal of the three other emissions.

Because the advanced technology case without limits has lower CO_2 emissions than the reference case, fewer shifts in electricity generation are required to meet the CO_2 limits when they are imposed. In addition, because reductions in CO_2 emissions also reduce SO_2 and Hg emissions, it is less costly to achieve reductions of these emissions in the advanced technology case than in the reference case. Additional investments in emissions control equipment are required to meet the limits. NO_x allowance prices are projected to decline to zero in the advanced technology case with emissions limits.

When the emissions limits are imposed in the advanced technology case, the higher electricity prices reduce the projected demand for electricity, but the reduction is less than projected in the reference case when the emissions limits are imposed, because the projected demand for electricity is already lower in the advanced technology case even without the limits, and because the projected increase in the electricity price is less than in the reference case. Similar trends in the generation mix are expected, although the magnitudes of the changes differ as the result of lower generation requirements and the higher level of renewable and nuclear generation in the advanced technology case without emissions limits.

Similar to the reference case, demand for natural gas is expected to be higher when emissions limits are imposed in the advanced technology case, due to fuel switching by electricity generators and increased cogeneration in the commercial and industrial sectors. Higher projected prices result in higher energy expenditures in the advanced technology case when the limits are imposed. From 2001 through 2020, the incremental cumulative resource costs of complying

Table 6. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, reference and advanced technology cases, 2010 and 2020

Projection	Reference case without emissions limits[a]	Reference case with emissions limits[a]	Advanced technology case without emissions limits	Advanced technology case with emissions limits
		2010		
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,238	1,276	2,240	1,324
Natural gas	826	1,395	719	1,292
Renewable fuels	396	492	402	515
Nuclear	720	741	744	744
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	93	NA	69
SO_2 (1999 dollars per ton)	180	46	168	152
NO_x (1999 dollars per ton)[b]	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	482	NA	510
Electricity price (1999 cents per kilowatthour)	6.1	8.0	5.9	7.4
Electricity sales (billion kilowatthours)	4,133	3,872	4,049	3,835
Electricity industry revenue (billion 1999 dollars)	252	310	239	284
		2020		
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	1,041	2,246	1,146
Natural gas	1,488	2,072	1,331	1,911
Renewable fuels	399	519	409	524
Nuclear	610	669	672	720
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	122	NA	58
SO_2 (1999 dollars per ton)	200	221	145	703
NO_x (1999 dollars per ton)[b]	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	306	NA	374
Electricity price (1999 cents per kilowatthour)	6.1	8.1	5.5	6.7
Electricity sales (billion kilowatthours)	4,763	4,320	4,610	4,294
Electricity industry revenue (billion 1999 dollars)	291	350	254	288
Cumulative resource costs, 2001-2020: difference from corresponding case without emissions limits (billion 1999 dollars)	NA	177	NA	142

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.

[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.

NA = not applicable.

with the emissions limits in the advanced technology case are projected to be $142 billion (an 8-percent increase), compared with $177 billion (a 9-percent increase) in the reference case.

In the *CEF-JL* moderate case, average delivered electricity prices are expected to be higher in 2020 when emissions limits are imposed (7.2 cents per kilowatthour compared with 6.0 cents per kilowatthour) because of the cost of allowance permits and emissions control equipment (Table 7). As a result of higher electricity prices, total projected electricity consumption in 2020 is reduced. However, electricity demand and prices are essentially unchanged in the advanced case with the addition of the emissions limits, because a $50 per ton carbon allowance price is assumed even without emissions limits.

In the *CEF-JL* advanced case with emissions limits, the CO_2 allowance price is essentially the same as in the advanced case without the limits, which assumes a $50 CO_2 allowance price across all energy markets. The projected costs for NO_x permits decrease to zero by 2020 in the *CEF-JL* advanced case as the actions taken to reduce CO_2 emissions result in NO_x emissions within the limits.

Between 2001 and 2020, the cumulative incremental resource costs to electricity generators to comply with the emissions limits are projected to be $162

Table 7. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, CEF-JL moderate and advanced technology cases, 2010 and 2020

Projection	Reference case without emissions limits[a]	Moderate case without emissions limits	Moderate case with emissions limits	Advanced case without emissions limits	Advanced case with emissions limits
			2010		
Generation by fuel, excluding cogenerators (billion kilowatthours)					
Coal	2,238	2,221	1,357	1,737	1,395
Natural gas	826	616	1,138	800	1,090
Renewable fuels	396	406	543	555	578
Nuclear	720	720	741	735	735
Emissions allowance prices					
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	NA	64	50	54
SO_2 (1999 dollars per ton)	180	169	316	102	130
NO_x (1999 dollars per ton)[b]	NA	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	NA	549	NA	481
Electricity price (1999 cents per kilowatthour)	6.1	5.8	7.1	6.5	6.7
Electricity sales (billion kilowatthours)	4,133	3,920	3,747	3,777	3,745
Electricity industry revenue (billion 1999 dollars)	252	227	266	246	251
			2020		
Generation by fuel, excluding cogenerators (billion kilowatthours)					
Coal	2,302	2,296	1,284	1,567	1,276
Natural gas	1,488	908	1,330	1,181	1,416
Renewable fuels	399	413	624	551	561
Nuclear	610	595	646	575	617
Emissions allowance prices					
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	NA	68	50	50
SO_2 (1999 dollars per ton)	200	184	905	707	670
NO_x (1999 dollars per ton)[b]	NA	NA	81	NA	0
Hg (million 1999 dollars per ton)	NA	NA	468	NA	391
Electricity price (1999 cents per kilowatthour)	6.1	6.0	7.2	6.6	6.6
Electricity sales (billion kilowatthours)	4,763	4,197	3,910	3,862	3,855
Electricity industry revenue (billion 1999 dollars)	291	252	282	255	254
Cumulative resource costs, 2001-2020: difference from corresponding case without emissions limits (billion 1999 dollars)	NA	NA	162	NA	129

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.
[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

billion and $129 billion in the moderate and advanced cases, respectively—increases of 9 and 8 percent. The lower costs of compliance projected in the advanced case are due to the availability of more efficient generating technologies compared with the moderate case. In addition, because lower SO_2 emissions are assumed in the *CEF-JL* advanced case even without the emissions limits to simulate the impact of particulate controls, the addition of the emissions limits can be achieved at a lower relative cost.

Because the *CEF-JL* advanced case already includes a $50 CO_2 allowance price, there is little additional CO_2 reduction required, and energy expenditures are only slightly higher. In the *CEF-JL* moderate case with emissions limits, higher projected prices for coal, natural gas, and electricity are projected to reduce energy consumption in the residential and commercial sectors, compared to the case without limits, and to increase total energy expenditures. In the industrial sector, projected energy consumption in 2020 is essentially unchanged, because higher demand for natural gas for cogeneration offsets lower demand for purchased electricity.

In the electricity generation sector, projected coal-fired generation in 2020 is reduced in the moderate and advanced cases with the addition of the emissions limits. The impact is less in the advanced case, however, because the advanced case without the limits already includes a $50 CO_2 allowance price and a reduction in particulate emissions. Generation from natural gas, existing nuclear power plants, and renewable sources is projected to be higher in both cases when the emissions limits are imposed, because the limits raise the cost of coal-fired generation. Cogeneration of electricity is also higher in the commercial and industrial sectors in the *CEF-JL* moderate case when emissions limits are imposed. Total projected CO_2 emissions in 2020 are reduced by 12 percent and 4 percent in the *CEF-JL* moderate and advanced cases with emissions limits, respectively, compared to the cases without the limits, primarily due to lower levels of coal-fired generation.

Fuel Market Impacts in the J/L Analysis

In the four cases, demand for natural gas is increased by electricity generators that are subject to the emissions limits. Natural gas demand is also projected to be higher for commercial and industrial cogeneration in all cases except the case with the advanced *CEF* policies. This case is the exception because the $50 per ton CO_2 allowance price in the case without limits is essentially the same as the CO_2 allowance price that results when the emissions limits are imposed.

As a result of higher projected natural gas demand, natural gas prices are projected to be higher by between 11 and 20 percent in all four cases when the emissions limits are imposed. Because the *CEF* advanced policies include a $50 per ton CO_2 allowance price and a policy to reduce particulate emissions, coal consumption is sharply reduced in that case and electricity prices are higher relative to the reference case, even without the emissions limits, and imposing emissions limits does not cause a significant additional reduction in total energy demand in that case. Although the total energy expenditures are lower in the advanced technology and *CEF* cases than in the reference case, energy expenditures are expected to increase when the emissions limits are imposed in all cases, except the case incorporating the *CEF* advanced policies.

Macroeconomic Impacts in the J/L Analysis

The assumed emissions limits are expected to have measurable short-term impacts on the economy when the limits are fully imposed in 2007, with a reduction in gross domestic product ranging from 0.4 to 0.8 percent. The impact is significantly reduced, even by 2010, as the economy adjusts to higher energy prices. In all cases except the reference case, the macroeconomic impacts of the emissions limits are greatly reduced by 2020, with reductions in gross domestic product ranging from zero to 0.1 percent.

Summary of Results for Congressional Studies

It is useful to identify findings that are common across the three Congressional analyses of multiple emissions strategies. Generally, the costs of implementing multiple emissions strategies vary with the stringency of the reductions required and, to a lesser extent, the time frame for compliance. The higher the requirement to reduce CO_2 emissions and the shorter the time frame for the reductions, the higher the costs are expected to be. For example, when the emission reduction requirements are increased from 75 percent in the SVB analysis that excludes CO_2 limits to 90 percent in the J/L cases, which include CO_2 limits, the projected cumulative resource costs to achieve them increase from $89 billion to between $129 and $177 billion.

Higher resource costs and higher electricity prices to consumers are projected in all the multiple emissions cases analyzed. Electricity prices increase as a result of investments in emission control technologies, purchases of allowances, construction of new generating equipment to replace existing equipment, and higher fuel costs. The highest increase in projected electricity prices in 2020, 49 percent above the reference case level, is seen in the high gas price case in the House analysis, which assumes limits on CO_2 emissions as well as NO_x, SO_2, and Hg.

In all the analyses, higher electricity prices result in part from increases in natural gas consumption and the attendant high prices for natural gas in the emissions limits cases over the prices that would be expected without emissions limits. Natural gas consumption increases because it has lower emissions than other fossil fuels, particularly coal. Nuclear power and renewable energy sources also have lower emissions than either coal or natural gas. When emissions limits are assumed, the use of coal as a fuel for electricity generation is less desirable, and as a result consumption declines. In most of the cases that include caps on CO_2 emissions, coal-fired generation in 2020 declines to about one-half the level expected without CO_2 emissions limits. The expected decreases in coal-fired generation are much smaller when NO_x, SO_2, and Hg emission caps are assumed without the caps on CO_2 emissions.

A number of uncertainties are inherent in the multi-emissions analyses. For example:

- Although the *AEO2001* reference case incorporated improvements in technology cost and performance over time based on trends in historical data and consumer purchase decisions, it is difficult to assess the extent to which those trends might change in response to increased funding for research and development or expanded public information and voluntary participation programs.
- Although technologies for controlling SO_2 emissions are relatively mature, control technologies for NO_x, Hg, and CO_2 emissions are not as far along in the development cycle. The multi-emissions analysis cases assumed that new SCR technology would remove between 75 and 80 percent of NO_x emissions, but there has been little experience with actual operating facilities. Small changes in the cost and performance of emissions control technologies could have significant impacts.
- Even among power plants with similar equipment, there is substantial variation in the amount of Hg removed by NO_x and SO_2 control equipment.
- A number of policy instruments could be used in efforts to reduce emissions, with different implications for the impacts of emission reductions. A cap and trade program, as assumed in these analyses, is expected to lead to the lowest resource cost for compliance. Other options could lead to lower electricity price impacts but higher resource costs.

Finally, EIA has not performed any analyses of the benefits that may accrue from implementing multi-emissions control policies. The EPA is responsible for such analyses, and interested readers are referred to the EPA web site (www.epa.gov) for studies that have been carried out.

Modeling Energy Efficiency

Definition of Energy Efficiency

Energy efficiency and conservation are high-profile issues in the current debate about U.S. energy policy. Energy efficiency can mean different things to different people. Here it is defined as the ratio of energy service provided (output) to energy consumed (input) [*71*]. By this definition, gains in energy efficiency can be achieved either by using less energy input to provide the same level of energy service or by providing more energy service from the same level of energy input. Energy conservation is defined as a reduction in energy consumption through a reduction in energy service provided. “Pure” conservation measures leave the ratio of energy service to energy consumption unchanged and thus do not affect efficiency. How narrowly or broadly energy services are defined can affect whether a change is characterized as an efficiency gain or a conservation measure.

Measuring the energy efficiency of the U.S. economy is a daunting task, because data sufficiently disaggregated to permit isolation of the various end-use components of energy consumption and energy service generally are not available. For example, data on residential energy consumption per household can be constructed from utility records, but detailed end-use energy consumption and energy service data are not separately measured or collected, and data on energy use for residential space heating and the energy service (heat) provided are not available on an economy-wide basis. In lieu of energy efficiency measures, the description of the U.S. economy usually is framed in terms of “energy intensity” concepts, such as energy consumption per unit of real GDP or energy consumption per capita. Energy intensity is generally defined as energy consumption per unit of an indicator (such as economic activity or population) that provides a rough proxy for energy service supplied. Because of their aggregate nature and the use of proxies for energy services, energy intensities can be affected by a variety of structural factors unrelated to energy efficiency.

Because energy input (consumption) is included in the numerator, intensity measures are inversely related to efficiency measures. Thus, other factors being held constant, an increase in energy efficiency will reduce energy intensity. Changes in energy intensity can occur, however, without underlying changes in energy efficiency. Examples include conservation, structural shifts among sectors or regions of the economy, and changes in the mix of activities within sectors.

In contrast to the limited availability of information for measuring the historical performance of the economy, NEMS includes rich technology characterizations and end-use consumption detail, as well as explicit projections for energy services supplied. This detail provides the basis for developing estimates of projected energy efficiency. In NEMS, the effects of efficiency increases on projected energy consumption are modeled by incorporating economically based decision rules for end-use energy-using technology choices, coupled with sufficient options to allow the potential purchase of advanced, energy-efficient equipment, and by incorporating the effects of legislated mandates for efficiency improvements, such as corporate average fuel economy (CAFE) standards and equipment standards. The detailed NEMS projections have been used to develop an aggregate composite efficiency index (ACEI) based on more than 2,500 detailed subsector and end-use inputs.

Classification of Energy Efficiency Improvements

Residential space heating is an end-use energy service that is both familiar and sufficiently complex to illustrate important issues in the classification of energy efficiency improvements. For example, replacing an old, inefficient natural gas furnace with a new, more efficient one would be considered an efficiency increase by virtually anyone's definition. On the other hand, turning down the thermostat in the winter but doing nothing else would generally be considered a conservation measure.

Not all actions have such clear classifications. For example, installing attic insulation to reduce heating needs could be classified either as an efficiency gain or as a conservation measure, depending on how the "energy service" is defined. Because adding insulation, like turning down the thermostat, reduces energy use for heating, it could be classified as an energy conservation measure. On the other hand, if the concept of "interior warmth" is used to represent the heating energy service as a composite service provided by the combination of furnace equipment and insulation, then insulation allows the end user to maintain a given level of energy service (interior warmth) with a lower level of energy consumption, which meets the definition of a gain in energy efficiency.

Another home heating example is the installation of time-of-day thermostats. The energy-saving feature of a time-of-day thermostat is that when heat is not needed (for example, when the house is unoccupied or the occupants are sleeping), the temperature can be reduced so that less energy is consumed. This measure could be viewed either as a reduction in energy service (conservation) or as a more efficient way of providing the same level of energy service to the occupants of the home (efficiency increase). In NEMS it is classified as a conservation measure, because less energy service (whether noticed or unnoticed) is provided.

Passenger transportation in light-duty vehicles (cars, sport utility vehicles, pickup trucks, vans, minivans, and motorcycles) is another familiar energy service that can be used to illustrate the issues involved in defining and calculating energy efficiency. In the *AEO2002* reference case, the fuel efficiency (miles per gallon) of the light-duty vehicle fleet is projected to increase by an average of 0.3 percent annually between 2000 and 2020. Whether that is an appropriate estimate depends on how the energy service is defined.

Two components of the light-duty vehicle fleet, passenger cars and light trucks, account for 99.8 percent of its energy consumption. (Motorcycles are the remainder and can be ignored in this example.) For passenger cars, the average fuel efficiency of the fleet is projected to increase from 21.6 miles per gallon in 2000 to 24.6 miles per gallon in 2020, an average annual rate of 0.7 percent. For light trucks, average fuel efficiency is projected to increase from 17.1 miles per gallon to 18.2 miles per gallon, an average annual rate of 0.3 percent. At the same time, the mix of vehicles in the fleet is expected to shift in favor of the larger, less fuel-efficient light truck component (including sport utility vehicles). Light trucks accounted for 42 percent of total light-duty vehicle energy consumption in 2000, but in 2020 they are projected to account for 56 percent of the total. As a result, when the energy services provided by the two vehicle categories are considered to be the same, the projected shift to less efficient light trucks results in a projected overall increase in fleet efficiency averaging 0.3 percent per year.

The calculation of separate efficiency indexes for cars and light trucks assumes that consumers value the energy services received from light trucks differently from those received from passenger cars [*72*] and, therefore, that cars and light trucks should be considered as separate end-use categories. When this assumption is made, calculation of the projected rate of increase in energy efficiency for light-duty vehicles as a whole involves weighting the expected increases for the two components by their projected proportions of light-duty vehicle energy consumption. By this method, the calculated rate of efficiency improvement is 0.5 percent per year, significantly higher than the 0.3-percent average annual increase that is projected when all light-duty vehicles are considered as a single end-use category providing the same energy service.

Calculating the Aggregate Composite Efficiency Index

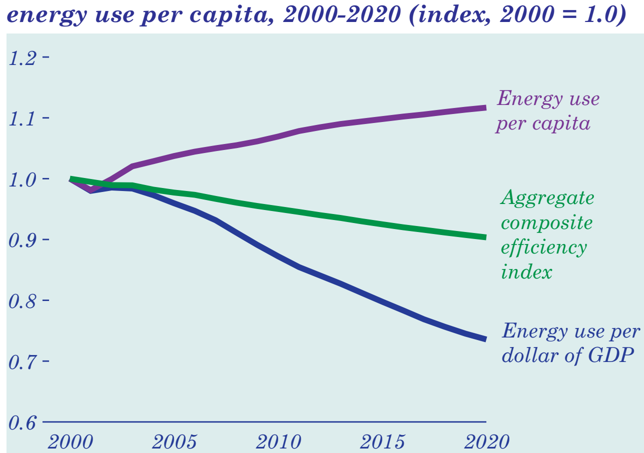
Energy consumption in the U.S. economy is fully accounted for by five broad sectors—residential, commercial, transportation, industrial, and electricity generation. NEMS energy projections include the effects of many factors in addition to efficiency changes, such as the energy consumption shares of the five sectors, the mix of industries producing industrial output, weather effects, short-run responses to changes in energy prices (elasticity effects), regional variations, housing unit size, and end-use penetration of energy-using technologies. In estimating energy efficiency, factors other than efficiency must be removed from the calculations, so that energy consumption unitized on the basis of service demand (e.g., adjusted energy consumption per square foot for buildings) can be used as a valid measure of end-use efficiency.

In the residential and commercial sectors, regional effects are an important consideration. For example, because the requirements for energy services for residential and commercial buildings are related to climate, a shift in population toward the South would be expected to increase the total U.S. demand for air conditioning. If regional effects were not taken into account, a population shift to warmer climates could be mistaken for a decrease in efficiency, because energy consumption per household for air conditioning would increase. Similarly, the energy service requirements for single-family homes differ from those for mobile homes, office buildings, or health care facilities. Thus, for efficiency calculations, energy services are tracked separately for the residential and commercial building types modeled in each of the nine Census divisions. The residential and commercial models include 3 and 11 building types, respectively, as well as 27 and 18 combinations of end-use service and fuel type, respectively [*73*]. For the transportation sector, energy services for 10 vehicle classifications are incorporated into the efficiency calculations. For the industrial sector, 13 industries are separately tracked. Electricity generation sector efficiency is modeled as sales to the end-use sectors divided by energy input.

Calculation of the ACEI involves what is in essence an energy-weighted average of the individual efficiency indexes. This procedure is similar to the indexing method used to construct the consumer price index (CPI) [*74*]. For comparability with intensity measures, the reciprocal of the ACEI is calculated. That is, an efficiency gain results in a decline in the ACEI, as it would for an intensity measure. The results are calculated for the five broad energy consumption sectors, as well as for the U.S. economy as a whole.

Figure 11 compares the ACEI with indexes of energy consumption per dollar of GDP and energy consumption per capita. The base year for all the indexes is 2000. The ACEI shown in Figure 11 is projected to improve (decline) steadily over time. The energy intensity of the economy is also projected to improve

Figure 11. Comparison of projections for the aggregate composite efficiency index, energy use per dollar of gross domestic product, and energy use per capita, 2000-2020 (index, 2000 = 1.0)

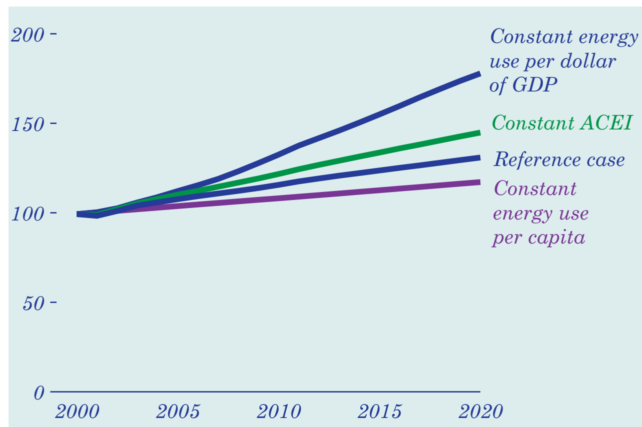


(decline) over time, whereas per capita energy intensity is expected to increase.

To illustrate the effects of the projected changes in the three indexes over the forecast period, Figure 12 compares the reference case projections of U.S. energy consumption with alternative projections derived by holding each of the indexes at its 2000 value. In the reference case, energy consumption is projected to increase at an average annual rate of 1.4 percent. If energy consumption per capita were projected to remain constant instead of increase, that growth rate would be reduced to 0.8 percent per year. In contrast, if there were no improvement in the energy intensity of the economy, or if energy efficiency did not increase, energy consumption would grow more rapidly than projected in the reference case. Assuming no change in the ACEI, energy consumption would be projected to grow at an average rate of 1.9 percent per year to 145 quadrillion Btu in 2020, 14 quadrillion Btu higher than the reference case projection of 131 quadrillion Btu. Assuming no change in the ratio of energy use to real GDP, energy consumption would be projected to grow at an average rate of 3.0 percent per year to 178 quadrillion Btu in 2020, 47 quadrillion Btu higher than the reference case projection.

The difference between the energy consumption projections in Figure 12 for the case assuming constant energy intensity of the economy and the case assuming constant energy efficiency as measured by the ACEI can be attributed to structural changes in the economy that are included in the ratio of energy use to real GDP but are removed from the efficiency calculations.

Figure 12. Projected primary energy consumption in the reference case and in alternative cases assuming no change in energy efficiency and energy intensity, 2000-2020 (quadrillion Btu)



Market Trends

The projections in *AEO2002* 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.

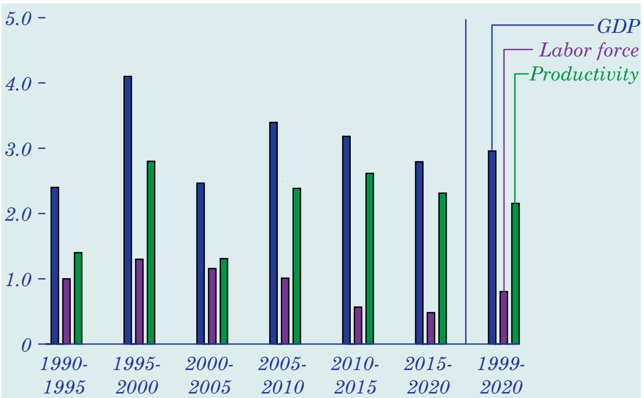
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 *AEO2002* 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 13. Projected average annual real growth rates of economic factors, 2000-2020 (percent)

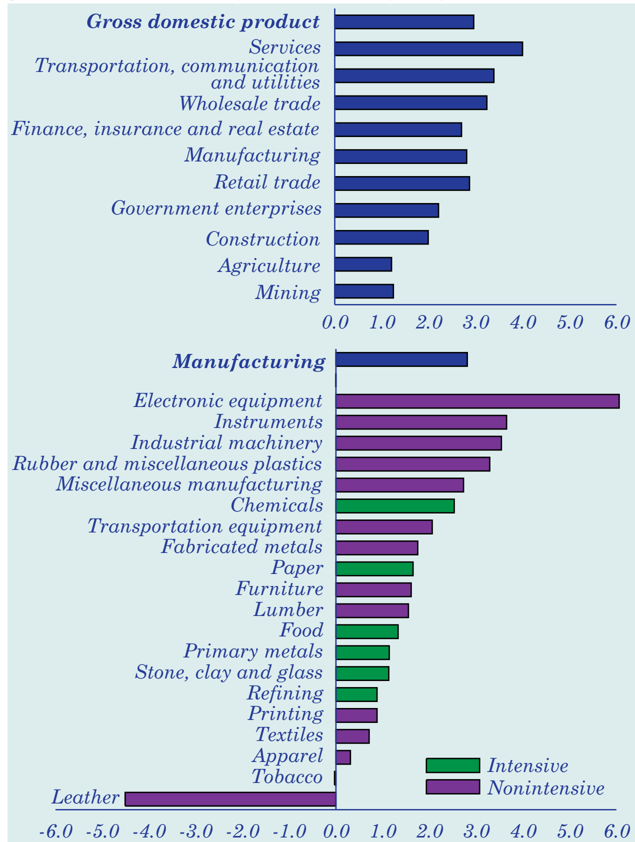


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 3.0 percent per year between 2000 and 2020 (with GDP based on 1996 chain-weighted dollars) (Figure 13), slightly higher than the 2.9-percent growth projected in *AEO2001* for the same period. The projected growth rate for the labor force is similar to last year's forecast through 2020; however, in the *AEO2002* projection, productivity growth (GDP growth minus labor force growth) is 2.2 percent per year, up from 2.0 percent per year in *AEO2001*.

The projected rates of growth in GDP and labor force productivity are lower in the first 5 years of the forecast period, 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 is expected to remain fairly constant after 2000, with an annual growth rate of 0.8 percent per year; the slowing growth in the size of the labor force results instead from the increasing size of the population over the age of 65 years after 2000. As more people retire from the work force, and as life expectancy rises, the labor force participation rate—the percentage of the population over 16 years of age actually employed or looking for employment—is expected to decline as "baby boom" cohorts begin to retire. After the first 5 years of the forecast period, labor force productivity growth is expected to remain well above 2 percent per year through 2020.

Electronic, Industrial Equipment Lead Manufacturing Growth

Figure 14. Projected sectoral composition of GDP growth, 2000-2020 (percent per year)

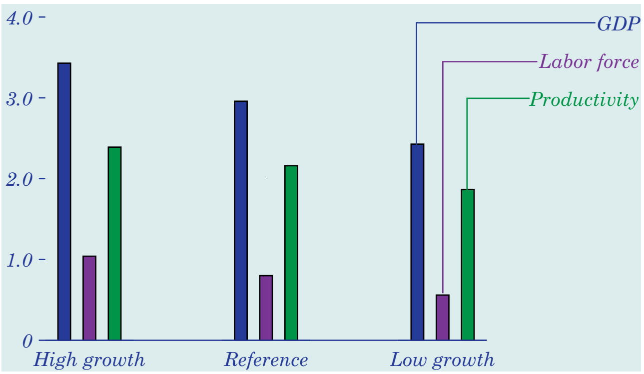


The projected growth rate for manufacturing production is 2.8 percent per year, slightly lower than the approximately 3.0-percent annual growth projected for the aggregate economy (Figure 14). Energy-intensive manufacturing sectors are projected to grow more slowly than the non-energy-intensive manufacturing sectors (1.2 percent and 3.3 percent annual growth, respectively).

The electronic equipment, instruments and related products, and industrial machinery sectors lead the expected growth in manufacturing, as semiconductors and computers find broader applications. The rubber and miscellaneous plastic products sector is expected to grow faster than manufacturing as a whole, with plastics continuing to penetrate new markets as well. As in last year's forecast, higher growth is expected for the services sector than for the manufacturing sector.

High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 15. Projected average annual real growth rates of economic factors in three cases, 2000-2020 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2002* includes high and low economic growth cases in addition to the reference case (Figure 15). The high and low growth cases show the projected effects of alternative growth assumptions on energy markets. The three economic growth cases are based on macroeconomic forecasts prepared by DRI-WEFA [*75*]. The DRI-WEFA forecasts incorporate the expected effects of recent events.

The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), labor force (1.0 percent per year), and labor productivity (2.4 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 3.4 percent per year. GDP per capita is expected to grow by 2.4 percent per year, compared with 2.1 percent in the reference case. The low economic growth case assumes lower growth rates for population (0.6 percent per year), labor force (0.6 percent per year), and productivity (1.9 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 2.4 percent per year from 2000 through 2020, and growth in GDP per capita is projected to slow to 1.8 percent per year.

Long-Run Trend Shows Slowing of the U.S. Economic Growth Rate

Figure 16. Annual GDP growth rate for the preceding 20 years, 1970-2020 (percent)

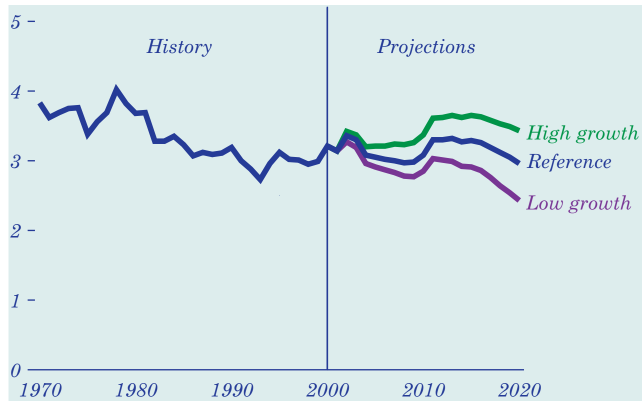
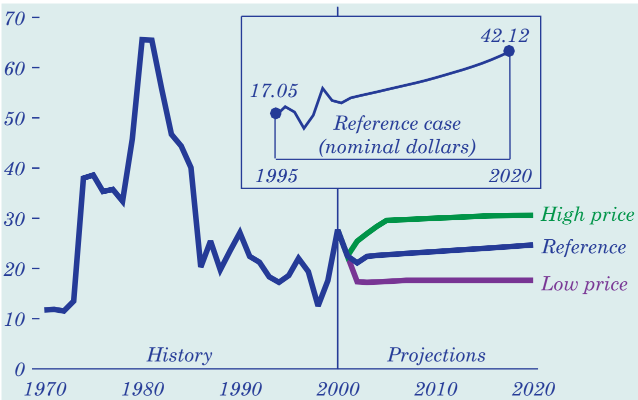


Figure 16 shows the trend in the moving 20-year average annual growth rate for GDP, including projections for the three *AEO2002* cases. The value for each year is calculated as the annual growth rate over the preceding 20 years. The 20-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes (although the increase shown for 2000-2002 reflects the slow and negative growth of 1980-1982). 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 the overall GDP growth for the aggregate economy. In the reference case, consumption is projected to grow by 2.9 percent per year, while investment grows at a 4.1-percent annual rate. In the high growth case, growth in investment is projected to increase to 4.8 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, coupled with higher labor force growth, yield faster aggregate economic growth than projected in the reference case. In the low growth case, annual growth in investment expenditures is projected to slow to 3.1 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 17. World oil prices in three cases, 1970-2020 (2000 dollars per barrel)



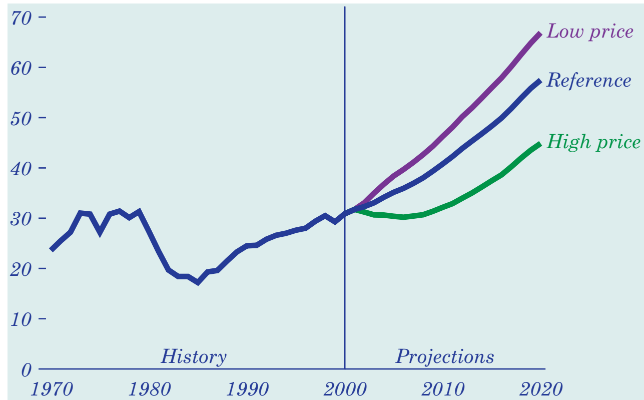
The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. Three *AEO2002* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 17). In the reference case, projected prices fall initially (through 2002) and then rise by about 0.9 percent per year, reaching $24.68 in 2020 (all prices in 2000 dollars unless otherwise noted). In nominal dollars, the reference case price is expected to exceed $42 in 2020. In the low price case, prices are projected to decline from their high in 2000, reaching $17.41 by 2005, and to remain at about that level out to 2020. The high price case projects a price rise of about 2.2 percent per year from 2001 to 2015, with prices remaining at about $30.50 out to 2020. 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 *AEO2001*, reflecting the recent success of OPEC production cutbacks in raising oil prices and a more optimistic economic outlook for the world's developing economies, particularly in Asia. Production from countries outside OPEC is expected to show a steady increase, exceeding 45 million barrels per day in 2000 and increasing gradually thereafter to 61 million barrels per day by 2020.

Total worldwide demand for oil is expected to reach almost 119 million barrels per day by 2020. Developing countries in Asia show the largest projected growth in demand, averaging 3.8 percent per year.

Uncertain Prospects for Persian Gulf Production Shape Oil Price Cases

Figure 18. OPEC oil production in three cases, 1970-2020 (million barrels per day)



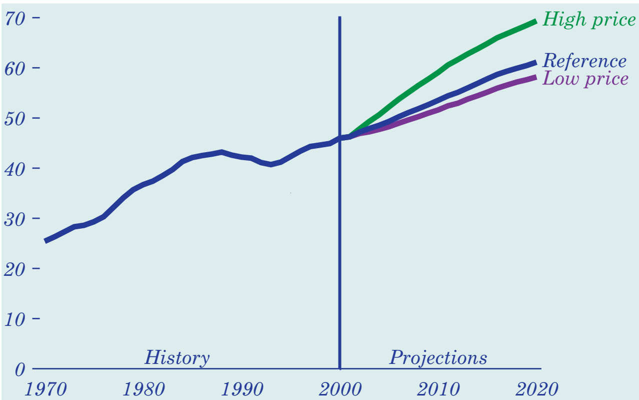
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher in the low price case and lower in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be the principal source 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 [*76*]. By 2020, OPEC production is projected to be over 57 million barrels per day (almost twice its 2000 production) in the reference case, 45 million in the high price case, and 67 million in the low price case (Figure 18). 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 about 125 million barrels per day in the low price case to about 115 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 only at sanction-allowed volumes through 2002. Iraq has indicated a desire to expand its production capacity aggressively, to about 6 million barrels per day, once the sanctions are lifted. Recent discoveries offshore of Nigeria, as well as Venezuela's aggressive capacity expansion plans, 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 19. Non-OPEC oil production in three cases, 1970-2020 (million barrels per day)

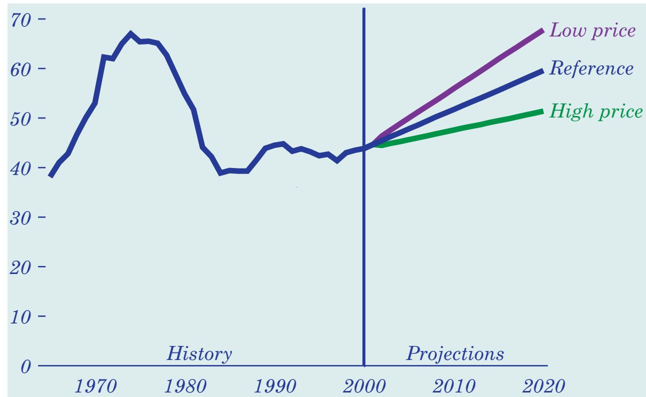


The growth and diversity in non-OPEC oil supply have shown surprising resilience even in the low price environment of the late 1990s. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. Countries in the Organization for Economic Cooperation and Development (OECD) that are expected to register production increases over the next decade include North Sea producers, Australia, Canada, and Mexico. In Latin America, Colombia, Brazil, and Argentina 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 *AEO2002* reference case, non-OPEC supply is projected to reach 61 million barrels per day by 2020 (Figure 19). In the low oil price case, non-OPEC supply is projected to grow to 58 million barrels per day by 2020, whereas in the high oil price case it is projected to reach 69 million barrels per day by the end of the forecast period.

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

Figure 20. Persian Gulf share of worldwide crude oil exports in three cases, 1965-2020 (percent)

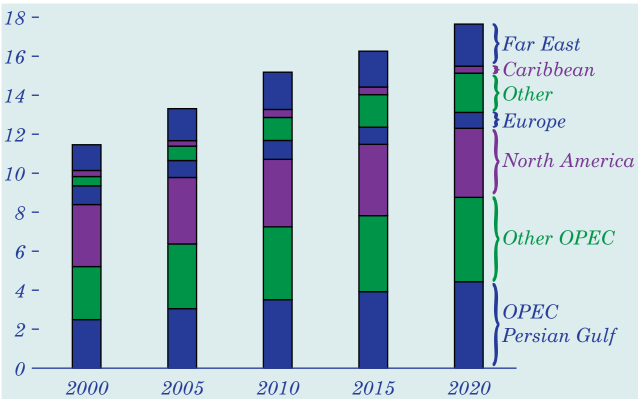


Considering the world market in crude oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the crude oil traded in world markets (Figure 20). The most recent historical low for Persian Gulf oil exports came in 1985 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 1985 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 50 percent when non-OPEC supply proved to be unexpectedly resilient.

In the *AEO2002* reference case, Persian Gulf producers are expected to account for more than 45 percent of worldwide trade by 2002—for the first time since the early 1980s. After 2002, the Persian Gulf share of worldwide petroleum exports is projected to increase gradually to almost 60 percent by 2020. In the low oil price case, the Persian Gulf share of total exports is projected to exceed 67 percent by 2020. 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 2002) are expected to nearly triple their current production capacity.

OPEC Is Expected To Account for Half of U.S. Oil Imports by 2020

Figure 21. Projected U.S. gross petroleum imports by source, 2000-2020 (million barrels per day)



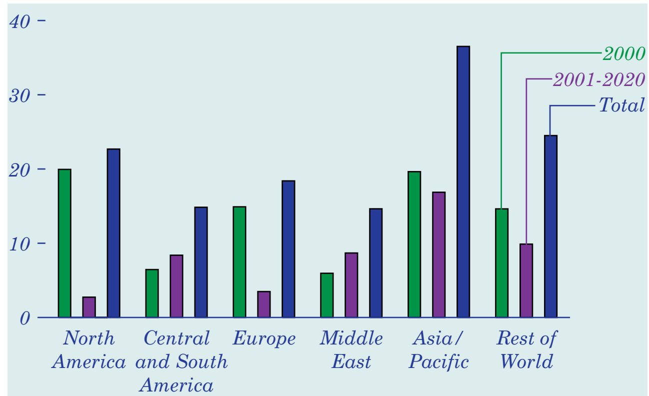
In the reference case, total U.S. gross oil imports are projected to increase from 11.5 million barrels per day in 2000 to 17.7 million in 2020 (Figure 21). Crude oil accounts for most of the expected increase in imports through 2005, whereas imports of petroleum products make up a larger share of the increase after 2005. Product imports are projected to increase 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 in 2020, and the Persian Gulf share of U.S. imports from OPEC is projected to range between 48 and 51 percent consistently throughout the forecast. Crude oil imports from the North Sea are projected to increase slightly through 2010, then to decline gradually as 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 nearly triple by 2020, to 4.5 million barrels per day. Most of the projected increase is from refiners in the Caribbean Basin 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 22. Projected worldwide refining capacity by region, 2000 and 2020 (million barrels per day)



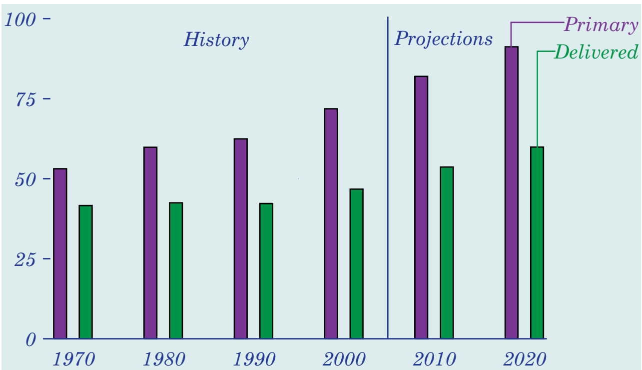
Worldwide crude oil distillation capacity was 81.5 million barrels per day at the beginning of 2000. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by about 61 percent—to more than 131 million barrels per day—by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 22).

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 by 2002. 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 23. Primary and delivered energy consumption, excluding transportation use, 1970-2020 (quadrillion Btu)



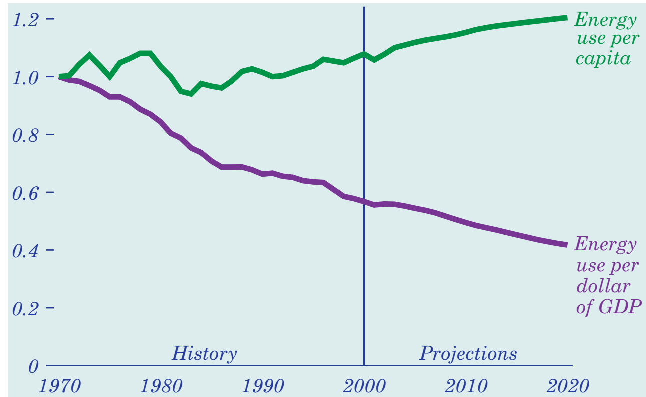
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*77*].

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 23). 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 both grow by 1.2 percent per year, 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 total energy consumption. In the development of carbon dioxide stabilization policies, growth rates for primary energy consumption may be more important than those for delivered energy.

Average Energy Use per Person Increases Slightly in the Forecast

Figure 24. Energy use per capita and per dollar of gross domestic product, 1970-2020 (index, 1970 = 1)

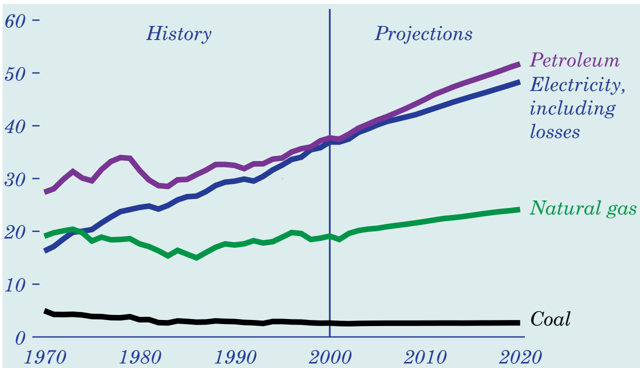


Energy intensity, both as measured by primary energy consumption per dollar of GDP and as measured on a per capita basis, declined between 1970 and the mid-1980s (Figure 24). Although the overall GDP-based energy intensity of the economy is projected to continue declining between 2000 and 2020, the decline is not expected to be as rapid as it was in the earlier period. GDP is estimated to increase by almost 80 percent between 2000 and 2020, compared with a 32-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 *AEO2002* forecast, the demand for energy services is projected to increase markedly over 2000 levels. The average home in 2020 is expected to be 6.5 percent larger and to use electricity more intensively. Annual personal highway travel and air travel per capita in 2020 are expected to be 31 percent and 68 percent higher, respectively, than in 2000. With the growth in demand for energy services, primary energy intensity on a per capita basis is projected to increase by 0.6 percent per year through 2020, 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 25. Delivered energy use by fossil fuel and primary energy use for electricity generation, 1970-2020 (quadrillion Btu)



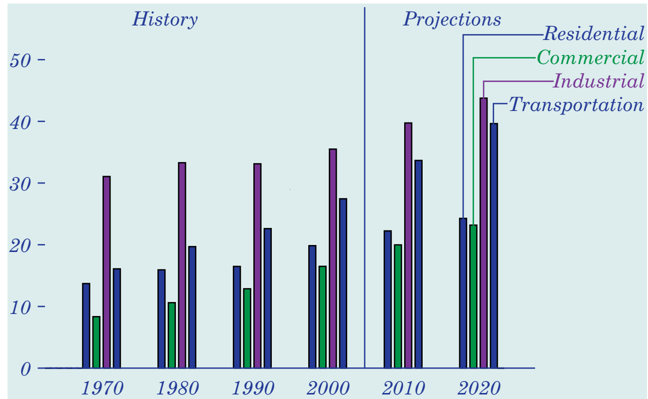
Consumption of petroleum products, mainly for transportation, is expected to claim the largest share of primary energy use in the *AEO2002* forecast (Figure 25). Energy demand growth in the transportation sector averaged 2.0 percent per year during the 1970s but was slowed in the 1980s by rising fuel prices and new Federal efficiency standards, leading to a 2.1-percent annual increase in average vehicle fuel economy. In the forecast, fuel economy gains are projected to slow as a result of expected stable real fuel prices and the absence of new legislative mandates. Projected growth in population and in travel per capita are expected to result in increases in 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. 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 2020.

End-use demand for renewable energy from sources such as wood, wood wastes, and ethanol is projected to increase by 1.6 percent per year. Geothermal and solar energy use in buildings is expected to increase by about 3.1 percent per year but is not expected to exceed 1 percent of energy use for space and water heating.

U.S. Primary Energy Use Approaches 131 Quadrillion Btu per Year by 2020

Figure 26. Primary energy consumption by sector, 1970-2020 (quadrillion Btu)



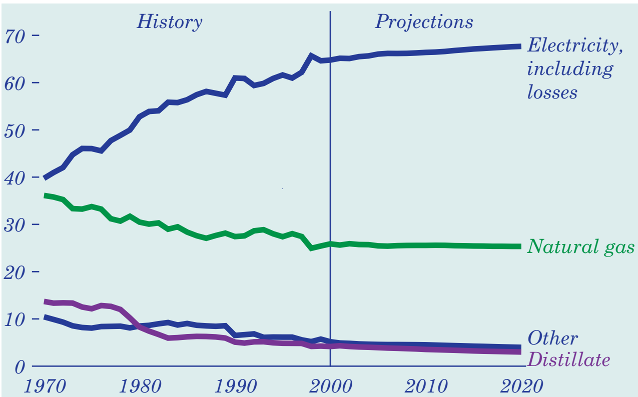
Primary energy use in the reference case is projected to reach 130.9 quadrillion Btu by 2020, 32 percent higher than the 2000 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 26). Between 1985 and 2000, however, stable energy prices contributed 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 3 percent lower than in the low world oil price case in 2020, 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 [*78*]. For 2020, the projection of total annual energy use in the high economic growth case is 11 percent higher than in the low economic growth case.

Residential Energy Use Grows by 22 Percent From 2000 to 2020

Figure 27. Residential primary energy consumption by fuel, 1970-2020 (percent of total)



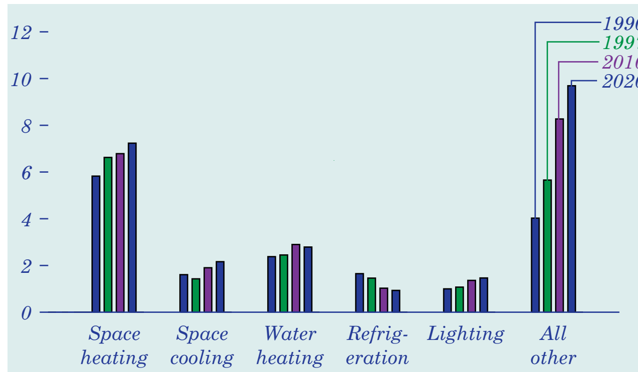
Residential energy consumption is projected to increase by 22 percent overall between 2000 and 2020. Most (81 percent) of the growth in total energy use is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 27).

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 0.9 percent per year through 2020. Natural gas prices to residential customers are projected to decline in the forecast and to be 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 are, on average, 14 percent larger than the existing 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 28. Residential primary energy consumption by end use, 1990, 1997, 2010, and 2020 (quadrillion Btu)



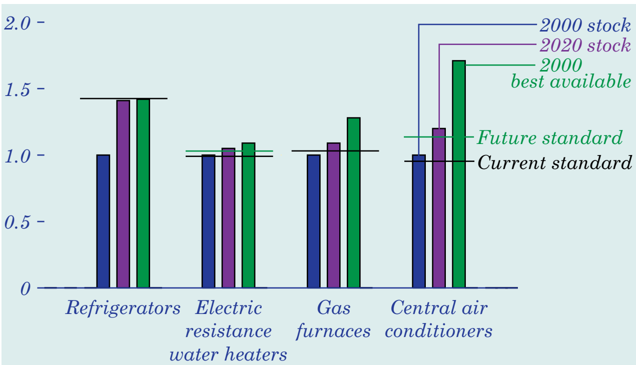
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 1.9 percent per year from 1990 to 1997 (Figure 28). Future growth is expected to be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand by about 7 percent per household in 2020 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 1.7 percent per year from 1990 to 1997 and is expected to decline by about 1.9 percent per year through 2020, 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 5 percent per year from 1990 to 1997 (Figure 28) and now accounts for 32 percent of residential primary energy use. It is projected to account for 40 percent in 2020, 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 2020, growing at an annual rate of 2.1 percent from 2000 to 2020.

Available Technologies Can Slow Future Residential Energy Demand

Figure 29. Efficiency indicators for selected residential appliances, 2000 and 2020 (index, 2000 stock efficiency =1)

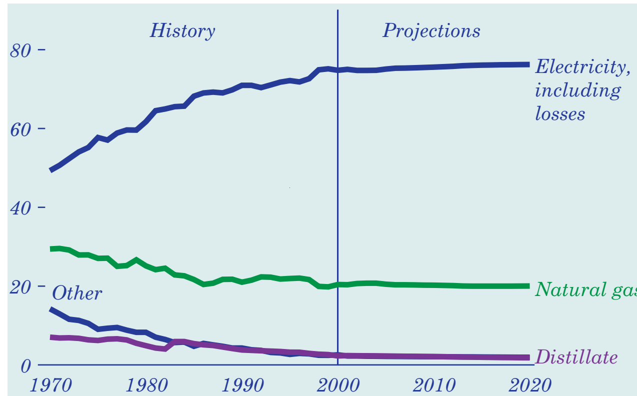


The *AEO2002* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 2000 stock, ensuring an increase in stock efficiency (Figure 29) 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. Effective dates for new efficiency standards for water heaters, clothes washers, central air conditioners, and heat pumps were announced in January 2001 and are included in the reference case, which assumes that current legal challenges will not prevent implementation of the standards in the most recent DOE announcement on July 25, 2001.

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 30. Commercial primary energy consumption by fuel, 1970-2020 (percent of total)

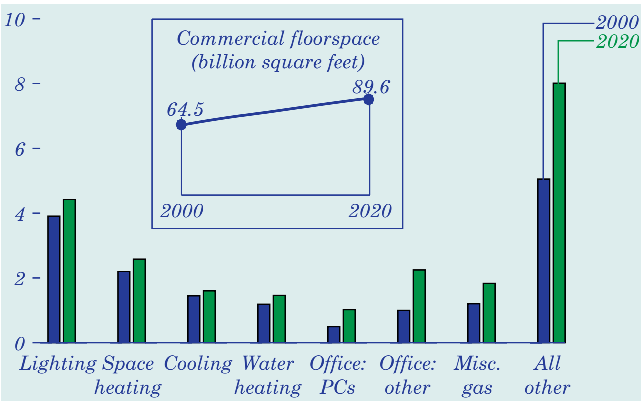


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past three decades (Figure 30). Commercial energy use, including electricity-related losses, is projected to grow at about the same rate as commercial floorspace, by 1.7 percent per year between 2000 and 2020. Energy consumption per square foot is projected to increase by a modest 0.1 percent per year, 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 is projected to account for three-fourths of commercial primary energy consumption throughout the forecast. 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 20 percent of commercial energy consumption in 2000, is projected to maintain that share throughout the forecast. Distillate fuel oil made up only 2 percent of commercial demand in 2000, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate remains at 2 percent in 2020, 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.

Commercial Lighting Is the Sector's Most Important Energy Application

Figure 31. Commercial primary energy consumption by end use, 2000 and 2020 (quadrillion Btu)

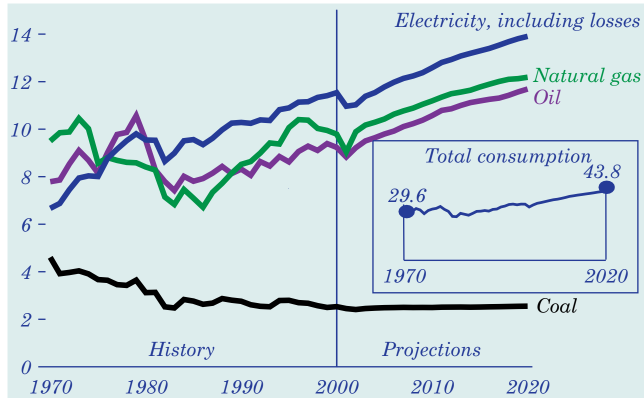


Through 2020, lighting is projected to remain the most important individual end use in the commercial sector [*79*]. Energy use for lighting is projected to increase slightly, as growth in lighting requirements is expected to outpace the adoption of more energy-efficient lighting equipment. Efficiency 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 31).

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 3.7 percent per year and for other office equipment, such as copiers, fax machines, and larger computers, by 4.1 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 2.1 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, service station equipment, and vending machines. Annual growth of 2.3 percent is expected for the "all other" category, slowing somewhat in the later years of the forecast as emerging technologies achieve greater market penetration.

Industrial Energy Use Could Grow by 23 Percent by 2020

Figure 32. Industrial primary energy consumption by fuel, 1970-2020 (quadrillion Btu)

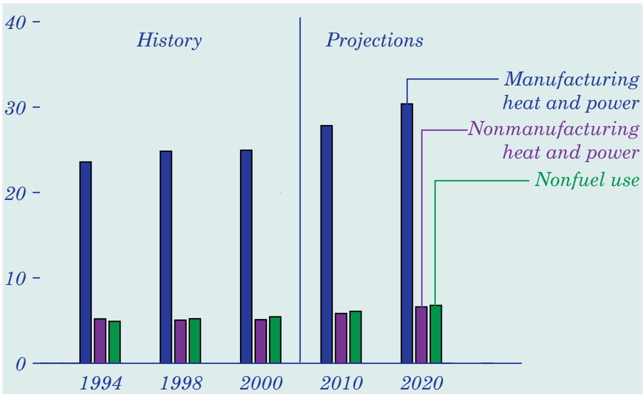


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 33 percent. The natural gas share fell from 32 percent to 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 1.1 percent per year (Figure 32). Electricity (for machine drive and some production processes) and natural gas (given its ease of handling) are the major energy sources for the industrial sector. Industrial delivered electricity use is projected to increase by 32 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 25 percent between 2000 and 2020. Industrial petroleum use is also projected to grow by 27 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 33. Industrial primary energy consumption by industry category, 1994-2020 (quadrillion Btu)



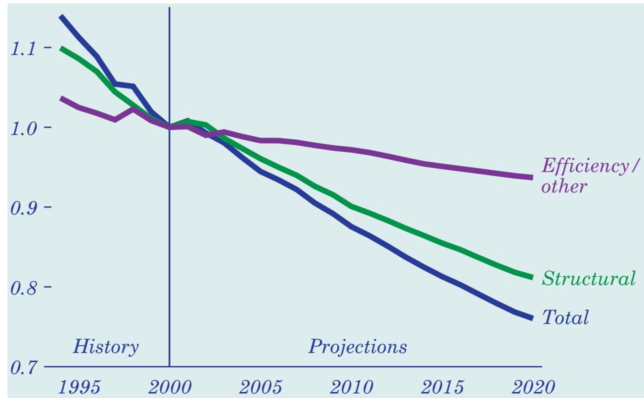
Approximately 70 percent of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing. The remainder is approximately equally distributed between nonmanufacturing heat and power and consumption for nonfuel purposes, such as raw materials and asphalt (Figure 33).

Nonfuel use of energy in the industrial sector is projected to grow more rapidly (1.1 percent per year) than heat and power consumption (1.0 percent per year). The feedstock portion of nonfuel use is projected to grow at a slightly lower rate (0.9 percent per year) than the output of the bulk chemical industry (1.1 percent per year) due to limited substitution possibilities. In 2020, feedstock consumption is projected to be 5.0 quadrillion Btu. Asphalt use, the other component of nonfuel energy use, is projected to grow by 1.6 percent per year, to 1.8 quadrillion Btu in 2020. The construction industry is the principal consumer of asphalt for paving and roofing. Asphalt use does not grow as rapidly as construction output (2.0 percent per year), because not all construction activities require asphalt.

Petroleum refining, chemicals, and pulp and paper are the largest end-use consumers of energy for heat and power in the manufacturing sector. These three energy-intensive industries used 8.9 quadrillion Btu in 2000. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for 60 percent of the 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 34. Industrial delivered energy intensity by component, 1994-2020 (index, 2000 = 1)

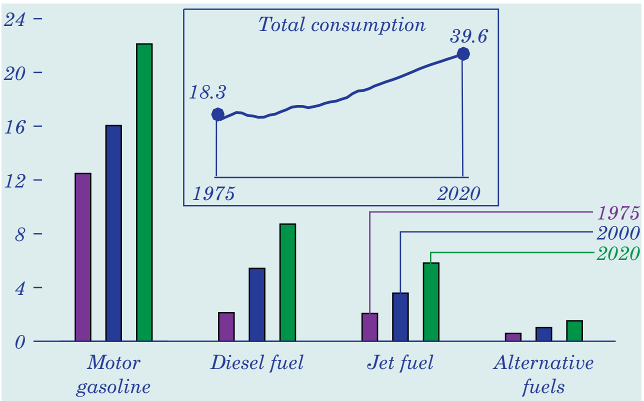


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of manufacturing output. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has dampened growth in industrial energy consumption. Thus, despite a 53-percent increase in industrial output, total energy use in the sector grew by only 8 percent between 1978 and 2000. These basic trends are expected to continue.

Industrial output is projected to grow by 2.6 percent per year from 2000 to 2020. The share of total industrial output attributed to the energy-intensive industries is projected to fall from 22 percent in 2000 to 17 percent in 2020. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial intensity would decline. Figure 34 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*80*]. Over the forecast period, industrial delivered energy intensity is projected to drop by 25 percent, and the changing composition of industrial output alone is projected to result in approximately a 19-percent drop. Thus, three-fourths 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 2 Percent of Light-Duty Vehicle Fuel Use in 2020

Figure 35. Transportation energy consumption by fuel, 1975, 2000, and 2020 (quadrillion Btu)



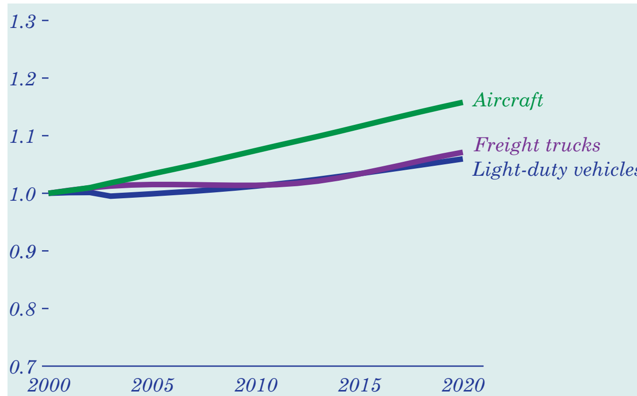
By 2020, total energy demand for transportation is expected to be 39.6 quadrillion Btu, compared with 27.5 quadrillion Btu in 2000 (Figure 35). Petroleum products dominate energy use in the sector. Motor gasoline use is projected to increase by 1.6 percent per year in the reference case, making up 56 percent of transportation energy demand. Alternative fuels are projected to displace about 184,000 barrels of oil equivalent per day [*81*] by 2020 (2 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 2020 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 3.5-percent projected annual increase in air travel, causing jet fuel use to increase by 2.5 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 1.5 percent per year, compared with 1.7 percent per year in the low oil price case.

Average Horsepower for New Cars Is Projected To Grow by 35 Percent

Figure 36. Projected transportation stock fuel efficiency by mode, 2000-2020 (index, 2000 = 1)



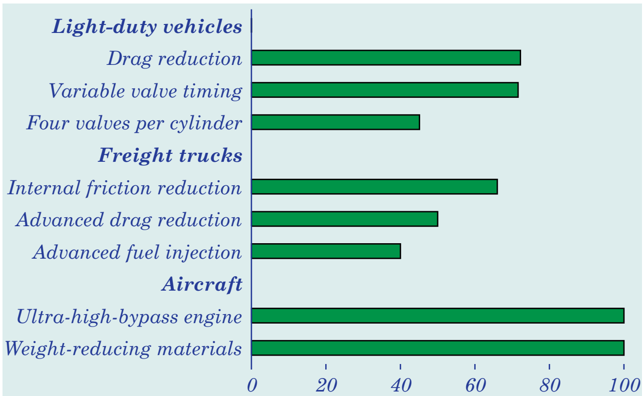
Fuel efficiency is projected to improve at a slower rate through 2020 than it did in the 1980s (Figure 36), with fuel efficiency standards for light-duty vehicles assumed to stay at current levels and projected low fuel prices and higher personal income expected to increase the demand for larger, more powerful vehicles. Average horsepower for new cars in 2020 is projected to be about 35 percent above the 2000 average (Table 8), but advanced technologies and materials are expected to keep new vehicle fuel economy from declining [*82*]. 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 3 miles per gallon, to 27.2 miles per gallon in 2020. A small percentage gain in efficiency is expected for freight trucks (from 5.9 miles per gallon in 2000 to 6.3 in 2020), and a larger gain is expected for aircraft (a 16-percent increase over the forecast period).

Table 8. New car and light truck horsepower ratings and market shares, 1990-2020

	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	175	226	167	186	223
Sales share	0.54	0.34	0.11	0.33	0.32	0.36
2010						
Horsepower	182	211	263	199	231	285
Sales share	0.52	0.36	0.13	0.32	0.33	0.35
2020						
Horsepower	203	227	268	211	242	303
Sales share	0.51	0.35	0.14	0.31	0.34	0.35

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 37. Projected technology penetration by mode of travel, 2020 (percent)



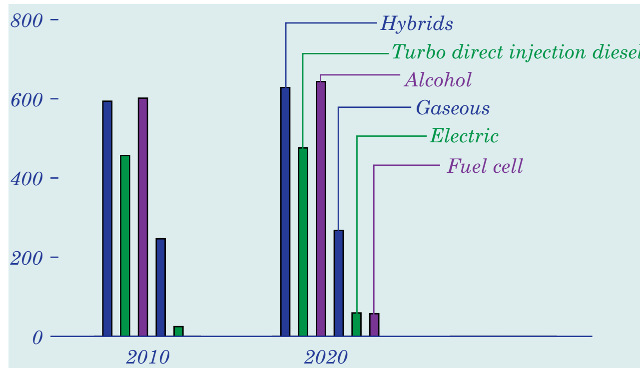
New automobile fuel economy is projected to reach approximately 31.7 miles per gallon by 2020, as a result of advances in fuel-saving technologies (Figure 37). Three of the most promising are advanced drag reduction, variable valve timing, and extension of four valve per cylinder technology to six-cylinder engines, each of which would provide over 8 percent higher fuel economy. 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 2020. Advanced technology penetration is projected to increase new freight truck fuel efficiency from 6.1 miles per gallon to 6.6 miles per gallon between 2000 and 2020.

New aircraft fuel efficiencies are projected to increase by 15 percent from 2000 levels by 2020. 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 12 Percent of Sales by 2020

Figure 38. Projected sales of advanced technology light-duty vehicles by fuel type, 2010 and 2020 (thousand vehicles sold)

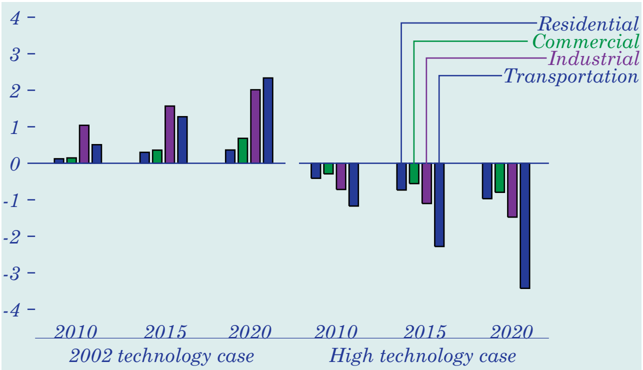


Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 2.1 million vehicle sales per year by 2020 (12 percent of total projected light-duty vehicle sales). Hybrid electric vehicles, introduced into the U.S. market by two manufacturers in 2000, are anticipated to sell well, at about 628,000 units by 2020 (Figure 38). Alcohol flexible-fueled vehicles are expected to lead advanced technology vehicle sales, reaching approximately 644,000 vehicle sales by 2020. Sales of turbo direct injection diesel vehicles are projected to increase to 476,000 units by 2020. These advanced technologies will initially sell for less than $3,000 above an equivalent gasoline vehicle, but only the gasoline hybrid and the turbo direct injection diesel can achieve vehicle ranges that exceed 600 miles while delivering 20 to 30 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 either 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. For a description of the ZEV accounting process for advanced technology vehicles, see "Legislation and Regulations," pages 16-17.

Alternative Cases Analyze Effects of Advances in Technology

Figure 39. Projected variation from reference case primary energy use by sector in two alternative cases, 2010, 2015, and 2020 (quadrillion Btu)



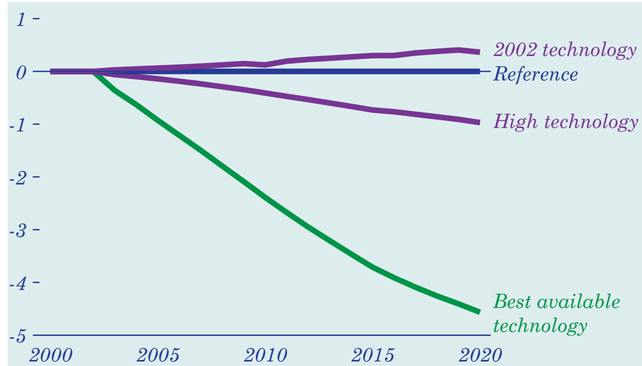
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of these assumptions (Figure 39). The alternative cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or on economic growth.

For the residential and commercial sectors, the 2002 technology case holds equipment and building shell efficiencies at 2002 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 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 2002 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 [*83*].

Advanced Technologies Could Reduce Residential Energy Use by 19 Percent

Figure 40. Projected variation from reference case primary residential energy use in three alternative cases, 2000-2020 (quadrillion Btu)



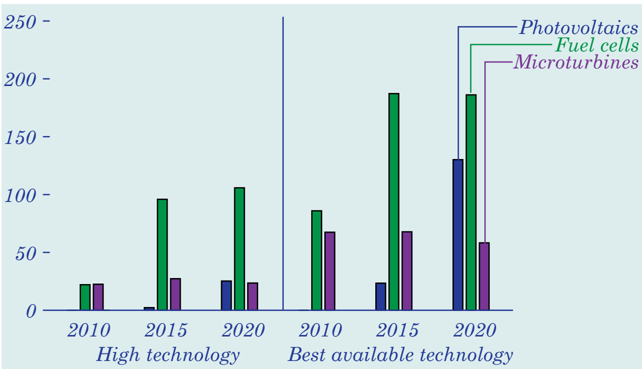
The *AEO2002* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2002 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 2002, 2 percent more energy would be required in 2020 (Figure 40).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected energy use in 2020 is 19 percent lower than in the reference case, and household primary energy use in 2020 is 20 percent lower than in the 2002 technology case. Through 2020, projected additional investment of $270 billion would be necessary to save a projected $136 billion in energy costs in this case [*84*].

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 savings in this case relative to the reference case are projected to reach 4 percent in 2020; 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 41. Buildings sector electricity generation from advanced technologies in alternative cases, 2010-2020 (percent change from reference case)



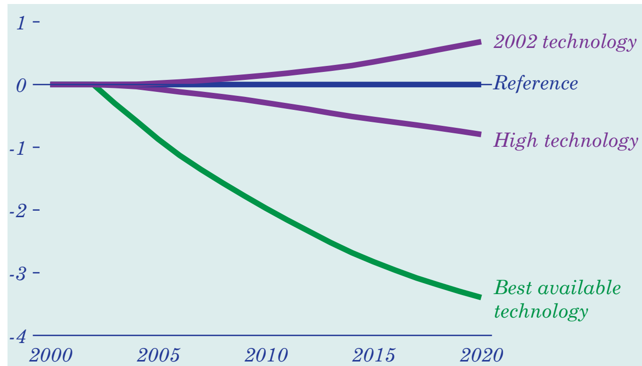
Alternative technology cases for the buildings sectors include a range of assumptions for the availability and market penetration of advanced distributed generation technologies. Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing 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 11 billion kilowatthours (41 percent) more electricity in 2020 than in the reference case, most of which offsets residential and commercial electricity purchases (Figure 41). In the best technology case, projected electricity generation in buildings in 2020 is 22 billion kilowatthours (79 percent) higher than in the reference case. In the 2002 technology case, assuming no further technological progress or cost reductions after 2002, electricity generation in buildings in 2020 is 16 billion kilowatthours (58 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, including residential fuel cells, 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 42. Projected variation from reference case primary commercial energy use in three alternative cases, 2000-2020 (quadrillion Btu)

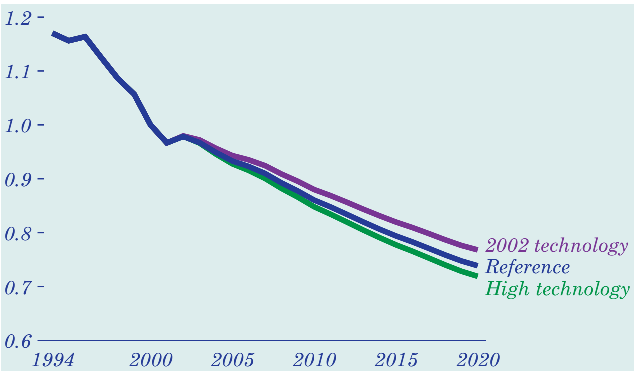


The *AEO2002* reference case incorporates efficiency improvements for commercial equipment and building shells, holding commercial energy intensity to a 0.1-percent annual increase over the forecast. The 2002 technology case assumes that future equipment and building shells will be no more efficient than those available in 2002. 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 2002 technology case is projected to be 3 percent higher than in the reference case by 2020 (Figure 42) as the result of a 0.2-percent annual increase in commercial primary energy intensity. The high technology case projects an additional 3-percent energy savings in 2020, with primary energy intensity falling by 0.1 percent per year from 2000 to 2020. 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 2020. Commercial primary energy intensity in this case is projected to decline more rapidly than in the high technology case, by 0.7 percent per year. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. Commercial solar photovoltaic systems are projected to generate 19 percent more electricity in the best technology case than in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 43. Projected industrial primary energy intensity in two alternative cases, 1994-2020 (index, 2000 = 1)



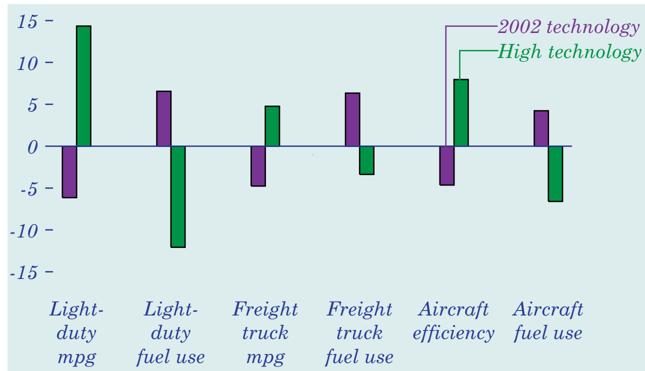
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor. In the reference case, these less energy-intensive industries are projected to grow 53 percent faster than the industrial average (4.0 percent and 2.6 percent per year, respectively).

In the high technology case, 1.5 quadrillion Btu less energy is projected to be used in 2020 than for the same level of output in the reference case. Industrial primary energy intensity is projected to decline by 1.7 percent per year through 2020 in this case, compared with a 1.5-percent annual decline in the reference case (Figure 43). Industrial cogeneration capacity is projected to increase more rapidly in the high technology case (3.5 percent per year) than in the reference case (2.4 percent per year).

In the 2002 technology case, industry is projected to use 2.0 quadrillion Btu more energy in 2020 than in the reference case. Energy efficiency remains at the level achieved by new plants in 2002, but average efficiency still improves as old plants are retired. Aggregate industrial energy intensity is projected to decline by 1.3 percent per year because of reduced efficiency gains. The change in industrial structure is the same in the 2002 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 2.3 percent per year from 2000 through 2020 in the 2002 technology case.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 44. Projected changes in key components of the transportation sector in two alternative cases, 2020 (percent change from reference case)



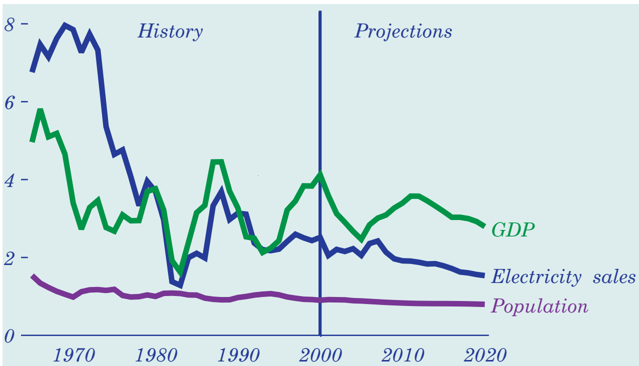
The transportation high technology case assumes lower costs, higher efficiencies, and earlier introduction for new technologies. Projected energy use for transportation is 3.4 quadrillion Btu (9 percent) lower in 2020 than in the reference case, reducing projected carbon dioxide emissions by 66 million metric tons carbon equivalent. About 76 percent (2.6 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 24.0 miles per gallon, as compared with a projected increase to 21.0 miles per gallon in the reference case (Figure 44).

Projected fuel demand for freight trucks in 2020 is 0.3 quadrillion Btu lower in the high technology case than in the reference case, and the projected stock efficiency is 5 percent higher. Advanced aircraft technologies are also projected to improve aircraft efficiency by 8 percent above the reference case projection, reducing the projected fuel use for air travel in 2020 by 0.4 quadrillion Btu.

In the 2002 technology case, with new technology efficiencies fixed at 2002 levels, efficiency improvements can result only from stock turnover. In 2020, the total projected energy demand for transportation is 2.3 quadrillion Btu (6 percent) higher than in the reference case, and projected carbon dioxide emissions are higher by 45 million metric tons carbon equivalent. The average fuel economy of new light-duty vehicles is projected to be 24.6 miles per gallon in 2020 in the 2002 technology case, 2.6 miles per gallon lower than projected in the reference case.

Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 45. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)



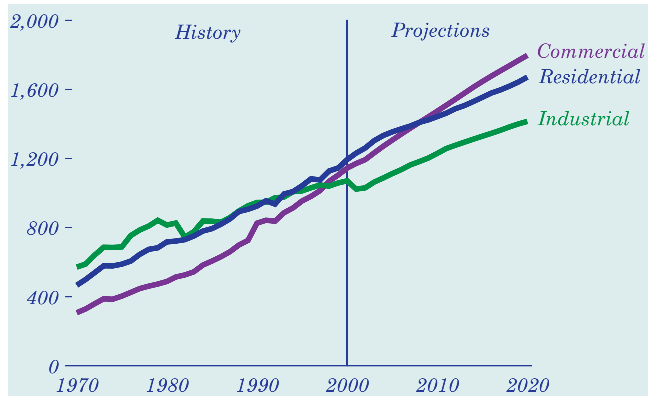
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 45). 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 dampened 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 efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 2000 and 2020, 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 future efficiency gains to some extent.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 46. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



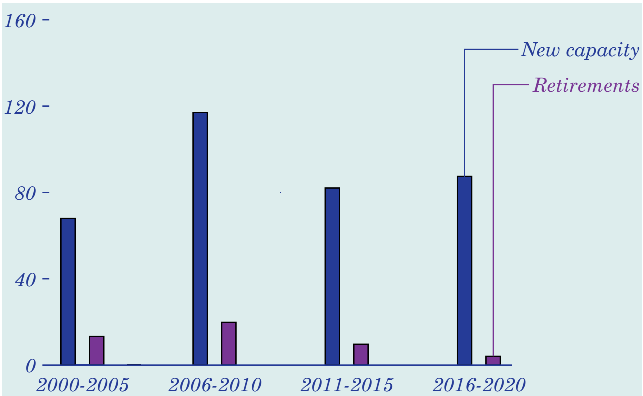
With the number of U.S. households projected to rise by 1.0 percent per year between 2000 and 2020, residential demand for electricity is expected to grow by 1.7 percent annually (Figure 46). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential 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. Although some regions now have surplus baseload capacity, growth in the residential sector is expected to create a need for more "peaking" capacity. Excluding cogeneration, peaking capacity from natural gas turbines and internal combustion engines is projected to increase from 78 gigawatts in 2000 to 178 gigawatts in 2020.

Electricity demand in the commercial and industrial sectors is projected to grow by 2.3 and 1.4 percent per year, respectively, between 2000 and 2020. Projected growth in commercial floorspace of 1.7 percent per year and growth in industrial output of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, cogenerators in 2000 produced 147 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight increase in their share of total generation, increasing their own-use generation to 228 billion kilowatthours as the demand for manufactured products increases.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 47. Projected new generating capacity and retirements, 2000-2020 (gigawatts)



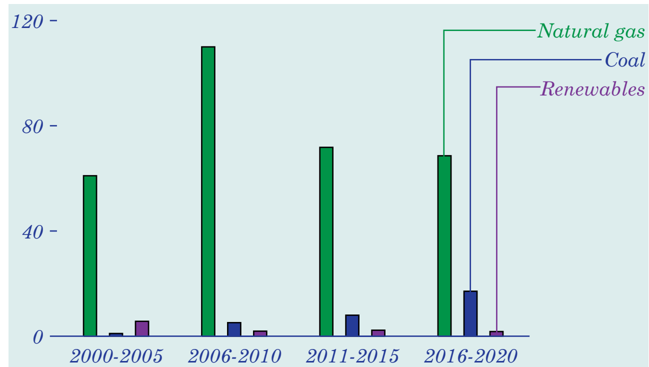
From 2000 to 2020, 355 gigawatts of new generating capacity (excluding cogenerators) is expected to be needed to meet growing demand and to replace retiring units (Figure 47). Between 2000 and 2020, 10 gigawatts (10 percent) of current nuclear capacity and 37 gigawatts (7 percent) of current fossil-fueled capacity [*85*] are expected to be retired, including 20 gigawatts of oil- and natural-gas-fired steam plants, nearly all before 2010. Of the 185 gigawatts of new capacity expected by 2010, 10 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 baseload requirements. Efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 49 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, most (59 percent) of the projected combined-cycle additions are expected before 2010. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become more competitive, and 80 percent of the projected additions of new coal-fired capacity are expected to be brought on line from 2010 to 2020.

As older nuclear power plants age and their operating costs rise, 10 percent of currently operating nuclear capacity is expected to be retired by 2020. More optimistic assumptions about operating costs for existing nuclear units would reduce the projected need for new fossil-based capacity and reduce fossil fuel prices.

Natural Gas Units Are Expected To Dominate New Capacity Additions

Figure 48. Projected electricity generation capacity additions by fuel type, including cogeneration, 2000-2020 (gigawatts)

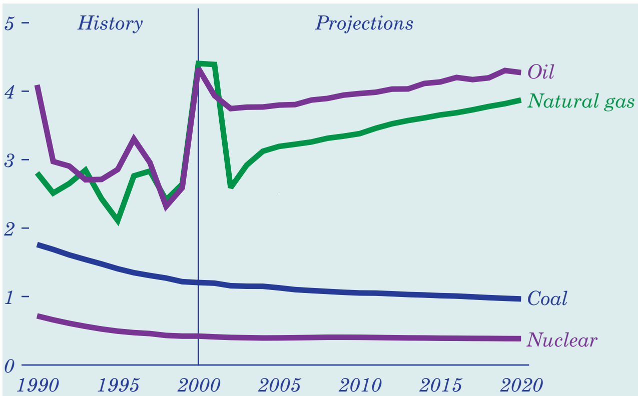


Before building new capacity, electricity generators are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, a total of 355 gigawatts of capacity (excluding cogenerators) is projected to be needed by 2020 to meet growing demand and to offset retirements. Of this new capacity, 88 percent is projected to be combined-cycle or combustion turbine technology, including distributed generation capacity, fueled by natural gas (Figure 48). Both 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 31 gigawatts of new coal-fired capacity is projected to come on line between 2000 and 2020, accounting for almost 9 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 efforts 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 2020—primarily wind, geothermal, and municipal solid waste units. About 19 gigawatts of distributed generation capacity is projected to be added by 2020, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, with higher fuel costs and lower efficiencies, are expected to account for very little of the new capacity in the forecast.

Rising Natural Gas Prices, Falling Coal Prices Are Projected

Figure 49. Fuel prices to electricity generators, 1990-2020 (2000 dollars per million Btu)

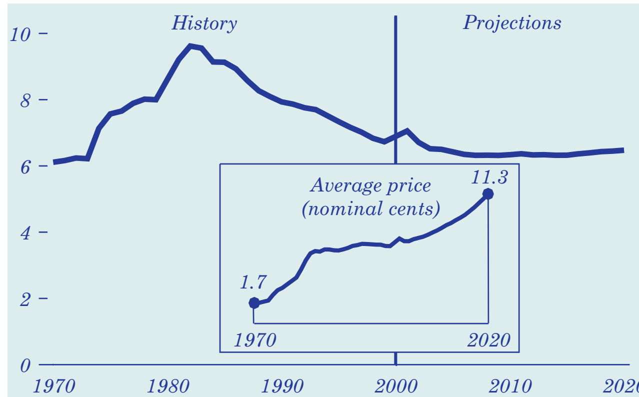


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 2000, fuel costs typically represented $22 million annually—or 76 percent of the total operational costs (fuel and variable operating and maintenance)—for a 300-megawatt coal-fired unit, and $66 million annually—or 93 percent of the total operational costs—for a natural-gas-fired combined-cycle unit of the same size. 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 2.2 percent per year in the forecast, from $2.64 per thousand cubic feet in 2002 to $3.94 in 2020 (Figure 49). 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 2020. Oil prices to utilities are expected to increase by 0.7 percent per year after 2002, leading to a 59-percent decline in oil-fired generation (excluding cogeneration) between 2000 and 2020. Oil currently accounts for only 3 percent of total generation, however, and that share is expected to decline to 1 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Average U.S. Electricity Prices Are Expected To Decline

Figure 50. Average U.S. retail electricity prices, 1970-2020 (2000 cents per kilowatthour)



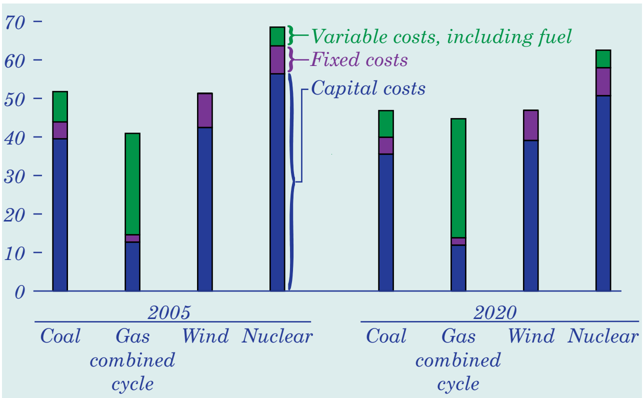
Between 2000 and 2020, the average price of electricity in real 2000 dollars is projected to decline by an average of 0.3 percent per year as a result of competition among electricity suppliers (Figure 50). By sector, projected prices in 2020 are 7, 8, and 3 percent lower than 2000 prices for residential, commercial, and industrial customers, respectively.

Before 2001, 14 States, including California, instituted competition in their retail electricity markets. Both the District of Columbia and Ohio began retail competition in 2001, and Texas and Virginia are scheduled to begin in 2002. Since the beginning of 2000, however, 7 States have delayed the opening of competitive retail markets beyond the dates originally planned, and in fall 2001 California suspended retail competition (see "Legislation and Regulations," pages 11-13).

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 51. Projected levelized electricity generation costs, 2005 and 2020 (2000 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 51). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

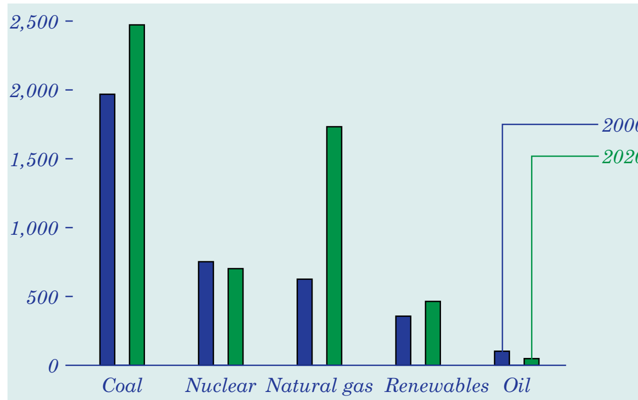
The costs and performance characteristics for new plants are expected to improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project 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 declining by 4 to 13 percent between 2000 and 2010, depending on the technology (Table 9). No further improvement is expected after 2010.

Table 9. Costs of producing electricity from new plants, 2005 and 2020

	2005		2020	
Costs	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2000 mills per kilowatthour			
Capital	39.51	12.71	35.55	11.92
Fixed	4.39	1.90	4.39	1.90
Variable	7.87	26.31	6.89	30.90
Total	**51.77**	**40.92**	**46.83**	**44.72**
	Btu per kilowatthour			
Heat rate	7,469	6,639	6,968	6,350

Gas- and Coal-Fired Generation Grows as Nuclear Plants Are Retired

Figure 52. Projected electricity generation by fuel, 2000 and 2020 (billion kilowatthours)



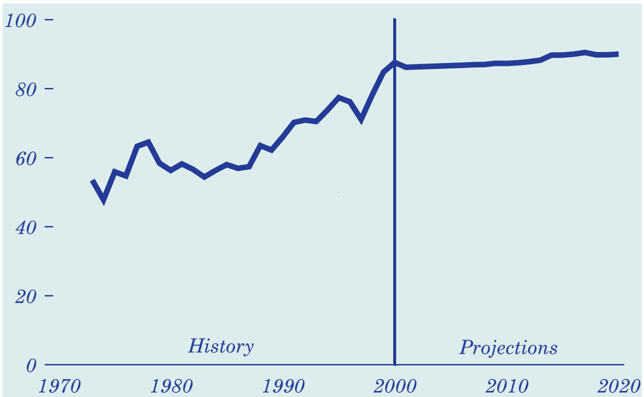
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 52). In 2000, coal accounted for 1,968 billion kilowatthours or 52 percent of total generation, including cogeneration. Although coal-fired generation is projected to increase to 2,472 billion kilowatthours in 2020, increasing gas-fired generation is expected to reduce coal's share to 46 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 before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants are expected to keep coal in its dominant position. By 2020, it is projected that 23 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

Investment in existing plants is expected to make nuclear power a growing source of electricity at least through 2001. As a result of recent improvements in the performance of nuclear power plants, nuclear generation is projected to remain at current levels until 2006, then decline as older units are retired.

In percentage terms, natural-gas-fired generation is projected to show the largest increase, from 16 percent of the total in 2000 to 32 percent in 2020. As a result, by 2004, 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 Operating Performance Is Expected To Improve

Figure 53. Nuclear power plant capacity factors, 1973-2020 (percent)



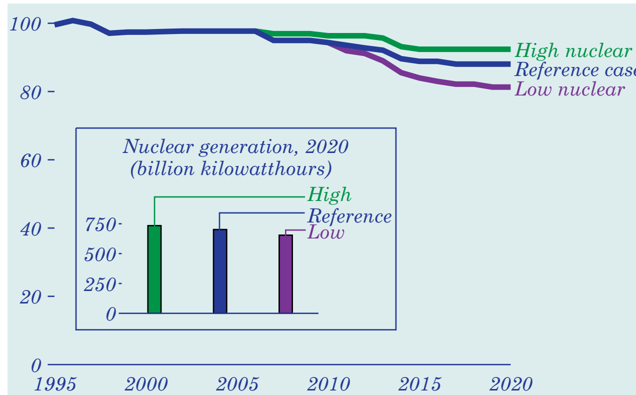
The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2000. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 88 percent in 2000 (Figure 53). It is assumed that performance improvements will continue, to an expected average capacity factor of 90 percent by 2015.

In the reference case, 10 percent of current nuclear capacity is projected to be taken out of service by 2020, primarily as a result of the high costs of maintaining the performance of older nuclear units as compared with the cost of constructing the least expensive alternative. No new nuclear units are expected to become operable between 2000 and 2020, 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. As a result, their operational lifetimes could be either shorter or longer than their current operating licenses. As of October 2001, license renewals for 6 nuclear units had been approved by the U.S. Nuclear Regulatory Commission, and 14 other applications were being reviewed. As many as 24 other 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. In addition, the Bush Administration's National Energy Policy Plan (NEPP) recommends support for the expansion of U.S. nuclear generating capability (see "Legislation and Regulations," pages 17-21).

Nuclear Power Could Be Key to Reducing Carbon Dioxide Emissions

Figure 54. Projected operable nuclear capacity in three cases, 1995-2020 (gigawatts)

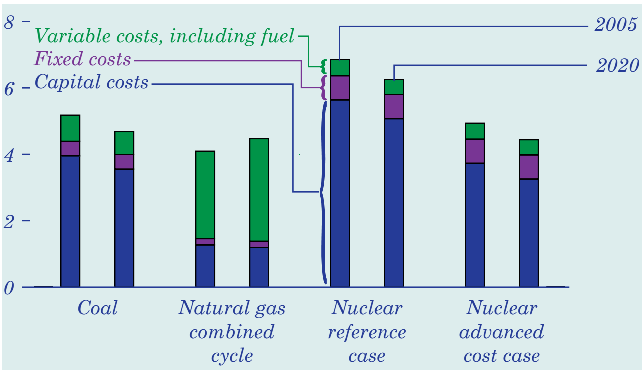


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 54). In the high nuclear case, which assumes that no aging-related capital expenditures will be required, fewer retirements of existing nuclear units are projected before 2020 than in the reference case. Conditions favoring continued operation of existing units could include performance improvements, a solution to the waste disposal problem, and stricter limits on emissions from fossil-fired generating facilities. The low nuclear case assumes that the capital expenditures required for continued operation are higher than assumed in the reference case, leading to the projected retirements of 9 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems.

In the high nuclear case it is projected that 5 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon dioxide emissions are projected to be 3 million metric tons carbon equivalent lower in 2020 than projected in the reference case. In the low nuclear case, 8 gigawatts of new fossil-fired capacity is projected to be built to replace additional retiring nuclear units beyond those projected to be retired in the reference case. The additional new capacity is projected to be made up predominantly of natural-gas-fired units (63 percent) and coal-fired units (37 percent). The additional fossil-fueled capacity is projected to increase carbon dioxide emissions in 2020 by 1 percent above the reference case projection.

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

Figure 55. Projected electricity generation costs by fuel type in the advanced nuclear cost case, 2005 and 2020 (2000 cents per kilowatthour)

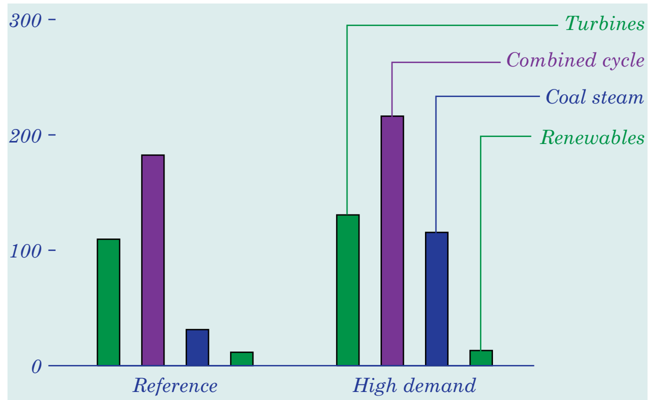


The *AEO2002* reference case assumptions for the cost and performance characteristics of new technologies are based on current estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. The cost assumptions are based on the Westinghouse AP600 advanced passive reactor design. For nuclear power plants, an advanced nuclear cost case analyzes the sensitivity of the projections to lower costs and construction times 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 23 percent initially compared with the reference case and by 33 percent in 2020—and shorter lead times. The advanced case assumes a 3-year lead time, which is a goal of the Office of Nuclear Energy. 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 2020 in the advanced cost case are competitive with the generating costs for new coal- and natural-gas-fired units (Figure 55). A total of 940 megawatts of advanced nuclear capacity is projected to come on line by 2020 in the advanced nuclear cost case. The projections in Figure 55 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. If non-baseload generation is needed, capital-intensive coal and nuclear generating technologies operating at lower capacity factors would be less competitive.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 56. Projected cumulative new generating capacity by type in two cases, 2000-2020 (gigawatts)

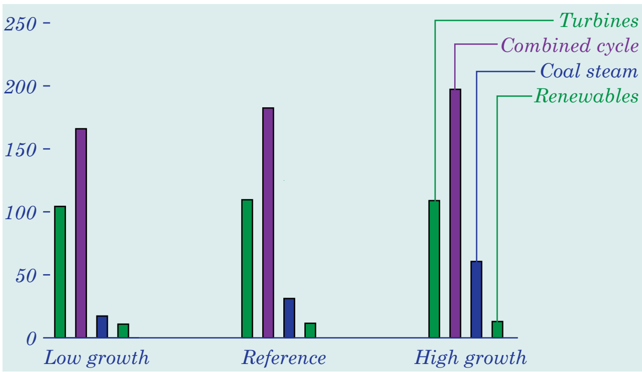


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 2000 and 2020, as compared with the growth rate 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, 147 gigawatts more new generating capacity, excluding cogenerators, is projected to be built between 2000 and 2020 than in the reference case (Figure 56). The shares of coal- and natural-gas-fired capacity additions (including non-coal steam, combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 23 percent and 74 percent, respectively, in the high demand case, compared with 9 and 88 percent in the reference case. Coal consumption is projected to be 19 percent higher in the high demand case than in the reference case, natural gas consumption 6 percent higher, and carbon dioxide emissions 17 percent (131 million metric tons carbon equivalent) higher. More rapid assumed growth in electricity demand also leads to higher projected prices for electricity in 2020, averaging 6.6 cents per kilowatthour in the high demand case, compared with 6.5 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 Advanced Coal-Fired Capacity

Figure 57. Projected cumulative new generating capacity by technology type in three economic growth cases, 2000-2020 (gigawatts)



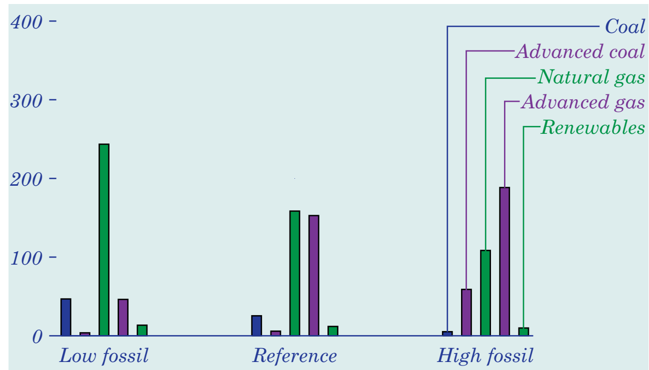
The projected annual average growth rate for GDP from 2000 to 2020 ranges from 3.4 percent in the high economic growth case to 2.4 percent in the low economic growth case. The difference leads to a 10-percent change in projected electricity demand in 2020, with a corresponding difference of 88 gigawatts (excluding cogenerators) 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 6 percent of their current capacity by 2020 as the result of increased operating costs for aging units.

Much 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 coal-fired plants, which make up 62 percent of the projected additional new capacity in the high growth case. The stronger assumed growth also is projected to stimulate additions of natural-gas-fired plants, accounting for 35 percent of the projected capacity increase in the high economic growth case over that projected in the reference case (Figure 57).

Current construction costs for a typical plant range from $456 per kilowatt for combined-cycle technologies to $1,338 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 2000 and 2020, 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 58. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 2000-2020 (gigawatts)

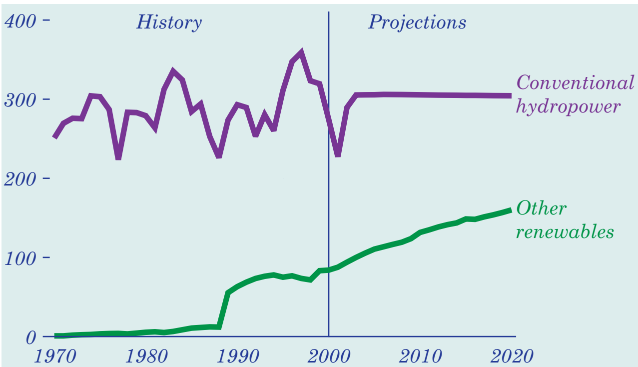


The *AEO2002* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry 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 80 percent to 88 percent across the cases, and the projected mix between current and advanced gas technologies varies significantly (Figure 58). In the low fossil fuel case 16 percent (46 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with 63 percent (188 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 (14 percent and 17 percent) than in the reference case (9 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 59. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

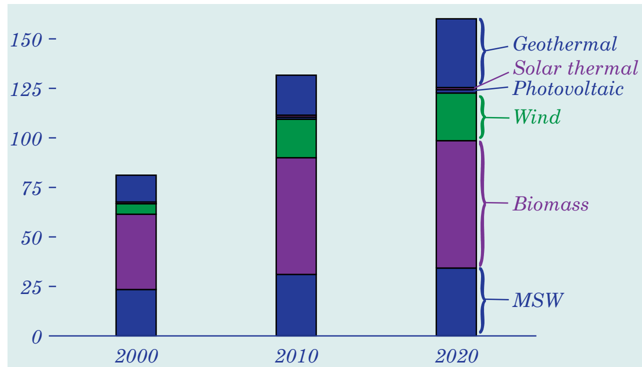


In the *AEO2002* reference case, despite improvements and incentives, grid-connected generators (including cogenerators and distributed generation) that use renewable fuels are projected to remain minor contributors to U.S. electricity supply, increasing from 357 billion kilowatthours of generation in 2000 (9 percent of the total, including cogeneration and distributed generation) to 464 billion (9 percent) in 2020. Lower than normal precipitation in 2000 reduced hydroelectric generation to 276 billion kilowatthours, from 316 billion in 1999. Despite the addition of 610 megawatts of new capacity by 2020, environmental and other requirements are projected to limit conventional hydroelectric generation to 304 billion kilowatthours in 2020, or 6 percent of total electricity supply (Figure 59).

Nonhydroelectric renewables account for 4 percent of projected additions to generating capacity from 2000 to 2020. Generation from nonhydropower renewable energy sources is projected to increase from 81 billion kilowatthours in 2000 (2 percent of both total generation and electricity sales) to 160 billion in 2020 (3 percent of total generation and electricity sales). The largest source of nonhydroelectric renewable generation in the forecast is biomass, including cogeneration and co-firing in coal-fired power plants. Electricity generation from biomass is projected to increase from 38 billion kilowatthours in 2000 to 64 billion kilowatthours (1 percent of total electricity supply) in 2020. Most of the increase (74 percent) is expected to come from cogenerators and a smaller amount from co-firing. Few new dedicated biomass plants are expected to be built.

Biomass and Geothermal Lead Growth in Nonhydro Renewables

Figure 60. Projected nonhydroelectric renewable electricity generation by energy source, 2010 and 2020 (billion kilowatthours)



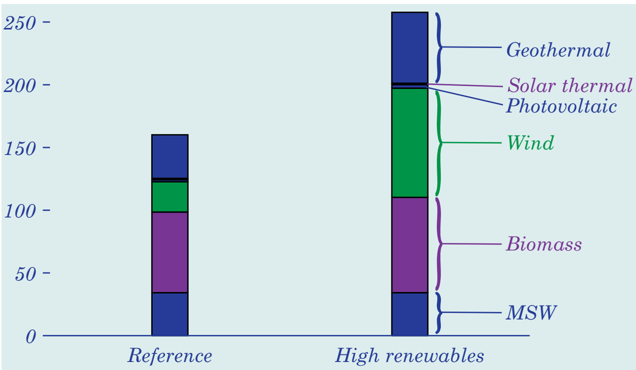
In addition to biomass, significant increases are projected for both geothermal energy and wind power capacity from 2000 to 2020 (Figure 60). High-output geothermal capacity increases by 87 percent in the forecast, to 5 gigawatts, and is projected to provide 35 billion kilowatthours of electricity generation (1 percent of total electricity supply) in 2020. The expansion of geothermal capacity is dependent on the success of several new, untested sites. Wind capacity increases by nearly 300 percent, to 4 gigawatts in 2001 and 9 gigawatts in 2020; and generation from wind plants, many of which are expected to be built in response to State mandates, is projected to increase from 5 billion kilowatthours in 2000 to 24 billion kilowatthours (less than 1 percent of total electricity supply) in 2020. The prospects for wind power are dependent on cost, performance, State and Federal incentives, and environmental preferences.

Electricity generation from municipal solid waste, including both direct firing with solid waste and the use of landfill gas, is projected to increase by 11 billion kilowatthours from 2000 to 2020. No new capacity additions are expected for plants that burn solid waste, but landfill gas capacity is projected to grow by more than 1 gigawatt.

Solar technologies are not expected to make significant contributions to U.S. electricity supplies through 2020. In total, central-station photovoltaic capacity and other grid-connected solar generators at end-use sites are projected to provide 0.05 percent of total electricity generation in 2020 [*86*].

Wind Energy Use Could Gain Most From Cost Reductions

Figure 61. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2020 (billion kilowatthours)

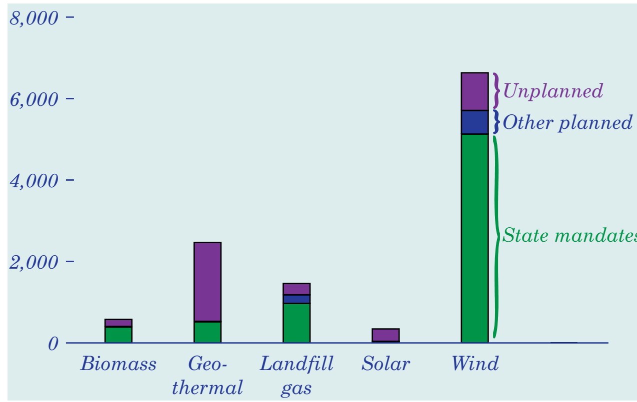


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including lower capital costs, higher capacity factors, and lower operating costs for some technologies [*87*]. The assumptions in the high renewables case approximate the renewable energy technology goals of the U.S. Department of Energy. Fossil and nuclear technology assumptions are not changed from those in 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 258 billion kilowatthours in 2020, compared with 160 billion in the reference case (Figure 61), increasing from 3 percent of total generation to 5 percent. About 63 billion kilowatthours of the projected difference is generated from wind power, 22 billion kilowatthours from baseload geothermal, and 11 billion kilowatthours from industrial cogeneration using biomass. Central-station solar technologies remain too expensive for use in new capacity additions, but the use of small-scale photovoltaics in end-use markets is expected to be slightly higher than in 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 18 million metric tons carbon equivalent (1 percent).

State Mandates Call for More Generation From Renewable Energy

Figure 62. Projected additions of renewable generating capacity, 2001-2020 (megawatts)

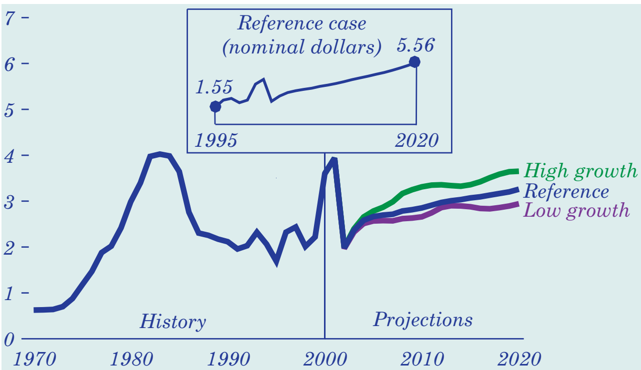


For *AEO2002* it is assumed that State mandates will require total additions of 7,035 megawatts of central-station renewable generating capacity from 2001 through 2020, including 5,129 megawatts of wind capacity, 969 megawatts of landfill gas capacity, 390 megawatts of biomass capacity, 516 megawatts of geothermal capacity, and 31 megawatts of solar (photovoltaic and thermal) capacity (Figure 62).

Estimates available from State implementation plans include new renewable energy capacity resulting from commercial builds, renewable portfolio standards, systems benefits charges, and other mandates. States with renewable fuel mandates or renewable portfolio standards that project significant capacity additions include Texas (2,279 megawatts), California (1,930 megawatts), Nevada (1,148 megawatts), and New Jersey (904 megawatts). Smaller amounts are projected for Massachusetts, Minnesota, Iowa, Wisconsin, and Arizona. The reference case assumes that 3,828 megawatts of new wind capacity required by State mandates after 2002 will be built; however, expectations for wind power are clouded by the current uncertainty about extension of the Federal production tax credit for renewable electricity generation, which expires at the end of 2001 [*88*]. The tax credit, applied to electricity produced from new renewable generators using wind or closed-loop biomass energy for 10 years after the facility has been placed in service, currently is worth 1.7 cents per kilowatthour. (Closed-loop biomass plants use energy crops grown specifically for energy production.) For further discussion of the tax credit and the potential impacts of a 5-year extension, see "Legislation and Regulations," page 14.

Natural Gas Prices Increase in All Economic Growth Cases

Figure 63. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (2000 dollars per thousand cubic feet)



From 1995 to 2000, the wellhead price of natural gas averaged $2.38 per thousand cubic feet (2000 dollars). Relative to that average, the price is expected to increase at an average rate of 1.6 percent per year in the reference case, reaching $3.26 in 2020 (Figure 63). In the low and high economic growth cases, the wellhead natural gas price is projected to increase at average annual rates of 1.1 percent and 2.2 percent, respectively, to $2.94 per thousand cubic feet in 2020 in the low growth case and $3.65 per thousand cubic feet in the high growth case.

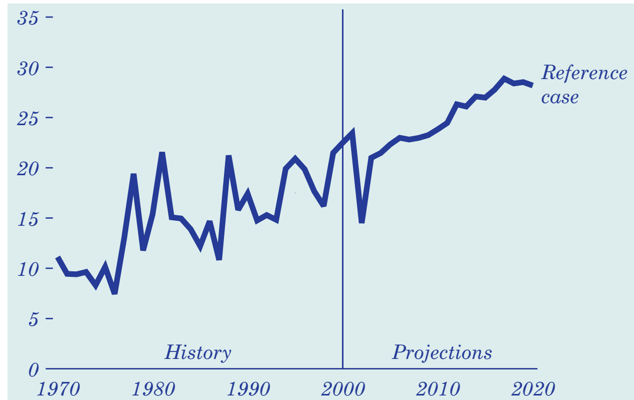
Increasing prices reflect the rising demand for natural gas; the progression of the discovery process from larger, shallower, and more profitable fields to smaller, deeper, and less profitable ones; and increasing production from higher cost sources, such as unconventional natural gas. Projected average growth in production from unconventional sources from 2000 to 2020 ranges from 3.1 to 3.6 percent per year across the cases, compared to a range of 2.0 to 2.2 percent per year for conventional sources. Technically recoverable gas resources (Table 10) are expected to remain more than adequate to meet the projected production increases. The price increases are expected to be tempered by technological progress in both discovering and producing natural gas.

Table 10. Technically recoverable U.S. natural gas resources as of January 1, 2000 (trillion cubic feet)

Proved	167
Unproved	1,023
Total	**1,190**

High Levels of Gas Reserve Additions Are Projected Through 2020

Figure 64. Lower 48 natural gas reserve additions, 1970-2020 (trillion cubic feet)



For most of the past two decades, production of natural gas in the lower 48 States has exceeded reserve additions. That pattern was reversed, however, for most of the period from 1994 through 2000. Only in 1998 did reserve additions fall below production, because of low prices. After 2002, rising prices are expected to result in natural gas reserve additions that exceed production (Figure 64), even as projected production increases.

The projected levels of natural gas reserve additions through 2020 reflect the expected increase in exploratory and developmental drilling (Table 11) that results from increasing natural gas prices. Reserve additions also reflect the assumed productivity gains from technology improvements, which are comparable with those of recent years.

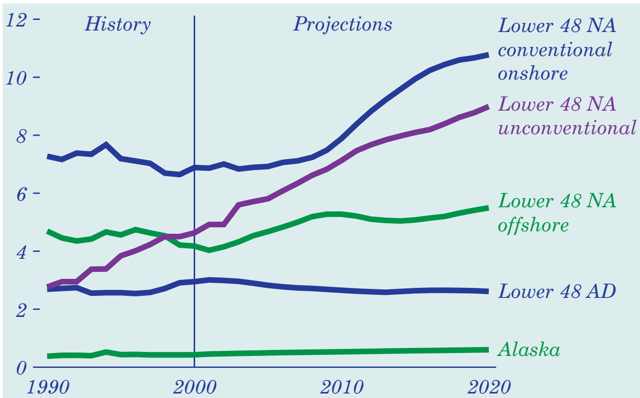
Although reserve additions are expected to fluctuate, they are relatively constant over the last 5 years of the forecast for the three growth cases. In the reference case, reserve additions are expected to average 28.4 trillion cubic feet per year from 2016 through 2020. In the low and high growth cases, projected reserve additions average 27.8 and 29.5 trillion cubic feet per year, respectively.

Table 11. Lower 48 natural gas drilling in three cases, 2000-2020 (thousand successful wells)

	2000	2010	2020
Low growth case		14.7	19.2
Reference case	15.2	15.4	21.7
High growth case		17.2	23.9

Growing Numbers of New Wells Increase Natural Gas Production

Figure 65. Natural gas production by source, 1990-2020 (trillion cubic feet)



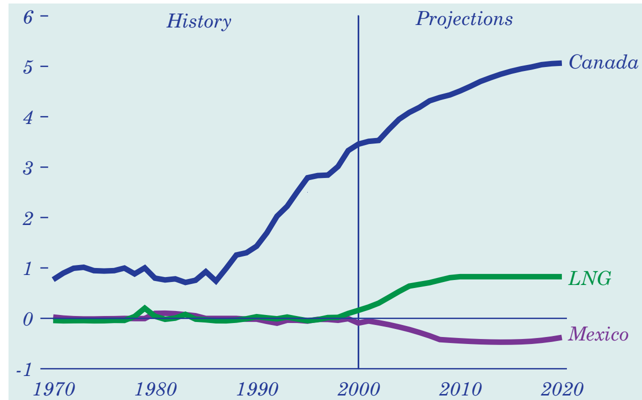
Growth in domestic natural gas production is expected to come primarily from lower 48 onshore nonassociated (NA) sources (Figure 65). Conventional onshore natural gas production is projected to grow rapidly in the last 10 years of the forecast, increasing its share of total lower 48 production from 37 percent in 2000 to 39 percent in 2020. As a result of technological improvements, production from unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly. Unconventional natural gas production is projected to increase from 25 percent of total lower 48 production in 2000 to 32 percent in 2020. Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves declines slightly in the projections, following the expected pattern of crude oil production. AD natural gas is projected to account for 9 percent of lower 48 natural gas production in 2020, compared with 16 percent in 2000.

Offshore production is expected to increase less rapidly, accounting for 24 percent of total lower 48 gas production in 2020. In recent years, innovative cost-saving technologies have been applied, particularly in the deep waters of the Gulf of Mexico, where significant finds are expected to continue.

Alaskan natural gas production is projected to grow by 1.7 percent per year through 2020 to meet expected State demand. Options for marketing the gas outside Alaska include transportation through a pipeline, conversion to liquefied natural gas (LNG), and conversion to synthetic petroleum products (which accounts for 0.9 trillion cubic feet of natural gas consumption in 2020 in the high oil price case).

Net Imports of Natural Gas Grow in the Projections

Figure 66. Net U.S. imports of natural gas, 1970-2020 (trillion cubic feet)



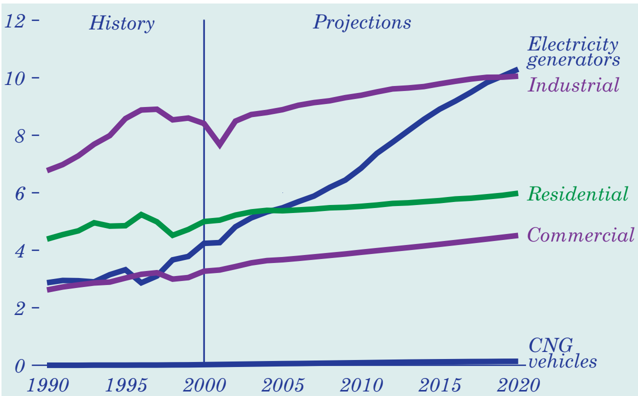
Net imports of natural gas make up the difference between U.S. production and consumption (Figure 66). Imports are generally expected to be priced competitively with domestic sources. Imports from Canada, primarily from western Canada and the Scotian Shelf in the offshore Atlantic, are expected to make up most of the increase in U.S. imports. Because most of the producing regions in Canada are less mature than those in the United States, there is strong potential for low-cost production. Net imports from Canada are projected to provide 15 percent of total U.S. supply in 2020, about the same as in 2000.

LNG imports are expected to increase, but they are not expected to become a major source of U.S. supply through 2020. Two LNG import facilities, at Cove Point, Maryland, and Elba Island, Georgia, have been closed for many years but are expected to reopen by 2002. It is expected that those facilities, plus the other two U.S. facilities, at Everett, Massachusetts, and Lake Charles, Louisiana, will be operating at full capacity by 2010, supplying 0.8 trillion cubic feet per year through 2020.

Although Mexico has a considerable natural gas resource base, trade with Mexico has until recently consisted primarily of exports from the United States. Mexico is projected to remain a net importer of U.S. natural gas through 2020; however, U.S. exports are expected to peak in 2015 and then decline as the infrastructure is developed for Mexican natural gas to meet indigenous demand.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

Figure 67. Natural gas consumption by sector, 1990-2020 (trillion cubic feet)

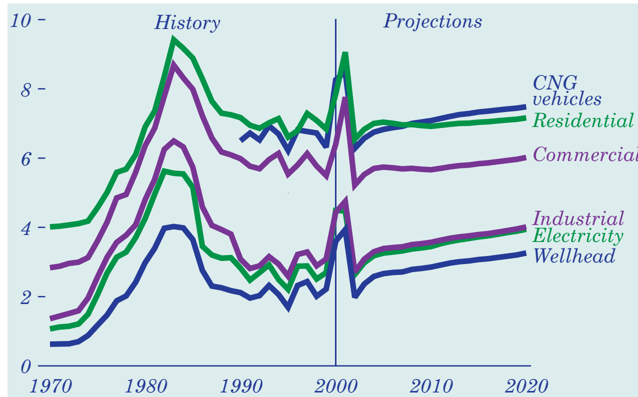


Total natural gas consumption is projected to increase from 2000 to 2020 in all the *AEO2002* cases. The projections for domestic consumption in 2020 range from 32.0 trillion cubic feet per year in the low economic growth case to 35.0 trillion cubic feet per year in the high economic growth case, as compared with an estimated 22.8 trillion cubic feet in 2000. In the reference case, increasing demand by electricity generators (excluding cogenerators) is expected to account for 55 percent of the total consumption growth by 2020 (Figure 67). Demand growth is also expected in the residential, commercial, industrial, and transportation sectors. Most new electricity generation capacity is expected to be fueled by natural gas, and natural gas consumption in the electricity sector is projected to grow rapidly throughout the forecast as electricity consumption increases.

In the reference case, natural gas consumption for electricity generation (excluding cogeneration) is projected to increase from 4.2 trillion cubic feet per year in 2000 to 10.3 trillion cubic feet per year in 2020, an average annual growth rate of 4.5 percent. At the end of the forecast period, electricity generation is expected to surpass the industrial sector as the largest consumer of natural gas. Although coal prices to the electricity generation sector are generally projected to fall throughout the forecast, natural-gas-fired electricity generators are expected to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions.

Delivered Prices Increase More Slowly Than Wellhead Prices

Figure 68. Natural gas end-use prices by sector, 1970-2020 (2000 dollars per thousand cubic feet)



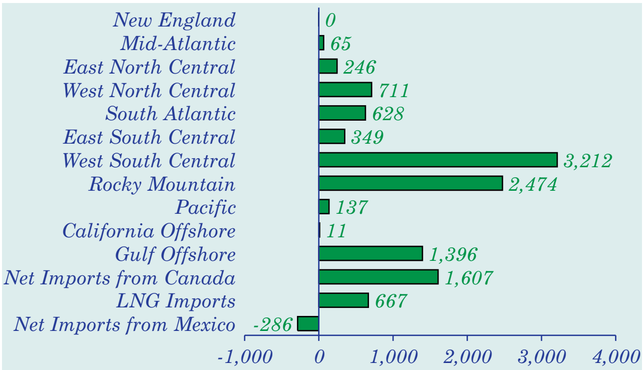
Long-term end-use prices for natural gas are projected to be lower than the relatively high prices experienced in 2000 and 2001. Average transmission and distribution margins are generally expected to remain constant or decline through 2020, moderating the projected increase in wellhead prices. The average end-use price is expected to increase by 35 cents per thousand cubic feet from 2005 through 2020, compared with an increase of 61 cents per thousand cubic feet in the average price of domestic and imported supply in the same period.

Declining margins are particularly important in restraining the rise in both residential and commercial end-use prices (Figure 68). From 2005 through 2020, residential and commercial end-use prices are projected to increase by only 12 cents per thousand cubic feet and 28 cents per thousand cubic feet, respectively.

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 electricity generators reduce their transmission costs by using lower cost interruptible transportation rates during the summer when spare pipeline capacity is available; however, as electricity generators take an increasing share of the market, they are expected to rely on higher cost firm transportation to a greater extent. The highest end-use prices are expected for compressed natural gas vehicles, because the costs of additional infrastructure requirements are expected to be added to pipeline and distribution rates.

Natural Gas Supplies from the West Are Expected To Grow

Figure 69. Projected changes in lower 48 natural gas supply by region and source, 2000-2020 (billion cubic feet)



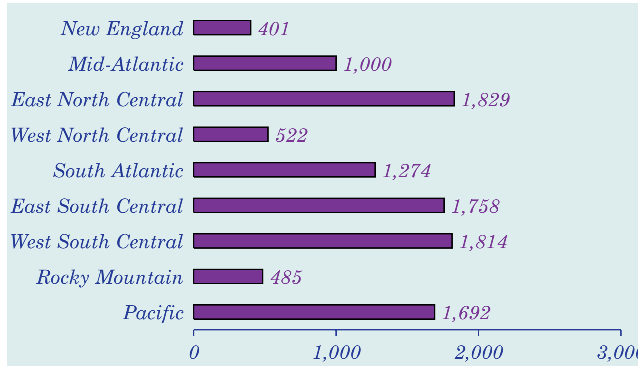
In the reference case, total lower 48 natural gas supplies are projected to grow by 11.2 trillion cubic feet between 2000 to 2020. Lower 48 natural gas production is expected to increase by 9.2 trillion cubic feet, accounting for 82 percent of the total growth in supply, and net imports are projected to increase by 2.0 trillion cubic feet, accounting for the remaining 18 percent.

The traditional onshore natural gas production areas of Louisiana, Oklahoma, and Texas are projected to have the largest growth in lower 48 production between 2000 and 2020, 3.2 trillion cubic feet (Figure 69). The next largest increase in lower 48 natural gas production, 2.5 trillion cubic feet, is projected to come from the Rocky Mountain region, predominantly from unconventional sources. Offshore Gulf of Mexico is expected to account for 1.4 trillion cubic feet of incremental lower 48 supply. Natural gas production from the West North Central region, primarily Kansas, is projected to grow by about 0.7 trillion cubic feet. In the South Atlantic region, Appalachian production is expected to grow by 0.6 trillion cubic feet per year.

Net imports of Canadian natural gas and LNG are expected to provide 1.6 trillion cubic feet and 0.7 trillion cubic feet, respectively, of incremental lower 48 natural gas supplies through 2020. About two-thirds of the growth in LNG imports, 440 billion cubic feet, is expected to be in the South Atlantic region as a result of the reactivation of the Cove Point, Maryland, and Elba Island, Georgia, terminals.

Natural Gas Consumption Is Expected To Increase in All Regions

Figure 70. Projected changes in lower 48 natural gas consumption by region, 2000-2020 (billion cubic feet)

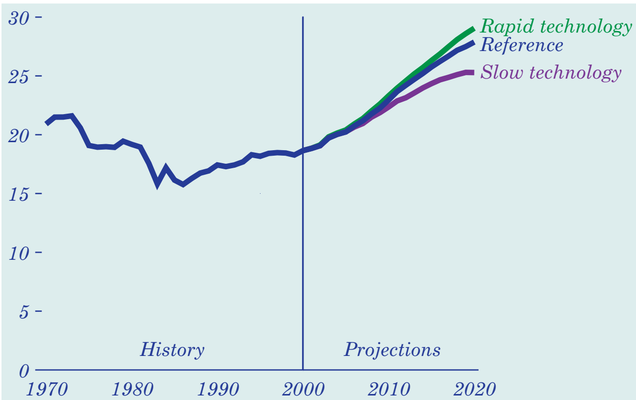


In the reference case, 58 percent of the growth in lower 48 natural gas consumption between 2000 to 2020 is projected to occur East of the Mississippi River, with the remaining 42 percent West of the Mississippi River (Figure 70). In the East, the largest increases in natural gas consumption are expected in the East North Central and East South Central regions, with each region accounting for 1.8 trillion cubic feet of incremental consumption. In the West, natural gas demand in the Pacific and West South Central regions is expected to increase by 1.7 trillion cubic feet and 1.8 trillion cubic feet, respectively. Together, these four regions are projected to account for 66 percent of the total increase in natural gas demand between 2000 to 2020 in the reference case.

Although more than half the increase in natural gas consumption between 2000 to 2020 is expected in the East, the West—including Canadian imports and most of the Gulf Offshore—is expected to provide approximately 80 percent of the incremental lower 48 natural gas supply in the reference case. As a result, most new natural gas pipelines are expected to be built from the West to the East. The exception is expected 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.

Technology Advances Could Improve Finding and Drilling Success Rates

Figure 71. Lower 48 natural gas production in three cases, 1970-2020 (trillion cubic feet)



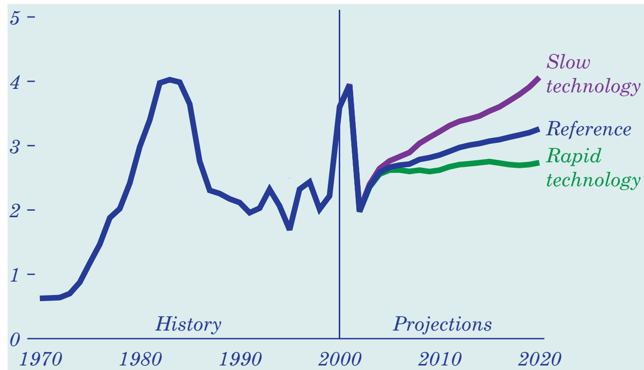
Continued improvements in technology have the potential to result in lower production costs for natural gas from the same resource base. The *AEO2002* reference case assumes that improvements in technology will continue at historic rates. The slow and rapid technology cases assume that the annual rate of technological improvement in production costs, finding rates, and success rates will respectively decrease or increase by 25 percent, relative to the historical rate.

The rapid technology case projects lower wellhead prices for natural gas, higher production, and higher consumption compared to the reference case. The slow technology case has the opposite effect of raising projected prices and lowering both production and consumption. In 2020, total U.S. natural gas production is expected to be 4 percent higher in the rapid technology case and 9 percent lower in the slow technology case than in the reference case (Figure 71). The strongest impacts are for production from unconventional natural gas sources, which are expected to be 15 percent higher in the rapid technology case and 17 percent lower in the slow technology case than in the reference case.

The impacts of the rapid and slow technology assumptions are more significant for natural gas production than for consumption. In 2020, natural gas consumption in the slow technology case is expected to be 8 percent lower than in the reference case.

Natural Gas Price Projections Change With Technology Assumptions

Figure 72. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (2000 dollars per thousand cubic feet)

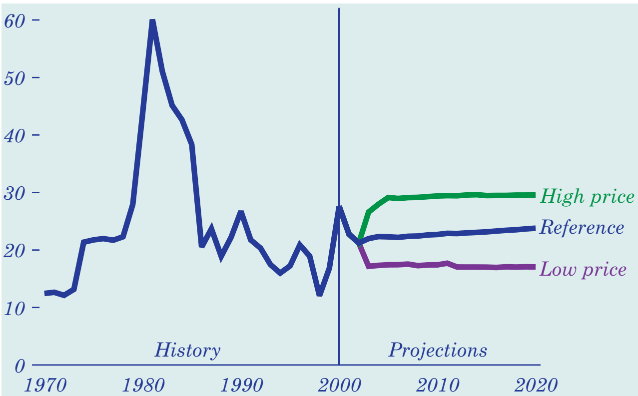


Wellhead natural gas prices are expected to be more sensitive to variation in technological change than are the levels of natural gas production and consumption (Figure 72). The projected price of natural gas supplies reflects the long-run marginal cost of domestic natural gas production and imports, which depends strongly on technological progress. Natural gas production and imports, however, vary across the technology cases only to the extent that demand for natural gas responds to the change in price. Natural gas demand is relatively unresponsive to price changes in the short term but can be more responsive over time as price differences among competing fuels lead to different decisions with regard to purchases of natural-gas-consuming equipment.

Over the projection period, lower 48 natural gas wellhead prices are projected to increase at average annual rates of 1.6 percent per year in the reference case, 2.7 percent in the slow technology case, and 0.7 percent in the rapid technology case, as compared with the average wellhead natural gas price of $2.38 per thousand cubic feet between 1995 and 2000. The slow technology case projects a wellhead price of $4.06 per thousand cubic feet in 2020, which is 25 percent higher than the reference case price of $3.26 per thousand cubic feet in 2020. In the rapid technology case, lower 48 natural gas wellhead prices are projected to remain relatively flat from 2005 through 2020, reaching $2.73 per thousand cubic feet in 2020, which is 16 percent lower than in the reference case.

Oil Prices Are Expected To Remain Above Low 1998 Levels

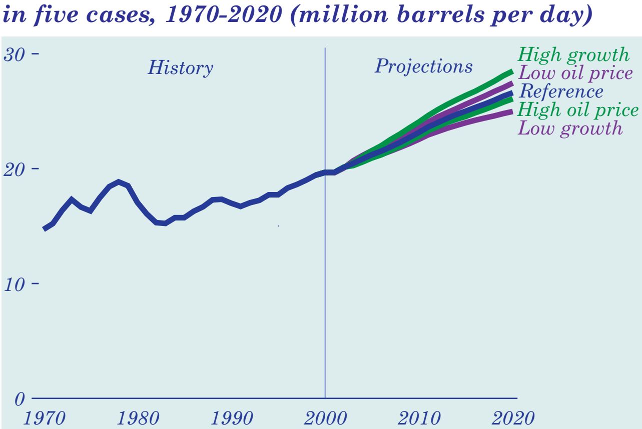
Figure 73. Lower 48 crude oil wellhead prices in three cases, 1970-2020 (2000 dollars per barrel)



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 0.6 percent per year after 2002, to $23.79 per barrel in 2020. The high and low world oil price cases use different assumptions for OPEC production. In the high price case, the lower 48 crude oil price increases by 1.9 percent per year from 2002 to 2020, when it is $29.58 per barrel, or 24 percent higher than in the reference case (Figure 73). In the low price case, the lower 48 price generally declines through 2015, to $17.06 per barrel in 2020.

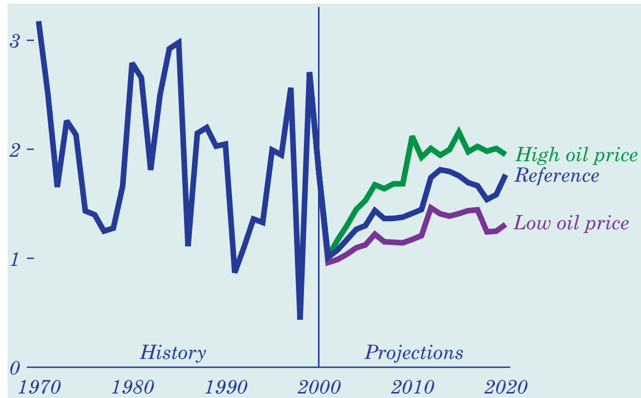
Projected U.S. petroleum consumption varies with crude oil price assumptions, but the largest variation is seen for different assumptions about economic growth. Total consumption in 2020 ranges from 25.0 million barrels per day to 28.5 million in the low and high growth cases, respectively (Figure 74).

Figure 74. U.S. petroleum consumption in five cases, 1970-2020 (million barrels per day)



Projected Oil Reserve Additions Are Sensitive to Oil Price Assumptions

Figure 75. Lower 48 crude oil reserve additions in three cases, 1970-2020 (billion barrels)



Crude oil reserve additions are sensitive to crude oil price projections (Figure 75). In the projections for 2020, lower 48 crude oil reserve additions range from a low of 1.3 billion barrels in the low world oil price case to 2.0 billion barrels in the high world oil price case. Reserve additions associated with enhanced oil recovery techniques are the category most sensitive to variations in projected world oil prices, with lower 48 additions ranging from 142 million barrels in the low oil price case to 423 million barrels in the high oil price case. Crude oil reserve additions reflect the level of oil wells completed during the forecast period (Table 12) and the size of the crude oil resource base (Table 13).

Table 12. Crude oil drilling in three cases, 2000-2020 (thousand successful wells)

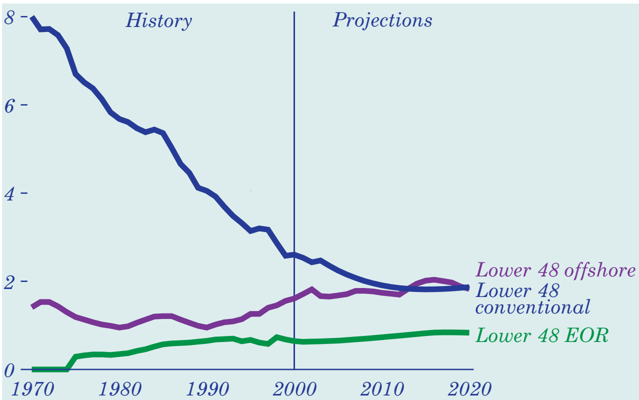
	2000	2010	2020
Low oil price case		4.1	4.2
Reference case	4.7	4.4	4.5
High oil price case		4.9	4.8

Table 13. Technically recoverable U.S. oil resources as of January 1, 2000 (billion barrels)

Proved	23
Unproved	113
Total	**136**

Lower 48 Crude Oil Production Continues To Decline

Figure 76. Lower 48 crude oil production by source, 1970-2020 (million barrels per day)



In the reference case, total lower 48 crude oil production is projected to decline from 2000 to 2012, increase from 2012 to 2016, and then decline again. By 2020, total lower 48 production is expected to be 4.5 million barrels per day, as compared with 4.9 million barrels per day in 2000. In the high oil price case, reserve additions are expected to be sufficient to support increases in lower 48 production over the projection period, reaching 5.3 million barrels per day in 2020. In the low price case, lower 48 crude oil production is projected to decline through 2020 to 3.9 million barrels per day. Production from enhanced oil recovery, which was 0.7 million barrels per day in 2000, is projected to reach 0.8 million barrels per day in the reference case (Figure 76), 0.5 million in the low price case, and 1.2 million in the high price case in 2020 [*89*].

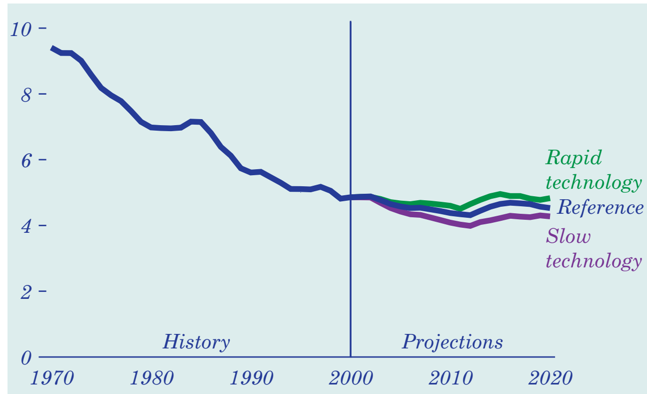
Total offshore production of crude oil was 1.6 million barrels per day in 2000 and is projected to increase to 1.8 million in 2020 in the reference case, 1.6 million in the low price case, and 2.1 million in the high price case. The offshore Gulf of Mexico region is an important production region, and its deepwater development is a major frontier area. Production from the Gulf is expected to increase slightly by 2020 (Table 14). Offshore crude oil reserves are projected to increase as a share of lower 48 oil reserves, from 23 percent in 2000 to 27 percent in 2020.

Table 14. Crude oil production from Gulf of Mexico offshore, 2000-2020 (million barrels per day)

	2000	2010	2020
Shallow	0.7	0.7	0.4
Deep	0.8	0.9	1.2
Total	**1.5**	**1.6**	**1.6**

More Rapid Technology Advances Could Raise Oil Production Slightly

Figure 77. Lower 48 crude oil production in three cases, 1970-2020 (million barrels per day)



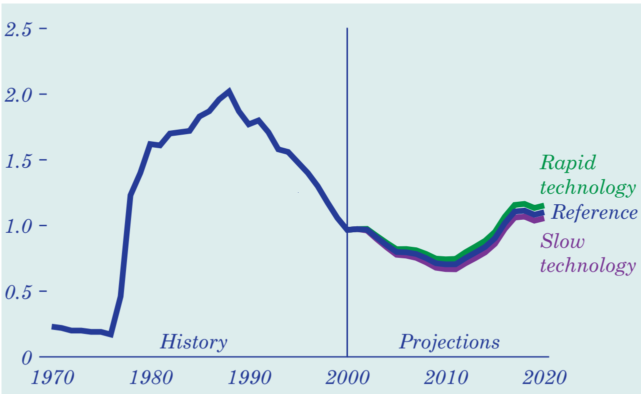
Lower 48 crude oil production is projected to reach 4.8 and 4.3 million barrels per day in 2020 in the rapid and slow technology cases, respectively, compared to 4.5 million barrels per day in the reference case (Figure 77). The technology cases assume the same world oil prices as in the reference case. 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 2020, net petroleum imports are projected to range from 16.0 million barrels per day in the rapid technology case to 17.7 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 the assumed changes in technological progress than onshore production, because large deepwater fields that are not profitable in the slow technology case are expected to become profitable in the rapid technology case. Relative to the reference case, cumulative offshore production from 2000 through 2020 is projected to be 555 million barrels (4 percent) higher in the rapid technology case and 750 million barrels (5 percent) lower in the slow technology case.

Projected lower 48 onshore crude oil production shows a larger variation in volume than does offshore production. Relative to the reference case, cumulative onshore production from 2000 through 2020 is projected to be 753 million barrels (4 percent) higher in the rapid technology case and 1,140 million barrels (5 percent) lower in the slow technology case.

Crude Oil Production in Alaska Is Projected To Rebound

Figure 78. Alaskan crude oil production in three cases, 1970-2020 (million barrels per day)



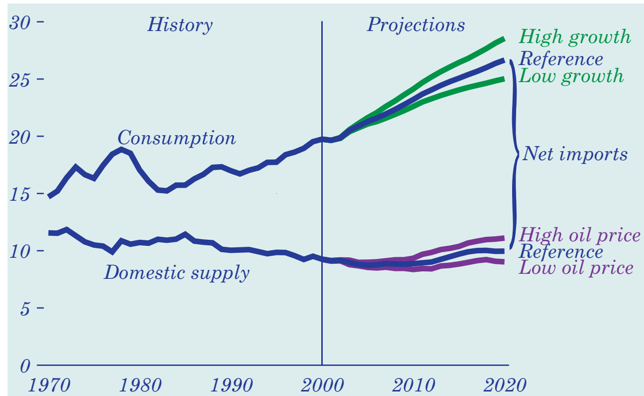
Alaskan crude oil production is expected mainly on the Alaskan North Slope, including the National Petroleum Reserve-Alaska (NPR-A), the State lands surrounding Prudhoe Bay. The first NPR-A lease sale was held on May 5, 1999. Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), *AEO2002* does not project any production from ANWR.

Crude oil production from Alaska is expected to decline to 0.7 million barrels per day in 2010 in the reference case (Figure 78). Projected drops in production from most Alaskan fields, particularly Prudhoe Bay, the State's largest producing field, are expected to be offset by production from the NPR-A, beginning in 2010. 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 1.1 million barrels per day by 2020, 14 percent higher than the 2000 production level. In the reference case, Alaskan crude oil production is projected to decline from 17 percent of total U.S. production in 2000 to 14 percent in 2010 and then to increase to a 20-percent share by 2020.

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 2000 through 2020 is projected to be 254 million barrels (4 percent) higher in the rapid technology case and 235 million barrels (4 percent) lower in the slow technology case.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 79. Petroleum supply, consumption, and imports, 1970-2020 (million barrels per day)



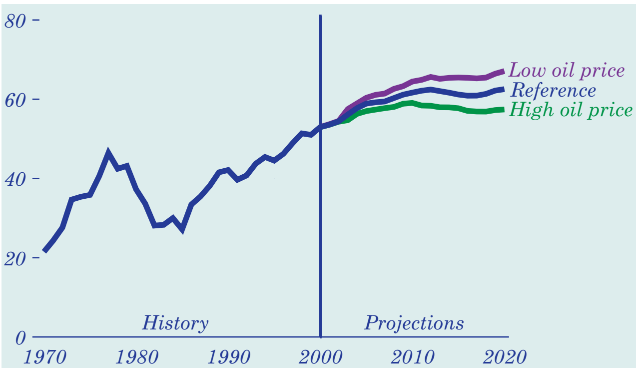
In the reference case, domestic petroleum supply is projected to increase from its 2000 level of 9.3 million barrels per day to 10.0 million barrels per day in 2020 (Figure 79). As U.S. crude oil production falls off, refinery gain and production of natural gas plant liquids are projected to increase. Domestic supply in 2020 is projected to fall to 9.0 million barrels per day in the low oil price case and to rise to 11.1 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 8.8 million barrels per day over the 2000 level in the high growth case, compared with a projected increase of only 5.3 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 low oil price case and the smallest in the high oil price case. The projections for net petroleum imports in 2020 range from a high of 18.4 million barrels per day in the low oil price case to a low of 15.0 million barrels per day in the high oil price case, compared with 16.6 million barrels per day in the reference case, increasing from 10.4 million barrels per day in 2000. The expected value of petroleum imports in 2020 ranges from $130.0 billion in the low world oil price case to $185.8 billion in the high economic growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $139.5 billion (in 2000 dollars) in 1980 [*90*], were $106.5 billion in 2000.

Growing Dependence on Petroleum Imports Is Projected

Figure 80. Share of U.S. petroleum consumption supplied by net imports in three cases, 1970-2020 (percent)



In 2000, net imports of petroleum accounted for 53 percent of domestic petroleum consumption. Continued dependence on petroleum imports is projected, reaching 62 percent in 2020 in the reference case (Figure 80). The corresponding import shares of total consumption in 2020 are expected to be 57 percent in the high oil price case and 67 percent in the low oil price case.

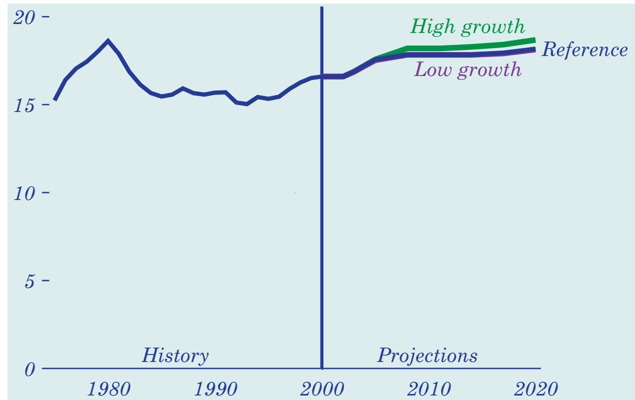
Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 26 percent of net petroleum imports in 2020 in the low economic growth case and 38 percent in the high growth case, compared with 33 percent in the reference case, increasing from a 13-percent share in 2000 (Table 15).

Table 15. Petroleum consumption and net imports in five cases, 2000 and 2020 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
2000	19.7	10.4	9.0	1.4
2020				
Reference	26.7	16.6	11.2	5.4
Low oil price	27.5	18.5	12.4	6.1
High oil price	26.1	15.0	10.1	4.9
Low growth	25.0	15.3	11.3	4.0
High growth	28.5	18.4	11.5	6.9

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

Figure 81. Domestic refining capacity in three cases, 1975-2020 (million barrels per day)



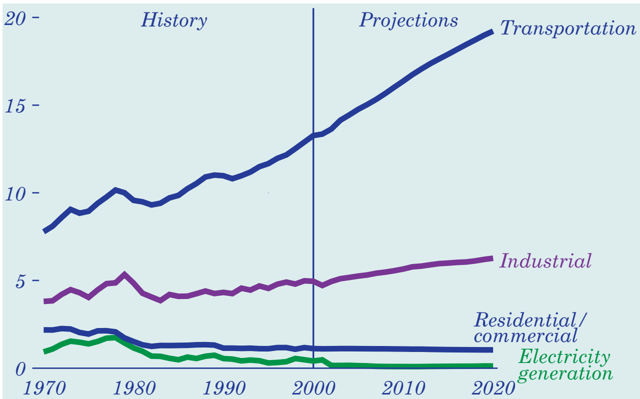
Falling demand for petroleum and deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1995, with 1.6 million barrels per day of distillation capacity added by 2001. Financial and legal considerations make it unlikely 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 *AEO2002* cases (Figure 81).

Distillation capacity is projected to grow from the 2000 year-end level of 16.6 million barrels per day to 18.2 million barrels per day in 2020 in the reference case, 18.1 million in the low economic growth case, and 18.7 million 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 throughout the forecast, in a range of 90 to 94 percent of design capacity. The 2000 utilization rate was 93 percent, well above the rates of 69 to 88 percent in the 1980s and early 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 82. Petroleum consumption by sector, 1970-2020 (million barrels per day)

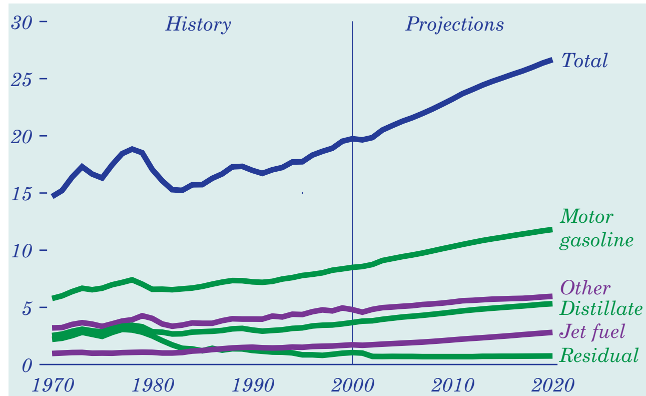


U.S. petroleum consumption is projected to increase by 6.9 million barrels per day between 2000 and 2020. Most of the increase is in the transportation sector (Figure 82), which accounted for two-thirds of U.S. petroleum use in 2000. Petroleum use for transportation increases by 6.0 million barrels per day in the reference case, 4.9 million in the low economic growth case, and 7.1 million in the high economic growth case. In the industrial sector, which currently accounts for 25 percent of U.S. petroleum use, consumption in 2020 is projected to be higher than in 2000 by 1.3 million barrels per day in the reference case, 0.8 million in the low economic growth case, and 2.0 million in the high economic growth case. About 95 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 for both uses and to electricity for heating. Increased oil use for heating and electricity generation is projected, however, in the low oil price case. Natural gas use for home heating is growing in New England, the last stronghold of home heating oil. Compared with 2000, total U.S. heating oil use is projected to be 71,000 barrels per day lower in 2020 in the high price case and 42,000 barrels per day higher in the low 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 cogeneration) is projected to be 340,000 barrels per day lower in 2020 than in 2000 in the high price case and 160,000 barrels per day higher in the low price case.

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

Figure 83. Consumption of petroleum products, 1970-2020 (million barrels per day)

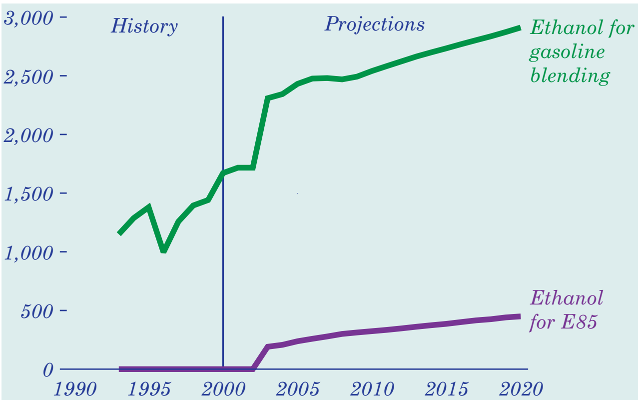


About 94 percent of the projected growth in petroleum consumption stems from increased consumption of "light products," including gasoline, diesel, heating oil, jet fuel, and liquefied petroleum gases, which are more difficult and costly to produce than heavy products (Figure 83). Although refinery investments and enhancements are expected to increase the ability of domestic refineries to produce light products, imports of light products are expected to more than triple by 2020.

In the forecast, gasoline continues to account for almost 45 percent of all the petroleum used in the United States. Between 2000 and 2020, U.S. gasoline consumption is projected to rise from 8.5 million barrels per day to 11.8 million barrels per day. Consumption of distillate fuel is projected to be 1.7 million barrels per day higher in 2020 than it was in 2000, with diesel fuel accounting for 94 percent of the projected increase as demand for freight transportation grows. With air travel also expected to increase, jet fuel consumption is projected to be 1.1 million barrels per day higher in 2020 than in 2000. Consumption of liquefied petroleum gas (LPG), included in "other" petroleum, is projected to increase by about 482,000 barrels per day between 2000 and 2020. Consumption of "other" petroleum products—including petrochemical feedstocks, still gas used to fuel refineries, asphalt and road oil, and other miscellaneous products—is projected to grow by 1.2 million barrels per day. Residual fuel use is projected to decline from 1.1 million barrels per day in 2000 to 750,000 barrels per day in 2020. Most of the projected decline is in residual fuel use for electricity generation.

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

Figure 84. U.S. ethanol consumption, 1993-2020 (million gallons)



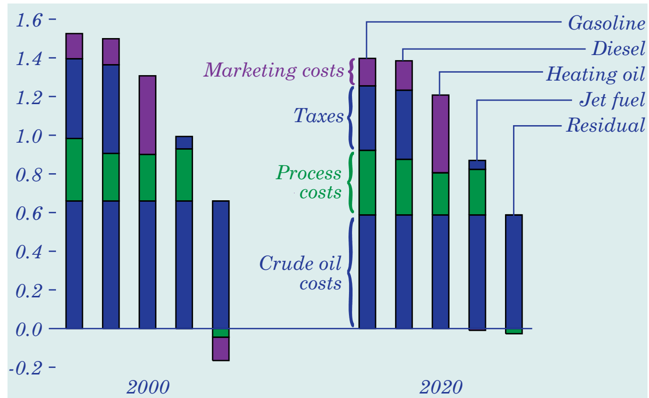
U.S. ethanol production, with corn as the primary feedstock, reached 1.6 billion gallons in 2000. Production is projected to increase to 3.4 billion gallons by 2020 (Figure 84), with more than 40 percent of the growth from the conversion of cellulosic biomass. Ethanol is used primarily in the Midwest 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. Corn-based ethanol production drops at the end of the forecast, from 80 percent of output in 2015 to 38 percent in 2020.

Ethanol is expected to replace MTBE as the oxygenate for reformulated gasoline (RFG) in 13 States that have placed limits on MTBE use 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 3.3 million gallons in 2000 to 450 million gallons in 2020. 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) through 2020.

Refining Costs for Most Petroleum Products Rise in the Forecast

Figure 85. Components of refined product costs, 2000 and 2020 (2000 dollars per gallon)



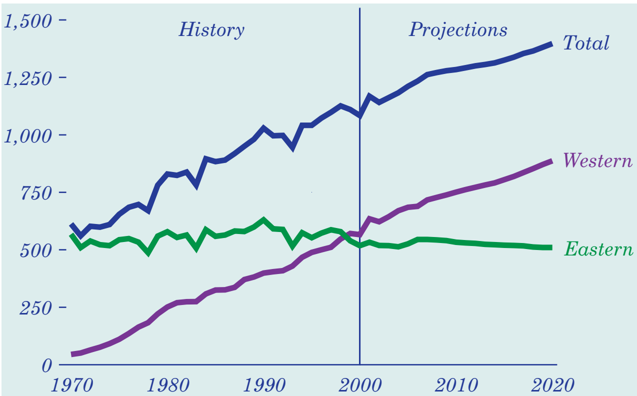
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 85). In the *AEO2002* projection, crude oil costs are projected to continue making the greatest contribution to product prices, and marketing costs are projected 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 1 to 4 cents per gallon from 2000 to 2020. 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 2 to 4 cents per gallon from 2000 to 2020.

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 *AEO2002* assumption of current laws and legislation, Federal motor fuel taxes are assumed to remain at nominal 2000 levels throughout the forecast. Although Federal motor fuel have been raised sporadically 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 2000 dollars between 2000 and 2020—7 cents per gallon for gasoline, 10 cents for diesel fuel, and 1 cent 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 86. Coal production by region, 1970-2020 (million short tons)



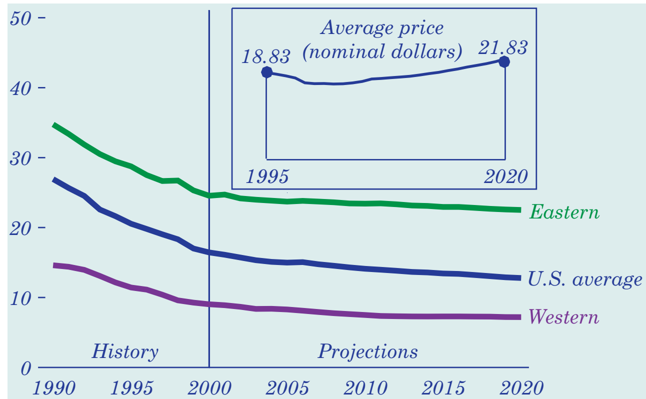
Continued improvements in mine productivity (which have averaged 6.6 percent per year since 1980) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject 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 2000 to 2020, high- and medium-sulfur coal production is projected to remain essentially unchanged, declining from 576 to 571 million tons, and low-sulfur coal production is projected to rise from 509 to 827 million tons (2.5 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 2020 (Figure 86), but its annual growth rate is projected to fall from the 8.8 percent achieved between 1970 and 2000 to 2.3 percent in the forecast period.

Minemouth Coal Prices Continue To Fall in the Projections

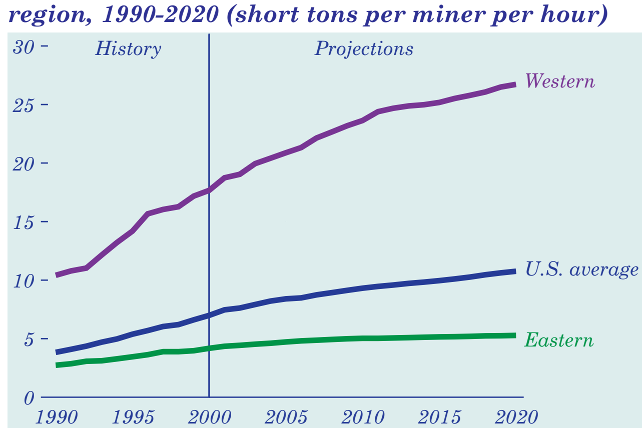
Figure 87. Average minemouth price of coal by region, 1990-2020 (2000 dollars per short ton)



Minemouth coal prices declined by $6.88 per ton (in 2000 dollars) between 1970 and 2000, and they are projected to decline by 1.3 percent per year, or $3.66 per ton, between 2000 and 2020 (Figure 87). The price of coal delivered to electricity generators, which declined by approximately $1.89 per ton between 1970 and 2000, is projected to fall to $19.00 per ton in 2020—a 1.2-percent annual decline.

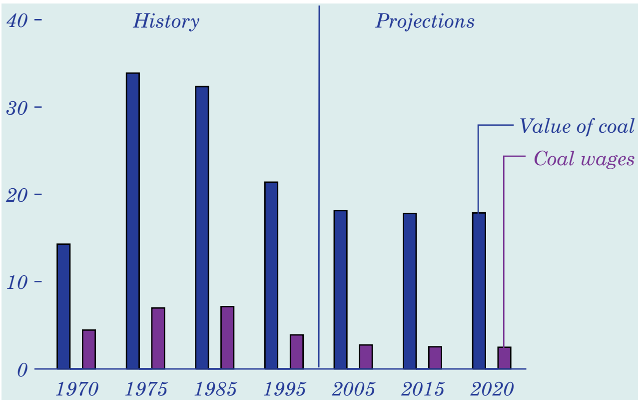
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 88) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 88. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Labor Cost Contribution to Total Coal Prices Continues To Decline

Figure 89. Labor cost component of minemouth coal prices, 1970-2020 (billion 2000 dollars)



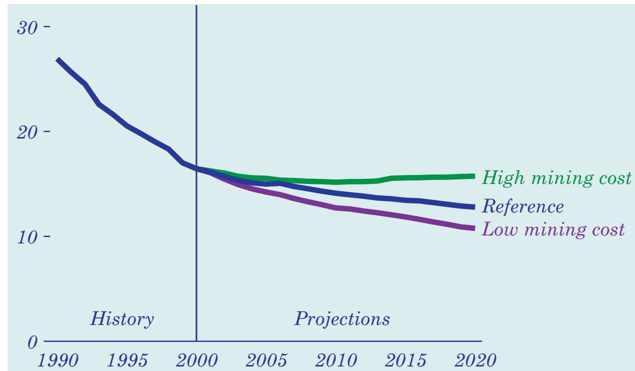
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from low sulfur, low-cost western and 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 2000, the average number of miners working daily fell by 2.2 percent per year. With production increases and productivity improvements expected to continue through 2020, a further decline of 0.9 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 [*91*], which fell from 31 percent to 17 percent between 1970 and 2000, is projected to decline to 14 percent by 2020 (Figure 89).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 90. Average minemouth coal prices in three mining cost cases, 1990-2020 (2000 dollars per short ton)



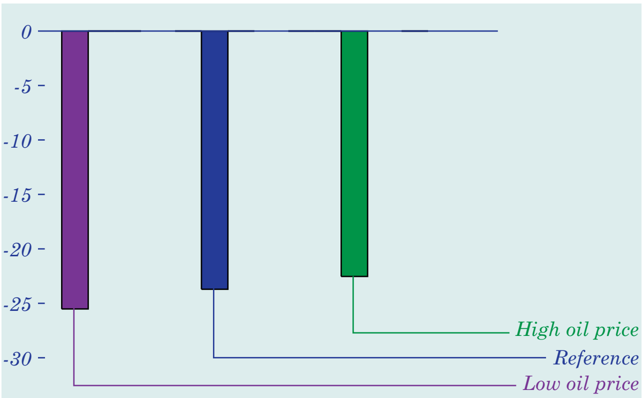
Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production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

Productivity is assumed to increase by 2.2 percent per year through 2020 in the reference case, while wage rates and equipment costs are constant in 2000 dollars. The national minemouth coal price is projected to decline by 1.3 percent per year to $12.79 per ton in 2020 (Figure 90).

In the low mining cost case, productivity is assumed to increase by 3.7 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*92*]. As a result, the average minemouth price is projected to fall by 2.1 percent per year to $10.76 per ton in 2020 (16 percent less than projected in the reference case). Eastern coal production is projected to be 8 million tons higher in the low mining cost case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by 0.6 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 0.2 percent per year to $15.74 per ton in 2020 (23 percent higher than in the reference case). Eastern production in 2020 is projected to be 9 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 91. Projected change in coal transportation costs in three cases, 1999-2020 (percent)

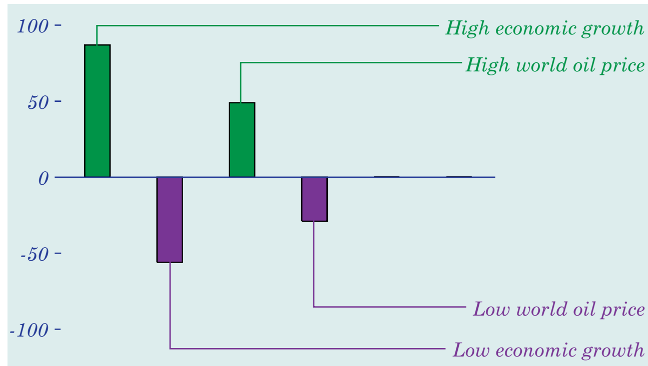


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Increases in fuel costs affect transportation costs (Figure 91), but they are balanced to some extent by improvements in transportation fuel efficiency. As a result, in the reference case, average coal transportation rates are projected to decline by 1.3 percent per year between 1999 and 2020. 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. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Mines in the Powder River Basin will require expansion of their train-loading capacities to meet the increase in demand resulting from the advent of Phase 2 of CAAA90, which became effective on January 1, 2000. The transition will require more low-sulfur coal than was projected in *AEO2001*, because demand for coal is expected to be higher. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary. Coal is transported from the Powder River Basin by two railroad systems, the Burlington Northern Santa Fe Railway and the Union Pacific Railroad.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 92. Projected variation from reference case projections of coal demand for electricity generators in four cases, 2020 (million short tons)

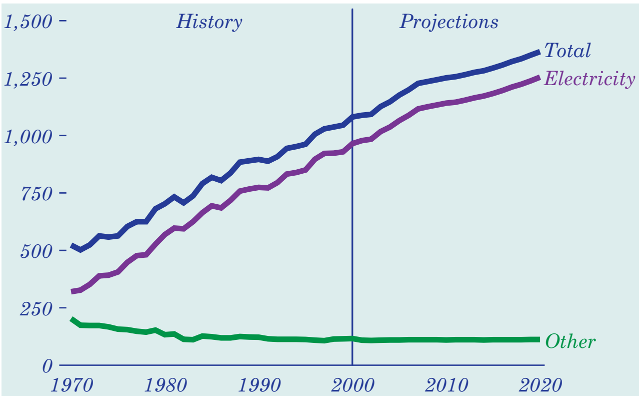


A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 92), with domestic coal consumption in 2020 projected to range from 1,303 to 1,462 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 143 million tons. The difference in total projected coal production between the two economic growth cases is 158 million tons, of which 90 million tons (57 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 remain competitively priced in all regions except the Northeast when its transportation costs are added to its low minemouth price.

The low world oil price case projects 78 million tons less coal use for electricity generation in 2020 than the high world oil price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels. In the high world oil price case, both oil and natural gas prices are expected to be higher than in the reference case. As a result, new additions of coal-fired generating capacity are expected to be higher than in the reference case, as is coal-fired electricity generation, reducing both natural-gas-fired capacity additions and generation from natural-gas-fired plants.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 93. Electricity and other coal consumption, 1970-2020 (million short tons)



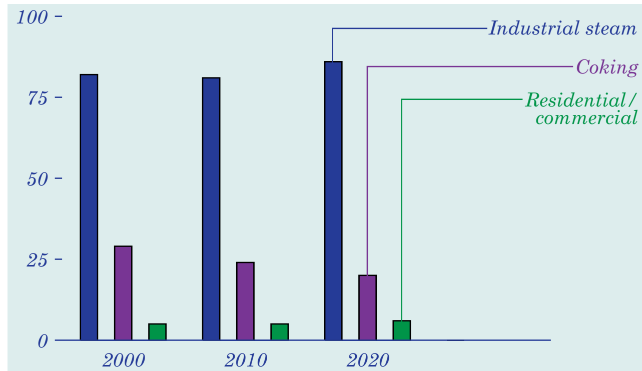
Domestic coal demand is projected to increase by 284 million tons in the reference case forecast, from 1,081 million tons in 2000 to 1,365 million tons in 2020 (Figure 93), because of projected growth in coal use for electricity generation. Coal demand in other domestic end-use sectors is projected to decline.

Coal consumption for electricity generation (excluding cogeneration) is projected to increase from 965 million tons in 2000 to 1,254 million tons in 2020 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 72 percent in 2000 to 84 percent in 2020. 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 2020, rising natural gas costs, increasing demand for electricity, and retirements of existing nuclear and 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 94. Projected coal consumption in the industrial and buildings sectors, 2010 and 2020 (million short tons)



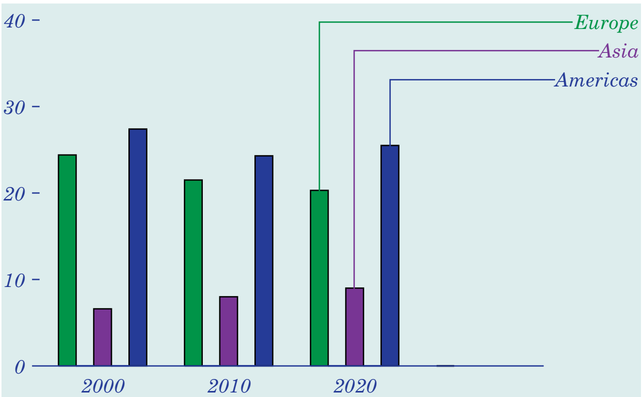
In the non-electricity sectors, a projected increase of 4 million tons in industrial steam coal consumption between 2000 and 2020 (0.2-percent annual growth) is expected to be offset by a decrease of 9 million tons in coking coal consumption (Figure 94). Increasing consumption of industrial steam coal 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 1.9 percent per year through 2020, but domestic production of coking coal is expected to be stabilized, in part, by sustained levels of export demand.

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 Asia Are Projected To Remain Stable

Figure 95. Projected U.S. coal exports by destination, 2010 and 2020 (million short tons)



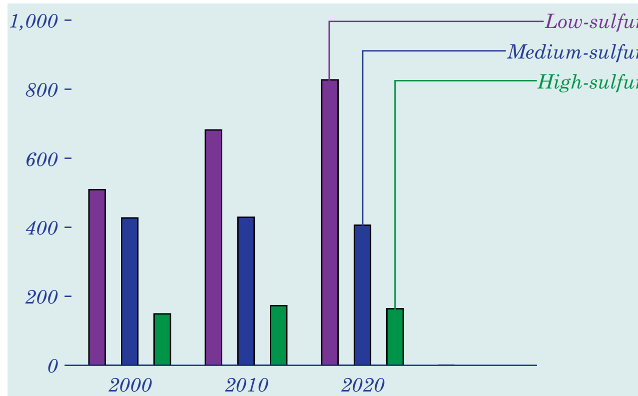
U.S. coal exports declined sharply between 1998 and 1999, from 78 million tons to 58 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 55 million tons by 2020 (Figure 95). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

The U.S. share of total world coal trade is projected to decline from 10 percent in 2000 to 8 percent by 2020 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 2000 to 2020, U.S. steam coal exports are projected to decline from 26 million tons to 20 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 increase slightly, from 33 million tons in 2000 to 35 million tons in 2020. A small increase in the world trade in coking coal is expected, primarily in Asia. Australia is expected to capture an increasing share of the international market for coking coal because of its proximity to Asian importers and its ample reserves of coking coal.

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

Figure 96. Projected coal production by sulfur content, 2010 and 2020 (million short tons)



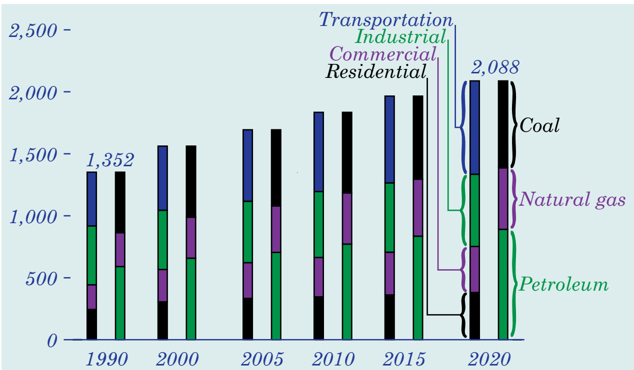
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing units serving generators over 25 megawatts capacity and all new units [*93*].

With relatively modest capital investments many generators can blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. 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. (The proceeds of such sales can be seen as further reducing fuel costs for the seller.) 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 96). 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 may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly mercury and carbon dioxide emissions from coal combustion are monetized and added to the costs of coal combustion. See "Issues in Focus," pages 37-50, for discussion of EIA analyses of multi-emissions reductions.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 97. Projected carbon dioxide emissions by sector and fuel, 2005-2020 (million metric tons carbon equivalent)



Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2000 to 2020, to 2,088 million metric tons carbon equivalent (Figure 97), and emissions per capita are projected to grow by 0.6 percent per year.

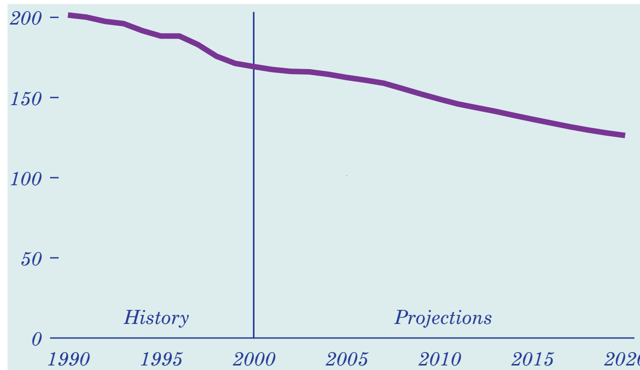
Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.1 percent per year, reflecting the ongoing trends of electrification and penetration of computers, electronics, and appliances. Significant 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 1.8 percent per year.

In the transportation sector, carbon dioxide emissions are projected to grow at an average annual rate of 1.9 percent as a result of projected increases in vehicle-miles traveled and freight and air travel, with small increases in average vehicle efficiency. Industrial emissions are projected to grow by 1.0 percent per year, as shifts to less energy-intensive industries and efficiency gains are projected to moderate growth in energy use.

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 98. Projected carbon dioxide emissions per unit of gross domestic product, 1990-2020 (metric tons carbon equivalent per million dollars)



Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2020, petroleum is projected to account for 891 million metric tons carbon equivalent, a 43-percent share of the projected total. About 82 percent (731 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use, which could be reduced with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

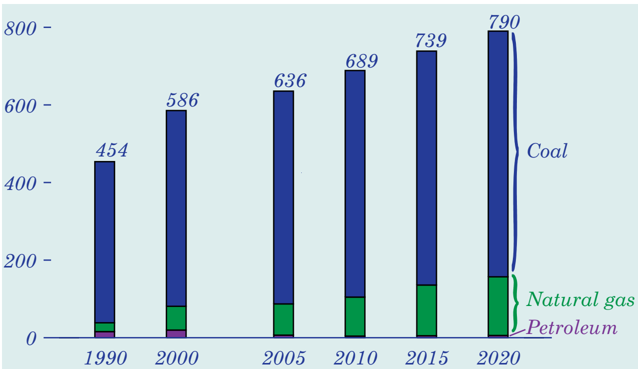
Coal is the second leading source of carbon dioxide emissions, projected to produce 701 million metric tons carbon equivalent in 2020, or 34 percent of the total. The coal share is projected to decline from 37 percent in 2000, because coal consumption is expected to increase at a slower rate through 2020 than consumption of petroleum and natural gas. Most of the increases in emissions from coal use result from electricity generation.

In 2020, natural gas use is projected to produce a 24-percent share of total carbon dioxide emissions, 496 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at an average annual rate of 2.0 percent; but natural gas produces only half the emissions of coal per unit of input.

As the economy becomes more energy-efficient, its carbon intensity also declines. Between 2000 and 2020, the carbon intensity of the economy is expected to decline at an average rate of 1.5 percent per year (Figure 98).

Electricity Use Is Another Major Cause of Carbon Dioxide Emissions

Figure 99. Projected carbon dioxide emissions from electricity generation by fuel, 2005-2020 (million metric tons carbon equivalent)



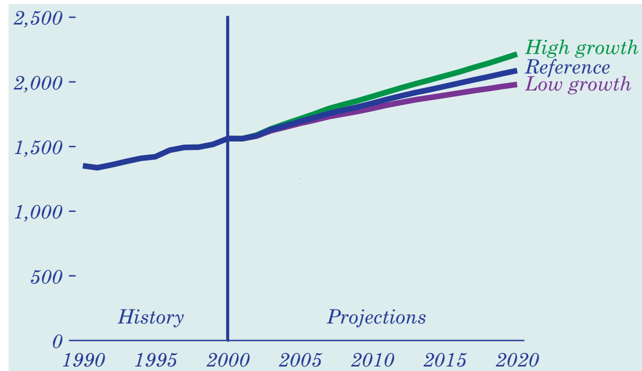
Electricity generation is a major source of carbon dioxide emissions. Although electricity produces no emissions at the point of use, generation (excluding cogeneration) accounted for 38 percent of total carbon dioxide emissions in 2000, and its share is expected to remain the same in 2020. Coal is projected to account for 49 percent of electricity generation in 2020 (excluding cogeneration) and to produce 80 percent of electricity-related carbon dioxide emissions (Figure 99). In 2020, natural gas is projected to account for 28 percent of electricity generation (excluding cogeneration) but only 19 percent of electricity-related carbon dioxide emissions.

Between 2000 and 2020, 10 gigawatts of nuclear capacity is projected to be retired, resulting in a 7-percent decline in nuclear generation. To make up for the loss of nuclear capacity and meet rising demand, 342 gigawatts of new fossil-fueled capacity (excluding cogeneration) is projected to be needed. Increased generation from fossil fuels is expected to raise carbon dioxide emissions from electricity generation (excluding cogeneration) by 204 million metric tons carbon equivalent, or 35 percent, from 2000 levels. Generation from renewable technologies (excluding cogeneration) is projected to increase by 86 billion kilowatthours, or 27 percent, between 2000 and 2020 but is not expected to be sufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation.

Emissions Projections Change With Economic Growth Assumptions

Figure 100. Projected carbon dioxide emissions in three economic growth cases, 1990-2020 (million metric tons carbon equivalent)



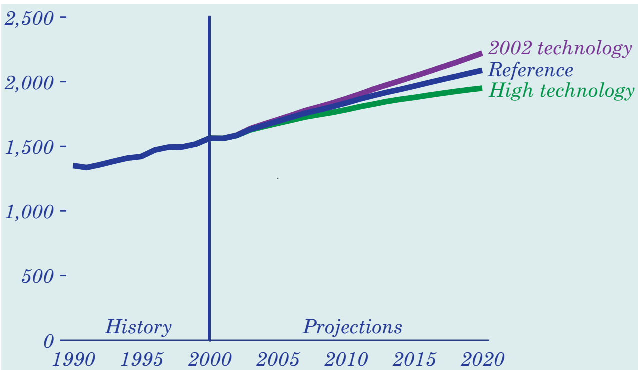
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.4 percent per year from 2000 to 2020, as compared 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 2.4 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 138.2 quadrillion Btu in 2020, 6 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to reach 2,215 million metric tons carbon equivalent in 2020, also 6 percent higher than in the reference case (Figure 100). 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 and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock.

In the low growth case, energy consumption reaches 124.1 quadrillion Btu in 2020, 5 percent lower than projected in the reference case, and carbon dioxide emissions in 2020 are also 5 percent lower at 1,980 million metric tons carbon equivalent. Energy intensity is projected to decline at a rate of 1.3 percent annually through 2020 in the low growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 101. Projected carbon dioxide emissions in three technology cases, 1990-2020 (million metric tons carbon equivalent)

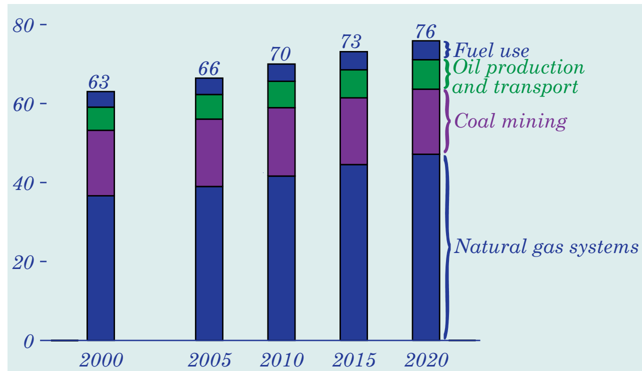


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, 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 [*94*]. Energy intensity is expected to decline on average by 1.8 percent per year through 2020 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 2020, at 123.5 quadrillion Btu, and carbon dioxide emissions are projected to be 7 percent lower than in the reference case, at 1,950 million metric tons carbon equivalent (Figure 101).

The 2002 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2002; that new building shell and plant efficiencies will remain at their 2002 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2002 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 2020. Energy consumption reaches 136.9 quadrillion Btu in 2020 in the 2002 technology case, and carbon dioxide emissions in 2020 are projected to be 6 percent higher than in the reference case, at 2,221 million metric tons carbon equivalent.

Moderate Growth in Methane Emissions Is Expected

Figure 102. Projected methane emissions from energy use, 2005-2020 (million metric tons carbon equivalent)

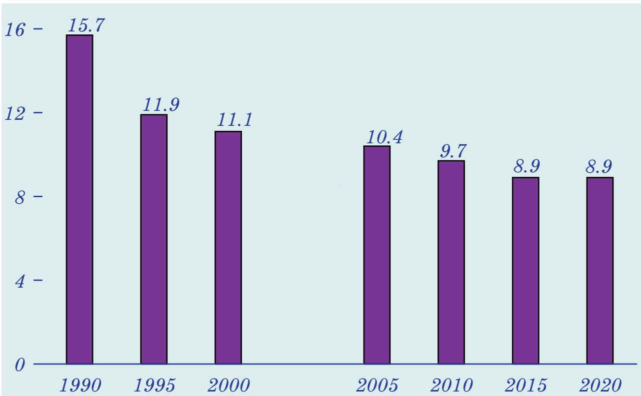


Methane emissions from energy use are projected to increase at an average rate of 0.9 percent per year from 2000 to 2020, somewhat slower than the 1.5-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered in the Kyoto Protocol. In 2000, methane accounted for 9 percent of total U.S. greenhouse gas emissions of 1,906 million metric tons carbon equivalent. About a third of U.S. methane emissions are related to energy activities, mostly from energy production and transportation and to a much smaller extent from 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 102). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase, despite declines in the average rate of emissions per unit of production. Emissions related to oil production and, to a lesser extent, refining and transport are also expected to increase. Coal-related methane emissions are expected to decline, with coal production from methane-intensive underground mining projected to remain flat over the forecast period while progress in the recovery of vented gas continues. About 6 percent of methane emissions in 2000 resulted from wood and fossil fuel combustion. A 22-percent increase is projected by 2020, with residential use of wood as a fuel expected to remain at about its 2000 level.

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 103. Projected sulfur dioxide emissions from electricity generation, 2000-2020 (million tons)



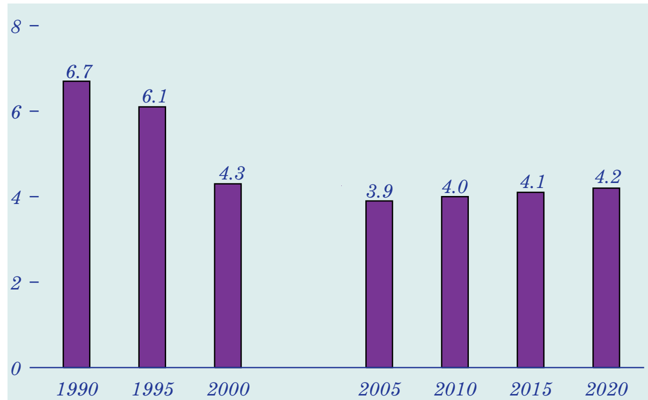
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. About 97 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, 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 may 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 by 1995.

In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants are tightened, and limits are set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are projected to decline from 11.9 million tons in 1995 to 11.1 million in 2000 (Figure 103). With the SO_2 emissions cap tightened in 2000 and after, the price of allowances is projected to reach $198 per ton by 2005. At that price level, 23 gigawatts of capacity is expected to be retrofitted with scrubbers to meet the Phase 2 goal.

Nitrogen Oxide Emissions Are Projected To Stay Below 2000 Levels

Figure 104. Projected nitrogen oxide emissions from electricity generation, 2000-2020 (million tons)



Nitrogen oxide (NO_x) emissions from U.S. electricity generation are projected to fall through 2005, as new legislation takes effect (Figure 104). 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. The 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 1.4 million tons between 1999 and 2000.

Even after the CAAA90 regulations have taken effect, further effort may be needed in some areas. 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, increase the operating costs of coal-fired and, to a lesser extent, natural-gas-fired units.

Forecast Comparisons

Two other organizations—DRI-WEFA and the Gas Research Institute (GRI)—also produce comprehensive energy projections with a time horizon similar to that of *AEO2002*. The most recent projections from those organizations (DRI-WEFA, Spring/Summer 2001; GRI, March 2001), as well as other forecasts that concentrate on petroleum, coal, and international oil markets, are compared here with the *AEO2002* projections.

Economic Growth

The *AEO2002* and DRI-WEFA reference cases project the same rates of economic growth, labor force growth, and productivity growth (Table 16). The *AEO2002* long-run forecast of average annual economic growth from 2000 to 2020 in the reference case is 3.0 percent—0.1 percent higher than the *AEO2001* forecast for the same period.

World Oil Prices

Comparisons with other oil price forecasts—including the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), and Deutsche Banc Alex. Brown (DBAB)—are shown in Table 17 (IEA, November 2000; PEL, June 2001; PIRA, October 2001; NRCan, January 2000; DBAB, July 2001). With the exception of PEL, the range between the *AEO2002* low and high world oil price cases spans the range of other published forecasts.

Total Energy Consumption

The *AEO2002* forecast of end-use sector energy consumption over the next two decades shows far less volatility than has occurred historically. Between 1974 and 1984, volatile world oil markets dampened domestic oil consumption. Consumers switched to electricity-based technologies in the buildings sector, while in the transportation sector new car fuel efficiency nearly doubled. Natural gas use declined as a result of high prices and limitations on new gas hookups. Between 1984 and 1995, however, both petroleum and natural gas consumption rebounded, bolstered by plentiful supplies and declining real energy prices. As a consequence, new car fuel efficiency in 1995 was less than 2 miles per gallon higher than in 1984, and natural gas use (residential, commercial, and industrial) was almost 25 percent higher than it was in 1984.

Electricity is expected to remain one of the fastest growing sources of delivered energy (Table 18), although its projected rate of growth is down from historical rates in each of the forecasts, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. Petroleum use and natural gas consumption are projected to grow at rates similar to those of recent years. For other fuels, future growth in consumption is expected to slow as a result of moderating economic growth, fuel switching, and increased end-use efficiency.

Residential and Commercial Sectors

Growth rates for primary energy demand in the residential and commercial sectors generally are expected to decrease significantly from the rates between 1984 and 1999, largely because of projected lower growth in population and housing starts. 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.

Table 16. Forecasts of economic growth, 2000-2020

Forecast	Average annual percentage growth: Real GDP	Labor force	Productivity
AEO2002			
Low growth	2.4	0.6	1.9
Reference	3.0	0.8	2.2
High growth	3.4	1.0	2.4
DRI-WEFA			
Reference	3.0	0.8	2.2

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

Table 17. Forecasts of world oil prices, 2000-2020

Forecast	2000 dollars per barrel: 2000	2005	2010	2015	2020
AEO2002 reference	27.72	22.73	23.36	24.00	24.68
AEO2002 high price		29.56	30.01	30.44	30.58
AEO2002 low price		17.41	17.64	17.64	17.64
DRI-WEFA	27.68	19.13	20.07	21.55	22.86
IEA	20.41	20.41	20.41	NA	27.83
PEL	28.00	13.53	14.77	13.38	NA
PIRA	30.31	24.31	24.21	27.75	NA
GRI	26.54	18.70	18.70	18.70	18.70
NRCan	21.79	21.79	21.79	21.79	21.79
DBAB	27.69	17.90	17.58	17.95	18.30

NA = not available.

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 both sectors across all forecasts (Table 19). All the forecasts project substantial growth in electricity use, with the *AEO2002* and GRI projections showing slower growth toward the end of the forecast and DRI-WEFA projecting the lowest growth rate. Natural gas use also is projected to grow but at lower rates, and projected petroleum use either is stable or continues to fall. GRI projects a more rapid decline in oil use, particularly for commercial uses, than the other forecasts. *AEO2002* projects growth in commercial oil demand while GRI and DRI-WEFA project declines, because GRI projects growth in commercial floorspace of 1.0 percent per year to 2020, compared with 1.7 percent in *AEO2002*. In addition, DRI-WEFA projects a shift from oil to electricity for heating and more rapid improvement in building shell efficiency than is projected in *AEO2002*.

Industrial Sector

The projected growth rates for delivered energy consumption in the industrial sector range from 1.1 percent to 1.4 percent per year (Table 20), and *AEO2002* is the lowest forecast, reflecting a continuing shift in the industrial output mix toward less energy-intensive products. For *AEO2002* and DRI-WEFA, the projected growth rates are similar to the actual rate from 1984 to 1999, whereas GRI projects somewhat higher growth.

The growth rates for different fuels in the industrial sector between 1984 and 1999 reflect a shift from petroleum products and coal to greater reliance on natural gas and electricity. In all the forecasts, natural gas use is expected to grow more slowly than in recent history, because much of the potential for fuel switching was realized during the 1980s. A key uncertainty in industrial coal forecasts is the environmental acceptability of coal as a boiler fuel.

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 *AEO2002* and DRI-WEFA forecasts (Table 21). The projections for gasoline demand and light-duty vehicle travel and efficiency are similar in the two forecasts, but DRI-WEFA projects more rapid growth in jet fuel consumption, due to more rapid growth in air travel, and slower growth in diesel fuel demand. All the forecasts anticipate slower growth both in light-duty

Table 18. Forecasts of average annual growth rates for energy consumption (percent)

	History		Projections (2000-2020)		
Energy use	1974-1984	1984-1999	AEO2002	DRI-WEFA	GRI
Petroleum*	-0.1	1.5	1.6	1.7	0.9
Natural gas*	-1.7	1.4	1.2	1.2	1.7
Coal*	-3.0	-1.0	0.1	0.2	-1.1
Electricity	3.0	2.5	1.8	1.5	2.3
Delivered energy	-0.2	1.4	1.5	1.5	1.3
Electricity losses	2.5	2.0	1.1	0.3	1.1
Primary energy	0.4	1.6	1.4	1.2	1.3

*Excludes consumption by electricity generators.

Table 19. Forecasts of average annual growth in residential and commercial energy demand (percent)

	History (1984-1999)	Projections (2000-2020)		
Forecast		AEO2002	DRI-WEFA	GRI
		Residential		
Petroleum	0.6	-0.7	0.2	-0.7
Natural gas	0.2	0.9	1.1	1.1
Electricity	2.6	1.7	1.2	2.5
Delivered energy	0.6	1.0	1.0	1.4
Electricity losses	2.1	1.0	0.1	1.4
Primary energy	1.2	1.0	0.6	1.4
		Commercial		
Petroleum	-4.0	0.4	-0.7	-1.0
Natural gas	1.3	1.6	0.5	1.6
Electricity	3.4	2.3	1.7	2.2
Delivered energy	1.5	1.9	1.0	1.7
Electricity losses	2.9	1.6	0.5	1.1
Primary energy	2.2	1.7	0.8	1.4

Table 20. Forecasts of average annual growth in industrial energy demand (percent)

	History (1984-1999)	Projections (2000-2020)		
Forecast		AEO2002	DRI-WEFA	GRI
Petroleum	0.9	1.2	1.2	1.5
Natural gas	2.1	1.1	1.5	1.8
Coal	-0.8	0.0	0.2	-1.1
Electricity	1.6	1.4	1.5	2.0
Delivered energy	1.2	1.1	1.2	1.4
Electricity losses	1.0	0.7	0.8	1.3
Primary energy	1.2	1.1	1.1	1.4

vehicle travel and air travel than in recent history. Demand for diesel fuel is also expected to grow more slowly in all three forecasts than it has in the past.

Total transportation energy demand in the GRI projections is expected to grow at a rate that is much slower than the historical rate and the rates in the other forecasts. GRI projects no growth in gasoline demand as a result of slower growth in light-duty vehicle travel and more rapid efficiency improvements than are projected in the *AEO2002* and DRI-WEFA forecasts. GRI also projects the slowest growth in air travel of all the forecasts, leading to slower growth in jet fuel demand. For diesel fuel, however, GRI projects growth in demand more comparable with that in the *AEO2002* forecast, because it projects similar annual growth in freight travel.

Table 21. Forecasts of average annual growth in transportation energy demand (percent)

	History		Projections (2000-2020)		
Forecast	1975-1985	1985-1999	AEO2002	DRI-WEFA	GRI
			Consumption		
Motor gasoline	0.2	1.6	1.6	1.7	0.0
Diesel fuel	4.2	3.5	2.4	1.7	2.0
Jet fuel	2.1	2.3	2.5	3.4	2.1
Residual fuel	1.0	0.1	-0.2	0.8	-0.2
All energy	1.0	1.9	1.9	2.0	0.9
			Key indicators		
Car and light truck travel	2.9	3.0	2.2	2.3	1.5
Air travel (revenue passenger-miles)	7.3	4.7	3.2	4.0	2.9
Average new car fuel efficiency	5.5	0.2	0.5	0.5	2.2
Gasoline prices	0.5	-2.3	-0.4	-1.0	-0.6

Electricity

Comparison across forecasts shows significant variation in projected electricity sales (Table 22). The forecasts for total electricity sales in 2020 range from 5,298 billion kilowatthours (GRI) to 4,578 billion kilowatthours (DRI-WEFA), compared with the *AEO2002* reference case value of 4,916 billion kilowatthours. In 2020, GRI's sales projection of 5,298 billion kilowatthours exceeds the *AEO2002* high economic growth projection of 5,173 billion kilowatthours, while the DRI-WEFA projection of 4,578 billion kilowatthours is below the *AEO2002* low economic growth projection of 4,691 billion kilowatthours. All the forecasts compared here agree that competition in wholesale markets and slow growth in electricity demand relative to GDP growth will tend to keep the price of electricity stable—or declining in real terms—until 2020.

Both the DRI-WEFA and GRI forecasts assume that the electric power industry will be fully restructured, resulting in average electricity prices that approach long-run marginal costs. *AEO2002* 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. *AEO2002* and GRI project slight increases in electricity prices in the last 5 years of the forecast, whereas DRI-WEFA projects a slight decrease, based on different projections for the rate of growth in electricity demand.

The distribution of sales among sectors affects the mix of capacity types needed to satisfy sectoral demand. Although the *AEO2002* mix of capacity among fuels is similar to those in the other forecasts, small differences in sectoral demands across the forecasts could lead to significant differences in the expected mix of capacity types. In general, recent growth in the residential sector results in a need for more peaking and intermediate capacity than baseload capacity. Consequently, generators are expected to build mostly natural-gas-fired power plants, either combustion turbine or combined cycle. All the forecasts project growth rates for electricity demand in the commercial sector that equal or exceed those for the residential sector, leading to moderate increases in the share of baseload capacity relative to all additions. In the GRI forecast, additions of coal-fired plants using pulverized coal or integrated gasification combined cycle technologies are roughly equal to those in the *AEO2002* projections; however, GRI's projection of 420 gigawatts of total coal-fired capacity in 2020 also includes the repowering of approximately 72 gigawatts of existing capacity.

Table 22. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	2000	AEO2002			Other forecasts	
		Reference	Low economic growth	High economic growth	DRI-WEFA	GRI
				2015		
Average end-use price (2000 cents per kilowatthour)	**6.9**	**6.3**	**6.2**	**6.6**	**5.8**	**5.6**
Residential	8.3	7.6	7.3	7.9	7.1	7.1
Commercial	7.5	6.8	6.6	7.1	6.0	6.5
Industrial	4.6	4.3	4.2	4.5	4.1	3.2
Net energy for load, including cogeneration	**4,005**	**5,278**	**5,109**	**5,481**	**4,802**	**5,225**
Coal	1,969	2,341	2,279	2,418	2,296	2,295
Oil	102	43	44	45	173	71
Natural gas	625	1,488	1,400	1,599	1,233	1,412
Nuclear	752	707	697	707	649	705
Hydroelectric/other [a]	357	453	449	457	417	492
Nonutility sales to grid [b]	163	204	202	207	NA	216
Net imports	35	41	39	47	34	35
Electricity sales	**3,426**	**4,556**	**4,404**	**4,735**	**4,271**	**4,871**
Residential	1,193	1,554	1,523	1,575	1,421	1,764
Commercial/other [c]	1,162	1,673	1,637	1,705	1,514	1,663
Industrial	1,071	1,329	1,244	1,455	1,336	1,444
Capability, including cogeneration (gigawatts) [d,e]	**809**	**1,049**	**1,017**	**1,083**	**1,096**	**1,113**
Coal	313	322	315	331	364	414
Oil and gas	282	509	487	533	518	467
Nuclear	98	89	87	89	94	91
Hydroelectric/other [a]	116	130	129	130	121	151
				2020		
Average end-use price (2000 cents per kilowatthour)	**6.9**	**6.5**	**6.2**	**6.8**	**5.6**	**5.8**
Residential	8.3	7.7	7.3	8.1	6.8	7.3
Commercial	7.5	6.9	6.6	7.3	5.8	6.7
Industrial	4.6	4.5	4.2	4.7	3.9	3.3
Net energy for load, including cogeneration	**4,005**	**5,683**	**5,426**	**5,978**	**5,137**	**5,682**
Coal	1,969	2,472	2,355	2,693	2,482	2,455
Oil	102	49	48	55	190	99
Natural gas	625	1,733	1,619	1,777	1,408	1,507
Nuclear	752	702	691	702	612	706
Hydroelectric/other [a]	357	464	459	478	414	654
Nonutility sales to grid [b]	163	224	219	230	NA	226
Net imports	35	40	36	44	32	34
Electricity sales	**3,426**	**4,916**	**4,691**	**5,173**	**4,578**	**5,298**
Residential	1,193	1,672	1,623	1,701	1,528	1,932
Commercial/other [c]	1,162	1,830	1,775	1,876	1,603	1,778
Industrial	1,071	1,415	1,293	1,596	1,447	1,588
Capability, including cogeneration (gigawatts) [d,e]	**809**	**1,138**	**1,092**	**1,187**	**1,155**	**1,166**
Coal	313	338	324	367	389	420
Oil and gas	282	580	552	598	559	480
Nuclear	98	88	87	88	88	89
Hydroelectric/other [a]	116	132	131	134	119	177

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

[b]For *AEO2002*, includes only net sales from cogeneration; for GRI, also includes distributed generation and backup power purchases.

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

[d]For DRI-WEFA, "capability" represents nameplate capacity; for the others, "capability" represents net summer capability.

[e]GRI generating capability includes only central utility and independent power producer capacity. It does not include cogeneration capacity in the commercial and industrial sectors, which would add another 129 gigawatts in 2015 and 149 gigawatts in 2020.

Sources: ***AEO2002:*** AEO2002 National Energy Modeling System, runs AEO2002.D102001B (reference case), LM2002.D102001B (low economic growth case), and HM2002.D102001B (high economic growth case). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001). **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001).

Natural Gas

The differences among published forecasts of natural gas prices, production, consumption, and imports (Table 23) 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 forecast from GRI incorporates a cyclical price trend based on exploration and production cycles, which can be deceptive when isolated years are considered.

In 2020, the forecast with the highest natural gas consumption is GRI (35.6 trillion cubic feet); and the forecast with the lowest level is DRI-WEFA (31.6 trillion cubic feet). The GRI forecast shows the greatest expected growth in natural gas consumption for the residential and industrial sectors from 2000 to 2020, whereas the *AEO2002* high economic growth case and reference case project the greatest growth for the commercial and electricity generator sectors, respectively.

GRI projects average annual growth in residential natural gas consumption of 1.1 percent between 2000 and 2020, whereas the *AEO2002* low economic growth forecast shows the lowest growth in this sector (0.7 percent). The *AEO2002* high economic growth case projects 1.7-percent annual growth in commercial natural gas consumption between 2000 and 2020, whereas the DRI-WEFA forecast shows the lowest expected growth in this sector (0.5 percent). The growth rate for commercial consumption in the GRI forecast is around 3 times higher than the DRI-WEFA projection, which is significantly lower than the other forecasts, due in part to definitional differences.

For consumption of natural gas in the industrial and electricity generation sectors, the forecasts are not strictly comparable because of differences in definitions. The *AEO2002* reference, low economic growth, and high economic growth cases all project lower growth in industrial consumption by 2020 than do the other forecasts. All the forecasts project the strongest growth in natural gas consumption for the electricity generation sector. Through 2020, the *AEO2002* high economic growth case has the highest projected annual growth rate for electricity sector natural gas consumption (4.6 percent), with DRI-WEFA coming in lowest (2.8 percent).

Domestic natural gas consumption is met by domestic production and imports. GRI projects the highest level of net imports in 2020, 2.6 trillion cubic feet higher than the *AEO2002* reference case projections. GRI also projects the highest share of imports relative to total supply, at 24 percent. The *AEO2002* low economic growth case projects the lowest share of imports relative to total supply in 2020 at 16 percent. For domestic natural gas production, the *AEO2002* reference and high economic growth case projections for 2020 both exceed the other forecasts; however, the GRI forecast shows the highest annual growth rate for domestic production, starting from a lower estimate of production in 2000. The *AEO2002* reference case projection for 2020 is 2.8 trillion cubic feet higher than the lowest projection, from DRI-WEFA.

GRI projects the lowest wellhead prices, even though it projects production levels that are nearly equal to those in the DRI-WEFA forecast for 2020. The DRI-WEFA wellhead natural gas price projections are relatively high given the relatively low production levels in the forecast, exceeded only by the price projections in the *AEO2002* high economic growth case, which projects significantly higher production.

For the residential and commercial sectors in 2020, DRI-WEFA projects the highest end-use margins relative to the wellhead, and GRI's tend to be the lowest. Across all the forecasts, residential margins are projected to decline from 2000 to 2020.

Because of definitional differences industrial prices are not as readily comparable, although on-system sale prices would generally be expected to be higher than an estimate of the average price to all industrial customers. Margins to the industrial sector are expected to decline or remain relatively stable through 2020 in all the forecasts. GRI projects the largest decline in industrial margins, by 44 cents per thousand cubic feet (30 percent) over the forecast period.

All the forecasts show margins to electricity generators dropping from relatively high 2000 levels to 2015, with the most dramatic drop in the DRI-WEFA forecast, at 42 percent. The GRI margin is similar to those in the *AEO2002* cases in 2020, but the DRI-WEFA margin remains relatively low.

Table 23. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	2000	AEO2002			Other forecasts	
		Reference	Low economic growth	High economic growth	DRI-WEFA	GRI[a]
				2015		
Lower 48 wellhead price (2000 dollars per thousand cubic feet)	**3.60**	**3.07**	**2.88**	**3.36**	**3.23**	**2.34**
Dry gas production[b]	**19.08**	**26.32**	**25.28**	**26.92**	**24.29**	**25.55**
Net imports	**3.52**	**5.26**	**4.96**	**5.94**	**6.01**	**6.38**
Consumption	**22.83**	**31.34**	**30.02**	**32.63**	**30.05**	**33.78**
Residential	5.00	5.73	5.60	5.80	5.82	5.75
Commercial[c]	3.27	4.21	4.13	4.26	3.72[d]	4.11
Industrial[c]	8.41	9.79	9.28	10.28	8.56[e]	11.76
Electricity generators[f]	4.24	8.91	8.39	9.51	9.22[g]	9.15
Other[h]	1.91	2.71	2.61	2.78	2.73	3.01
End-use prices (2000 dollars per thousand cubic feet)						
Residential	7.85	7.04	6.84	7.31	7.35	6.14
Commercial[c]	6.40	5.84	5.63	6.12	6.30	5.21
Industrial[c]	4.43	3.79	3.59	4.11	4.38[i]	3.54[i]
Electricity generators[f]	4.49	3.72	3.52	4.04	3.70	3.12
				2020		
Lower 48 wellhead price (2000 dollars per thousand cubic feet)	**3.60**	**3.26**	**2.94**	**3.65**	**3.48**	**2.81**
Dry gas production[b]	**19.08**	**28.48**	**27.25**	**28.93**	**25.64**	**25.60**
Net imports	**3.52**	**5.51**	**5.00**	**6.25**	**6.28**	**8.10**
Consumption	**22.83**	**33.78**	**32.03**	**34.99**	**31.64**	**35.57**
Residential	5.00	5.98	5.79	6.08	6.14	5.95
Commercial[c]	3.27	4.52	4.39	4.61	3.71[d]	4.34
Industrial[c]	8.41	10.06	9.39	10.94	9.28[e]	12.71
Electricity generators[f]	4.24	10.30	9.65	10.36	9.71[g]	9.35
Other[h]	1.91	2.93	2.81	2.99	2.81	3.21
End-use prices (2000 dollars per thousand cubic feet)						
Residential	7.85	7.16	6.89	7.52	7.56	6.26
Commercial[c]	6.40	6.02	5.72	6.39	6.51	5.39
Industrial[c]	4.43	4.01	3.68	4.43	4.62[i]	3.82[i]
Electricity generators[f]	4.49	3.94	3.63	4.33	3.95	3.46

[a]The baseline projection includes a cyclical price trend based on exploration and production cycles; therefore, forecast values for an isolated year may be misleading. The conversion factor for natural gas is 1,030 Btu per cubic foot for all end-use sectors, net imports, production and consumption. A factor of 1.0227 was applied to convert prices in 1999 dollars to 2000 dollars.
[b]Does not include supplemental fuels.
[c]Includes natural gas consumed in cogeneration.
[d]Excludes natural gas used for cogenerators and other nonutility generation.
[e]Excludes cogenerators' energy attributed to generating electricity.
[f]Includes independent power producers and excludes cogenerators.
[g]Includes portion of cogeneration attributed to electricity generation.
[h]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[i]On-system sales or system natural gas (i.e., does not include natural gas delivered for the account of others).
Sources: ***AEO2002*:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B (reference case), LM2002.D102001B (low economic growth case), and HM2002.D102001B (high economic growth case). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001). **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001).

Petroleum

The *AEO2002* low world oil price and *AEO2002* high world oil price forecasts for 2015 and 2020 form intervals that bound the other forecasts (Table 24). The *AEO2002* reference case projects increasing world crude oil prices over the period 2003 to 2020, reaching $24.00 per barrel in 2015 and $24.68 per barrel in 2020. The *AEO2002* low world oil price case and high world oil price case and the DRI-WEFA projections also increase over some or all of their respective horizons. DRI-WEFA's crude oil price is $2.45 per barrel below the *AEO2002* reference case projection in 2015 and $1.82 per barrel below the *AEO2002* reference case in 2020. GRI forecasts a constant real crude oil price of $18.70 per barrel.

The *AEO2002* reference case projects an increase in domestic crude oil production after 2010 to 5.6 million barrels per day by 2020. GRI projects increasing crude oil production until 2015. The GRI production forecast decreases after 2015 but is still higher in 2020 than the *AEO2002* reference case projection, by 0.5 million barrels per day. The DRI-WEFA projection for domestic crude oil is 0.5 million barrels per day below the *AEO2002* reference case projection. The Independent Petroleum Association of America (IPAA) projects much higher crude oil production for 2005 than any other forecast, at 6.6 million barrels per day, followed by decreasing production through 2015. The IPAA forecast for 2015 is the same as DRI-WEFA's and is below the *AEO2002* reference case projection by 0.2 million barrels per day.

The pattern of increasing production to 2015 followed by a decrease to 2020 is seen in GRI's projections for both crude oil and natural gas liquids (NGL). In the GRI forecast, NGL production in 2020 of 2.8 million barrels per day is similar to the *AEO2002* reference case and declines from 2.9 million barrels per day in 2015. NGL production is projected to increase steadily in the *AEO2002* reference case, to 2.8 million barrels per day in 2020. DRI-WEFA and IPAA also project increasing NGL production. GRI projects an increase in total domestic production of crude oil and NGL to 9.3 million barrels per day in 2015 and then a decline to 8.9 million barrels per day in 2020, higher than the *AEO2002* reference case projection for total domestic production of 8.5 million barrels per day in 2020. DRI-WEFA and IPAA project total domestic production of 7.9 million barrels per day in 2020 and 7.7 million barrels per day in 2015, respectively. The *AEO2002* high world oil price case projects the highest world crude oil price and, not surprisingly, the highest domestic production of both crude oil and NGL in 2020.

Oil price forecasts may differ because of assumptions about world supply in each forecast. DRI-WEFA expects increased cooperation between the Organization of Petroleum Exporting Countries (OPEC), Norway, Mexico, and Russia on oil exports. Price forecasts may also differ because of assumptions about technology in energy consumption and production and assumptions about the availability of exploration and production rights. Advances in energy consumption are often summarized in the ratio of total energy consumption to GDP. Energy consumption per unit of GDP is generally expected to decline. GRI predicts a constant real crude oil price that is closer to that in the *AEO2002* low world oil price case than to the reference case yet also predicts fairly high domestic production.

Even the forecasts that project increases in domestic oil and NGL production expect domestic product demand to outpace the increased production. DRI-WEFA expects total product demand to reach 27.2 million barrels per day by 2020, and the GRI forecast is 22.3 million barrels per day. The *AEO2002* reference case projection is 26.7 million barrels per day. Total net imports and import share of product supplied increase in the *AEO2002* reference case and low world oil price cases and in the DRI-WEFA and IPAA forecasts. Only in the *AEO2002* high world oil price case does import share decrease slightly from 2015 to 2020. The *AEO2002* and DRI-WEFA forecasts show increasing motor gasoline demand to 2020. GRI's dissenting view is that gasoline demand growth will be reversed after 2010. By 2020, GRI's gasoline demand forecast is 3.6 million barrels per day lower than DRI-WEFA and 3.7 million barrels per day below the *AEO2002* reference case. All three *AEO2002* cases, GRI, DRI-WEFA, and IPAA project increasing distillate and jet fuel demand over their forecast periods. As might be expected, the *AEO2002* low world oil price case projects the largest total petroleum product demand in 2020.

Table 24. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	2000	AEO2002			Other forecasts		
		Reference	Low world oil price	High world oil price	DRI-WEFA	GRI	IPAA
		2015					
World oil price (2000 dollars per barrel)[a]	**27.72**	**24.00**	**17.64**	**30.44**	**21.55**	**18.70**	**NA**
Crude oil and NGL production	**7.73**	**8.20**	**7.51**	**8.76**	**8.01**	**9.34**	**7.73**
Crude oil	5.82	5.56	4.92	6.10	5.33[b]	6.43	5.34
Natural gas liquids	1.91	2.64	2.59	2.66	2.48	2.91	2.40
Total net imports	**10.42**	**15.30**	**16.76**	**14.17**	**15.98**	**NA**	**13.72**
Crude oil	9.02	11.01	12.02	10.17	10.90	NA	11.45
Petroleum products	1.40	4.29	4.74	4.00	5.08	NA	2.27
Petroleum demand	**19.74**	**25.07**	**25.67**	**24.59**	**25.39**	**21.41**	**24.25**
Motor gasoline	8.50	11.13	11.27	10.92	10.99	8.32	10.63
Jet fuel	1.73	2.47	2.49	2.45	2.82	2.30	2.41
Distillate fuel	3.67	4.99	5.16	4.91	4.79	4.45	4.64
Residual fuel	1.05	0.73	0.94	0.66	0.89	0.59	0.77
Kerosene	0.07	0.06	0.06	0.06	0.08	0.07	NA
Liquefied petroleum gas	2.23	2.59	2.62	2.51	2.82	2.38	NA
Other	2.49	3.10	3.14	3.10	3.00	3.30	5.80
Import share of product supplied (percent)	**53.0**	**61.0**	**65.3**	**57.6**	**62.9**	**NA**	**56.6**
		2020					
World oil price (2000 dollars per barrel)[a]	**27.72**	**24.68**	**17.64**	**30.58**	**22.86**	**18.70**	**NA**
Crude oil and NGL production	**7.73**	**8.47**	**7.71**	**9.31**	**7.90**	**8.90**	**NA**
Crude oil	5.82	5.63	4.94	6.43	5.13[b]	6.11	NA
Natural gas liquids	1.91	2.84	2.77	2.88	2.59	2.79	NA
Total net imports	**10.42**	**16.64**	**18.43**	**14.97**	**17.87**	**NA**	**NA**
Crude oil	9.02	11.20	12.37	10.08	11.22	NA	NA
Petroleum products	1.40	5.44	6.06	4.89	6.65	NA	NA
Petroleum demand	**19.74**	**26.66**	**27.52**	**26.12**	**27.22**	**22.25**	**NA**
Motor gasoline	8.50	11.81	12.00	11.54	11.69	8.10	NA
Jet fuel	1.73	2.81	2.83	2.79	3.33	2.50	NA
Distillate fuel	3.67	5.32	5.64	5.24	5.16	4.83	NA
Residual fuel	1.05	0.75	0.97	0.68	0.85	0.58	NA
Kerosene	0.07	0.06	0.06	0.06	0.08	0.07	NA
Liquefied petroleum gas	2.23	2.71	2.75	2.61	3.00	2.58	NA
Other	2.49	3.20	3.27	3.20	3.11	3.59	NA
Import share of product supplied (percent)	**53.0**	**62.4**	**67.0**	**57.3**	**65.7**	**NA**	**NA**

[a]Composite of U.S. refiners' acquisition cost.
[b]Includes shale and other.
NA = Not available.

Notes: The GRI price, originally in 1999 dollars per barrel, was multiplied by 1.021126 to convert to 2000 dollars. IPAA includes jet fuel in demand for "aviation fuels." GRI and DRI-WEFA forecast aviation gasoline demand of 20 thousand barrels per day from 2005 to 2020.

Sources: ***AEO2002*:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B (reference case), LW2002.D102001B (low world oil price case), and HW2002.D102001B (high world oil price case). **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Coal

The coal forecasts by DRI-WEFA and Hill & Associates, Inc. project lower production and overall consumption than does *AEO2002* (Table 25). The differences stem from differences in assumptions related to growth in electricity demand and whether the forecast includes the effects of emissions limits proposed by the U.S. Environmental Protection Agency, which could force the retirement of many older coal plants. *AEO2002* represents the provisions of the State implementation plan (SIP) call for 19 States where NO_x caps were finalized but does not incorporate revised limits on emissions of particulate matter. In contrast, Hill & Associates includes revised limits on particulate matter beginning in 2008.

EIA projects growing domestic consumption over the forecast horizon in combination with shrinking real coal prices. Hill & Associates projects declines in coal consumption between 2015 and 2020. The DRI-WEFA forecast has the lowest coal consumption projection for the electricity generation sector. DRI-WEFA's coal consumption forecast shows virtually no growth (only 7 million tons) between 2015 and 2020. For the same period, the *AEO2002* reference case projects an increase of 71 million tons. Although DRI-WEFA projects 81 gigawatts of coal-fired capacity additions over the forecast period, most of those represent replacement capacity for retiring coal plants.

The differences among the forecasts for coal exports are significant. U.S. coal exports declined from 90 million tons in 1996 to 58 million tons in 2000, and net coal exports in 2000 (after adjustment for imports) were 46 million tons. EIA expects net exports to decline to 34 million tons in 2015 and remain approximately at that level through 2020. Hill & Associates projects an even more dramatic decline in net exports to 18 million tons in 2015 and 16 million tons in 2020. The projections for a long-term decline in exports are based on expected strong price competition by other exporters and the loss of markets as Europe moves away from coal for environmental reasons. DRI-WEFA projects relative stability in U.S. net coal exports, at 44 million tons in 2015 and 42 million tons in 2020.

All the forecasts show declining real coal prices over the forecast horizon. The *AEO2002* and Hill & Associates price forecasts for national average minemouth coal prices (all shown in 2000 dollars) differ, however. The Hill & Associates minemouth price projections are somewhat lower than the *AEO2002* reference case projections, which include exported and metallurgical coal in the calculation. (Exported and metallurgical coal tend to be more expensive.) Hill & Associates shows lower delivered coal prices to electricity generators than are projected for 2015 and 2020 in the *AEO2002* reference case, whereas the DRI-WEFA price projections (per million Btu) are 24 percent higher in 2020.

The coal forecasts reviewed provide a broad range of views, reflecting 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. The uncertainties are, and will continue to be, passed on to U.S. coal producers in the form of demands for higher quality products at ever lower prices.

Table 25. Comparison of coal forecasts (million short tons, except where noted)

Projection	2000	AEO2002 Reference	AEO2002 Low economic growth	AEO2002 High economic growth	Other forecasts DRI-WEFA	Other forecasts Hill & Associates
				2015		
Production	1,084	1,325	1,298	1,366	1,202	1,172
Consumption by sector						
Electricity generation	965	1,183	1,156	1,218	1,048	1,075
Coking plants	29	22	22	22	26	18
Industrial/other	87	89	84	95	85	61
Total	1,081	1,294	1,262	1,335	1,159	1,154
Net coal exports	46	34	39	34	44	18
Minemouth price						
(2000 dollars per short ton)	16.45	13.44	13.17	13.51	NA	9.77[a]
(2000 dollars per million Btu)	0.79	0.66	0.65	0.67	NA	0.46[a]
Average delivered price to electricity generators						
(2000 dollars per short ton)	24.36	20.15	19.91	20.55	26.03	18.23
(2000 dollars per million Btu)	1.20	1.01	1.00	1.03	1.26	0.87
				2020		
Production	1,084	1,397	1,335	1,493	1,208	1,160
Consumption by sector						
Electricity generation	965	1,254	1,198	1,341	1,054	1,071
Coking plants	29	20	20	20	24	15
Industrial/other	87	92	85	101	88	58
Total	1,081	1,365	1,303	1,462	1,166	1,144
Net coal exports	46	35	35	35	42	16
Minemouth price						
(2000 dollars per short ton)	16.45	12.79	12.56	13.23	NA	8.98[a]
(2000 dollars per million Btu)	0.79	0.64	0.62	0.66	NA	0.42[a]
Average delivered price to electricity generators						
(2000 dollars per short ton)	24.36	19.00	18.72	19.75	24.70	17.26
(2000 dollars per million Btu)	1.20	0.97	0.95	1.00	1.20	0.82

[a]In the Hill & Associates forecast, minemouth prices represent an average for domestic steam coal only. Exports and coking coal are not included in the average.

NA = Not available.

Btu = British thermal unit.

Sources: ***AEO2002*:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B (reference case), LM2002.D102001B (low economic growth case), and HM2002.D102001B (high economic growth case). **Hill & Associates:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2020* (March 2001). **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001).

List of Acronyms

ACEI	Aggregate composite efficiency index
AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
ANWR	Arctic National Wildlife Refuge
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CAISO	California Independent Systems Operator
CARB	California Air Resources Board
CCAP	Climate Change Action Plan
CDM	Clean Development Mechanism
CEC	California Energy Commission
CO_2	Carbon dioxide
CPI	Consumer price index
CPUC	California Public Utilities Commission
CSE	Cold-side electrostatic precipitator
DBAB	Deutsche Banc Alex. Brown
DOE	U.S. Department of Energy
DWR	California Department of Water Resources
E85	Motor fuel with 85 percent ethanol
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
EU	European Union
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GRI	Gas Research Institute
HC	Hydrocarbons
Hg	Mercury
IEA	International Energy Agency
IPAA	Independent Petroleum Association of America
ISO	Independent systems operator
LEV	Low-emission vehicle
LEVP	Low-Emission Vehicle Program
LIHEAP	Low-Income Home Energy Assistance Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
M85	Motor fuel with 85 percent methanol
MSATs	Mobile source air toxics
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NAECA	National Appliance Energy Conservation Act
NEMS	National Energy Modeling System
NEPP	National Energy Policy Plan
NGL	Natural gas liquids
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPR-A	National Petroleum Reserve-Alaska
NRCan	Natural Resources Canada
NRDC	Natural Resources Defense Council
NYMEX	New York Mercantile Exchange
OBD	On-board diagnostics
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
OTR	Ozone Transport Rule
PADDs	Petroleum Administration for Defense Districts
PEL	Petroleum Economics Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
ppm	Parts per million
PSC	Public Service Commission
PTC	Production tax credit (renewables)
PUC	Public Utilities Commission
PX	Power Exchange (California)
PZEV	Partial zero-emission vehicle
RFG	Reformulated gasoline
RPS	Renewable Portfolio Standard
RTO	Regional transmission organization
Rvp	Reid vapor pressure
SCR	Selective catalytic reduction
SEER	Seasonal energy efficiency ratio
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SULEV	Super-ultra-low-emission vehicle
TAME	Tertiary amyl methyl ether
ULEV	Ultra-low-emission vehicle
ULSD	Ultra-low-sulfur diesel fuel
VMT	Vehicle-miles traveled
VOCs	Volatile organic compounds
ZEV	Zero-emission vehicle

Text Notes

Legislation and Regulations

[*1*] The tax of 4.3 cents per gallon is in nominal terms.

[*2*] Most of the information on State legislation and regulation comes from Energy Information Administration, "Status of State Electric Industry Restructuring Activity, September 2001," web site www.eia.doe.gov//electricity/chg_str/tab5rev.html. Other information comes from individual State legislation and utility commission documents and from C.H. Guernsey & Company, "Electric Restructuring Links," web site www.chguernsey.com/frame-index1c.html.

[*3*] The concept of net metering is to allow the electric meters of customers with generating facilities to turn backward when their generators are producing more energy than they use. Net metering allows customers to use their generation to offset their consumption over the entire billing period, not just instantaneously.

[*4*] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[*5*] Energy Information Administration, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*, SR/OIAF/2001-01 (Washington, DC, May 2001), web site www.eia.doe.gov/oiaf/servicerpt/ulsd/index.html.

[*6*] State of California Air Resources Board, *Staff Report: Proposed Regulations for Low Emission Vehicles and Clean Fuels* (Sacramento, CA, August 13, 1990).

[*7*] State of California Air Resources Board, Mobile Source Control Division, *Staff Report: Initial Statement of Reasons, Proposed Amendments to California Exhaust and Evaporative Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles—"LEV II" and Proposed Amendments to California Motor Vehicle Certification, Assembly-Line and In-Use Test Requirements—"CAP 2000"* (El Monte, CA, September 18, 1998).

[*8*] State of California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*9*] *National Energy Policy: A Report of the National Energy Policy Development Group* (May 2001), web site www.whitehouse.gov/energy/National-Energy-Policy.pdf

[*10*] Energy Information Administration, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, SR/OIAF/2001-02 (Washington, DC, May 2001), web site www.eia.doe.gov/oiaf/servicerpt/naturalgas/pdf/oiaf00102.pdf.

[*11*] Energy Information Administration, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, SR/OIAF/2001-06 (Washington, DC, December 2001), web site www.eia.doe.gov/oiaf/servicerpt/naturalgas/pdf/oiaf00106.pdf.

[*12*] President William J. Clinton and Vice President Albert Gore, Jr.*, The Climate Change Action Plan* (Washington, DC, October 1993).

[*13*] Carbon dioxide is absorbed by growing vegetation and soils. Defining the total impacts of CCAP as net reductions accounts for the increased sequestration of carbon dioxide as a result of the forestry and land-use actions in the program.

[*14*] Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Union, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Turkey is an Annex I nation that has not ratified the Framework Convention and did not commit to quantifiable emissions targets.

[*15*] Antigua and Barbuda, Argentina, Azerbaijan, Bahamas, Bangladesh, Barbados, Bolivia, Burundi, Cook Islands, Cyprus, Ecuador, El Salvador, Equatorial Guinea, Fiji, Gambia, Georgia, Guatemala, Guinea, Honduras, Jamaica, Kiribati, Lesotho, Malawi, the Maldives, Mauritius, Mexico, Micronesia, Mongolia, Nauru, Nicaragua, Niue, Palau, Panama, Paraguay, Romania, Samoa, Senegal, Trinidad and Tobago, Turkmenistan, Tuvalu, Uruguay, Vanuatu, and Uzbekistan.

[*16*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001), web site www.eia.doe.gov//1605/ggrpt/.

[*17*] Hydrofluorocarbons (HFCs) are non-ozone-depleting substitutes for chlorofluorocarbons (CFCs); perfluorocarbons (PFCs) are byproducts of aluminum production and are also used in semiconductor manufacturing; and sulfur hexafluoride (SF_6) is used as an insulator in electrical equipment and in semiconductor manufacturing.

[*18*] Web site www.state.gov/www/global/global_issues/climate/fs-9911_bonn_climate_conf.html.

[*19*] Web site http://cop6.unfccc.int/media/press.html.

[*20*] "U.N. Conference Fails to Reach Accord on Global Warming," *New York Times* (November 26, 2000).

[*21*] "Odd Culprits in Collapse of Climate Talks," *New York Times* (November 28, 2000).

[*22*] Pew Center on Global Climate Change, "Climate Talks in Marrakech—COP 7: Update, November 9, 2001—Final Analysis, web site www.pewclimate.org/cop7/update_110901.cfm.

[*23*] United Nations Framework Convention on Climate Change,"Governments Ready To Ratify Kyoto Protocol," Press Release (November 10, 2001), web site http://unfccc.int/press/prel2001/pressrel101101.pdf.

[*24*] Remarks by President Bush on Global Climate Change, Office of the Press Secretary, The White House (June 11, 2001).

Notes and Sources

Issues in Focus

[*25*] The marginal cost is the cost to produce one more unit of the good or service.

[*26*] The marginal benefit is the benefit received by purchasing one more unit of a particular good or service.

[*27*] Some supporters of regulation also believe that increased electricity supply must be carefully regulated to protect the environment. They thus justify the prolonged amount of time needed to build new generation as a result of environmental permitting regulations, which in a competitive market will hamper the ability of supply to respond to demand price signals.

[*28*] High-pollutant diesel reciprocating engines can be converted to lower polluting gas engines at a low cost when necessary to meet emissions standards. Fuel cells are also considered a cost-effective choice when reliability is considered essential and meeting strict emissions standards are necessary.

[*29*] A line-item competitive transition charge (CTC) was added to the distribution charge portion of the bill of each electricity customer to pay for stranded costs.

[*30*] Although customers would normally pay for all utility investments under a regulated system, they would have paid them off over the lifetime (according to financing guidelines) of the plant, lowering the price per kilowatthour of generation.

[*31*] Energy Information Administration, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply, 2. Electricity Reliability Issues in California, A Summary," web site www.eia.doe.gov/emeu/ steo/ pub/ special/ california/ june01article/caelec.html.

[*32*] Energy Information Administration, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply, 2. Electricity Reliability Issues in California, A Summary," web site www.eia.doe.gov/ emeu/ steo/ pub/ special/ california/ june01article/caelec.html.

[*33*] M. Warwick, Pacific National Laboratories, "The New California Power Market: How it Works, What Went Wrong, What Next," presentation to the U.S. Department of Transportation, Bureau of Transportation Statistics (November 7, 2000).

[*34*] When actual reserves fall below 7 percent, a Stage 1 Alert is triggered; below 5 percent a Stage 2 Alert is triggered; and below 1.5 percent, Stage 3.

[*35*] When a customer purchases electricity from a competitive supplier that offers a lower generation rate than the utility default generation rate, the account of the customer is credited for the savings, which are called "shopping credits."

[*36*] California Energy Commission, *Annual Project Activity Report to the Legislature* (Sacramento, CA, December 2000).

[*37*] California Energy Commission, *California Energy Outlook: Volume I. Electricity and Natural Gas Trends Report*, Publication 200-01-002, Staff Draft (Sacramento, CA, September 7, 2001), pp. 62-64.

[*38*] California Energy Commission for the Public Interest Energy Research (PIER) Program, *Five-Year Investment Plan, 2002 Through 2006, Volume 1*, Report to the California Legislature (Sacramento, CA, March 1, 2001).

[*39*] California Energy Commission for the Public Interest Energy Research (PIER) Program, *Five-Year Investment Plan, 2002 Through 2006, Volume 1*, Report to the California Legislature (Sacramento, CA, March 1, 2001). For example, 80 percent of requests for new capacity additions for 2001-2003 in Santa Clara City are to accommodate internet load growth.

[*40*] Capacity retirements were greater than capacity additions during this period. See web site www.eia.doe.gov/cneaf/electricity/california/background.html.

[*41*] Web site www.eia.doe.gov/cneaf/electricity/california/background.html.

[*42*] Web site www.eia.doe.gov/cneaf/electricity/california/background.html.

[*43*] The effect of high natural gas prices on California's electricity market is discussed below. When natural gas production is curtailed, it takes 6 to 18 months for it to be restarted.

[*44*] Web site www.eia.doe.gov/cneaf/electricity/california/background.html.

[*45*] Congestion occurs when too much power is transmitted through wires with limited capacity, causing a blockage and slowing or stopping the flow of energy through that blocked point.

[*46*] Federal Energy Regulatory Commission, U.S. Department of Energy, et al., Docket No. ER98-2843-008, *Order On Rehearing, Directing Compliance Filing, Granting Clarification, and Accepting Compliance Filing* (January 14, 2000).

[*47*] W.W. Hogan, "Coordination for Competition: Electricity Market Design Principles," presentation to Public Utility Commission of Texas Workshop on ERCOT Protocols (February 15, 2001).

[*48*] Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities* (Washington, DC, November 1, 2000).

[*49*] Web site www.eia.doe.gov/cneaf/electricity/california/background.html.

[*50*] Federal Energy Regulatory Commission, *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange* (various proceedings throughout 2001).

[*51*] Letter from Pat Wood, III to Bill Massey, Linda Breathitt, and Nora Brownell, Open Meeting, Item E-3, Docket No. EX01-3, *Discussion of RTO Progress* (September 26, 2001).

[*52*] A "market center" is a physical location on the transmission system where many transmission pipelines interconnect, giving buyers and sellers considerable flexibility in transporting gas from many different production regions to many geographically diverse consumption centers.

[*53*] California electricity prices are given in 2000 dollars to show changes in the price projections from *AEO2001* to *AEO2002* and comparisons over the forecast period in real terms.

[*54*] Energy Information Administration, *Electricity Shortage in California: Issues for Petroleum and*

Natural Gas, Chapter 6, "Natural Gas," web site www. eia. doe. gov/ emeu/ steo/ pub/ special/ california/ june01article/canatgas.html.

[*55*] Downstream Alternatives, Inc., *The Use of Ethanol in California Clean Burning Gasoline: Ethanol Supply and Demand* (Bremen, IN, February 5, 1999).

[*56*] Maine has passed legislation that sets a goal of phasing out MTBE.

[*57*] Bills introduced in the 107th Congress included: S.265, H.R. 454, H.R. 608, H.R. 20, H.R. 2230, S. 950, S.892, H.R. 1999, H.R. 1696, S. 670, H.R. 2587, and H.R. 4.

[*58*] AEO2001 National Energy Modeling System, runs OMBREF.D081301A, TRGM0O2R.D081301A, and TRGM0O0Z.D081601C.

[*59*] Because power companies accumulated (banked) emissions allowances during Phase I of the program (1995 to 1999), the Phase II cap of 8.95 million tons per year will not become binding until the banked allowances have been exhausted.

[*60*] In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

[*61*] Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/index. html.

[*62*] Energy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants,* SR/OIAF/2001-04 (Washington, DC, September 2001), web site www.eia.doe.gov/oiaf/servicerpt/mepp/pdf/sroiaf(2001)04.pdf.

[*63*] Energy Information Administration, *Analysis of Strategies for Reducing Emissions from Electric Power Plants with Advanced Technology Scenarios*, SR/OIAF/2001-05 (Washington, DC, October 2001), web site www.eia.doe.gov/oiaf/servicerpt/eppats/pdf/sroiaf(2001)05.pdf.

[*64*] Numerous policy instruments are available, including taxes, maximum achievable control technology (MACT), no-cost allowance allocation with cap and trade, allowance auction with cap and trade, and generation performance standard (GPS) allowance allocation with cap and trade. Each of the options would have different price and cost impacts.

[*65*] One case prepared for this analysis assumed that emissions allowances would be treated as having zero value in regions where electricity prices continue to be based on cost of service rather than competitive pricing.

[*66*] In the early years of the forecast, electricity prices are projected to be higher in the case that combines an RPS with caps on NO_x, SO_2, and Hg emissions than in the case that includes only the four emission caps.

[*67*] Retail electricity prices are assumed to be determined competitively in regions where most of the States have passed legislation or issued regulatory orders to deregulate their electricity sectors. In other regions, retail electricity prices are assumed to continue to be based on cost of service pricing.

[*68*] Cogenerators currently account for approximately 8 percent of total generation, with approximately two-thirds being generated from natural gas.

[*69*] Emission leakage occurs when control programs in a covered sector lead to actions that increase emissions in a sector not covered by the program.

[*70*] Interlaboratory Working Group, *Scenarios for a Clean Energy Future,* ORNL/CON-476 and LBNL-44029 (Oak Ridge National Laboratory, Oak Ridge, TN, and Lawrence Berkeley National Laboratory, Berkeley, CA, November 2000), web site www.ornl.gov/ORNL/Energy_Eff/CEFOnep.pdf.

[*71*] The ratio of energy service output to energy input is a typical measure of energy efficiency. For a thorough discussion of the issues involved in measuring efficiency, see Energy Information Administration, *Measuring Energy Efficiency in the United States' Economy: A Beginning*, DOE/EIA-0555(95)/2 (Washington, DC, October 1995); and E. Burns and S. Battles, "United States Energy Usage and Efficiency: Measuring Changes Over Time," presentation to the 17th Congress of the World Energy Council (Houston, TX, September 14, 1998).

[*72*] This assumption is bolstered by the increasing popularity of sport utility vehicles despite their higher prices. Possible differences between the transportation services provided by light trucks and those provided by cars include increased safety in collisions with smaller vehicles, better view of the road, four-wheel drive capability, and larger cargo capacity.

[*73*] The use of separate combinations of end use and fuel type removes the effects of fuel switching from the efficiency calculations. For example, a home heated with a natural gas furnace consumes more energy on site than does a home heated with an electric heat pump. If space heating were not delineated by fuel, a situation akin to the light-duty vehicle issue described above could arise. That is, a shift from electric heat to gas heat over time would be measured as an efficiency loss.

[*74*] The index used to construct the ACEI is the Tornqvist index (also referred to as the Discrete Divisia index). It is somewhat different from the CPI indexing procedure, using the average of base period and current period weights applied to percentage changes computed logarithmically. This index has a number of attractive theoretical features and is often used when data availability is not a constraint. For more information see W.E. Diewert, "Exact and Superlative Index Numbers," *Journal of Econometrics*, Vol. 4 (1976), pp. 115-145; and B.M. Balk and W.E. Diewert, "A Characterization of the Tornqvist Price Index, Discussion Paper No. 00-16, The University of British Columbia (October 2000).

Market Trends

[*75*] Based on DRI-WEFA, Simulation T250701 (July 2001).

[*76*] 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).

[*77*] 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.

[*78*] The high and low macroeconomic growth cases are linked to higher and lower population growth, respectively, which affects energy use in all sectors.

[*79*] The definition of the commercial sector for *AEO2002* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS). See Energy Information Administration, 1995 CBECS Micro-Data Files (February 17, 1998), web site www.eia.doe.gov/emeu/cbecs/. Nonsampling and sampling errors (found in any statistical sample survey) and a change in the target building population resulted in a lower commercial floorspace estimate than found with the previous CBECS. In addition, 1995 CBECS energy intensities for specific end uses varied from earlier estimates, providing a different composition of end-use consumption. These factors contribute to the pattern of commercial energy use projected for *AEO2002*. Energy consumption data from the 1999 CBECS were not available at the time of publication. Further discussion is provided in Appendix G.

[*80*] 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).

[*81*] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence.

[*82*] 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.

[*83*] 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, R. Cuenca, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*84*] Values for incremental investments and energy expenditure savings are discounted back to 2001 at a 7-percent real discount rate.

[*85*] Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and cogenerator capacity.

[*86*] *AEO2002* does not include off-grid photovoltaics (PV). EIA estimates that another 76 megawatts of remote electricity generation PV applications were in service in 1999, plus an additional 205 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See *Annual Energy Review 2000,* Table 10.6. Remote electric generation means electricity generated for general application that does not interact with the electrical distribution system, such as at isolated residential sites. Other off-grid PV end uses include electricity generation but only for application-specific uses, such as remote water pumping and highway safety signs.

[*87*] 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.

[*88*] Because the reference case assumes current law, the *AEO2002* projections exclude 382 megawatts of additional post-2001 wind capacity planned for Colorado, Montana, New York, and Pennsylvania because it is dependent upon extension of the Federal 1.7-cents-per-kilowatthour production tax credit, currently scheduled to expire December 31, 2001.

[*89*] Enhanced oil recovery (EOR) is the additional extraction of oil from a reservoir beyond what would be produced by primary and secondary (water flooding) recovery methods and involves the injection of heated fluids, pressured gases, or special chemicals into the oil reservoir. Because EOR oil production is considerably more expensive than primary and secondary oil recovery techniques, the deployment of EOR technology is particularly sensitive to prevailing crude oil prices.

[*90*] Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001).

[*91*] 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.

[*92*] 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.

[*93*] U.S. Environmental Protection Agency, web site www.epa.gov/acidrain/overview.html (September 1997).

[*94*] 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 for five cases: Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Table 2. Effective dates of appliance efficiency standards, 1988-2007: Office of Integrated Analysis and Forecasting.

Table 3. Key results for the electricity generation sector in the House analysis, 2010 and 2020: Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/ servicerpt/epp/index.html.

Table 4. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis without holding carbon dioxide emissions to 2008 levels, 2010 and 2020: Energy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, SR/OIAF/2001-04 (Washington, DC, September 2001), web site www. eia. doe. gov/ oiaf/ servicerpt/ mepp/ pdf/ sroiaf (2001) 04.pdf.

Table 5. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis holding carbon dioxide emissions to 2008 levels, 2020: Energy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, SR/OIAF/2001-04 (Washington, DC, September 2001), web site www.eia.doe.gov/ oiaf/servicerpt/mepp/pdf/sroiaf(2001)04.pdf.

Table 6. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, reference and advanced technology cases, 2010 and 2020: Energy Information Administration, *Analysis of Strategies for Reducing Emissions from Electric Power Plants with Advanced Technology Scenarios*, SR/OIAF/2001-05 (Washington, DC, October 2001), web site www.doe.gov/ oiaf/servicerpt/eppats/pdf/sroiaf(2001)05.pdf.

Table 7. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, CEF-JL moderate and advanced technology cases, 2010 and 2020: Energy Information Administration, *Analysis of Strategies for Reducing Emissions from Electric Power Plants with Advanced Technology Scenarios*, SR/OIAF/ 2001-05 (Washington, DC, October 2001), web site www.eia.doe.gov/servicerpt/eppats/pdf/sroiaf(2001)05.pdf.

Table 8. New car and light truck horsepower ratings and market shares, 1990-2020: History: U.S. Department of Transportation, National Highway Traffic Safety Administration. **Projections:** AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Table 9. Costs of producing electricity from new plants, 2005 and 2020: AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Table 10. Technically recoverable U.S. natural gas resources as of January 1, 2000: Energy Information Administration, Office of Integrated Analysis and Forecasting. Note: The values shown in the table differ from those shown in the comparable table (Table 14) in *AEO2001*. The differences result from: (1) an accounting of net reserve additions and production in 1999, (2) the use of a more refined method to estimate the share of resources in areas where drilling is officially prohibited, (3) new estimates of offshore resources from the Minerals Management Service, and (4) elimination of a double-counting error for lower 48 associated-dissolved gas undiscovered resources in the *AEO2001* table (but not in the *AEO2001* model resource inputs).

Table 11. Lower 48 natural gas drilling in three cases, 2000-2020: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LM2002.D102001B, and HM2002. D102001B.

Table 12. Crude oil drilling in three cases, 2000-2020: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LW2002.D102001B, and HW2002. D102001B.

Table 13. Technically recoverable U.S. crude oil resources as of January 1, 2000: Energy Information Administration, Office of Integrated Analysis and Forecasting. Note: The values shown in the table differ from those shown in the comparable table (Table 14) in *AEO2001*. The differences result from: (1) an accounting of net reserve additions and production in 1999, (2) the use of a more refined method to estimate the share of resources in areas where drilling is officially prohibited, (3) new estimates of offshore resources from the Minerals Management Service, and (4) exclusion of natural gas liquids, which were erroneously included in the *AEO2001* table (but not in the *AEO2001* model resource inputs).

Table 14. Crude oil production from Gulf of Mexico offshore, 2000-2020: AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Table 15. Petroleum consumption and net imports in five cases, 2000 and 2020: 2000: Energy Information Administration, *Petroleum Supply Annual 2000*, Vol. 1, DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). **Projections:** Tables A11, B11, and C11.

Table 16. Forecasts of economic growth, 2000-2020: *AEO2002*: Table B20. DRI-WEFA: Simulation T250701 (July 2001).

Table 17. Forecasts of world oil prices, 2000-2020: *AEO2002*: Tables A1 and C1. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **IEA:** International Energy Agency, *World Energy Outlook 2000*. **PEL:** Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (June 2001). PIRA: PIRA Energy Group, "Retainer Client Seminar" (October 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001). **NRCan:** Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (January 2000). **DBAB:** Deutsche Banc Alex.Brown, World Oil Supply and Demand Estimates (July 2001).

Table 18. Forecasts of average annual growth rates for energy consumption: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). ***AEO2002*:** Table A2. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001). **Note:** Delivered energy includes petroleum, natural gas, coal, and electricity (excluding generation and transmission losses) consumed in the residential, commercial, industrial, and transportation sectors.

Table 19. Forecasts of average annual growth in residential and commercial energy demand: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). ***AEO2002*:** Table A2. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Table 20. Forecasts of average annual growth in industrial energy demand: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). ***AEO2002*:** Table A2. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Table 21. Forecasts of average annual growth in transportation energy demand: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001); Federal Highway Administration, *Highway Statistics 1999* (Washington, DC, 2001); Research and Special Programs Administration, "Fuel Cost and Consumption Tables"; and National Highway Transportation Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2001). ***AEO2002*:** Tables A2, A3, and A7. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Table 22. Comparison of electricity forecasts: *AEO2002*: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LM2002.D102001B, and HM2002.D102001B. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Table 23. Comparison of natural gas forecasts: *AEO2002*: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LM2002.D102001B, and HM2002.D102001B. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001).

Table 24. Comparison of petroleum forecasts: *AEO2002*: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LW2002.D102001B, and HW2002.D102001B. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand to 2020*, 2001 Edition (March 2001). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 2001).

Table 25. Comparison of coal forecasts: *AEO2002*: AEO2002 National Energy Modeling System, runs AEO2002.D102001B, LM2002.D102001B, and HM2002.D102001B. **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook* (Spring/Summer 2001). **Hill & Associates:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2020* (March 2001).

Figure Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and F of this report.

Figure 1. Energy price projections, 2000-2020: *AEO2001* and *AEO2002* compared: *AEO2001* projections: Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000). ***AEO2002* projections:** Table A1.

Figure 2. Energy consumption by fuel, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Tables A1 and A18.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Table A20.

Figure 4. Electricity generation by fuel, 1970-2020: History: Energy Information Administration (EIA), Form EIA-860B, "Annual Electric Generator Report—Nonutility"; EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001); and Edison Electric Institute. **Projections:** Table A8.

Figure 5. Total energy production and consumption, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Table A1.

Figure 6. Energy production by fuel, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Tables A1 and A18.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001). **Projections:** Table A19.

Figure 8. Direct access customers in California's retail electricity market, 1998-2001: California Public Utility web site www.cpuc.ca.gov/static/industry/electric/electric+restructuring/direct+access+and+retail+competition.

Figure 9. Direct access customer load in California's retail electricity market, 1998-2000: California Public Utility web site www.cpuc.ca.gov/static/industry/electric/electric+restructuring/direct+access+and+retail+competition.

Figure 10. California's Power Exchange (PX) energy price, 1998-2000: California Public Utility web site www.cpuc.ca.gov/static/industry/electric/electric+restructuring/direct+access+and+retail+competition.

Figure 11. Comparison of projections for the aggregate composite efficiency index, energy use per dollar of gross domestic product, and energy use per capita, 2000-2020: AEO2002 National Energy Modeling System.

Figure 12. Projected primary energy consumption in the reference case and in alternative cases assuming no change in energy efficiency and energy intensity, 2000-2020: AEO2002 National Energy Modeling System.

Figure 13. Projected average annual real growth rates of economic factors, 2000-2020: History: U.S. Department of Commerce, Bureau of Economic Analysis. **Projections:** AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Figure 14. Projected sectoral composition of GDP growth, 2000-2020: History: U.S. Department of Commerce, Bureau of Economic Analysis. **Projections:** AEO2002 National Energy Modeling System, run AEO2002.D102001B.

Figure 15. Projected average annual real growth rates of economic factors in three cases, 2000-2020: History: U.S. Department of Commerce, Bureau of Economic Analysis. **Projections:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B, HM2002.D102001B, and LM2002.D102001B.

Figure 16. Annual GDP growth rate for the preceding 20 years, 1970-2020: History: U.S. Department of Commerce, Bureau of Economic Analysis. **Projections:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B, HM2002.D102001B, and LM2002.D102001B.

Figure 17. World oil prices in three cases, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Tables A1 and C1.

Figure 18. OPEC oil production in three cases, 1970-2020: History: Energy Information Administration, *International Petroleum Monthly*, DOE/EIA-0520(2001/09) (Washington, DC, September 2001). **Projections:** Tables A21 and C21.

Figure 19. Non-OPEC oil production in three cases, 1970-2020: History: Energy Information Administration, *International Petroleum Monthly*, DOE/EIA-0520(2001/09) (Washington, DC, September 2001). **Projections:** Tables A21 and C21.

Figure 20. Persian Gulf share of worldwide crude oil exports in three cases, 1965-2020: History: Energy Information Administration, *International Petroleum Monthly*, DOE/EIA-0520(2001/09) (Washington, DC, September 2001). **Projections:** AEO2002 National Energy Modeling System, runs AEO2002.D102001B, HW2002.D102001B, and LW2002.D102001B.

Figure 21. Projected U.S. gross petroleum imports by source, 2000-2020: AEO2002 National Energy Modeling System, run AEO2002.D102001B; and World Oil, Refining, Logistics, and Demand (WORLD) Model, run AEO02B.

Figure 22. Projected worldwide refining capacity by region, 2000 and 2020: History: *Oil and Gas Journal*, Energy Database (January 2000). **Projections:** AEO2002 National Energy Modeling System, run AEO2002.D102001B; and World Oil, Refining, Logistics, and Demand (WORLD) Model, run AEO02B.

Figure 23. Primary and delivered energy consumption, excluding transportation use, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Table A2.

Figure 24. Energy use per capita and per dollar of gross domestic product, 1970-2020: History: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** Table A2.

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Appendixes

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	12.43	12.33	11.38	10.76	11.76	11.92	-0.2%
Natural Gas Plant Liquids	2.62	2.71	3.02	3.37	3.74	4.03	2.0%
Dry Natural Gas	19.20	19.59	21.29	24.12	27.03	29.25	2.0%
Coal	23.15	22.58	24.95	26.23	26.91	28.11	1.1%
Nuclear Power	7.74	8.03	8.10	7.87	7.55	7.49	-0.3%
Renewable Energy[1]	6.69	6.46	7.37	7.89	8.47	8.93	1.6%
Other[2]	1.66	1.10	0.68	0.85	1.04	0.93	-0.8%
Total	**73.50**	**72.80**	**76.79**	**81.09**	**86.51**	**90.66**	**1.1%**
Imports							
Crude Oil[3]	18.96	19.69	22.63	24.36	24.04	24.45	1.1%
Petroleum Products[4]	4.19	4.73	5.68	7.83	10.31	12.69	5.1%
Natural Gas	3.66	3.85	5.01	5.64	6.04	6.20	2.4%
Other Imports[5]	0.56	0.76	1.07	0.95	1.07	1.09	1.8%
Total	**27.37**	**29.04**	**34.39**	**38.79**	**41.46**	**44.44**	**2.2%**
Exports							
Petroleum[6]	1.96	2.15	1.70	1.91	2.02	2.11	-0.1%
Natural Gas	0.16	0.25	0.41	0.63	0.66	0.56	4.2%
Coal	1.52	1.53	1.41	1.36	1.34	1.38	-0.5%
Total	**3.64**	**3.93**	**3.52**	**3.90**	**4.01**	**4.05**	**0.2%**
Discrepancy[7]	**0.13**	**-1.37**	**0.04**	**0.37**	**0.32**	**0.20**	**N/A**
Consumption							
Petroleum Products[8]	38.25	38.63	41.40	45.20	48.85	51.99	1.5%
Natural Gas	22.57	23.43	26.16	28.85	32.14	34.63	2.0%
Coal	21.56	22.34	24.03	25.41	26.16	27.35	1.0%
Nuclear Power	7.74	8.03	8.10	7.87	7.55	7.49	-0.3%
Renewable Energy[1]	6.70	6.48	7.37	7.90	8.48	8.94	1.6%
Other[9]	0.28	0.38	0.55	0.38	0.46	0.44	0.7%
Total	**97.10**	**99.29**	**107.61**	**115.61**	**123.64**	**130.85**	**1.4%**
Net Imports - Petroleum	**21.19**	**22.28**	**26.61**	**30.29**	**32.33**	**35.04**	**2.3%**
Prices (2000 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.60	27.72	22.73	23.36	24.00	24.68	-0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.27	3.60	2.66	2.85	3.07	3.26	-0.5%
Coal Minemouth Price (dollars per ton)	17.01	16.45	14.99	14.11	13.44	12.79	-1.3%
Average Electricity Price (cents per kilowatthour)	6.7	6.9	6.4	6.3	6.3	6.5	-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, 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 and heat loss when natural gas 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 coal minemouth prices: EIA, *Coal Industry Annual 1999*, DOE/EIA-0584(99) (Washington, DC, June 2001). Other 1999 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 2000 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000).
Projections: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Energy Consumption							
Residential							
Distillate Fuel	0.81	0.83	0.85	0.79	0.75	0.73	-0.6%
Kerosene	0.11	0.09	0.08	0.07	0.07	0.07	-1.5%
Liquefied Petroleum Gas	0.53	0.47	0.44	0.45	0.42	0.41	-0.7%
Petroleum Subtotal	1.46	1.38	1.37	1.30	1.24	1.20	-0.7%
Natural Gas	4.86	5.14	5.53	5.68	5.89	6.15	0.9%
Coal	0.04	0.04	0.05	0.05	0.05	0.05	0.6%
Renewable Energy[1]	0.40	0.43	0.43	0.43	0.44	0.45	0.2%
Electricity	3.91	4.07	4.62	4.92	5.30	5.70	1.7%
Delivered Energy	**10.67**	**11.06**	**11.99**	**12.40**	**12.92**	**13.55**	**1.0%**
Electricity Related Losses	8.44	8.79	9.72	9.85	10.25	10.72	1.0%
Total	**19.10**	**19.85**	**21.71**	**22.24**	**23.17**	**24.27**	**1.0%**
Commercial							
Distillate Fuel	0.42	0.38	0.42	0.42	0.42	0.42	0.5%
Residual Fuel	0.09	0.14	0.12	0.12	0.13	0.13	-0.1%
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	1.2%
Liquefied Petroleum Gas	0.09	0.08	0.08	0.09	0.09	0.10	0.9%
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Petroleum Subtotal	0.65	0.65	0.67	0.69	0.70	0.71	0.4%
Natural Gas	3.14	3.36	3.77	4.04	4.33	4.64	1.6%
Coal	0.07	0.07	0.07	0.07	0.07	0.08	0.7%
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Electricity	3.77	3.90	4.46	5.03	5.62	6.13	2.3%
Delivered Energy	**7.70**	**8.07**	**9.05**	**9.91**	**10.80**	**11.64**	**1.9%**
Electricity Related Losses	8.13	8.42	9.38	10.06	10.85	11.53	1.6%
Total	**15.84**	**16.49**	**18.42**	**19.98**	**21.65**	**23.18**	**1.7%**
Industrial[4]							
Distillate Fuel	1.08	1.11	1.17	1.22	1.29	1.38	1.1%
Liquefied Petroleum Gas	2.26	2.36	2.50	2.66	2.85	3.00	1.2%
Petrochemical Feedstock	1.31	1.32	1.36	1.45	1.54	1.59	0.9%
Residual Fuel	0.25	0.27	0.18	0.23	0.26	0.27	0.1%
Motor Gasoline[2]	0.15	0.22	0.23	0.24	0.26	0.27	1.2%
Other Petroleum[5]	4.35	3.96	4.36	4.77	4.99	5.17	1.3%
Petroleum Subtotal	9.40	9.23	9.80	10.57	11.19	11.69	1.2%
Natural Gas[6]	9.95	9.79	10.43	11.19	11.77	12.19	1.1%
Metallurgical Coal	0.75	0.77	0.69	0.64	0.59	0.54	-1.8%
Steam Coal	1.69	1.69	1.72	1.74	1.79	1.85	0.5%
Net Coal Coke Imports	0.06	0.06	0.07	0.11	0.14	0.16	4.6%
Coal Subtotal	2.50	2.53	2.49	2.50	2.51	2.55	0.0%
Renewable Energy[7]	2.29	2.41	2.66	2.89	3.18	3.43	1.8%
Electricity	3.61	3.65	3.80	4.20	4.53	4.83	1.4%
Delivered Energy	**27.75**	**27.62**	**29.17**	**31.35**	**33.19**	**34.69**	**1.1%**
Electricity Related Losses	7.80	7.89	7.98	8.39	8.76	9.08	0.7%
Total	**35.54**	**35.50**	**37.15**	**39.74**	**41.96**	**43.76**	**1.1%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Transportation							
Distillate Fuel[8]	5.16	5.42	6.35	7.27	8.09	8.72	2.4%
Jet Fuel[9]	3.46	3.58	3.88	4.46	5.12	5.82	2.5%
Motor Gasoline[2]	15.86	16.05	17.67	19.32	20.86	22.12	1.6%
Residual Fuel	0.93	1.14	1.07	1.08	1.09	1.10	-0.2%
Liquefied Petroleum Gas	0.02	0.02	0.03	0.04	0.04	0.05	4.6%
Other Petroleum[10]	0.22	0.22	0.25	0.26	0.28	0.29	1.4%
Petroleum Subtotal	25.65	26.42	29.24	32.43	35.48	38.11	1.8%
Pipeline Fuel Natural Gas	0.75	0.79	0.80	0.86	0.95	1.02	1.3%
Compressed Natural Gas	0.02	0.02	0.06	0.09	0.12	0.14	9.8%
Renewable Energy (E85)[11]	0.01	0.02	0.03	0.03	0.04	0.05	5.0%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.06	0.06	0.07	0.08	0.09	0.11	3.1%
Delivered Energy	**26.49**	**27.32**	**30.19**	**33.50**	**36.69**	**39.43**	**1.9%**
Electricity Related Losses	0.13	0.13	0.15	0.16	0.18	0.21	2.4%
Total	**26.61**	**27.45**	**30.33**	**33.66**	**36.87**	**39.64**	**1.9%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.47	7.73	8.78	9.70	10.55	11.24	1.9%
Kerosene	0.15	0.14	0.13	0.13	0.12	0.12	-0.6%
Jet Fuel[9]	3.46	3.58	3.88	4.46	5.12	5.82	2.5%
Liquefied Petroleum Gas	2.90	2.93	3.05	3.23	3.41	3.56	1.0%
Motor Gasoline[2]	16.04	16.29	17.93	19.59	21.14	22.42	1.6%
Petrochemical Feedstock	1.31	1.32	1.36	1.45	1.54	1.59	0.9%
Residual Fuel	1.26	1.54	1.37	1.43	1.48	1.51	-0.1%
Other Petroleum[12]	4.56	4.16	4.59	5.01	5.25	5.44	1.4%
Petroleum Subtotal	37.15	37.69	41.07	45.00	48.61	51.71	1.6%
Natural Gas[6]	18.71	19.11	20.58	21.87	23.06	24.14	1.2%
Metallurgical Coal	0.75	0.77	0.69	0.64	0.59	0.54	-1.8%
Steam Coal	1.80	1.80	1.83	1.86	1.91	1.98	0.5%
Net Coal Coke Imports	0.06	0.06	0.07	0.11	0.14	0.16	4.6%
Coal Subtotal	2.61	2.64	2.60	2.62	2.64	2.68	0.1%
Renewable Energy[13]	2.79	2.93	3.19	3.44	3.74	4.00	1.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.34	11.69	12.94	14.23	15.54	16.77	1.8%
Delivered Energy	**72.60**	**74.06**	**80.39**	**87.15**	**93.60**	**99.31**	**1.5%**
Electricity Related Losses	24.50	25.23	27.22	28.46	30.04	31.54	1.1%
Total	**97.10**	**99.29**	**107.61**	**115.61**	**123.64**	**130.85**	**1.4%**
Electric Generators[14]							
Distillate Fuel	0.09	0.08	0.06	0.05	0.05	0.06	-0.9%
Residual Fuel	1.01	0.86	0.26	0.16	0.19	0.22	-6.7%
Petroleum Subtotal	1.10	0.93	0.32	0.21	0.24	0.28	-5.9%
Natural Gas	3.86	4.32	5.58	6.98	9.08	10.49	4.5%
Steam Coal	18.95	19.69	21.44	22.80	23.52	24.67	1.1%
Nuclear Power	7.74	8.03	8.10	7.87	7.55	7.49	-0.3%
Renewable Energy[15]	3.91	3.55	4.18	4.46	4.74	4.94	1.7%
Electricity Imports[16]	0.28	0.38	0.54	0.38	0.45	0.44	0.7%
Total	**35.84**	**36.92**	**40.16**	**42.69**	**45.58**	**48.32**	**1.4%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Total Energy Consumption							
Distillate Fuel	7.56	7.80	8.84	9.75	10.61	11.31	1.9%
Kerosene	0.15	0.14	0.13	0.13	0.12	0.12	-0.6%
Jet Fuel[9]	3.46	3.58	3.88	4.46	5.12	5.82	2.5%
Liquefied Petroleum Gas	2.90	2.93	3.05	3.23	3.41	3.56	1.0%
Motor Gasoline[2]	16.04	16.29	17.93	19.59	21.14	22.42	1.6%
Petrochemical Feedstock	1.31	1.32	1.36	1.45	1.54	1.59	0.9%
Residual Fuel	2.27	2.40	1.63	1.59	1.67	1.72	-1.6%
Other Petroleum[12]	4.56	4.16	4.59	5.01	5.25	5.44	1.4%
Petroleum Subtotal	38.25	38.63	41.40	45.20	48.85	51.99	1.5%
Natural Gas	22.57	23.43	26.16	28.85	32.14	34.63	2.0%
Metallurgical Coal	0.75	0.78	0.69	0.64	0.59	0.54	-1.8%
Steam Coal	20.75	21.50	23.27	24.66	25.43	26.65	1.1%
Net Coal Coke Imports	0.06	0.07	0.07	0.11	0.14	0.16	4.6%
Coal Subtotal	21.56	22.34	24.03	25.41	26.16	27.35	1.0%
Nuclear Power	7.74	8.03	8.10	7.87	7.55	7.49	-0.3%
Renewable Energy[17]	6.70	6.48	7.37	7.90	8.48	8.94	1.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports[16]	0.28	0.38	0.54	0.38	0.45	0.44	0.7%
Total	**97.10**	**99.29**	**107.61**	**115.61**	**123.64**	**130.85**	**1.4%**
Energy Use and Related Statistics							
Delivered Energy Use	72.60	74.06	80.39	87.15	93.60	99.31	1.5%
Total Energy Use	97.10	99.29	107.61	115.61	123.64	130.85	1.4%
Population (millions)	273.25	275.69	288.09	300.24	312.66	325.33	0.8%
Gross Domestic Product (billion 1996 dollars)	8,857	9,224	10,418	12,312	14,399	16,525	3.0%
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1,517.2	1,561.7	1,693.5	1,834.7	1,965.4	2,087.8	1.5%

[1]Includes wood used for residential heating. See Table A18 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 electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. 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 cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, 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 all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. 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 cogeneration. Excludes net electricity imports.
[16]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]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 1999 and 2000 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: 1999 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 and 2000 electric utility fuel consumption: EIA, *Electric Power Annual 1999, Volume 1,* DOE/EIA-0348(99)/1 (Washington, DC, August 2000). 1999 and 2000 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A3. Energy Prices by Sector and Source
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Residential	**13.53**	**14.42**	**13.34**	**13.50**	**13.68**	**14.04**	**-0.1%**
Primary Energy[1]	6.89	8.26	7.33	7.27	7.40	7.49	-0.5%
Petroleum Products[2]	7.85	10.78	9.45	9.84	10.29	10.41	-0.2%
Distillate Fuel	6.39	9.42	7.68	7.94	8.43	8.54	-0.5%
Liquefied Petroleum Gas	10.50	13.65	12.91	13.26	13.65	13.81	0.1%
Natural Gas	6.65	7.64	6.85	6.73	6.84	6.97	-0.5%
Electricity	24.33	24.36	22.38	22.41	22.18	22.55	-0.4%
Commercial	**13.21**	**14.03**	**12.96**	**12.89**	**13.15**	**13.57**	**-0.2%**
Primary Energy[1]	5.25	6.31	5.60	5.57	5.77	5.93	-0.3%
Petroleum Products[2]	5.15	7.19	6.10	6.36	6.77	6.91	-0.2%
Distillate Fuel	4.46	7.08	5.45	5.73	6.25	6.39	-0.5%
Residual Fuel	2.65	3.46	3.75	3.83	3.92	4.02	0.8%
Natural Gas[3]	5.34	6.23	5.58	5.51	5.68	5.86	-0.3%
Electricity	21.37	22.11	20.40	19.87	19.85	20.33	-0.4%
Industrial[4]	**5.32**	**6.88**	**5.73**	**5.97**	**6.27**	**6.49**	**-0.3%**
Primary Energy	3.97	5.69	4.49	4.76	5.05	5.19	-0.5%
Petroleum Products[2]	5.53	8.10	6.36	6.69	7.08	7.13	-0.6%
Distillate Fuel	4.71	7.21	5.54	5.89	6.52	6.70	-0.4%
Liquefied Petroleum Gas	8.77	11.73	8.28	8.60	8.98	9.11	-1.3%
Residual Fuel	2.75	3.27	3.57	3.65	3.74	3.86	0.8%
Natural Gas[5]	3.00	4.31	3.30	3.47	3.69	3.90	-0.5%
Metallurgical Coal	1.71	1.62	1.60	1.56	1.52	1.46	-0.5%
Steam Coal	1.43	1.41	1.35	1.30	1.26	1.21	-0.8%
Electricity	13.00	13.50	12.72	12.54	12.62	13.04	-0.2%
Transportation	**8.46**	**10.88**	**9.58**	**9.98**	**10.04**	**9.99**	**-0.4%**
Primary Energy	8.43	10.86	9.57	9.96	10.02	9.96	-0.4%
Petroleum Products[2]	8.43	10.86	9.56	9.96	10.01	9.96	-0.4%
Distillate Fuel[6]	8.36	10.81	9.23	10.14	10.09	9.98	-0.4%
Jet Fuel[7]	4.81	7.36	5.52	5.87	6.32	6.37	-0.7%
Motor Gasoline[8]	9.67	12.20	11.02	11.27	11.28	11.28	-0.4%
Residual Fuel	2.59	4.38	3.40	3.48	3.57	3.67	-0.9%
Liquefied Petroleum Gas[9]	13.09	15.91	14.15	14.43	14.70	14.65	-0.4%
Natural Gas[10]	6.14	8.04	6.64	6.89	7.13	7.28	-0.5%
Ethanol (E85)[11]	14.78	17.33	19.17	20.59	21.71	21.19	1.0%
Electricity	20.95	21.78	16.56	18.20	19.27	17.91	-1.0%
Average End-Use Energy	**8.64**	**10.40**	**9.28**	**9.53**	**9.73**	**9.90**	**-0.2%**
Primary Energy	6.41	8.41	7.28	7.61	7.81	7.89	-0.3%
Electricity	19.72	20.20	18.83	18.58	18.53	18.97	-0.3%
Electric Generators[12]							
Fossil Fuel Average	1.51	1.88	1.58	1.61	1.77	1.85	-0.1%
Petroleum Products	2.59	4.33	3.80	3.97	4.14	4.27	-0.1%
Distillate Fuel	4.22	6.89	4.93	5.23	5.73	5.87	-0.8%
Residual Fuel	2.45	4.11	3.53	3.60	3.69	3.81	-0.4%
Natural Gas	2.64	4.41	3.19	3.38	3.65	3.87	-0.6%
Steam Coal	1.22	1.20	1.13	1.05	1.01	0.97	-1.1%

Table A3. Energy Prices by Sector and Source (Continued)
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Average Price to All Users[13]							
Petroleum Products[2]	7.55	10.05	8.78	9.19	9.35	9.34	-0.4%
Distillate Fuel	7.36	9.93	8.38	9.22	9.37	9.33	-0.3%
Jet Fuel	4.81	7.36	5.52	5.87	6.32	6.37	-0.7%
Liquefied Petroleum Gas	9.12	12.06	9.06	9.37	9.70	9.79	-1.0%
Motor Gasoline[8]	9.67	12.20	11.02	11.27	11.28	11.28	-0.4%
Residual Fuel	2.55	4.11	3.46	3.54	3.64	3.75	-0.5%
Natural Gas	4.15	5.43	4.45	4.47	4.61	4.79	-0.6%
Coal	1.24	1.22	1.15	1.07	1.03	0.98	-1.1%
Ethanol (E85)[11]	14.78	17.33	19.17	20.59	21.71	21.19	1.0%
Electricity	19.72	20.20	18.83	18.58	18.53	18.97	-0.3%
Non-Renewable Energy Expenditures by Sector (billion 2000 dollars)							
Residential	138.85	153.41	154.25	161.45	170.74	184.01	0.9%
Commercial	100.72	112.06	116.21	126.73	140.90	156.92	1.7%
Industrial	113.77	142.86	124.06	136.11	150.46	162.53	0.6%
Transportation	217.56	288.38	281.21	325.09	357.95	382.65	1.4%
Total Non-Renewable Expenditures	570.90	696.71	675.73	749.39	820.07	886.10	1.2%
Transportation Renewable Expenditures	0.17	0.31	0.48	0.70	0.88	1.00	6.1%
Total Expenditures	**571.07**	**697.01**	**676.21**	**750.09**	**820.95**	**887.11**	**1.2%**

[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]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes use for lease and plant fuel.
[6]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[13]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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1999*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2000). 2000 prices for gasoline, distillate, and jet fuel are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf. 1999 and 2000 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 electric generators natural gas delivered prices, Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1999 and 2000 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 1999 and 2000 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. 1999 residential electricity prices derived from EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/ forecasting/steo/oldsteos/oct01.pdf. 1999 and 2000 electricity prices for commercial, industrial, and transportation: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Key Indicators and Consumption	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Key Indicators							
Households (millions)							
Single-Family	75.67	76.57	81.18	85.88	90.55	95.27	1.1%
Multifamily	21.79	21.97	22.59	23.15	23.77	24.58	0.6%
Mobile Homes	6.59	6.61	6.63	6.95	7.14	7.27	0.5%
Total	**104.05**	**105.15**	**110.41**	**115.98**	**121.46**	**127.12**	**1.0%**
Average House Square Footage	**1673**	**1678**	**1707**	**1735**	**1762**	**1787**	**0.3%**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.5	105.2	108.6	106.9	106.4	106.6	0.1%
Total Energy Consumption	183.6	188.8	196.6	191.8	190.7	190.9	0.1%
(thousand Btu per square foot)							
Delivered Energy Consumption	61.3	62.7	63.6	61.6	60.4	59.6	-0.2%
Total Energy Consumption	109.8	112.5	115.2	110.5	108.2	106.8	-0.3%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.42	0.46	0.48	0.50	0.53	1.2%
Space Cooling	0.55	0.56	0.60	0.63	0.68	0.75	1.5%
Water Heating	0.40	0.41	0.42	0.41	0.41	0.39	-0.2%
Refrigeration	0.43	0.43	0.38	0.34	0.32	0.32	-1.4%
Cooking	0.10	0.11	0.11	0.12	0.12	0.13	1.0%
Clothes Dryers	0.22	0.23	0.24	0.25	0.26	0.28	1.0%
Freezers	0.12	0.12	0.10	0.09	0.09	0.09	-1.5%
Lighting	0.34	0.35	0.41	0.45	0.48	0.51	1.8%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	1.1%
Color Televisions	0.12	0.13	0.17	0.20	0.23	0.26	3.4%
Personal Computers	0.04	0.04	0.06	0.08	0.10	0.11	4.5%
Furnace Fans	0.08	0.08	0.09	0.10	0.10	0.11	1.8%
Other Uses[2]	1.06	1.14	1.51	1.71	1.95	2.16	3.2%
Delivered Energy	**3.91**	**4.07**	**4.62**	**4.92**	**5.30**	**5.70**	**1.7%**
Natural Gas							
Space Heating	3.20	3.44	3.69	3.82	3.99	4.22	1.0%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	10.1%
Water Heating	1.28	1.32	1.42	1.44	1.46	1.47	0.5%
Cooking	0.19	0.20	0.21	0.22	0.24	0.25	1.2%
Clothes Dryers	0.07	0.07	0.08	0.09	0.10	0.10	2.0%
Other Uses[3]	0.11	0.12	0.12	0.11	0.11	0.11	-0.4%
Delivered Energy	**4.86**	**5.14**	**5.53**	**5.68**	**5.89**	**6.15**	**0.9%**
Distillate							
Space Heating	0.68	0.70	0.72	0.67	0.64	0.63	-0.6%
Water Heating	0.13	0.12	0.13	0.12	0.11	0.10	-1.0%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.81**	**0.83**	**0.85**	**0.79**	**0.75**	**0.73**	**-0.6%**
Liquefied Petroleum Gas							
Space Heating	0.36	0.33	0.31	0.31	0.30	0.29	-0.7%
Water Heating	0.12	0.10	0.09	0.09	0.09	0.08	-1.0%
Cooking	0.04	0.03	0.03	0.03	0.03	0.03	-0.2%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%
Delivered Energy	**0.53**	**0.47**	**0.44**	**0.45**	**0.42**	**0.41**	**-0.7%**
Marketed Renewables (wood)[5]	0.40	0.43	0.43	0.43	0.44	0.45	0.2%
Other Fuels[6]	0.15	0.13	0.13	0.12	0.12	0.12	-0.8%

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

Key Indicators and Consumption	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Delivered Energy Consumption by End-Use							
Space Heating	5.20	5.45	5.73	5.83	5.98	6.23	0.7%
Space Cooling	0.55	0.56	0.60	0.64	0.68	0.75	1.5%
Water Heating	1.93	1.95	2.06	2.07	2.06	2.04	0.2%
Refrigeration	0.43	0.43	0.38	0.34	0.32	0.32	-1.4%
Cooking	0.33	0.33	0.36	0.37	0.39	0.41	1.0%
Clothes Dryers	0.29	0.29	0.33	0.34	0.36	0.38	1.3%
Freezers	0.12	0.12	0.10	0.09	0.09	0.09	-1.5%
Lighting	0.34	0.35	0.41	0.45	0.48	0.51	1.8%
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	1.1%
Color Televisions	0.12	0.13	0.17	0.20	0.23	0.26	3.4%
Personal Computers	0.04	0.04	0.06	0.08	0.10	0.11	4.5%
Furnace Fans	0.08	0.08	0.09	0.10	0.10	0.11	1.8%
Other Uses[7]	1.18	1.27	1.63	1.83	2.07	2.28	3.0%
Delivered Energy	**10.67**	**11.06**	**11.99**	**12.40**	**12.92**	**13.55**	**1.0%**
Electricity Related Losses	**8.44**	**8.79**	**9.72**	**9.85**	**10.25**	**10.72**	**1.0%**
Total Energy Consumption by End-Use							
Space Heating	6.03	6.36	6.69	6.78	6.96	7.23	0.6%
Space Cooling	1.73	1.77	1.88	1.90	2.00	2.16	1.0%
Water Heating	2.80	2.83	2.95	2.90	2.84	2.79	-0.1%
Refrigeration	1.37	1.36	1.19	1.03	0.95	0.93	-1.9%
Cooking	0.55	0.56	0.59	0.61	0.63	0.65	0.7%
Clothes Dryers	0.76	0.78	0.84	0.85	0.87	0.90	0.7%
Freezers	0.38	0.37	0.30	0.27	0.25	0.25	-1.9%
Lighting	1.08	1.11	1.28	1.36	1.42	1.47	1.4%
Clothes Washers	0.09	0.10	0.10	0.10	0.09	0.09	-0.6%
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.7%
Color Televisions	0.39	0.42	0.54	0.60	0.66	0.74	3.0%
Personal Computers	0.13	0.14	0.19	0.24	0.28	0.31	4.1%
Furnace Fans	0.24	0.25	0.27	0.29	0.30	0.32	1.3%
Other Uses[7]	3.47	3.73	4.81	5.26	5.83	6.34	2.7%
Total	**19.10**	**19.85**	**21.71**	**22.24**	**23.17**	**24.27**	**1.0%**
Non-Marketed Renewables							
Geothermal[8]	0.02	0.02	0.02	0.03	0.03	0.04	4.6%
Solar[9]	0.02	0.02	0.03	0.03	0.03	0.04	2.0%
Total	**0.04**	**0.04**	**0.05**	**0.06**	**0.07**	**0.08**	**3.2%**

[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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Key Indicators and Consumption	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	61.1	62.3	69.6	75.5	81.7	87.5	1.7%
New Additions	2.0	2.2	2.1	2.1	2.1	2.0	-0.3%
Total	**63.1**	**64.5**	**71.7**	**77.5**	**83.8**	**89.6**	**1.7%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	122.1	125.1	126.2	127.8	128.9	130.0	0.2%
Electricity Related Losses	129.0	130.6	130.8	129.8	129.6	128.8	-0.1%
Total Energy Consumption	251.1	255.7	257.1	257.6	258.5	258.8	0.1%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.16	0.16	0.16	0.16	0.5%
Space Cooling[1]	0.46	0.45	0.48	0.50	0.53	0.54	0.9%
Water Heating[1]	0.15	0.15	0.16	0.16	0.16	0.16	0.5%
Ventilation	0.18	0.18	0.20	0.21	0.22	0.23	1.2%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Lighting	1.22	1.24	1.34	1.42	1.50	1.53	1.1%
Refrigeration	0.18	0.19	0.20	0.22	0.23	0.24	1.2%
Office Equipment (PC)	0.14	0.16	0.25	0.32	0.35	0.35	4.2%
Office Equipment (non-PC)	0.30	0.32	0.41	0.52	0.65	0.78	4.6%
Other Uses[2]	0.97	1.05	1.23	1.49	1.79	2.10	3.5%
Delivered Energy	**3.77**	**3.90**	**4.46**	**5.03**	**5.62**	**6.13**	**2.3%**
Natural Gas[3]							
Space Heating[1]	1.41	1.50	1.64	1.72	1.79	1.87	1.1%
Space Cooling[1]	0.02	0.01	0.02	0.02	0.03	0.04	4.4%
Water Heating[1]	0.64	0.65	0.72	0.79	0.85	0.91	1.7%
Cooking	0.21	0.21	0.23	0.26	0.27	0.29	1.7%
Other Uses[4]	0.85	0.99	1.16	1.25	1.37	1.54	2.2%
Delivered Energy	**3.14**	**3.36**	**3.77**	**4.04**	**4.33**	**4.64**	**1.6%**
Distillate							
Space Heating[1]	0.23	0.23	0.25	0.25	0.24	0.24	0.3%
Water Heating[1]	0.08	0.08	0.08	0.08	0.08	0.08	0.3%
Other Uses[5]	0.11	0.07	0.09	0.09	0.09	0.09	1.5%
Delivered Energy	**0.42**	**0.38**	**0.42**	**0.42**	**0.42**	**0.42**	**0.5%**
Other Fuels[6]	**0.31**	**0.34**	**0.32**	**0.34**	**0.36**	**0.37**	**0.4%**
Marketed Renewable Fuels							
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.0%**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.78	1.88	2.04	2.13	2.20	2.27	1.0%
Space Cooling[1]	0.48	0.47	0.49	0.53	0.56	0.58	1.1%
Water Heating[1]	0.87	0.87	0.96	1.03	1.10	1.15	1.4%
Ventilation	0.18	0.18	0.20	0.21	0.22	0.23	1.2%
Cooking	0.24	0.24	0.27	0.29	0.30	0.32	1.5%
Lighting	1.22	1.24	1.34	1.42	1.50	1.53	1.1%
Refrigeration	0.18	0.19	0.20	0.22	0.23	0.24	1.2%
Office Equipment (PC)	0.14	0.16	0.25	0.32	0.35	0.35	4.2%
Office Equipment (non-PC)	0.30	0.32	0.41	0.52	0.65	0.78	4.6%
Other Uses[7]	2.32	2.53	2.89	3.25	3.69	4.18	2.5%
Delivered Energy	**7.70**	**8.07**	**9.05**	**9.91**	**10.80**	**11.64**	**1.9%**

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

Key Indicators and Consumption	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Electricity Related Losses	**8.13**	**8.42**	**9.38**	**10.06**	**10.85**	**11.53**	**1.6%**
Total Energy Consumption by End-Use							
Space Heating[1]	2.09	2.20	2.37	2.45	2.52	2.58	0.8%
Space Cooling[1]	1.48	1.45	1.49	1.53	1.57	1.60	0.5%
Water Heating[1]	1.19	1.19	1.28	1.35	1.41	1.46	1.0%
Ventilation	0.55	0.56	0.61	0.63	0.64	0.65	0.7%
Cooking	0.31	0.31	0.33	0.35	0.36	0.38	1.0%
Lighting	3.86	3.91	4.16	4.27	4.39	4.42	0.6%
Refrigeration	0.58	0.59	0.63	0.65	0.67	0.69	0.7%
Office Equipment (PC)	0.43	0.49	0.78	0.95	1.03	1.02	3.7%
Office Equipment (non-PC)	0.94	1.00	1.28	1.57	1.91	2.24	4.1%
Other Uses[7]	4.41	4.79	5.48	6.23	7.14	8.13	2.7%
Total	**15.84**	**16.49**	**18.42**	**19.98**	**21.65**	**23.18**	**1.7%**
Non-Marketed Renewable Fuels							
Solar[8]	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Total	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**1.2%**

[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]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Key Indicators and Consumption	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Key Indicators							
Value of Gross Output (billion 1992 dollars)							
Manufacturing	3804	4022	4550	5373	6210	7003	2.8%
Nonmanufacturing	990	1039	1127	1211	1325	1444	1.7%
Total	**4794**	**5062**	**5677**	**6584**	**7535**	**8447**	**2.6%**
Energy Prices (2000 dollars per million Btu)							
Electricity	13.00	13.50	12.72	12.54	12.62	13.04	-0.2%
Natural Gas	3.00	4.31	3.30	3.47	3.69	3.90	-0.5%
Steam Coal	1.43	1.41	1.35	1.30	1.26	1.21	-0.8%
Residual Oil	2.75	3.27	3.57	3.65	3.74	3.86	0.8%
Distillate Oil	4.71	7.21	5.54	5.89	6.52	6.70	-0.4%
Liquefied Petroleum Gas	8.77	11.73	8.28	8.60	8.98	9.11	-1.3%
Motor Gasoline	9.61	12.18	10.97	11.22	11.24	11.24	-0.4%
Metallurgical Coal	1.71	1.62	1.60	1.56	1.52	1.46	-0.5%
Energy Consumption							
Consumption[1]							
Purchased Electricity	3.61	3.65	3.80	4.20	4.53	4.83	1.4%
Natural Gas[2]	9.95	9.79	10.43	11.19	11.77	12.19	1.1%
Steam Coal	1.69	1.69	1.72	1.74	1.79	1.85	0.5%
Metallurgical Coal and Coke[3]	0.81	0.84	0.77	0.75	0.72	0.70	-0.9%
Residual Fuel	0.25	0.27	0.18	0.23	0.26	0.27	0.1%
Distillate	1.08	1.11	1.17	1.22	1.29	1.38	1.1%
Liquefied Petroleum Gas	2.26	2.36	2.50	2.66	2.85	3.00	1.2%
Petrochemical Feedstocks	1.31	1.32	1.36	1.45	1.54	1.59	0.9%
Other Petroleum[4]	4.50	4.17	4.59	5.01	5.25	5.45	1.3%
Renewables[5]	2.29	2.41	2.66	2.89	3.18	3.43	1.8%
Delivered Energy	**27.75**	**27.62**	**29.17**	**31.35**	**33.19**	**34.69**	**1.1%**
Electricity Related Losses	7.80	7.89	7.98	8.39	8.76	9.08	0.7%
Total	**35.54**	**35.50**	**37.15**	**39.74**	**41.96**	**43.76**	**1.1%**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)							
Purchased Electricity	0.75	0.72	0.67	0.64	0.60	0.57	-1.2%
Natural Gas[2]	2.07	1.93	1.84	1.70	1.56	1.44	-1.5%
Steam Coal	0.35	0.33	0.30	0.26	0.24	0.22	-2.1%
Metallurgical Coal and Coke[3]	0.17	0.17	0.13	0.11	0.10	0.08	-3.4%
Residual Fuel	0.05	0.05	0.03	0.04	0.03	0.03	-2.5%
Distillate	0.23	0.22	0.21	0.19	0.17	0.16	-1.5%
Liquefied Petroleum Gas	0.47	0.47	0.44	0.40	0.38	0.36	-1.4%
Petrochemical Feedstocks	0.27	0.26	0.24	0.22	0.20	0.19	-1.6%
Other Petroleum[4]	0.94	0.82	0.81	0.76	0.70	0.64	-1.2%
Renewables[5]	0.48	0.48	0.47	0.44	0.42	0.41	-0.8%
Delivered Energy	**5.79**	**5.46**	**5.14**	**4.76**	**4.41**	**4.11**	**-1.4%**
Electricity Related Losses	1.63	1.56	1.41	1.27	1.16	1.07	-1.8%
Total	**7.41**	**7.01**	**6.54**	**6.04**	**5.57**	**5.18**	**-1.5%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1999*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2000). 2000 prices for gasoline and distillate are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_ annual/current/pdf/pmaall.pdf. 1999 and 2000 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. 1999 and 2000 electricity prices: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. Other 1999 values and other 2000 prices derived from EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001). Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2305	2340	2659	2981	3318	3631	2.2%
Commercial Light Trucks (VMT)[1]	67	70	77	89	101	112	2.4%
Freight Trucks >10,000 pounds (VMT)	201	214	251	285	323	360	2.6%
Air (seat miles available)	1137	1184	1317	1603	1949	2342	3.5%
Rail (ton miles traveled)	1382	1415	1609	1757	1907	2066	1.9%
Domestic Shipping (ton miles traveled)	665	689	741	792	855	910	1.4%
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.0	24.5	25.1	25.7	26.6	27.2	0.5%
New Car (miles per gallon)[2]	27.7	28.6	29.6	30.2	31.0	31.7	0.5%
New Light Truck (miles per gallon)[2]	20.7	21.1	21.6	22.3	23.3	23.8	0.6%
Light-Duty Fleet (miles per gallon)[3]	19.7	19.8	19.8	20.1	20.5	21.0	0.3%
New Commercial Light Truck (MPG)[1]	14.0	14.2	14.4	14.9	15.5	15.9	0.6%
Stock Commercial Light Truck (MPG)[1]	13.6	13.6	14.1	14.4	14.9	15.4	0.6%
Aircraft Efficiency (seat miles per gallon)	51.7	52.1	53.8	55.9	58.1	60.3	0.7%
Freight Truck Efficiency (miles per gallon)	5.9	5.9	6.0	6.0	6.1	6.3	0.3%
Rail Efficiency (ton miles per thousand Btu)	2.8	2.8	2.9	3.1	3.3	3.4	1.0%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	0.2%
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	14.80	14.97	16.74	18.49	20.07	21.37	1.8%
Commercial Light Trucks[1]	0.61	0.64	0.69	0.77	0.85	0.91	1.8%
Freight Trucks[4]	4.55	4.80	5.51	6.24	6.91	7.42	2.2%
Air[5]	3.50	3.62	3.92	4.51	5.19	5.91	2.5%
Rail[6]	0.58	0.58	0.63	0.66	0.69	0.72	1.0%
Marine[7]	1.50	1.73	1.68	1.73	1.78	1.82	0.3%
Pipeline Fuel	0.75	0.79	0.80	0.86	0.95	1.02	1.3%
Lubricants	0.18	0.18	0.21	0.22	0.24	0.25	1.7%
Total	**26.49**	**27.32**	**30.19**	**33.50**	**36.69**	**39.43**	**1.9%**
Energy Use by Mode (million barrels per day oil equivalent)							
Light-Duty Vehicles	7.73	7.82	8.85	9.76	10.59	11.27	1.8%
Commercial Light Trucks[1]	0.32	0.33	0.36	0.41	0.45	0.48	1.9%
Freight Trucks[4]	2.03	2.14	2.47	2.81	3.12	3.35	2.3%
Railroad	0.23	0.24	0.26	0.27	0.28	0.28	0.9%
Domestic Shipping	0.13	0.14	0.15	0.16	0.17	0.18	1.2%
International Shipping	0.39	0.48	0.45	0.45	0.45	0.46	-0.2%
Air[5]	1.46	1.51	1.62	1.89	2.21	2.56	2.7%
Military Use	0.29	0.30	0.34	0.35	0.36	0.36	1.0%
Bus Transportation	0.09	0.09	0.09	0.09	0.10	0.10	0.6%
Rail Transportation[6]	0.04	0.04	0.04	0.05	0.05	0.05	1.9%
Recreational Boats	0.16	0.16	0.17	0.18	0.19	0.20	0.9%
Lubricants	0.09	0.09	0.10	0.11	0.11	0.12	1.7%
Pipeline Fuel	0.38	0.40	0.40	0.44	0.48	0.52	1.3%
Total	**13.33**	**13.73**	**15.28**	**16.95**	**18.55**	**19.92**	**1.9%**

[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 recreation 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.

Sources: 1999: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000); Federal Highway Administration, *Highway Statistics 1999* (Washington, DC, November 2000); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, 15, 16, 17, 18, 19, and 20* (Oak Ridge, TN, November 2000); 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; and EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001). 2000: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2000/1999* (Washington, DC, 2000); EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/ forecasting/steo/oldsteos/oct01.pdf; EIA, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0535(99) (Washington, DC, August 2000); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Generation by Fuel Type							
Electric Generators[1]							
Coal	1837	1922	2086	2215	2292	2423	1.2%
Petroleum	110	93	39	28	33	38	-4.4%
Natural Gas[2]	363	417	607	893	1202	1414	6.3%
Nuclear Power	728	752	759	737	707	702	-0.3%
Pumped Storage	-2	-1	-1	-1	-1	-1	0.4%
Renewable Sources[3]	356	321	375	391	401	407	1.2%
Total	**3392**	**3504**	**3865**	**4263**	**4634**	**4983**	**1.8%**
Nonutility Generation for Own Use	25	30	33	33	33	33	0.4%
Distributed Generation	0	0	0	2	5	8	N/A
Cogenerators[4]							
Coal	50	46	49	49	49	49	0.3%
Petroleum	14	9	10	10	10	11	0.9%
Natural Gas	198	209	239	260	286	318	2.1%
Other Gaseous Fuels[5]	8	6	9	9	10	12	3.9%
Renewable Sources[3]	33	33	37	41	47	52	2.3%
Other[6]	11	4	4	4	4	4	0.1%
Total	**315**	**307**	**348**	**374**	**408**	**447**	**1.9%**
Other End-Use Generators[7]	**6**	**4**	**5**	**5**	**5**	**5**	**1.4%**
Sales to Utilities	168	163	180	189	204	224	1.6%
Generation for Own Use	153	147	172	190	208	228	2.2%
Net Imports[8]	**25**	**35**	**49**	**35**	**41**	**40**	**0.7%**
Electricity Sales by Sector							
Residential	1145	1193	1354	1443	1554	1672	1.7%
Commercial	1104	1144	1306	1475	1646	1798	2.3%
Industrial	1058	1071	1112	1230	1329	1415	1.4%
Transportation	17	18	20	23	27	32	3.1%
Total	**3324**	**3426**	**3793**	**4170**	**4556**	**4916**	**1.8%**
End-Use Prices (2000 cents per kilowatthour)[9]							
Residential	8.3	8.3	7.6	7.6	7.6	7.7	-0.4%
Commercial	7.3	7.5	7.0	6.8	6.8	6.9	-0.4%
Industrial	4.4	4.6	4.3	4.3	4.3	4.5	-0.2%
Transportation	7.1	7.4	5.7	6.2	6.6	6.1	-1.0%
All Sectors Average	**6.7**	**6.9**	**6.4**	**6.3**	**6.3**	**6.5**	**-0.3%**
Prices by Service Category (2000 cents per kilowatthour) [9]							
Generation	4.1	4.3	3.9	3.7	3.7	3.9	-0.4%
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.3%
Distribution	2.0	2.0	1.9	1.9	1.9	1.9	-0.3%
Emissions (million short tons)							
Sulfur Dioxide	12.45	11.05	10.39	9.70	8.95	8.95	-1.0%
Nitrogen Oxide	5.71	4.28	3.94	4.04	4.12	4.18	-0.1%

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[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]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Electric generators and cogenerators generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Electric Power Annual 1999, Volume 2,* DOE/EIA-0348(99)/2 (Washington, DC, October 2000), and supporting databases. Other generators: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and Department of Energy, Office of Energy Efficiency and Renewable Energy estimates. Commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 20* (Oak Ridge, TN, November 2000). Prices: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **2000 and projections**: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Electric Generators[2]							
Capability							
Coal Steam	304.6	304.6	303.7	305.7	313.1	329.0	0.4%
Other Fossil Steam[3]	135.7	135.0	127.4	115.6	114.4	113.3	-0.9%
Combined Cycle	20.7	30.6	59.6	139.9	182.4	213.8	10.2%
Combustion Turbine/Diesel	63.2	77.7	104.9	128.9	149.6	177.9	4.2%
Nuclear Power	97.5	97.5	97.7	94.3	88.8	88.0	-0.5%
Pumped Storage	19.2	19.2	19.6	19.6	19.6	19.6	0.1%
Fuel Cells	0.0	0.0	0.1	0.2	0.2	0.3	35.2%
Renewable Sources[4]	88.9	89.1	95.2	97.2	99.5	101.2	0.6%
Distributed Generation[5]	0.0	0.0	0.9	5.1	11.1	19.0	N/A
Total	**729.6**	**753.6**	**809.1**	**906.4**	**978.8**	**1062.2**	**1.7%**
Cumulative Planned Additions[6]							
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	6.6	6.6	6.6	6.6	N/A
Combustion Turbine/Diesel	0.0	0.0	3.7	3.7	3.7	3.7	N/A
Nuclear Power	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	N/A
Fuel Cells	0.0	0.0	0.1	0.2	0.2	0.2	N/A
Renewable Sources[4]	0.0	0.0	5.6	7.0	7.9	8.2	N/A
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**16.3**	**17.7**	**18.7**	**19.0**	**N/A**
Cumulative Unplanned Additions[6]							
Coal Steam	0.0	0.0	1.0	6.2	14.1	31.2	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	21.6	101.9	144.5	175.9	N/A
Combustion Turbine/Diesel	0.0	0.0	28.2	53.6	76.7	105.9	N/A
Nuclear Power	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	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.0	0.0	0.0	0.6	1.9	3.4	N/A
Distributed Generation[5]	0.0	0.0	0.9	5.1	11.1	19.0	N/A
Total	**0.0**	**0.0**	**51.7**	**167.3**	**248.3**	**335.5**	**N/A**
Cumulative Total Additions	**0.0**	**0.0**	**68.0**	**185.0**	**267.1**	**354.5**	**N/A**
Cumulative Retirements[7]							
Coal Steam	0.0	0.0	2.1	5.2	5.8	7.0	N/A
Other Fossil Steam[3]	0.0	0.0	6.4	18.2	19.4	20.5	N/A
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combustion Turbine/Diesel	0.0	0.0	4.7	6.1	8.5	9.5	N/A
Nuclear Power	0.0	0.0	0.0	3.4	8.9	9.7	N/A
Pumped Storage	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	N/A
Renewable Sources[4]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**13.3**	**33.1**	**42.8**	**46.9**	**N/A**

Table A9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Cogenerators[8]							
Capability							
Coal	8.4	8.9	8.9	8.6	8.6	8.6	-0.2%
Petroleum	2.6	2.6	2.5	2.5	2.6	2.6	0.0%
Natural Gas	33.8	35.9	40.2	43.5	47.1	51.6	1.8%
Other Gaseous Fuels	0.7	0.7	1.1	1.2	1.4	1.6	4.4%
Renewable Sources[4]	5.8	5.8	6.4	7.1	8.1	8.9	2.2%
Other	0.9	0.9	0.9	0.9	0.9	0.9	-0.0%
Total	**52.2**	**54.7**	**60.0**	**63.8**	**68.7**	**74.2**	**1.5%**
Cumulative Additions[6]	**0.0**	**0.0**	**5.3**	**9.1**	**14.0**	**19.5**	**N/A**
Other End-Use Generators[9]							
Renewable Sources[10]	1.0	1.0	1.1	1.4	1.4	1.4	1.9%
Cumulative Additions	0.0	0.0	0.1	0.4	0.4	0.4	N/A

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 2000.
[7]Cumulative total retirements after December 31, 2000.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B: "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]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.
[10]See Table A17 for more detail.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 and 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability estimates for electric utility generators.
Sources: 1999 electric utilities capability and projected planned additions: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutilities including cogenerators capability and projected planned additions: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and NewGen Data and Analysis, RDI Consulting/FT Energy (Boulder, CO, August 2000). 1999 other generators capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and Department of Energy, Office of Energy Efficiency and Renewable Energy estimates. **2000 and projections**: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Electricity Trade	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	182.2	156.9	125.3	102.9	45.7	0.0	N/A
Gross Domestic Economy Trade	117.0	151.0	188.8	189.5	198.2	205.1	1.5%
Gross Domestic Trade	**299.2**	**307.8**	**314.1**	**292.4**	**243.9**	**205.1**	**-2.0%**
Gross Domestic Firm Power Sales (million 2000 dollars)	8798.5	7576.3	6050.5	4970.1	2208.9	0.0	N/A
Gross Domestic Economy Sales (million 2000 dollars)	3685.1	6849.1	6224.4	5909.5	6711.2	7262.7	0.3%
Gross Domestic Sales (million 2000 dollars)	**12483.6**	**14425.4**	**12274.9**	**10879.6**	**8920.1**	**7262.7**	**-3.4%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico[1]	19.0	23.7	10.7	5.8	2.6	0.0	N/A
Economy Imports From Canada and Mexico[1]	19.9	24.2	55.4	45.1	50.4	47.4	3.4%
Gross Imports From Canada and Mexico[1]	**38.9**	**47.9**	**66.1**	**51.0**	**52.9**	**47.4**	**-0.1%**
Firm Power Exports To Canada and Mexico	3.0	6.6	9.7	8.7	3.9	0.0	N/A
Economy Exports To Canada and Mexico	10.5	6.4	7.0	7.7	7.7	7.7	0.9%
Gross Exports To Canada and Mexico	**13.5**	**13.0**	**16.7**	**16.4**	**11.5**	**7.7**	**-2.6%**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 and 2000 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: 1999 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1999. 1999 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1999 firm/economy share: National Energy Board, *Annual Report 1999*. **2000 and projections:** Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Supply and Disposition	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Crude Oil							
Domestic Crude Production[1]	5.87	5.82	5.38	5.08	5.56	5.63	-0.2%
Alaska	1.06	0.97	0.80	0.70	0.90	1.10	0.6%
Lower 48 States	4.82	4.85	4.58	4.38	4.65	4.53	-0.3%
Net Imports	8.61	9.02	10.37	11.18	11.01	11.20	1.1%
Gross Imports	8.73	9.07	10.42	11.22	11.07	11.26	1.1%
Exports	0.12	0.05	0.05	0.04	0.06	0.06	1.1%
Other Crude Supply[2]	0.31	0.23	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**14.79**	**15.07**	**15.75**	**16.26**	**16.57**	**16.83**	**0.6%**
Natural Gas Plant Liquids	**1.85**	**1.91**	**2.13**	**2.38**	**2.64**	**2.84**	**2.0%**
Other Inputs[3]	**0.60**	**0.35**	**0.34**	**0.42**	**0.51**	**0.47**	**1.5%**
Refinery Processing Gain[4]	**0.89**	**0.95**	**0.88**	**1.00**	**1.01**	**1.02**	**0.4%**
Net Product Imports[5]	**1.30**	**1.40**	**2.12**	**3.09**	**4.29**	**5.44**	**7.0%**
Gross Refined Product Imports[6]	1.73	2.04	2.51	3.21	4.31	5.49	5.1%
Unfinished Oil Imports	0.32	0.27	0.38	0.75	0.88	0.90	6.1%
Ether Imports	0.08	0.08	0.00	0.00	0.00	0.00	N/A
Exports	0.82	0.99	0.76	0.87	0.90	0.94	-0.3%
Total Primary Supply[7]	**19.43**	**19.68**	**21.22**	**23.15**	**25.01**	**26.61**	**1.5%**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.36	8.50	9.44	10.32	11.13	11.81	1.7%
Jet Fuel[9]	1.67	1.73	1.87	2.15	2.47	2.81	2.5%
Distillate Fuel[10]	3.55	3.67	4.16	4.58	4.99	5.32	1.9%
Residual Fuel	0.99	1.05	0.71	0.69	0.73	0.75	-1.6%
Other[11]	4.95	4.80	5.10	5.46	5.75	5.97	1.1%
Total	**19.53**	**19.74**	**21.27**	**23.21**	**25.07**	**26.66**	**1.5%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.17	1.12	1.11	1.09	1.06	1.04	-0.3%
Industrial[12]	4.98	4.96	5.25	5.66	6.00	6.27	1.2%
Transportation	12.89	13.26	14.76	16.37	17.90	19.22	1.9%
Electric Generators[13]	0.48	0.41	0.14	0.09	0.11	0.12	-5.8%
Total	**19.53**	**19.74**	**21.27**	**23.21**	**25.07**	**26.66**	**1.5%**
Discrepancy[14]	**-0.10**	**-0.07**	**-0.06**	**-0.06**	**-0.06**	**-0.05**	**N/A**
World Oil Price (2000 dollars per barrel)[15]	**17.60**	**27.72**	**22.73**	**23.36**	**24.00**	**24.68**	**-0.6%**
Import Share of Product Supplied	**0.51**	**0.53**	**0.59**	**0.62**	**0.61**	**0.62**	**0.8%**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2000 dollars)	**61.09**	**106.46**	**105.28**	**125.51**	**141.00**	**159.84**	**2.1%**
Domestic Refinery Distillation Capacity[16]	**16.5**	**16.6**	**17.6**	**17.8**	**17.9**	**18.2**	**0.5%**
Capacity Utilization Rate (percent)	**93.0**	**93.0**	**90.0**	**91.7**	**93.2**	**93.2**	**0.0%**

[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, and natural gas 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 blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[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 by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000 product supplied data from Table A2. Other 1999 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 2000 data: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A12. Petroleum Product Prices
(2000 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
World Oil Price (2000 dollars per barrel)	**17.60**	**27.72**	**22.73**	**23.36**	**24.00**	**24.68**	**-0.6%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	88.6	130.7	106.5	110.1	116.9	118.5	-0.5%
Liquefied Petroleum Gas	90.4	117.1	110.7	113.8	117.1	118.5	0.1%
Commercial							
Distillate Fuel	61.8	98.2	75.5	79.4	86.7	88.6	-0.5%
Residual Fuel	39.7	51.8	56.1	57.3	58.7	60.2	0.8%
Residual Fuel (2000 dollars per barrel)	16.68	21.77	23.56	24.08	24.67	25.29	0.8%
Industrial[1]							
Distillate Fuel	65.4	99.9	76.8	81.7	90.4	93.0	-0.4%
Liquefied Petroleum Gas	75.5	100.6	71.0	73.7	77.1	78.2	-1.3%
Residual Fuel	41.1	48.9	53.4	54.7	56.1	57.9	0.8%
Residual Fuel (2000 dollars per barrel)	17.28	20.55	22.45	22.97	23.54	24.30	0.8%
Transportation							
Diesel Fuel (distillate)[2]	116.0	149.9	128.0	140.6	140.0	138.5	-0.4%
Jet Fuel[3]	64.9	99.3	74.6	79.2	85.4	86.0	-0.7%
Motor Gasoline[4]	121.0	152.6	136.6	139.6	139.8	139.7	-0.4%
Liquid Petroleum Gas	112.7	136.5	121.4	123.8	126.1	125.7	-0.4%
Residual Fuel	38.7	65.6	50.9	52.1	53.5	55.0	-0.9%
Residual Fuel (2000 dollars per barrel)	16.27	27.56	21.36	21.88	22.47	23.10	-0.9%
Ethanol (E85)	132.4	155.3	171.5	184.1	194.1	189.5	1.0%
Electric Generators[5]							
Distillate Fuel	58.6	95.6	68.4	72.6	79.5	81.4	-0.8%
Residual Fuel	36.6	61.5	52.8	53.9	55.3	57.0	-0.4%
Residual Fuel (2000 dollars per barrel)	15.39	25.83	22.18	22.66	23.22	23.93	-0.4%
Refined Petroleum Product Prices[6]							
Distillate Fuel	102.1	137.7	116.3	127.8	129.9	129.5	-0.3%
Jet Fuel[3]	64.9	99.3	74.6	79.2	85.4	86.0	-0.7%
Liquefied Petroleum Gas	78.5	103.5	77.8	80.4	83.2	84.0	-1.0%
Motor Gasoline[4]	121.0	152.6	136.6	139.6	139.8	139.7	-0.4%
Residual Fuel	38.1	61.5	51.8	53.1	54.5	56.1	-0.5%
Residual Fuel (2000 dollars per barrel)	16.01	25.83	21.77	22.29	22.89	23.56	-0.5%
Average	**99.3**	**130.5**	**113.6**	**118.9**	**120.5**	**120.5**	**-0.4%**

[1]Includes cogenerators.
[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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1999*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma_historical.html (August 2000). 2000 prices for gasoline, distillate, and jet fuel are based on prices in the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/ petroleum_marketing_annual/current/pdf/pmaall.pdf. 1999 and 2000 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Production							
Dry Gas Production[1]	18.69	19.08	20.73	23.48	26.32	28.48	2.0%
Supplemental Natural Gas[2]	0.10	0.10	0.11	0.11	0.11	0.11	0.7%
Net Imports	**3.42**	**3.52**	**4.50**	**4.89**	**5.26**	**5.51**	**2.3%**
Canada	3.33	3.46	4.08	4.51	4.90	5.06	1.9%
Mexico	-0.01	-0.09	-0.22	-0.45	-0.47	-0.38	7.2%
Liquefied Natural Gas	0.10	0.16	0.64	0.83	0.83	0.83	8.6%
Total Supply	**22.21**	**22.69**	**25.35**	**28.49**	**31.69**	**34.10**	**2.1%**
Consumption by Sector							
Residential	4.72	5.00	5.37	5.53	5.73	5.98	0.9%
Commercial	3.05	3.27	3.67	3.93	4.21	4.52	1.6%
Industrial[3]	8.60	8.41	8.89	9.39	9.79	10.06	0.9%
Electric Generators[4]	3.79	4.24	5.48	6.85	8.91	10.30	4.5%
Transportation[5]	0.02	0.02	0.06	0.09	0.12	0.14	9.8%
Pipeline Fuel	0.74	0.77	0.77	0.84	0.93	0.99	1.3%
Lease and Plant Fuel[6]	1.08	1.12	1.25	1.50	1.66	1.80	2.4%
Total	**21.99**	**22.83**	**25.50**	**28.13**	**31.34**	**33.78**	**2.0%**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[7]	**0.22**	**-0.14**	**-0.15**	**0.36**	**0.35**	**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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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, 1999 and 2000 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). Other 1999 consumption derived from: EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001). 2000 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 1999 imports and dry gas production derived from: EIA, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A14. Natural Gas Prices, Margins, and Revenues
(2000 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Source Price							
Average Lower 48 Wellhead Price[1]	2.27	3.60	2.66	2.85	3.07	3.26	-0.5%
Average Import Price	2.29	3.94	2.68	2.91	3.13	3.40	-0.7%
Average[2]	**2.27**	**3.66**	**2.67**	**2.86**	**3.08**	**3.28**	**-0.5%**
Delivered Prices							
Residential	6.84	7.85	7.04	6.92	7.04	7.16	-0.5%
Commercial	5.49	6.40	5.74	5.66	5.84	6.02	-0.3%
Industrial[3]	3.09	4.43	3.39	3.57	3.79	4.01	-0.5%
Electric Generators[4]	2.69	4.49	3.25	3.44	3.72	3.94	-0.6%
Transportation[5]	6.31	8.26	6.83	7.08	7.33	7.48	-0.5%
Average[6]	**4.26**	**5.58**	**4.57**	**4.59**	**4.74**	**4.92**	**-0.6%**
Transmission and Distribution Margins[7]							
Residential	4.57	4.19	4.37	4.05	3.95	3.88	-0.4%
Commercial	3.22	2.74	3.07	2.80	2.76	2.74	-0.0%
Industrial[3]	0.82	0.78	0.72	0.70	0.71	0.73	-0.3%
Electric Generators[4]	0.42	0.83	0.59	0.58	0.64	0.66	-1.2%
Transportation[5]	4.04	4.61	4.16	4.22	4.25	4.20	-0.5%
Average[6]	**1.99**	**1.92**	**1.91**	**1.73**	**1.66**	**1.63**	**-0.8%**
Transmission and Distribution Revenue (billion 2000 dollars)							
Residential	21.58	20.96	23.49	22.40	22.65	23.21	0.5%
Commercial	9.83	8.98	11.29	11.00	11.59	12.35	1.6%
Industrial[3]	7.01	6.55	6.42	6.62	6.95	7.33	0.6%
Electric Generators[4]	1.60	3.53	3.22	3.98	5.71	6.80	3.3%
Transportation[5]	0.06	0.10	0.23	0.37	0.51	0.58	9.3%
Total	**40.08**	**40.12**	**44.65**	**44.37**	**47.41**	**50.28**	**1.1%**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.

Sources: 1999 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1999 and 2000 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). **Other 1999 values, other 2000 values, and projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Crude Oil							
Lower 48 Average Wellhead Price[1] (2000 dollars per barrel)	**16.84**	**27.59**	**22.28**	**22.70**	**23.15**	**23.79**	**-0.7%**
Production (million barrels per day)[2]							
U.S. Total	**5.87**	**5.82**	**5.38**	**5.08**	**5.56**	**5.63**	**-0.2%**
Lower 48 Onshore	3.26	3.25	2.90	2.64	2.64	2.70	-0.9%
Conventional	2.58	2.60	2.24	1.91	1.82	1.87	-1.6%
Enhanced Oil Recovery	0.68	0.65	0.65	0.73	0.82	0.83	1.3%
Lower 48 Offshore	1.55	1.61	1.68	1.74	2.01	1.83	0.6%
Alaska	1.06	0.97	0.80	0.70	0.90	1.10	0.7%
Lower 48 End of Year Reserves (billion barrels)[2]	**18.27**	**18.29**	**15.44**	**14.23**	**14.63**	**14.45**	**-1.2%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2000 dollars per thousand cubic feet)	**2.27**	**3.60**	**2.66**	**2.85**	**3.07**	**3.26**	**-0.5%**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**18.69**	**19.08**	**20.73**	**23.48**	**26.32**	**28.48**	**2.0%**
Lower 48 Onshore	12.89	13.31	14.36	16.45	19.40	21.13	2.3%
Associated-Dissolved[4]	1.74	1.79	1.63	1.43	1.37	1.36	-1.3%
Non-Associated	11.14	11.52	12.73	15.02	18.04	19.77	2.7%
Conventional	6.64	6.89	6.92	7.89	9.94	10.77	2.3%
Unconventional	4.50	4.63	5.81	7.13	8.09	8.99	3.4%
Lower 48 Offshore	5.38	5.34	5.87	6.50	6.35	6.75	1.2%
Associated-Dissolved[4]	1.17	1.16	1.19	1.22	1.27	1.25	0.4%
Non-Associated	4.21	4.18	4.68	5.28	5.08	5.50	1.4%
Alaska	0.42	0.43	0.50	0.53	0.57	0.60	1.7%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**157.67**	**162.31**	**167.16**	**174.09**	**181.49**	**187.79**	**0.7%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.7%**
Total Lower 48 Wells (thousands)	**18.87**	**24.05**	**23.34**	**24.32**	**25.55**	**33.08**	**1.6%**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). 1999 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(99) (Washington, DC, December 2000). 1999 natural gas lower 48 average wellhead price and total natural gas production: EIA, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 1999 and 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Production[1]							
Appalachia	435	430	424	428	417	406	-0.3%
Interior	163	144	157	158	146	143	-0.0%
West	512	510	631	698	762	848	2.6%
East of the Mississippi	539	518	526	533	520	510	-0.1%
West of the Mississippi	571	566	685	751	805	887	2.3%
Total	**1110**	**1084**	**1211**	**1284**	**1325**	**1397**	**1.3%**
Net Imports							
Imports	9	13	18	19	19	20	2.3%
Exports	58	58	56	54	53	55	-0.3%
Total	**-49**	**-46**	**-38**	**-35**	**-34**	**-35**	**-1.4%**
Total Supply[2]	**1061**	**1038**	**1173**	**1249**	**1291**	**1362**	**1.4%**
Consumption by Sector							
Residential and Commercial	5	5	5	5	6	6	0.8%
Industrial[3]	82	82	80	81	83	86	0.2%
Coke Plants	28	29	26	24	22	20	-1.9%
Electric Generators[4]	929	965	1065	1141	1183	1254	1.3%
Total	**1044**	**1081**	**1176**	**1251**	**1294**	**1365**	**1.2%**
Discrepancy and Stock Change[5]	**16**	**-43**	**-2**	**-2**	**-3**	**-3**	**N/A**
Average Minemouth Price							
(2000 dollars per short ton)	17.01	16.45	14.99	14.11	13.44	12.79	-1.3%
(2000 dollars per million Btu)	0.82	0.79	0.73	0.69	0.66	0.64	-1.1%
Delivered Prices (2000 dollars per short ton)[6]							
Industrial	32.31	31.86	29.19	28.11	27.21	26.14	-1.0%
Coke Plants	46.89	44.41	42.93	41.86	40.71	39.22	-0.6%
Electric Generators							
(2000 dollars per short ton)	25.28	24.36	22.69	21.02	20.15	19.00	-1.2%
(2000 dollars per million Btu)	1.22	1.20	1.13	1.05	1.01	0.97	-1.1%
Average	**25.75**	**25.42**	**23.58**	**21.89**	**20.95**	**19.75**	**-1.3%**
Exports[7]	37.33	34.90	36.45	35.84	34.96	33.67	-0.2%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Energy Information Administration (EIA), *Coal Industry Annual 1999*, DOE/EIA-0584(99) (Washington, DC, June 2001). 2000 data based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Electric Generators[1] (excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	79.30	79.29	79.78	79.90	79.90	79.90	0.0%
Geothermal[2]	2.79	2.85	3.05	3.57	4.52	5.32	3.2%
Municipal Solid Waste[3]	2.75	2.84	3.50	3.88	4.18	4.30	2.1%
Wood and Other Biomass[4]	1.37	1.39	1.61	1.73	1.82	1.97	1.8%
Solar Thermal	0.33	0.33	0.34	0.36	0.39	0.41	1.0%
Solar Photovoltaic[5]	0.01	0.01	0.05	0.11	0.19	0.27	19.8%
Wind	2.33	2.42	6.82	7.65	8.46	9.06	6.8%
Total	**88.87**	**89.13**	**95.16**	**97.19**	**99.46**	**101.22**	**0.6%**
Generation (billion kilowatthours)							
Conventional Hydropower	310.30	272.33	301.26	301.14	300.54	300.00	0.5%
Geothermal[2]	15.27	13.52	15.67	20.20	28.06	34.71	4.8%
Municipal Solid Waste[3]	17.96	20.15	24.90	27.78	30.05	30.98	2.2%
Wood and Other Biomass[4]	7.51	8.37	14.96	20.86	18.84	15.32	3.1%
Dedicated Plants	7.01	7.46	8.94	9.72	10.32	11.25	2.1%
Cofiring	0.51	0.91	6.03	11.14	8.52	4.07	7.8%
Solar Thermal	0.87	0.87	0.90	0.96	1.05	1.12	1.3%
Solar Photovoltaic	0.00	0.01	0.11	0.26	0.46	0.68	22.8%
Wind	4.17	5.30	16.74	19.45	21.95	24.07	7.9%
Total	**356.09**	**320.54**	**374.55**	**390.65**	**400.95**	**406.87**	**1.2%**
Cogenerators[6]							
Net Summer Capability							
Municipal Solid Waste	0.51	0.51	0.51	0.51	0.51	0.51	-0.0%
Biomass	5.26	5.26	5.92	6.64	7.62	8.43	2.4%
Total	**5.77**	**5.77**	**6.43**	**7.15**	**8.13**	**8.94**	**2.2%**
Generation (billion kilowatthours)							
Municipal Solid Waste	3.23	3.29	3.29	3.29	3.29	3.29	0.0%
Biomass	29.97	29.63	33.72	38.04	44.04	48.99	2.5%
Total	**33.20**	**32.93**	**37.02**	**41.34**	**47.33**	**52.28**	**2.3%**
Other End-Use Generators[7]							
Net Summer Capability							
Conventional Hydropower[8]	0.98	0.98	0.98	0.98	0.98	0.98	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic[5]	0.01	0.02	0.11	0.39	0.42	0.46	17.6%
Total	**0.99**	**0.99**	**1.09**	**1.36**	**1.40**	**1.44**	**1.9%**
Generation (billion kilowatthours)							
Conventional Hydropower[8]	5.45	3.98	4.33	4.32	4.32	4.31	0.4%
Geothermal	0.15	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.01	0.04	0.23	0.81	0.89	0.98	17.6%
Total	**5.60**	**4.02**	**4.56**	**5.14**	**5.21**	**5.29**	**1.4%**

[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]Does not include off-grid photovoltaics (PV). EIA estimates that another 76 megawatts of remote electricity generation PV applications were in service in 1999, plus an additional 205 megawatts in communications, transportation, and assorted other non-grid-connected applications.
[6]Cogenerators produce electricity and other useful thermal energy.
[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 1999 and 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2002. Net summer capability 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: 1999 and 2000 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 and 2000 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 and 2000 generation: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Marketed Renewable Energy[2]							
Residential	**0.40**	**0.43**	**0.43**	**0.43**	**0.44**	**0.45**	**0.2%**
Wood	0.40	0.43	0.43	0.43	0.44	0.45	0.2%
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.0%**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Industrial[3]	**2.29**	**2.41**	**2.66**	**2.89**	**3.18**	**3.43**	**1.8%**
Conventional Hydroelectric	0.20	0.20	0.20	0.20	0.20	0.20	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	-0.0%
Biomass	2.09	2.21	2.46	2.69	2.98	3.23	1.9%
Transportation	**0.12**	**0.14**	**0.22**	**0.24**	**0.26**	**0.28**	**3.6%**
Ethanol used in E85[4]	0.00	0.00	0.02	0.03	0.03	0.04	N/A
Ethanol used in Gasoline Blending	0.12	0.14	0.20	0.21	0.23	0.24	2.8%
Electric Generators[5]	**3.91**	**3.55**	**4.18**	**4.46**	**4.74**	**4.94**	**1.7%**
Conventional Hydroelectric	3.21	2.82	3.12	3.11	3.11	3.10	0.5%
Geothermal	0.28	0.28	0.36	0.50	0.75	0.96	6.3%
Municipal Solid Waste[6]	0.27	0.28	0.34	0.38	0.41	0.42	2.1%
Biomass	0.11	0.11	0.18	0.25	0.23	0.19	2.7%
Dedicated Plants	0.10	0.10	0.11	0.12	0.12	0.14	1.7%
Cofiring	0.01	0.01	0.07	0.13	0.10	0.05	7.4%
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	3.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.05	0.05	0.17	0.20	0.23	0.25	7.9%
Total Marketed Renewable Energy	**6.81**	**6.60**	**7.57**	**8.10**	**8.70**	**9.17**	**1.7%**
Sources of Ethanol							
From Corn	0.12	0.14	0.21	0.22	0.23	0.22	2.3%
From Cellulose	0.00	0.00	0.01	0.02	0.03	0.06	N/A
Total	**0.12**	**0.14**	**0.22**	**0.24**	**0.26**	**0.28**	**3.6%**
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	**0.04**	**0.04**	**0.05**	**0.06**	**0.07**	**0.08**	**3.2%**
Solar Hot Water Heating	0.02	0.02	0.03	0.03	0.03	0.03	1.8%
Geothermal Heat Pumps	0.02	0.02	0.02	0.03	0.03	0.04	4.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	21.2%
Commercial	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**1.2%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.8%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	16.4%

[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 cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 1999 and 2000 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 and 2000: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
Residential							
Petroleum	27.3	27.5	25.9	24.6	23.3	22.6	-1.0%
Natural Gas	69.9	73.2	79.6	81.8	84.8	88.6	1.0%
Coal	1.2	1.2	1.2	1.3	1.3	1.3	0.3%
Electricity	192.9	204.0	226.9	238.3	252.0	268.7	1.4%
Total	**291.4**	**305.9**	**333.5**	**346.0**	**361.4**	**381.1**	**1.1%**
Commercial							
Petroleum	13.1	14.2	13.2	13.6	13.8	14.0	-0.1%
Natural Gas	45.1	49.3	54.4	58.2	62.3	66.8	1.5%
Coal	1.8	1.8	1.7	1.8	1.9	2.0	0.5%
Electricity	186.0	195.6	218.9	243.6	266.9	288.9	2.0%
Total	**246.0**	**260.9**	**288.2**	**317.1**	**344.8**	**371.7**	**1.8%**
Industrial[1]							
Petroleum	97.7	93.7	98.6	107.2	112.9	117.8	1.2%
Natural Gas[2]	138.3	136.1	147.6	158.5	166.8	172.4	1.2%
Coal	64.1	65.2	63.0	63.3	63.7	64.7	-0.0%
Electricity	178.3	183.0	186.4	203.1	215.5	227.4	1.1%
Total	**478.4**	**478.1**	**495.7**	**532.1**	**558.9**	**582.3**	**1.0%**
Transportation							
Petroleum[3]	487.6	502.5	560.3	621.8	680.3	730.7	1.9%
Natural Gas[4]	11.0	11.4	12.3	13.7	15.4	16.7	1.9%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Electricity	2.9	3.0	3.4	3.8	4.4	5.1	2.7%
Total[3]	**501.5**	**516.9**	**576.1**	**639.4**	**700.2**	**752.7**	**1.9%**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	625.7	637.9	698.0	767.2	830.3	885.0	1.7%
Natural Gas	264.3	270.0	293.8	312.2	329.3	344.5	1.2%
Coal	67.1	68.2	65.9	66.4	66.9	67.9	-0.0%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Electricity	560.1	585.6	635.7	688.8	738.7	790.2	1.5%
Total[3]	**1517.2**	**1561.7**	**1693.5**	**1834.7**	**1965.4**	**2087.8**	**1.5%**
Electric Generators[6]							
Petroleum	23.5	19.9	6.8	4.3	5.1	5.9	-5.9%
Natural Gas	51.1	61.1	80.4	100.6	130.7	151.1	4.6%
Coal	485.5	504.6	548.5	583.9	602.9	633.2	1.1%
Total	**560.1**	**585.6**	**635.7**	**688.8**	**738.7**	**790.2**	**1.5%**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	649.3	657.8	704.8	771.5	835.4	890.9	1.5%
Natural Gas	315.3	331.2	374.2	412.8	460.0	495.6	2.0%
Coal	552.6	572.8	614.5	650.3	669.8	701.2	1.0%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total[3]	**1517.2**	**1561.7**	**1693.5**	**1834.7**	**1965.4**	**2087.8**	**1.5%**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**5.7**	**5.9**	**6.1**	**6.3**	**6.4**	**0.6%**

[1]Includes consumption by cogenerators.
[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 1998, international bunker fuels accounted for 25 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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2000,* DOE/EIA-0573(2000) (Washington, DC, November 2001). **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 1999	2000	2005	2010	2015	2020	Annual Growth 2000-2020 (percent)
GDP Chain-Type Price Index (1996=1.000)	**1.047**	**1.070**	**1.209**	**1.369**	**1.561**	**1.826**	**2.7%**
Real Gross Domestic Product	**8857**	**9224**	**10418**	**12312**	**14399**	**16525**	**3.0%**
Real Consumption	5968	6258	7148	8256	9545	10991	2.9%
Real Investment	1660	1773	1923	2518	3252	3953	4.1%
Real Government Spending	1532	1573	1754	1892	2016	2149	1.6%
Real Exports	1035	1133	1346	1968	2840	4032	6.6%
Real Imports	1352	1532	1778	2263	3090	4369	5.4%
Real Disposable Personal Income	**6320**	**6539**	**7593**	**8742**	**10202**	**11698**	**3.0%**
AA Utility Bond Rate (percent)	**7.05**	**7.91**	**7.01**	**7.37**	**7.66**	**8.07**	**0.1%**
Real Yield on Government 10 Year Bonds (percent)	**4.75**	**4.84**	**3.88**	**4.54**	**4.99**	**5.34**	**N/A**
Real Utility Bond Rate (percent)	**5.52**	**6.27**	**4.28**	**4.94**	**4.95**	**4.64**	**N/A**
Energy Intensity (thousand Btu per 1996 dollar of GDP)							
Delivered Energy	8.20	8.04	7.72	7.09	6.51	6.02	N/A
Total Energy	10.97	10.77	10.34	9.40	8.59	7.92	-1.5%
Consumer Price Index (1982-84=1.00)	**1.67**	**1.72**	**1.98**	**2.27**	**2.64**	**3.15**	**3.1%**
Unemployment Rate (percent)	**4.23**	**4.01**	**5.21**	**4.49**	**4.56**	**4.04**	**0.0%**
Housing Starts (millions)	**2.00**	**1.82**	**1.84**	**1.93**	**1.90**	**2.01**	**0.5%**
Single-Family	1.31	1.23	1.29	1.33	1.32	1.36	N/A
Multifamily	0.34	0.34	0.27	0.29	0.30	0.36	0.3%
Mobile Home Shipments	0.35	0.25	0.27	0.30	0.27	0.28	0.6%
Commercial Floorspace, Total (billion square feet)	**63.1**	**64.5**	**71.7**	**77.5**	**83.8**	**89.6**	**1.7%**
Gross Output (billion 1992 dollars)							
Total Industrial	4794	5062	5677	6584	7535	8447	2.6%
Nonmanufacturing	990	1039	1127	1211	1325	1444	1.7%
Manufacturing	3804	4022	4550	5373	6210	7003	2.8%
Energy-Intensive Manufacturing	1057	1100	1178	1251	1340	1410	1.2%
Non-Energy-Intensive Manufacturing	2747	2922	3372	4122	4870	5593	3.3%
Unit Sales of Light-Duty Vehicles (millions)	**16.89**	**17.36**	**16.62**	**17.34**	**17.81**	**18.24**	**0.2%**
Population (millions)							
Population with Armed Forces Overseas	273.2	275.7	288.1	300.2	312.7	325.3	0.8%
Population (aged 16 and over)	211.0	213.1	224.8	236.6	246.7	256.5	0.9%
Employment, Non-Agriculture	127.5	130.1	136.9	145.2	150.2	154.5	0.9%
Employment, Manufacturing	17.6	17.5	16.5	16.3	15.5	15.3	-0.7%
Labor Force	139.4	140.9	149.2	156.9	161.4	165.3	0.8%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 1999 and 2000: DRI-WEFA, Simulation CTL0901. **Projections:** Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table A21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
World Oil Price (2000 dollars per barrel)[1]	**17.60**	**27.72**	**22.73**	**23.36**	**24.00**	**24.68**	**-0.6%**
Production[2]							
OECD							
U.S. (50 states)	9.21	9.03	8.72	8.87	9.71	9.95	0.5%
Canada	2.63	2.74	3.01	3.20	3.37	3.55	1.3%
Mexico	3.37	3.54	4.08	4.24	4.39	4.44	1.1%
OECD Europe[3]	7.02	7.06	7.33	7.20	6.92	6.65	-0.3%
Other OECD	0.78	0.98	0.93	0.92	0.90	0.88	-0.5%
Total OECD	**23.01**	**23.35**	**24.08**	**24.43**	**25.29**	**25.46**	**0.4%**
Developing Countries							
Other South & Central America	3.85	3.78	4.19	4.82	5.58	6.48	2.7%
Pacific Rim	2.30	2.31	2.62	2.63	2.59	2.55	0.5%
OPEC	29.05	30.93	35.15	40.78	48.32	57.46	3.1%
Other Developing Countries	4.85	4.96	5.38	6.25	7.23	8.38	2.7%
Total Developing Countries	**40.05**	**41.98**	**47.35**	**54.48**	**63.73**	**74.86**	**2.9%**
Eurasia							
Former Soviet Union	7.40	7.83	9.67	12.02	13.72	14.89	3.3%
Eastern Europe	0.24	0.24	0.28	0.30	0.33	0.36	2.0%
China	3.21	3.26	3.09	3.07	3.05	3.02	-0.4%
Total Eurasia	**10.85**	**11.33**	**13.04**	**15.39**	**17.10**	**18.26**	**2.4%**
Total Production	**73.91**	**76.66**	**84.46**	**94.31**	**106.12**	**118.59**	**2.2%**
Consumption							
OECD							
U.S. (50 states)	19.53	19.74	21.27	23.21	25.07	26.66	1.5%
U.S. Territories	0.34	0.35	0.40	0.43	0.45	0.48	1.6%
Canada	1.93	1.96	2.02	2.09	2.12	2.14	0.4%
Mexico	1.95	2.03	2.33	2.75	3.33	4.11	3.6%
Japan	5.57	5.54	5.66	5.62	5.64	5.62	0.1%
Australia and New Zealand.	0.98	1.00	1.02	1.09	1.18	1.28	1.2%
OECD Europe[3]	14.49	14.53	15.46	15.80	16.12	16.44	0.6%
Total OECD	**44.79**	**45.16**	**48.16**	**50.98**	**53.91**	**56.72**	**1.1%**
Developing Countries							
Other South and Central America	4.18	4.29	4.82	5.86	7.11	8.62	3.6%
Pacific Rim	7.87	8.20	10.23	12.20	14.46	16.76	3.6%
OPEC	5.68	5.81	6.55	7.55	8.72	10.08	2.8%
Other Developing Countries	2.76	2.85	3.33	4.20	5.41	7.12	4.7%
Total Developing Countries	**20.50**	**21.15**	**24.93**	**29.81**	**35.70**	**42.58**	**3.6%**
Eurasia							
Former Soviet Union	3.65	3.66	4.87	5.56	6.79	7.69	3.8%
Eastern Europe	1.53	1.54	1.56	1.63	1.68	1.69	0.5%
China	4.31	4.53	5.22	6.62	8.35	10.18	4.1%
Total Eurasia	**9.49**	**9.73**	**11.66**	**13.81**	**16.82**	**19.57**	**3.6%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Total Consumption	**74.76**	**75.99**	**84.76**	**94.61**	**106.42**	**118.89**	**2.3%**
Non-OPEC Production	44.85	45.73	49.30	53.52	57.80	61.12	1.5%
Net Eurasia Exports	1.36	1.61	1.38	1.59	0.28	-1.30	N/A
OPEC Market Share	0.39	0.40	0.42	0.43	0.46	0.48	0.9%

[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, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 and 2000 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		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	12.33	10.71	10.76	10.81	11.43	11.76	12.00	11.66	11.92	12.30
Natural Gas Plant Liquids	2.71	3.30	3.37	3.45	3.60	3.74	3.82	3.86	4.03	4.09
Dry Natural Gas	19.59	23.59	24.12	24.70	25.97	27.03	27.65	27.98	29.25	29.72
Coal	22.58	25.88	26.23	26.69	26.33	26.91	27.72	26.88	28.11	30.08
Nuclear Power	8.03	7.87	7.87	7.87	7.44	7.55	7.55	7.38	7.49	7.49
Renewable Energy[1]	6.46	7.74	7.89	8.06	8.23	8.47	8.72	8.59	8.93	9.37
Other[2]	1.10	0.82	0.85	0.56	0.91	1.04	0.88	0.91	0.93	0.73
Total	**72.80**	**79.92**	**81.09**	**82.15**	**83.89**	**86.51**	**88.33**	**87.26**	**90.66**	**93.79**
Imports										
Crude Oil[3]	19.69	24.26	24.36	25.30	24.17	24.04	24.68	24.62	24.45	25.04
Petroleum Products[4]	4.73	6.92	7.83	8.76	8.75	10.31	12.05	9.80	12.69	15.41
Natural Gas	3.85	5.38	5.64	6.09	5.73	6.04	6.74	5.68	6.20	6.97
Other Imports[5]	0.76	0.89	0.95	1.06	1.01	1.07	1.20	1.00	1.09	1.22
Total	**29.04**	**37.44**	**38.79**	**41.21**	**39.66**	**41.46**	**44.67**	**41.12**	**44.44**	**48.64**
Exports										
Petroleum[6]	2.15	1.87	1.91	1.96	1.98	2.02	2.08	2.04	2.11	2.21
Natural Gas	0.25	0.63	0.63	0.63	0.66	0.66	0.66	0.56	0.56	0.56
Coal	1.53	1.44	1.36	1.44	1.47	1.34	1.34	1.38	1.38	1.37
Total	**3.93**	**3.94**	**3.90**	**4.03**	**4.11**	**4.01**	**4.08**	**3.99**	**4.05**	**4.14**
Discrepancy[7]	**-1.37**	**0.38**	**0.37**	**0.25**	**0.27**	**0.32**	**0.21**	**0.25**	**0.20**	**0.04**
Consumption										
Petroleum Products[8]	38.63	44.04	45.20	46.96	46.88	48.85	51.43	48.84	51.99	55.60
Natural Gas	23.43	28.07	28.85	29.88	30.78	32.14	33.45	32.84	34.63	35.87
Coal	22.34	24.97	25.41	25.84	25.41	26.16	27.02	26.08	27.35	29.41
Nuclear Power	8.03	7.87	7.87	7.87	7.44	7.55	7.55	7.38	7.49	7.49
Renewable Energy[1]	6.48	7.75	7.90	8.07	8.23	8.48	8.73	8.59	8.94	9.38
Other[9]	0.38	0.34	0.38	0.45	0.43	0.46	0.53	0.40	0.44	0.48
Total	**99.29**	**113.04**	**115.61**	**119.07**	**119.17**	**123.64**	**128.70**	**124.13**	**130.85**	**138.24**
Net Imports - Petroleum	**22.28**	**29.30**	**30.29**	**32.09**	**30.94**	**32.33**	**34.65**	**32.39**	**35.04**	**38.25**
Prices (2000 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.72	22.75	23.36	23.87	23.09	24.00	24.82	23.45	24.68	25.81
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	2.66	2.85	3.31	2.88	3.07	3.36	2.94	3.26	3.65
Coal Minemouth Price (dollars per ton)	16.45	13.70	14.11	14.04	13.17	13.44	13.51	12.56	12.79	13.23
Average Electricity Price (cents per kilowatthour)	6.9	6.2	6.3	6.6	6.2	6.3	6.6	6.2	6.5	6.8

[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. 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, 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 and heat loss when natural gas 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		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	0.83	0.79	0.79	0.79	0.75	0.75	0.75	0.73	0.73	0.73
Kerosene	0.09	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.47	0.45	0.45	0.44	0.42	0.42	0.42	0.41	0.41	0.41
Petroleum Subtotal	1.38	1.31	1.30	1.30	1.25	1.24	1.24	1.20	1.20	1.20
Natural Gas	5.14	5.64	5.68	5.68	5.76	5.89	5.97	5.95	6.15	6.25
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.43	0.43	0.43	0.44	0.43	0.44	0.45	0.43	0.45	0.46
Electricity	4.07	4.87	4.92	4.95	5.20	5.30	5.37	5.54	5.70	5.80
Delivered Energy	**11.06**	**12.31**	**12.40**	**12.43**	**12.68**	**12.92**	**13.08**	**13.17**	**13.55**	**13.76**
Electricity Related Losses	8.79	9.78	9.85	9.83	10.11	10.25	10.23	10.51	10.72	10.75
Total	**19.85**	**22.08**	**22.24**	**22.27**	**22.80**	**23.17**	**23.31**	**23.68**	**24.27**	**24.51**
Commercial										
Distillate Fuel	0.38	0.42	0.42	0.43	0.42	0.42	0.43	0.41	0.42	0.43
Residual Fuel	0.14	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.14
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.65	0.69	0.69	0.70	0.70	0.70	0.72	0.70	0.71	0.73
Natural Gas	3.36	4.02	4.04	4.02	4.25	4.33	4.38	4.51	4.64	4.74
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.90	4.97	5.03	5.08	5.49	5.62	5.72	5.95	6.13	6.29
Delivered Energy	**8.07**	**9.83**	**9.91**	**9.95**	**10.59**	**10.80**	**10.98**	**11.32**	**11.64**	**11.92**
Electricity Related Losses	8.42	9.97	10.06	10.08	10.70	10.85	10.90	11.30	11.53	11.65
Total	**16.49**	**19.80**	**19.98**	**20.03**	**21.29**	**21.65**	**21.88**	**22.61**	**23.18**	**23.57**
Industrial[4]										
Distillate Fuel	1.11	1.16	1.22	1.30	1.20	1.29	1.40	1.24	1.38	1.53
Liquefied Petroleum Gas	2.36	2.52	2.66	2.88	2.66	2.85	3.25	2.66	3.00	3.45
Petrochemical Feedstock	1.32	1.38	1.45	1.57	1.42	1.54	1.71	1.41	1.59	1.81
Residual Fuel	0.27	0.22	0.23	0.26	0.22	0.26	0.28	0.22	0.27	0.29
Motor Gasoline[2]	0.22	0.23	0.24	0.25	0.24	0.26	0.27	0.25	0.27	0.30
Other Petroleum[5]	3.96	4.62	4.77	4.96	4.82	4.99	5.21	4.91	5.17	5.49
Petroleum Subtotal	9.23	10.13	10.57	11.23	10.55	11.19	12.11	10.70	11.69	12.86
Natural Gas[6]	9.79	10.86	11.19	11.63	11.19	11.77	12.31	11.44	12.19	13.12
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	1.69	1.66	1.74	1.87	1.68	1.79	1.93	1.70	1.85	2.04
Net Coal Coke Imports	0.06	0.09	0.11	0.15	0.11	0.14	0.20	0.12	0.16	0.24
Coal Subtotal	2.53	2.40	2.50	2.66	2.37	2.51	2.71	2.35	2.55	2.82
Renewable Energy[7]	2.41	2.78	2.89	3.07	2.98	3.18	3.43	3.13	3.43	3.79
Electricity	3.65	4.01	4.20	4.51	4.25	4.53	4.97	4.41	4.83	5.45
Delivered Energy	**27.62**	**30.17**	**31.35**	**33.10**	**31.35**	**33.19**	**35.52**	**32.03**	**34.69**	**38.04**
Electricity Related Losses	7.89	8.04	8.39	8.95	8.26	8.76	9.46	8.38	9.08	10.09
Total	**35.50**	**38.22**	**39.74**	**42.05**	**39.61**	**41.96**	**44.98**	**40.40**	**43.76**	**48.12**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		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]	5.42	7.06	7.27	7.59	7.69	8.09	8.60	8.10	8.72	9.52
Jet Fuel[9]	3.58	4.34	4.46	4.67	4.86	5.12	5.45	5.36	5.82	6.33
Motor Gasoline[2]	16.05	18.97	19.32	19.80	20.20	20.86	21.61	21.11	22.12	23.14
Residual Fuel	1.14	1.07	1.08	1.08	1.08	1.09	1.10	1.09	1.10	1.12
Liquefied Petroleum Gas	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Other Petroleum[10]	0.22	0.26	0.26	0.27	0.27	0.28	0.29	0.27	0.29	0.31
Petroleum Subtotal	26.42	31.74	32.43	33.46	34.14	35.48	37.10	35.98	38.11	40.47
Pipeline Fuel Natural Gas	0.79	0.84	0.86	0.89	0.91	0.95	0.98	0.97	1.02	1.04
Compressed Natural Gas	0.02	0.09	0.09	0.10	0.11	0.12	0.13	0.13	0.14	0.15
Renewable Energy (E85)[11]	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.08	0.08	0.08	0.09	0.09	0.09	0.11	0.11	0.11
Delivered Energy	**27.32**	**32.78**	**33.50**	**34.57**	**35.30**	**36.69**	**38.35**	**37.24**	**39.43**	**41.83**
Electricity Related Losses	0.13	0.16	0.16	0.16	0.18	0.18	0.18	0.20	0.21	0.21
Total	**27.45**	**32.94**	**33.66**	**34.73**	**35.48**	**36.87**	**38.53**	**37.44**	**39.64**	**42.04**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.73	9.43	9.70	10.11	10.06	10.55	11.18	10.48	11.24	12.21
Kerosene	0.14	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[9]	3.58	4.34	4.46	4.67	4.86	5.12	5.45	5.36	5.82	6.33
Liquefied Petroleum Gas	2.93	3.08	3.23	3.45	3.21	3.41	3.81	3.21	3.56	4.01
Motor Gasoline[2]	16.29	19.23	19.59	20.08	20.46	21.14	21.91	21.39	22.42	23.46
Petrochemical Feedstock	1.32	1.38	1.45	1.57	1.42	1.54	1.71	1.41	1.59	1.81
Residual Fuel	1.54	1.42	1.43	1.47	1.43	1.48	1.51	1.44	1.51	1.54
Other Petroleum[12]	4.16	4.85	5.01	5.22	5.06	5.25	5.47	5.16	5.44	5.78
Petroleum Subtotal	37.69	43.86	45.00	46.70	46.64	48.61	51.17	48.57	51.71	55.26
Natural Gas[6]	19.11	21.45	21.87	22.32	22.23	23.06	23.77	23.01	24.14	25.31
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	1.80	1.78	1.86	1.99	1.80	1.91	2.05	1.82	1.98	2.17
Net Coal Coke Imports	0.06	0.09	0.11	0.15	0.11	0.14	0.20	0.12	0.16	0.24
Coal Subtotal	2.64	2.52	2.62	2.79	2.50	2.64	2.83	2.48	2.68	2.95
Renewable Energy[13]	2.93	3.32	3.44	3.62	3.53	3.74	4.00	3.68	4.00	4.38
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.69	13.94	14.23	14.62	15.03	15.54	16.16	16.01	16.77	17.65
Delivered Energy	**74.06**	**85.08**	**87.15**	**90.05**	**89.92**	**93.60**	**97.93**	**93.75**	**99.31**	**105.56**
Electricity Related Losses	25.23	27.95	28.46	29.02	29.25	30.04	30.78	30.38	31.54	32.69
Total	**99.29**	**113.04**	**115.61**	**119.07**	**119.17**	**123.64**	**128.70**	**124.13**	**130.85**	**138.24**
Electric Generators[14]										
Distillate Fuel	0.08	0.05	0.05	0.05	0.07	0.05	0.05	0.08	0.06	0.08
Residual Fuel	0.86	0.14	0.16	0.21	0.18	0.19	0.21	0.19	0.22	0.26
Petroleum Subtotal	0.93	0.18	0.21	0.26	0.24	0.24	0.26	0.27	0.28	0.34
Natural Gas	4.32	6.62	6.98	7.56	8.55	9.08	9.69	9.83	10.49	10.56
Steam Coal	19.69	22.45	22.80	23.05	22.92	23.52	24.19	23.61	24.67	26.46
Nuclear Power	8.03	7.87	7.87	7.87	7.44	7.55	7.55	7.38	7.49	7.49
Renewable Energy[15]	3.55	4.43	4.46	4.45	4.70	4.74	4.72	4.91	4.94	5.00
Electricity Imports[16]	0.38	0.34	0.38	0.45	0.42	0.45	0.52	0.39	0.44	0.48
Total	**36.92**	**41.89**	**42.69**	**43.64**	**44.28**	**45.58**	**46.93**	**46.39**	**48.32**	**50.34**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Total Energy Consumption										
Distillate Fuel	7.80	9.48	9.75	10.16	10.13	10.61	11.23	10.55	11.31	12.28
Kerosene	0.14	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[9]	3.58	4.34	4.46	4.67	4.86	5.12	5.45	5.36	5.82	6.33
Liquefied Petroleum Gas	2.93	3.08	3.23	3.45	3.21	3.41	3.81	3.21	3.56	4.01
Motor Gasoline[2]	16.29	19.23	19.59	20.08	20.46	21.14	21.91	21.39	22.42	23.46
Petrochemical Feedstock	1.32	1.38	1.45	1.57	1.42	1.54	1.71	1.41	1.59	1.81
Residual Fuel	2.40	1.55	1.59	1.68	1.60	1.67	1.72	1.64	1.72	1.80
Other Petroleum[12]	4.16	4.85	5.01	5.22	5.06	5.25	5.47	5.16	5.44	5.78
Petroleum Subtotal	38.63	44.04	45.20	46.96	46.88	48.85	51.43	48.84	51.99	55.60
Natural Gas	23.43	28.07	28.85	29.88	30.78	32.14	33.45	32.84	34.63	35.87
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	21.50	24.24	24.66	25.04	24.72	25.43	26.24	25.43	26.65	28.63
Net Coal Coke Imports	0.06	0.09	0.11	0.15	0.11	0.14	0.20	0.12	0.16	0.24
Coal Subtotal	22.34	24.97	25.41	25.84	25.41	26.16	27.02	26.08	27.35	29.41
Nuclear Power	8.03	7.87	7.87	7.87	7.44	7.55	7.55	7.38	7.49	7.49
Renewable Energy[17]	6.48	7.75	7.90	8.07	8.23	8.48	8.73	8.59	8.94	9.38
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.38	0.34	0.38	0.45	0.42	0.45	0.52	0.39	0.44	0.48
Total	**99.29**	**113.04**	**115.61**	**119.07**	**119.17**	**123.64**	**128.70**	**124.13**	**130.85**	**138.24**
Energy Use and Related Statistics										
Delivered Energy Use	74.06	85.08	87.15	90.05	89.92	93.60	97.93	93.75	99.31	105.56
Total Energy Use	99.29	113.04	115.61	119.07	119.17	123.64	128.70	124.13	130.85	138.24
Population (millions)	275.69	293.98	300.24	306.50	302.92	312.66	322.41	311.94	325.33	338.71
Gross Domestic Product (billion 1996 dollars)	9224	11759	12312	13021	13395	14399	15450	14901	16525	18102
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1561.7	1794.9	1834.7	1887.5	1896.5	1965.4	2046.4	1980.3	2087.8	2214.7

1Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
2Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
3Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
4Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
5Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
6Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
7Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
8Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
9Includes only kerosene type.
10Includes aviation gas and lubricants.
11E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
12Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
13Includes 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.
14Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
15Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
16In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
17Includes 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 2000 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 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1999, Volume 1,* DOE/EIA-0348(99)/1 (Washington, DC, August 2000). 2000 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B3. Energy Prices by Sector and Source
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**14.42**	**13.13**	**13.50**	**14.17**	**13.23**	**13.68**	**14.28**	**13.40**	**14.04**	**14.82**
Primary Energy[1]	8.26	7.07	7.27	7.65	7.19	7.40	7.64	7.22	7.49	7.81
Petroleum Products[2]	10.78	9.62	9.84	10.00	9.89	10.29	10.45	10.01	10.41	10.63
Distillate Fuel	9.42	7.76	7.94	8.01	8.09	8.43	8.56	8.24	8.54	8.72
Liquefied Petroleum Gas	13.65	12.97	13.26	13.61	13.12	13.65	13.85	13.21	13.81	14.13
Natural Gas	7.64	6.53	6.73	7.17	6.65	6.84	7.11	6.70	6.97	7.32
Electricity	24.36	21.84	22.41	23.44	21.44	22.18	23.24	21.45	22.55	23.88
Commercial	**14.03**	**12.51**	**12.89**	**13.59**	**12.73**	**13.15**	**13.74**	**12.92**	**13.57**	**14.31**
Primary Energy[1]	6.31	5.38	5.57	5.95	5.55	5.77	6.02	5.64	5.93	6.26
Petroleum Products[2]	7.19	6.16	6.36	6.45	6.42	6.77	6.92	6.58	6.91	7.12
Distillate Fuel	7.08	5.52	5.73	5.78	5.87	6.25	6.40	6.07	6.39	6.57
Residual Fuel	3.46	3.73	3.83	3.91	3.78	3.92	4.05	3.83	4.02	4.20
Natural Gas[3]	6.23	5.32	5.51	5.94	5.48	5.68	5.95	5.57	5.86	6.21
Electricity	22.11	19.36	19.87	20.81	19.28	19.85	20.72	19.40	20.33	21.41
Industrial[4]	**6.88**	**5.74**	**5.97**	**6.34**	**5.95**	**6.27**	**6.61**	**6.07**	**6.49**	**6.92**
Primary Energy	5.69	4.55	4.76	5.03	4.75	5.05	5.28	4.84	5.19	5.50
Petroleum Products[2]	8.10	6.46	6.69	6.85	6.64	7.08	7.22	6.73	7.13	7.38
Distillate Fuel	7.21	5.63	5.89	5.92	6.04	6.52	6.67	6.33	6.70	6.91
Liquefied Petroleum Gas	11.73	8.31	8.60	8.93	8.42	8.98	9.12	8.51	9.11	9.36
Residual Fuel	3.27	3.56	3.65	3.74	3.60	3.74	3.87	3.68	3.86	4.03
Natural Gas[5]	4.31	3.28	3.47	3.90	3.49	3.69	4.00	3.58	3.90	4.31
Metallurgical Coal	1.62	1.55	1.56	1.57	1.50	1.52	1.53	1.45	1.46	1.49
Steam Coal	1.41	1.28	1.30	1.32	1.24	1.26	1.29	1.19	1.21	1.26
Electricity	13.50	12.16	12.54	13.25	12.22	12.62	13.31	12.37	13.04	13.89
Transportation	**10.88**	**9.78**	**9.98**	**10.23**	**9.67**	**10.04**	**10.33**	**9.62**	**9.99**	**10.45**
Primary Energy	10.86	9.76	9.96	10.21	9.65	10.02	10.30	9.60	9.96	10.43
Petroleum Products[2]	10.86	9.75	9.96	10.21	9.64	10.01	10.30	9.60	9.96	10.42
Distillate Fuel[6]	10.81	9.88	10.14	10.53	9.62	10.09	10.43	9.55	9.98	10.44
Jet Fuel[7]	7.36	5.64	5.87	6.01	5.84	6.32	6.49	6.00	6.37	6.60
Motor Gasoline[8]	12.20	11.08	11.27	11.51	10.97	11.28	11.61	10.91	11.28	11.85
Residual Fuel	4.38	3.38	3.48	3.56	3.43	3.57	3.70	3.48	3.67	3.85
Liquefied Petroleum Gas[9]	15.91	14.05	14.43	14.90	14.09	14.70	15.00	13.99	14.65	15.11
Natural Gas[10]	8.04	6.64	6.89	7.41	6.83	7.13	7.51	6.87	7.28	7.75
Ethanol (E85)[11]	17.33	20.67	20.59	21.23	21.20	21.71	21.55	21.24	21.19	21.62
Electricity	21.78	17.82	18.20	18.95	18.78	19.27	20.02	17.17	17.91	18.68
Average End-Use Energy	**10.40**	**9.30**	**9.53**	**9.88**	**9.39**	**9.73**	**10.05**	**9.50**	**9.90**	**10.35**
Primary Energy	8.41	7.42	7.61	7.87	7.50	7.81	8.06	7.56	7.89	8.26
Electricity	20.20	18.15	18.58	19.36	18.03	18.53	19.28	18.15	18.97	19.89
Electric Generators[12]										
Fossil Fuel Average	1.88	1.55	1.61	1.76	1.69	1.77	1.89	1.74	1.85	1.95
Petroleum Products	4.33	3.88	3.97	4.02	4.01	4.14	4.24	4.11	4.27	4.47
Distillate Fuel	6.89	5.00	5.23	5.29	5.29	5.73	5.95	5.45	5.87	6.00
Residual Fuel	4.11	3.50	3.60	3.71	3.54	3.69	3.84	3.58	3.81	4.01
Natural Gas	4.41	3.19	3.38	3.79	3.45	3.65	3.96	3.56	3.87	4.25
Steam Coal	1.20	1.04	1.05	1.07	1.00	1.01	1.03	0.95	0.97	1.00

Table B3. Energy Prices by Sector and Source (Continued)
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		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[13]										
Petroleum Products[2]	10.05	9.00	9.19	9.39	8.98	9.35	9.58	8.99	9.34	9.72
Distillate Fuel	9.93	8.97	9.22	9.52	8.90	9.37	9.67	8.91	9.33	9.74
Jet Fuel	7.36	5.64	5.87	6.01	5.84	6.32	6.49	6.00	6.37	6.60
Liquefied Petroleum Gas	12.06	9.11	9.37	9.65	9.18	9.70	9.77	9.26	9.79	9.98
Motor Gasoline[8]	12.20	11.08	11.27	11.51	10.97	11.28	11.61	10.91	11.28	11.85
Residual Fuel	4.11	3.45	3.54	3.63	3.49	3.64	3.77	3.55	3.75	3.93
Natural Gas	5.43	4.30	4.47	4.86	4.44	4.61	4.89	4.50	4.79	5.15
Coal	1.22	1.06	1.07	1.09	1.02	1.03	1.06	0.97	0.98	1.02
Ethanol (E85)[11]	17.33	20.67	20.59	21.23	21.20	21.71	21.55	21.24	21.19	21.62
Electricity	20.20	18.15	18.58	19.36	18.03	18.53	19.28	18.15	18.97	19.89
Non-Renewable Energy Expenditures by Sector (billion 2000 dollars)										
Residential	153.41	155.96	161.45	169.96	162.07	170.74	180.32	170.73	184.01	197.20
Commercial	112.06	121.98	126.73	134.16	133.77	140.90	149.74	145.23	156.92	169.46
Industrial	142.86	125.20	136.11	153.85	133.70	150.46	171.70	138.70	162.53	193.39
Transportation	288.38	311.63	325.09	343.89	331.80	357.95	384.98	348.11	382.65	425.12
Total Non-Renewable Expenditures	696.71	714.78	749.39	801.86	761.34	820.07	886.74	802.78	886.10	985.16
Transportation Renewable Expenditures	0.31	0.66	0.70	0.75	0.81	0.88	0.95	0.91	1.00	1.12
Total Expenditures	**697.01**	**715.44**	**750.09**	**802.61**	**762.15**	**820.95**	**887.69**	**803.69**	**887.11**	**986.28**

[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]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes use for lease and plant fuel.
[6] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[13]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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline, distillate, and jet fuel are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/ data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf. 2000 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 2000 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. 2000 electricity prices for commercial, industrial, and transportation: EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	76.57	84.72	85.88	87.15	88.23	90.55	92.55	91.57	95.27	98.02
Multifamily	21.97	22.88	23.15	23.67	23.28	23.77	24.51	23.84	24.58	25.58
Mobile Homes	6.61	6.87	6.95	7.03	6.98	7.14	7.22	7.02	7.27	7.33
Total	**105.15**	**114.47**	**115.98**	**117.86**	**118.49**	**121.46**	**124.28**	**122.44**	**127.12**	**130.93**
Average House Square Footage	**1678**	**1731**	**1735**	**1737**	**1755**	**1762**	**1766**	**1776**	**1787**	**1792**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	105.2	107.5	106.9	105.5	107.0	106.4	105.2	107.6	106.6	105.1
Total Energy Consumption	188.8	192.9	191.8	188.9	192.4	190.7	187.6	193.4	190.9	187.2
(thousand Btu per square foot)										
Delivered Energy Consumption	62.7	62.1	61.6	60.7	61.0	60.4	59.6	60.6	59.6	58.7
Total Energy Consumption	112.5	111.4	110.5	108.7	109.6	108.2	106.2	108.9	106.8	104.4
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.42	0.47	0.48	0.48	0.49	0.50	0.51	0.52	0.53	0.54
Space Cooling	0.56	0.63	0.63	0.64	0.66	0.68	0.69	0.72	0.75	0.76
Water Heating	0.41	0.41	0.41	0.42	0.40	0.41	0.41	0.39	0.39	0.40
Refrigeration	0.43	0.34	0.34	0.35	0.32	0.32	0.33	0.31	0.32	0.33
Cooking	0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.12	0.13	0.13
Clothes Dryers	0.23	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.28	0.28
Freezers	0.12	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Lighting	0.35	0.45	0.45	0.45	0.48	0.48	0.48	0.50	0.51	0.51
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	0.02	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.20	0.22	0.23	0.23	0.25	0.26	0.26
Personal Computers	0.04	0.08	0.08	0.08	0.09	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.08	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Other Uses[2]	1.14	1.69	1.71	1.72	1.91	1.95	1.97	2.10	2.16	2.20
Delivered Energy	**4.07**	**4.87**	**4.92**	**4.95**	**5.20**	**5.30**	**5.37**	**5.54**	**5.70**	**5.80**
Natural Gas										
Space Heating	3.44	3.79	3.82	3.81	3.89	3.99	4.04	4.07	4.22	4.29
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.32	1.43	1.44	1.44	1.43	1.46	1.48	1.42	1.47	1.50
Cooking	0.20	0.22	0.22	0.23	0.23	0.24	0.24	0.24	0.25	0.26
Clothes Dryers	0.07	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**5.14**	**5.64**	**5.68**	**5.68**	**5.76**	**5.89**	**5.97**	**5.95**	**6.15**	**6.25**
Distillate										
Space Heating	0.70	0.67	0.67	0.67	0.64	0.64	0.64	0.63	0.63	0.63
Water Heating	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.83**	**0.79**	**0.79**	**0.79**	**0.75**	**0.75**	**0.75**	**0.73**	**0.73**	**0.73**
Liquefied Petroleum Gas										
Space Heating	0.33	0.31	0.31	0.31	0.30	0.30	0.29	0.29	0.29	0.28
Water Heating	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.08	0.08
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.47**	**0.45**	**0.45**	**0.44**	**0.42**	**0.42**	**0.42**	**0.41**	**0.41**	**0.41**
Marketed Renewables (wood)[5]	0.43	0.43	0.43	0.44	0.43	0.44	0.45	0.43	0.45	0.46
Other Fuels[6]	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	5.45	5.80	5.83	5.84	5.88	5.98	6.05	6.06	6.23	6.32
Space Cooling	0.56	0.63	0.64	0.64	0.67	0.68	0.69	0.73	0.75	0.77
Water Heating	1.95	2.05	2.07	2.07	2.02	2.06	2.08	1.99	2.04	2.08
Refrigeration	0.43	0.34	0.34	0.35	0.32	0.32	0.33	0.31	0.32	0.33
Cooking	0.33	0.37	0.37	0.38	0.38	0.39	0.40	0.40	0.41	0.42
Clothes Dryers	0.29	0.34	0.34	0.34	0.35	0.36	0.36	0.37	0.38	0.38
Freezers	0.12	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Lighting	0.35	0.45	0.45	0.45	0.48	0.48	0.48	0.50	0.51	0.51
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	0.02	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.20	0.22	0.23	0.23	0.25	0.26	0.26
Personal Computers	0.04	0.08	0.08	0.08	0.09	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.08	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Other Uses[7]	1.27	1.82	1.83	1.84	2.03	2.07	2.09	2.22	2.28	2.32
Delivered Energy	**11.06**	**12.31**	**12.40**	**12.43**	**12.68**	**12.92**	**13.08**	**13.17**	**13.55**	**13.76**
Electricity Related Losses	**8.79**	**9.78**	**9.85**	**9.83**	**10.11**	**10.25**	**10.23**	**10.51**	**10.72**	**10.75**
Total Energy Consumption by End-Use										
Space Heating	6.36	6.74	6.78	6.79	6.84	6.96	7.02	7.04	7.23	7.32
Space Cooling	1.77	1.88	1.90	1.91	1.96	2.00	2.01	2.10	2.16	2.18
Water Heating	2.83	2.88	2.90	2.90	2.80	2.84	2.86	2.72	2.79	2.82
Refrigeration	1.36	1.02	1.03	1.04	0.93	0.95	0.96	0.90	0.93	0.95
Cooking	0.56	0.60	0.61	0.62	0.62	0.63	0.64	0.63	0.65	0.67
Clothes Dryers	0.78	0.85	0.85	0.85	0.86	0.87	0.87	0.88	0.90	0.90
Freezers	0.37	0.26	0.27	0.27	0.25	0.25	0.26	0.24	0.25	0.26
Lighting	1.11	1.36	1.36	1.34	1.41	1.42	1.41	1.45	1.47	1.45
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.08	0.09	0.09
Dishwashers	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.42	0.59	0.60	0.59	0.66	0.66	0.66	0.73	0.74	0.75
Personal Computers	0.14	0.23	0.24	0.24	0.28	0.28	0.28	0.31	0.31	0.32
Furnace Fans	0.25	0.28	0.29	0.29	0.30	0.30	0.31	0.31	0.32	0.33
Other Uses[7]	3.73	5.21	5.26	5.26	5.74	5.83	5.85	6.20	6.34	6.40
Total	**19.85**	**22.08**	**22.24**	**22.27**	**22.80**	**23.17**	**23.31**	**23.68**	**24.27**	**24.51**
Non-Marketed Renewables										
Geothermal[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.05
Solar[9]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Total	**0.04**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**	**0.07**	**0.08**	**0.08**

[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf.
Projections: EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	62.3	74.4	75.5	76.6	79.6	81.7	83.8	84.2	87.5	90.7
New Additions	2.2	1.9	2.1	2.3	1.9	2.1	2.3	1.8	2.0	2.3
Total	**64.5**	**76.3**	**77.5**	**78.9**	**81.5**	**83.8**	**86.1**	**86.0**	**89.6**	**93.0**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	125.1	128.8	127.8	126.1	130.0	128.9	127.4	131.6	130.0	128.2
Electricity Related Losses	130.6	130.7	129.8	127.8	131.3	129.6	126.6	131.4	128.8	125.2
Total Energy Consumption	255.7	259.5	257.6	253.9	261.2	258.5	254.0	263.1	258.8	253.4
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17
Space Cooling[1]	0.45	0.50	0.50	0.50	0.52	0.53	0.53	0.53	0.54	0.56
Water Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17
Ventilation	0.18	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.24	1.41	1.42	1.43	1.47	1.50	1.51	1.51	1.53	1.55
Refrigeration	0.19	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.24	0.24
Office Equipment (PC)	0.16	0.31	0.32	0.32	0.34	0.35	0.36	0.34	0.35	0.37
Office Equipment (non-PC)	0.32	0.51	0.52	0.53	0.63	0.65	0.67	0.74	0.78	0.81
Other Uses[2]	1.05	1.47	1.49	1.51	1.74	1.79	1.83	2.02	2.10	2.17
Delivered Energy	**3.90**	**4.97**	**5.03**	**5.08**	**5.49**	**5.62**	**5.72**	**5.95**	**6.13**	**6.29**
Natural Gas[3]										
Space Heating[1]	1.50	1.71	1.72	1.71	1.76	1.79	1.81	1.82	1.87	1.89
Space Cooling[1]	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Water Heating[1]	0.65	0.78	0.79	0.78	0.84	0.85	0.86	0.89	0.91	0.92
Cooking	0.21	0.26	0.26	0.25	0.27	0.27	0.28	0.29	0.29	0.30
Other Uses[4]	0.99	1.25	1.25	1.25	1.34	1.37	1.40	1.48	1.54	1.60
Delivered Energy	**3.36**	**4.02**	**4.04**	**4.02**	**4.25**	**4.33**	**4.38**	**4.51**	**4.64**	**4.74**
Distillate										
Space Heating[1]	0.23	0.25	0.25	0.25	0.24	0.24	0.25	0.24	0.24	0.25
Water Heating[1]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09
Other Uses[5]	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Delivered Energy	**0.38**	**0.42**	**0.42**	**0.43**	**0.42**	**0.42**	**0.43**	**0.41**	**0.42**	**0.43**
Other Fuels[6]	**0.34**	**0.33**	**0.34**	**0.34**	**0.35**	**0.36**	**0.36**	**0.36**	**0.37**	**0.38**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.88	2.12	2.13	2.12	2.17	2.20	2.23	2.22	2.27	2.31
Space Cooling[1]	0.47	0.52	0.53	0.53	0.54	0.56	0.56	0.56	0.58	0.59
Water Heating[1]	0.87	1.03	1.03	1.03	1.08	1.10	1.11	1.13	1.15	1.17
Ventilation	0.18	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23
Cooking	0.24	0.29	0.29	0.28	0.30	0.30	0.31	0.32	0.32	0.32
Lighting	1.24	1.41	1.42	1.43	1.47	1.50	1.51	1.51	1.53	1.55
Refrigeration	0.19	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.24	0.24
Office Equipment (PC)	0.16	0.31	0.32	0.32	0.34	0.35	0.36	0.34	0.35	0.37
Office Equipment (non-PC)	0.32	0.51	0.52	0.53	0.63	0.65	0.67	0.74	0.78	0.81
Other Uses[7]	2.53	3.22	3.25	3.28	3.61	3.69	3.77	4.03	4.18	4.32
Delivered Energy	**8.07**	**9.83**	**9.91**	**9.95**	**10.59**	**10.80**	**10.98**	**11.32**	**11.64**	**11.92**

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electricity Related Losses	**8.42**	**9.97**	**10.06**	**10.08**	**10.70**	**10.85**	**10.90**	**11.30**	**11.53**	**11.65**
Total Energy Consumption by End-Use										
Space Heating[1]	2.20	2.44	2.45	2.44	2.49	2.52	2.54	2.53	2.58	2.62
Space Cooling[1]	1.45	1.52	1.53	1.53	1.55	1.57	1.58	1.57	1.60	1.62
Water Heating[1]	1.19	1.35	1.35	1.35	1.40	1.41	1.42	1.44	1.46	1.48
Ventilation	0.56	0.62	0.63	0.62	0.63	0.64	0.64	0.64	0.65	0.66
Cooking	0.31	0.35	0.35	0.34	0.36	0.36	0.36	0.37	0.38	0.38
Lighting	3.91	4.24	4.27	4.26	4.34	4.39	4.40	4.37	4.42	4.42
Refrigeration	0.59	0.65	0.65	0.65	0.66	0.67	0.67	0.67	0.69	0.69
Office Equipment (PC)	0.49	0.93	0.95	0.96	1.00	1.03	1.05	0.98	1.02	1.05
Office Equipment (non-PC)	1.00	1.54	1.57	1.59	1.86	1.91	1.95	2.16	2.24	2.31
Other Uses[7]	4.79	6.16	6.23	6.28	7.00	7.14	7.26	7.88	8.13	8.34
Total	**16.49**	**19.80**	**19.98**	**20.03**	**21.29**	**21.65**	**21.88**	**22.61**	**23.18**	**23.57**
Non-Marketed Renewable Fuels										
Solar[8]	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]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Value of Gross Output (billion 1992 dollars)										
Manufacturing	4022	5150	5373	5801	5848	6210	6874	6473	7003	8023
Nonmanufacturing	1039	1148	1211	1284	1222	1325	1424	1293	1444	1587
Total	**5062**	**6298**	**6584**	**7085**	**7070**	**7535**	**8297**	**7767**	**8447**	**9610**
Energy Prices (2000 dollars per million Btu)										
Electricity	13.50	12.16	12.54	13.25	12.22	12.62	13.31	12.37	13.04	13.89
Natural Gas	4.31	3.28	3.47	3.90	3.49	3.69	4.00	3.58	3.90	4.31
Steam Coal	1.41	1.28	1.30	1.32	1.24	1.26	1.29	1.19	1.21	1.26
Residual Oil	3.27	3.56	3.65	3.74	3.60	3.74	3.87	3.68	3.86	4.03
Distillate Oil	7.21	5.63	5.89	5.92	6.04	6.52	6.67	6.33	6.70	6.91
Liquefied Petroleum Gas	11.73	8.31	8.60	8.93	8.42	8.98	9.12	8.51	9.11	9.36
Motor Gasoline	12.18	11.04	11.22	11.46	10.93	11.24	11.57	10.87	11.24	11.82
Metallurgical Coal	1.62	1.55	1.56	1.57	1.50	1.52	1.53	1.45	1.46	1.49
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.65	4.01	4.20	4.51	4.25	4.53	4.97	4.41	4.83	5.45
Natural Gas[2]	9.79	10.86	11.19	11.63	11.19	11.77	12.31	11.44	12.19	13.12
Steam Coal	1.69	1.66	1.74	1.87	1.68	1.79	1.93	1.70	1.85	2.04
Metallurgical Coal and Coke[3]	0.84	0.73	0.75	0.80	0.69	0.72	0.78	0.65	0.70	0.78
Residual Fuel	0.27	0.22	0.23	0.26	0.22	0.26	0.28	0.22	0.27	0.29
Distillate	1.11	1.16	1.22	1.30	1.20	1.29	1.40	1.24	1.38	1.53
Liquefied Petroleum Gas	2.36	2.52	2.66	2.88	2.66	2.85	3.25	2.66	3.00	3.45
Petrochemical Feedstocks	1.32	1.38	1.45	1.57	1.42	1.54	1.71	1.41	1.59	1.81
Other Petroleum[4]	4.17	4.85	5.01	5.22	5.06	5.25	5.48	5.16	5.45	5.79
Renewables[5]	2.41	2.78	2.89	3.07	2.98	3.18	3.43	3.13	3.43	3.79
Delivered Energy	**27.62**	**30.17**	**31.35**	**33.10**	**31.35**	**33.19**	**35.52**	**32.03**	**34.69**	**38.04**
Electricity Related Losses	7.89	8.04	8.39	8.95	8.26	8.76	9.46	8.38	9.08	10.09
Total	**35.50**	**38.22**	**39.74**	**42.05**	**39.61**	**41.96**	**44.98**	**40.40**	**43.76**	**48.12**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)										
Purchased Electricity	0.72	0.64	0.64	0.64	0.60	0.60	0.60	0.57	0.57	0.57
Natural Gas[2]	1.93	1.72	1.70	1.64	1.58	1.56	1.48	1.47	1.44	1.37
Steam Coal	0.33	0.26	0.26	0.26	0.24	0.24	0.23	0.22	0.22	0.21
Metallurgical Coal and Coke[3]	0.17	0.12	0.11	0.11	0.10	0.10	0.09	0.08	0.08	0.08
Residual Fuel	0.05	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03
Distillate	0.22	0.18	0.19	0.18	0.17	0.17	0.17	0.16	0.16	0.16
Liquefied Petroleum Gas	0.47	0.40	0.40	0.41	0.38	0.38	0.39	0.34	0.36	0.36
Petrochemical Feedstocks	0.26	0.22	0.22	0.22	0.20	0.20	0.21	0.18	0.19	0.19
Other Petroleum[4]	0.82	0.77	0.76	0.74	0.72	0.70	0.66	0.66	0.64	0.60
Renewables[5]	0.48	0.44	0.44	0.43	0.42	0.42	0.41	0.40	0.41	0.39
Delivered Energy	**5.46**	**4.79**	**4.76**	**4.67**	**4.43**	**4.41**	**4.28**	**4.12**	**4.11**	**3.96**
Electricity Related Losses	1.56	1.28	1.27	1.26	1.17	1.16	1.14	1.08	1.07	1.05
Total	**7.01**	**6.07**	**6.04**	**5.94**	**5.60**	**5.57**	**5.42**	**5.20**	**5.18**	**5.01**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, 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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline and distillate are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_ annual/current/pdf/pmaall.pdf. 2000 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. 2000 electricity prices: EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. Other 2000 prices derived from EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001). Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2340	2902	2981	3068	3184	3318	3452	3430	3631	3818
Commercial Light Trucks (VMT)[1]	70	87	89	94	96	101	109	105	112	124
Freight Trucks >10,000 pounds (VMT)	214	275	285	299	305	323	346	331	360	397
Air (seat miles available)	1184	1554	1603	1694	1836	1949	2096	2129	2342	2571
Rail (ton miles traveled)	1415	1731	1757	1813	1840	1907	2000	1941	2066	2233
Domestic Shipping (ton miles traveled)	689	771	792	820	812	855	898	845	910	973
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.5	25.7	25.7	25.7	26.5	26.6	26.6	27.1	27.2	27.4
New Car (miles per gallon)[2]	28.6	30.2	30.2	30.2	30.9	31.0	31.0	31.6	31.7	31.9
New Light Truck (miles per gallon)[2]	21.1	22.3	22.3	22.3	23.2	23.3	23.3	23.7	23.8	23.9
Light-Duty Fleet (miles per gallon)[3]	19.8	20.1	20.1	20.1	20.5	20.5	20.5	21.0	21.0	21.0
New Commercial Light Truck (MPG)[1]	14.2	14.9	14.9	14.9	15.5	15.5	15.6	15.9	15.9	16.0
Stock Commercial Light Truck (MPG)[1]	13.6	14.4	14.4	14.4	14.9	14.9	14.9	15.4	15.4	15.4
Aircraft Efficiency (seat miles per gallon)	52.1	55.8	55.9	56.1	57.8	58.1	58.4	59.9	60.3	60.6
Freight Truck Efficiency (miles per gallon)	5.9	6.0	6.0	6.0	6.1	6.1	6.1	6.3	6.3	6.4
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.3	3.3	3.3	3.4	3.4	3.4
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	14.97	18.15	18.49	18.93	19.44	20.07	20.77	20.40	21.37	22.31
Commercial Light Trucks[1]	0.64	0.75	0.77	0.81	0.81	0.85	0.91	0.86	0.91	1.01
Freight Trucks[4]	4.80	6.05	6.24	6.54	6.55	6.91	7.38	6.85	7.42	8.14
Air[5]	3.62	4.40	4.51	4.73	4.93	5.19	5.52	5.44	5.91	6.42
Rail[6]	0.58	0.66	0.66	0.68	0.67	0.69	0.72	0.68	0.72	0.77
Marine[7]	1.73	1.72	1.73	1.74	1.75	1.78	1.80	1.79	1.82	1.86
Pipeline Fuel	0.79	0.84	0.86	0.89	0.91	0.95	0.98	0.97	1.02	1.04
Lubricants	0.18	0.21	0.22	0.23	0.22	0.24	0.25	0.23	0.25	0.27
Total	**27.32**	**32.78**	**33.50**	**34.57**	**35.30**	**36.69**	**38.35**	**37.24**	**39.43**	**41.83**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	7.82	9.58	9.76	10.00	10.26	10.59	10.96	10.76	11.27	11.77
Commercial Light Trucks[1]	0.33	0.39	0.41	0.43	0.43	0.45	0.48	0.45	0.48	0.53
Freight Trucks[4]	2.14	2.71	2.81	2.95	2.95	3.12	3.34	3.09	3.35	3.70
Railroad	0.24	0.26	0.27	0.28	0.27	0.28	0.29	0.27	0.28	0.31
Domestic Shipping	0.14	0.15	0.16	0.16	0.16	0.17	0.18	0.16	0.18	0.19
International Shipping	0.48	0.45	0.45	0.45	0.45	0.45	0.45	0.46	0.46	0.46
Air[5]	1.51	1.84	1.89	1.99	2.09	2.21	2.36	2.34	2.56	2.79
Military Use	0.30	0.35	0.35	0.36	0.35	0.36	0.37	0.35	0.36	0.38
Bus Transportation	0.09	0.10	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Rail Transportation[6]	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Recreational Boats	0.16	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20
Lubricants	0.09	0.10	0.11	0.11	0.11	0.11	0.12	0.11	0.12	0.13
Pipeline Fuel	0.40	0.43	0.44	0.45	0.46	0.48	0.50	0.49	0.52	0.53
Total	**13.73**	**16.59**	**16.95**	**17.48**	**17.85**	**18.55**	**19.38**	**18.82**	**19.92**	**21.12**

[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 recreation 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 are model results and may differ slightly from official EIA data reports.

Sources: 2000: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2000/1999* (Washington, DC, 2000); Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf; EIA, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0535(99) (Washington, DC, August 2000); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Supply, Disposition, and Prices	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Generation by Fuel Type										
Electric Generators[1]										
Coal	1922	2185	2215	2243	2230	2292	2368	2307	2423	2644
Petroleum	93	26	28	34	34	33	35	37	38	45
Natural Gas[2]	417	840	893	975	1120	1202	1303	1314	1414	1440
Nuclear Power	752	737	737	737	697	707	707	691	702	702
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	321	389	391	390	400	401	401	407	407	414
Total	**3504**	**4177**	**4263**	**4377**	**4479**	**4634**	**4813**	**4756**	**4983**	**5243**
Nonutility Generation for Own Use	30	33	33	33	33	33	33	32	33	33
Distributed Generation	0	2	2	3	4	5	6	7	8	9
Cogenerators[4]										
Coal	46	49	49	50	49	49	49	48	49	49
Petroleum	9	10	10	10	10	10	10	11	11	11
Natural Gas	209	257	260	264	280	286	296	305	318	337
Other Gaseous Fuels[5]	6	9	9	9	10	10	11	11	12	12
Renewable Sources[3]	33	40	41	44	44	47	51	47	52	58
Other[6]	4	4	4	4	4	4	4	4	4	4
Total	**307**	**369**	**374**	**381**	**397**	**408**	**422**	**426**	**447**	**472**
Other End-Use Generators[7]	**4**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	163	189	189	190	202	204	207	219	224	230
Generation for Own Use	147	186	190	196	200	208	220	212	228	247
Net Imports[8]	**35**	**31**	**35**	**41**	**39**	**41**	**47**	**36**	**40**	**44**
Electricity Sales by Sector										
Residential	1193	1429	1443	1452	1523	1554	1575	1623	1672	1701
Commercial	1144	1457	1475	1488	1610	1646	1678	1744	1798	1843
Industrial	1071	1176	1230	1321	1244	1329	1455	1293	1415	1596
Transportation	18	23	23	24	27	27	28	31	32	33
Total	**3426**	**4084**	**4170**	**4284**	**4404**	**4556**	**4735**	**4691**	**4916**	**5173**
End-Use Prices (2000 cents per kwh)[9]										
Residential	8.3	7.5	7.6	8.0	7.3	7.6	7.9	7.3	7.7	8.1
Commercial	7.5	6.6	6.8	7.1	6.6	6.8	7.1	6.6	6.9	7.3
Industrial	4.6	4.1	4.3	4.5	4.2	4.3	4.5	4.2	4.5	4.7
Transportation	7.4	6.1	6.2	6.5	6.4	6.6	6.8	5.9	6.1	6.4
All Sectors Average	**6.9**	**6.2**	**6.3**	**6.6**	**6.2**	**6.3**	**6.6**	**6.2**	**6.5**	**6.8**
Prices by Service Category[9] (2000 cents per kilowatthour)										
Generation	4.3	3.6	3.7	4.0	3.6	3.7	4.0	3.7	3.9	4.2
Transmission	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	2.0	1.9	1.9	1.9	1.9	1.9	1.9
Emissions (million short tons)										
Sulfur Dioxide	11.05	9.70	9.70	9.70	8.95	8.95	8.94	8.95	8.95	8.94
Nitrogen Oxide	4.28	4.00	4.04	4.08	4.08	4.12	4.15	4.12	4.18	4.22

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[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]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Generators[2]										
Capability										
Coal Steam	304.6	303.6	305.7	307.4	306.2	313.1	322.1	315.0	329.0	358.3
Other Fossil Steam[3]	135.0	115.6	115.6	115.2	114.2	114.4	113.2	113.1	113.3	112.3
Combined Cycle	30.6	131.2	139.9	149.6	167.6	182.4	201.4	197.3	213.8	228.6
Combustion Turbine/Diesel	77.7	126.5	128.9	135.9	145.5	149.6	152.9	172.3	177.9	176.8
Nuclear Power	97.5	94.3	94.3	94.3	87.3	88.8	88.8	86.5	88.0	88.0
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Renewable Sources[4]	89.1	97.1	97.2	97.3	99.2	99.5	99.7	100.5	101.2	102.6
Distributed Generation[5]	0.0	4.1	5.1	6.3	9.0	11.1	12.8	15.2	19.0	21.6
Total	**753.6**	**892.2**	**906.4**	**926.0**	**948.9**	**978.8**	**1010.8**	**1019.8**	**1062.2**	**1108.0**
Cumulative Planned Additions[6]										
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[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Combustion Turbine/Diesel	0.0	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
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	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[4]	0.0	7.0	7.0	7.0	7.9	7.9	7.9	8.2	8.2	8.2
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**17.7**	**17.7**	**17.7**	**18.7**	**18.7**	**18.7**	**19.0**	**19.0**	**19.0**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	4.2	6.2	7.7	7.3	14.1	23.2	17.3	31.2	60.7
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	93.2	101.9	111.7	129.6	144.5	163.4	159.3	175.9	190.6
Combustion Turbine/Diesel	0.0	51.4	53.6	60.7	72.6	76.7	80.6	100.7	105.9	105.2
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[4]	0.0	0.5	0.6	0.7	1.6	1.9	2.2	2.7	3.4	4.8
Distributed Generation[5]	0.0	4.1	5.1	6.3	9.0	11.1	12.8	15.2	19.0	21.6
Total	**0.0**	**153.5**	**167.3**	**187.2**	**220.1**	**248.3**	**282.1**	**295.2**	**335.5**	**382.9**
Cumulative Total Additions	**0.0**	**171.2**	**185.0**	**204.9**	**238.9**	**267.1**	**300.9**	**314.2**	**354.5**	**401.9**
Cumulative Retirements[7]										
Coal Steam	0.0	5.4	5.2	5.1	5.9	5.8	5.9	7.1	7.0	7.1
Other Fossil Steam[3]	0.0	18.2	18.2	18.6	19.6	19.4	20.6	20.7	20.5	21.6
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combustion Turbine/Diesel	0.0	6.3	6.1	6.2	8.4	8.5	9.0	9.8	9.5	9.9
Nuclear Power	0.0	3.4	3.4	3.4	10.4	8.9	8.9	11.2	9.7	9.7
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[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**33.5**	**33.1**	**33.4**	**44.5**	**42.8**	**44.6**	**49.0**	**46.9**	**48.4**

Table B9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Cogenerators[8]										
Capability										
Coal	8.9	8.6	8.6	8.8	8.6	8.6	8.6	8.5	8.6	8.6
Petroleum	2.6	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6
Natural Gas	35.9	43.1	43.5	44.1	46.2	47.1	48.5	49.7	51.6	54.2
Other Gaseous Fuels	0.7	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6
Renewable Sources[4]	5.8	6.9	7.1	7.6	7.6	8.1	8.8	8.0	8.9	9.9
Other	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**54.7**	**63.2**	**63.8**	**65.1**	**67.2**	**68.7**	**70.7**	**71.2**	**74.2**	**77.7**
Cumulative Additions[6]	**0.0**	**8.5**	**9.1**	**10.3**	**12.5**	**14.0**	**16.0**	**16.5**	**19.5**	**23.0**
Other End-Use Generators[9]										
Renewable Sources[10]	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Cumulative Additions	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas
[6]Cumulative additions after December 31, 2000.
[7]Cumulative total retirements after December 31, 2000.
[8]Nameplate capacity is reported for nonutilities onForm EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]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.
[10]See Table B17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model estimates and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Electricity Trade	2000	Projections								
		2010			2015			2020		
		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	156.9	102.9	102.9	102.9	45.7	45.7	45.7	0.0	0.0	0.0
Gross Domestic Economy Trade	151.0	190.7	189.5	190.3	191.6	198.2	185.4	197.2	205.1	187.8
Gross Domestic Trade	**307.8**	**293.6**	**292.4**	**293.2**	**237.4**	**243.9**	**231.1**	**197.2**	**205.1**	**187.8**
Gross Domestic Firm Power Sales (million 2000 dollars)	7576.3	4970.1	4970.1	4970.1	2208.9	2208.9	2208.9	0.0	0.0	0.0
Gross Domestic Economy Sales (million 2000 dollars)	6849.1	5610.4	5909.5	6601.0	6161.8	6711.2	6722.1	6437.9	7262.7	7208.2
Gross Domestic Sales (million 2000 dollars)	**14425.4**	**10580.5**	**10879.6**	**11571.1**	**8370.7**	**8920.1**	**8931.0**	**6437.9**	**7262.7**	**7208.2**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	23.7	5.8	5.8	5.8	2.6	2.6	2.6	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	24.2	41.4	45.1	51.3	47.7	50.4	56.3	43.5	47.4	51.2
Gross Imports From Canada and Mexico[1]	**47.9**	**47.2**	**51.0**	**57.1**	**50.2**	**52.9**	**58.9**	**43.5**	**47.4**	**51.2**
Firm Power Exports To Canada and Mexico	6.6	8.7	8.7	8.7	3.9	3.9	3.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.4	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**13.0**	**16.4**	**16.4**	**16.4**	**11.5**	**11.5**	**11.5**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 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, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		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]	5.82	5.06	5.08	5.11	5.40	5.56	5.67	5.51	5.63	5.81
Alaska	0.97	0.70	0.70	0.70	0.90	0.90	0.90	1.10	1.10	1.10
Lower 48 States	4.85	4.36	4.38	4.40	4.50	4.65	4.76	4.41	4.53	4.71
Net Imports	9.02	11.13	11.18	11.61	11.08	11.01	11.30	11.28	11.20	11.47
Gross Imports	9.07	11.17	11.22	11.65	11.13	11.07	11.37	11.34	11.26	11.54
Exports	0.05	0.04	0.04	0.04	0.05	0.06	0.06	0.06	0.06	0.07
Other Crude Supply[2]	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.07**	**16.20**	**16.26**	**16.72**	**16.48**	**16.57**	**16.97**	**16.79**	**16.83**	**17.28**
Natural Gas Plant Liquids	**1.91**	**2.33**	**2.38**	**2.43**	**2.53**	**2.64**	**2.69**	**2.72**	**2.84**	**2.88**
Other Inputs[3]	**0.35**	**0.41**	**0.42**	**0.29**	**0.45**	**0.51**	**0.44**	**0.46**	**0.47**	**0.38**
Refinery Processing Gain[4]	**0.95**	**0.98**	**1.00**	**1.03**	**1.01**	**1.01**	**1.02**	**1.02**	**1.02**	**1.04**
Net Product Imports[5]	**1.40**	**2.64**	**3.09**	**3.59**	**3.52**	**4.29**	**5.25**	**3.99**	**5.44**	**6.90**
Gross Refined Product Imports[6]	2.04	2.84	3.21	3.73	3.55	4.31	5.22	4.01	5.49	6.91
Unfinished Oil Imports	0.27	0.66	0.75	0.75	0.86	0.88	0.96	0.89	0.90	0.98
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.99	0.85	0.87	0.89	0.89	0.90	0.93	0.91	0.94	0.98
Total Primary Supply[7]	**19.68**	**22.55**	**23.15**	**24.06**	**23.99**	**25.01**	**26.37**	**24.97**	**26.61**	**28.49**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.50	10.12	10.32	10.57	10.78	11.13	11.54	11.26	11.81	12.36
Jet Fuel[9]	1.73	2.10	2.15	2.26	2.35	2.47	2.63	2.59	2.81	3.06
Distillate Fuel[10]	3.67	4.46	4.58	4.78	4.76	4.99	5.28	4.96	5.32	5.78
Residual Fuel	1.05	0.68	0.69	0.73	0.70	0.73	0.75	0.71	0.75	0.78
Other[11]	4.80	5.25	5.46	5.78	5.46	5.75	6.24	5.50	5.97	6.56
Total	**19.74**	**22.61**	**23.21**	**24.13**	**24.05**	**25.07**	**26.44**	**25.02**	**26.66**	**28.54**
Refined Petroleum Products Supplied										
Residential and Commercial	1.12	1.09	1.09	1.10	1.06	1.06	1.07	1.04	1.04	1.06
Industrial[12]	4.96	5.41	5.66	6.03	5.65	6.00	6.54	5.71	6.27	6.94
Transportation	13.26	16.02	16.37	16.89	17.23	17.90	18.71	18.16	19.22	20.40
Electric Generators[13]	0.41	0.08	0.09	0.12	0.11	0.11	0.12	0.12	0.12	0.15
Total	**19.74**	**22.61**	**23.21**	**24.13**	**24.05**	**25.07**	**26.44**	**25.02**	**26.66**	**28.54**
Discrepancy[14]	**-0.07**	**-0.06**	**-0.06**	**-0.07**	**-0.05**	**-0.06**	**-0.06**	**-0.05**	**-0.05**	**-0.06**
World Oil Price (2000 dollars per barrel)[15]	**27.72**	**22.75**	**23.36**	**23.87**	**23.09**	**24.00**	**24.82**	**23.45**	**24.68**	**25.81**
Import Share of Product Supplied	**0.53**	**0.61**	**0.62**	**0.63**	**0.61**	**0.61**	**0.63**	**0.61**	**0.62**	**0.64**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2000 dollars)	**106.46**	**117.49**	**125.51**	**136.91**	**127.84**	**141.00**	**159.02**	**137.28**	**159.84**	**185.75**
Domestic Refinery Distillation Capacity[16]	**16.6**	**17.8**	**17.8**	**18.2**	**17.9**	**17.9**	**18.3**	**18.1**	**18.2**	**18.7**
Capacity Utilization Rate (percent)	**93.0**	**91.3**	**91.7**	**92.5**	**92.8**	**93.2**	**93.3**	**93.2**	**93.2**	**93.3**

[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, and natural gas 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 blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[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 by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 product supplied data from Table B2. Other 2000 data: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B12. Petroleum Product Prices
(2000 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (2000 dollars per barrel)	**27.72**	**22.75**	**23.36**	**23.87**	**23.09**	**24.00**	**24.82**	**23.45**	**24.68**	**25.81**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	130.7	107.6	110.1	111.0	112.3	116.9	118.8	114.2	118.5	120.9
Liquefied Petroleum Gas	117.1	111.2	113.8	116.7	112.6	117.1	118.9	113.3	118.5	121.2
Commercial										
Distillate Fuel	98.2	76.6	79.4	80.2	81.4	86.7	88.8	84.2	88.6	91.2
Residual Fuel	51.8	55.9	57.3	58.6	56.6	58.7	60.7	57.3	60.2	62.9
Residual Fuel (2000 dollars per barrel)	21.77	23.47	24.08	24.60	23.76	24.67	25.48	24.08	25.29	26.41
Industrial[1]										
Distillate Fuel	99.9	78.1	81.7	82.1	83.7	90.4	92.5	87.7	93.0	95.9
Liquefied Petroleum Gas	100.6	71.3	73.7	76.6	72.2	77.1	78.2	73.0	78.2	80.3
Residual Fuel	48.9	53.3	54.7	55.9	53.9	56.1	57.9	55.0	57.9	60.3
Residual Fuel (2000 dollars per barrel)	20.55	22.37	22.97	23.49	22.63	23.54	24.32	23.11	24.30	25.33
Transportation										
Diesel Fuel (distillate)[2]	149.9	137.1	140.6	146.0	133.4	140.0	144.7	132.4	138.5	144.9
Jet Fuel[3]	99.3	76.1	79.2	81.1	78.8	85.4	87.7	81.0	86.0	89.1
Motor Gasoline[4]	152.6	137.3	139.6	142.7	135.9	139.8	143.8	135.2	139.7	146.8
Liquid Petroleum Gas	136.5	120.5	123.8	127.8	120.9	126.1	128.7	120.0	125.7	129.7
Residual Fuel	65.6	50.7	52.1	53.3	51.3	53.5	55.4	52.1	55.0	57.6
Residual Fuel (2000 dollars per barrel)	27.56	21.28	21.88	22.39	21.55	22.47	23.26	21.88	23.10	24.20
Ethanol (E85)	155.3	184.8	184.1	189.8	189.5	194.1	192.7	189.9	189.5	193.4
Electric Generators[5]										
Distillate Fuel	95.6	69.4	72.6	73.3	73.3	79.5	82.5	75.6	81.4	83.2
Residual Fuel	61.5	52.4	53.9	55.5	53.0	55.3	57.6	53.6	57.0	60.1
Residual Fuel (2000 dollars per barrel)	25.83	22.00	22.66	23.33	22.24	23.22	24.17	22.53	23.93	25.23
Refined Petroleum Product Prices[6]										
Distillate Fuel	137.7	124.4	127.8	132.0	123.4	129.9	134.0	123.6	129.5	135.1
Jet Fuel[3]	99.3	76.1	79.2	81.1	78.8	85.4	87.7	81.0	86.0	89.1
Liquefied Petroleum Gas	103.5	78.2	80.4	82.8	78.8	83.2	83.8	79.4	84.0	85.6
Motor Gasoline[4]	152.6	137.3	139.6	142.7	135.9	139.8	143.8	135.2	139.7	146.8
Residual Fuel	61.5	51.6	53.1	54.4	52.3	54.5	56.5	53.1	56.1	58.8
Residual Fuel (2000 dollars per barrel)	25.83	21.67	22.29	22.85	21.95	22.89	23.72	22.30	23.56	24.70
Average	**130.5**	**116.5**	**118.9**	**121.5**	**116.0**	**120.5**	**123.3**	**116.1**	**120.5**	**125.3**

[1]Includes cogenerators.
[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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline, distillate, and jet fuel are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/ data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf. 2000 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Production										
Dry Gas Production[1]	19.08	22.97	23.48	24.05	25.28	26.32	26.92	27.25	28.48	28.93
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**3.52**	**4.64**	**4.89**	**5.33**	**4.96**	**5.26**	**5.94**	**5.00**	**5.51**	**6.25**
Canada	3.46	4.26	4.51	4.92	4.60	4.90	5.40	4.55	5.06	5.63
Mexico	-0.09	-0.45	-0.45	-0.42	-0.47	-0.47	-0.29	-0.38	-0.38	-0.20
Liquefied Natural Gas	0.16	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
Total Supply	**22.69**	**27.71**	**28.49**	**29.49**	**30.35**	**31.69**	**32.97**	**32.36**	**34.10**	**35.30**
Consumption by Sector										
Residential	5.00	5.49	5.53	5.53	5.60	5.73	5.80	5.79	5.98	6.08
Commercial	3.27	3.91	3.93	3.91	4.13	4.21	4.26	4.39	4.52	4.61
Industrial[3]	8.41	9.10	9.39	9.79	9.28	9.79	10.28	9.39	10.06	10.94
Electric Generators[4]	4.24	6.50	6.85	7.42	8.39	8.91	9.51	9.65	10.30	10.36
Transportation[5]	0.02	0.08	0.09	0.09	0.11	0.12	0.13	0.13	0.14	0.15
Pipeline Fuel	0.77	0.82	0.84	0.86	0.89	0.93	0.95	0.95	0.99	1.01
Lease and Plant Fuel[6]	1.12	1.47	1.50	1.53	1.61	1.66	1.70	1.74	1.80	1.82
Total	**22.83**	**27.37**	**28.13**	**29.14**	**30.02**	**31.34**	**32.63**	**32.03**	**33.78**	**34.99**
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]	**-0.14**	**0.35**	**0.36**	**0.36**	**0.34**	**0.35**	**0.34**	**0.33**	**0.32**	**0.31**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B14. Natural Gas Prices, Margins, and Revenue
(2000 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2000	Projections								
		2010			2015			2020		
		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]	3.60	2.66	2.85	3.31	2.88	3.07	3.36	2.94	3.26	3.65
Average Import Price	3.94	2.80	2.91	3.08	3.01	3.13	3.32	3.15	3.40	3.67
Average[2]	**3.66**	**2.69**	**2.86**	**3.27**	**2.90**	**3.08**	**3.35**	**2.98**	**3.28**	**3.65**
Delivered Prices										
Residential	7.85	6.71	6.92	7.37	6.84	7.04	7.31	6.89	7.16	7.52
Commercial	6.40	5.46	5.66	6.10	5.63	5.84	6.12	5.72	6.02	6.39
Industrial[3]	4.43	3.37	3.57	4.01	3.59	3.79	4.11	3.68	4.01	4.43
Electric Generators[4]	4.49	3.25	3.44	3.86	3.52	3.72	4.04	3.63	3.94	4.33
Transportation[5]	8.26	6.83	7.08	7.61	7.02	7.33	7.72	7.06	7.48	7.97
Average[6]	**5.58**	**4.42**	**4.59**	**4.99**	**4.56**	**4.74**	**5.02**	**4.62**	**4.92**	**5.29**
Transmission & Distribution Margins[7]										
Residential	4.19	4.03	4.05	4.10	3.94	3.95	3.96	3.91	3.88	3.87
Commercial	2.74	2.78	2.80	2.84	2.73	2.76	2.77	2.74	2.74	2.73
Industrial[3]	0.78	0.69	0.70	0.75	0.69	0.71	0.76	0.70	0.73	0.78
Electric Generators[4]	0.83	0.56	0.58	0.60	0.62	0.64	0.69	0.65	0.66	0.67
Transportation[5]	4.61	4.14	4.22	4.35	4.12	4.25	4.37	4.09	4.20	4.32
Average[6]	**1.92**	**1.73**	**1.73**	**1.72**	**1.66**	**1.66**	**1.67**	**1.65**	**1.63**	**1.64**
Transmission & Distribution Revenue (billion 2000 dollars)										
Residential	20.96	22.11	22.40	22.69	22.06	22.65	23.00	22.63	23.21	23.54
Commercial	8.98	10.87	11.00	11.10	11.30	11.59	11.79	12.05	12.35	12.60
Industrial[3]	6.55	6.25	6.62	7.31	6.38	6.95	7.84	6.60	7.33	8.49
Electric Generators[4]	3.53	3.66	3.98	4.42	5.17	5.71	6.54	6.28	6.80	6.99
Transportation[5]	0.10	0.35	0.37	0.40	0.46	0.51	0.55	0.52	0.58	0.64
Total	**40.12**	**43.24**	**44.37**	**45.93**	**45.36**	**47.41**	**49.72**	**48.07**	**50.28**	**52.27**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). **Other 2000 values and projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B15. Oil and Gas Supply

Production and Supply	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (2000 dollars per barrel)	**27.59**	**22.09**	**22.70**	**23.29**	**22.20**	**23.15**	**23.99**	**22.53**	**23.79**	**24.92**
Production (million barrels per day)[2]										
U.S. Total	**5.82**	**5.06**	**5.08**	**5.11**	**5.40**	**5.56**	**5.67**	**5.51**	**5.63**	**5.81**
Lower 48 Onshore	3.25	2.62	2.64	2.66	2.60	2.64	2.68	2.62	2.70	2.78
Conventional	2.60	1.90	1.91	1.93	1.80	1.82	1.85	1.83	1.87	1.91
Enhanced Oil Recovery	0.65	0.73	0.73	0.73	0.80	0.82	0.83	0.79	0.83	0.87
Lower 48 Offshore	1.61	1.73	1.74	1.74	1.89	2.01	2.08	1.79	1.83	1.93
Alaska	0.97	0.70	0.70	0.70	0.90	0.90	0.90	1.10	1.10	1.10
Lower 48 End of Year Reserves (billion barrels)[2]	**18.29**	**14.16**	**14.23**	**14.33**	**14.37**	**14.63**	**14.86**	**13.90**	**14.45**	**14.94**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2000 dollars per thousand cubic feet)	**3.60**	**2.66**	**2.85**	**3.31**	**2.88**	**3.07**	**3.36**	**2.94**	**3.26**	**3.65**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.08**	**22.97**	**23.48**	**24.05**	**25.28**	**26.32**	**26.92**	**27.25**	**28.48**	**28.94**
Lower 48 Onshore	13.31	16.01	16.45	16.91	18.57	19.40	19.78	20.23	21.13	21.43
Associated-Dissolved[4]	1.79	1.43	1.43	1.44	1.36	1.37	1.39	1.35	1.36	1.38
Non-Associated	11.52	14.58	15.02	15.47	17.21	18.04	18.40	18.88	19.77	20.05
Conventional	6.89	7.76	7.89	8.14	9.50	9.94	9.95	10.38	10.77	10.67
Unconventional	4.63	6.82	7.13	7.34	7.71	8.09	8.45	8.51	8.99	9.38
Lower 48 Offshore	5.34	6.43	6.50	6.60	6.14	6.35	6.56	6.41	6.75	6.89
Associated-Dissolved[4]	1.16	1.22	1.22	1.23	1.25	1.27	1.28	1.25	1.25	1.26
Non-Associated	4.18	5.21	5.28	5.37	4.89	5.08	5.28	5.17	5.50	5.63
Alaska	0.43	0.53	0.53	0.54	0.57	0.57	0.57	0.60	0.60	0.61
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**162.31**	**172.93**	**174.09**	**174.39**	**180.51**	**181.49**	**185.04**	**189.52**	**187.79**	**194.89**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**24.05**	**23.30**	**24.32**	**26.74**	**24.85**	**25.55**	**27.71**	**29.44**	**33.08**	**36.63**

[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.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.

Sources: 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

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

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	430	413	428	430	408	417	429	387	406	437
Interior	144	148	158	148	131	146	138	125	143	154
West	510	710	698	729	759	762	798	823	848	902
East of the Mississippi	518	513	533	533	500	520	527	482	510	550
West of the Mississippi	566	758	751	774	798	805	839	853	887	943
Total	**1084**	**1271**	**1284**	**1307**	**1298**	**1325**	**1366**	**1335**	**1397**	**1493**
Net Imports										
Imports	13	19	19	19	19	19	19	20	20	20
Exports	58	57	54	57	58	53	53	55	55	54
Total	**-46**	**-38**	**-35**	**-38**	**-39**	**-34**	**-34**	**-35**	**-35**	**-35**
Total Supply[2]	**1038**	**1233**	**1249**	**1269**	**1259**	**1291**	**1332**	**1300**	**1362**	**1459**
Consumption by Sector										
Residential and Commercial	5	5	5	6	6	6	6	6	6	6
Industrial[3]	82	77	81	87	78	83	89	79	86	95
Coke Plants	29	24	24	24	22	22	22	20	20	20
Electric Generators[4]	965	1129	1141	1155	1156	1183	1218	1198	1254	1341
Total	**1081**	**1235**	**1251**	**1271**	**1262**	**1294**	**1335**	**1303**	**1365**	**1462**
Discrepancy and Stock Change[5]	**-43**	**-2**	**-2**	**-2**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**
Average Minemouth Price										
(2000 dollars per short ton)	16.45	13.70	14.11	14.04	13.17	13.44	13.51	12.56	12.79	13.23
(2000 dollars per million Btu)	0.79	0.67	0.69	0.69	0.65	0.66	0.67	0.62	0.64	0.66
Delivered Prices (2000 dollars per short ton)[6]										
Industrial	31.86	27.70	28.11	28.39	26.74	27.21	27.68	25.54	26.14	27.06
Coke Plants	44.41	41.51	41.86	42.08	40.20	40.71	41.08	38.84	39.22	39.81
Electric Generators										
(2000 dollars per short ton)	24.36	20.74	21.02	21.29	19.91	20.15	20.55	18.72	19.00	19.75
(2000 dollars per million Btu)	1.20	1.04	1.05	1.07	1.00	1.01	1.03	0.95	0.97	1.00
Average	**25.42**	**21.59**	**21.89**	**22.17**	**20.69**	**20.95**	**21.37**	**19.44**	**19.75**	**20.50**
Exports[7]	34.90	35.32	35.84	35.90	34.16	34.96	35.37	33.29	33.67	34.41

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 data based on Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	79.29	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal[2]	2.85	3.51	3.57	3.57	4.43	4.52	4.47	5.18	5.32	5.32
Municipal Solid Waste[3]	2.84	3.83	3.88	3.97	4.08	4.18	4.22	4.25	4.30	4.34
Wood and Other Biomass[4]	1.39	1.73	1.73	1.73	1.78	1.82	1.96	1.83	1.97	2.76
Solar Thermal	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.41	0.41	0.41
Solar Photovoltaic[5]	0.01	0.11	0.11	0.11	0.19	0.19	0.19	0.27	0.27	0.27
Wind	2.42	7.69	7.65	7.67	8.40	8.46	8.60	8.69	9.06	9.60
Total	**89.13**	**97.12**	**97.19**	**97.30**	**99.16**	**99.46**	**99.72**	**100.53**	**101.22**	**102.59**
Generation (billion kilowatthours)										
Conventional Hydropower	272.33	301.12	301.14	301.16	300.53	300.54	300.57	299.96	300.00	300.04
Geothermal[2]	13.52	19.64	20.20	20.19	27.26	28.06	27.62	33.51	34.71	34.68
Municipal Solid Waste[3]	20.15	27.40	27.78	28.53	29.19	30.05	30.33	30.56	30.98	31.27
Wood and Other Biomass[4]	8.37	20.37	20.86	19.01	19.38	18.84	18.29	18.13	15.32	20.28
Dedicated Plants	7.46	9.72	9.72	9.69	10.07	10.32	11.20	10.36	11.25	16.55
Cofiring	0.91	10.65	11.14	9.31	9.32	8.52	7.09	7.78	4.07	3.73
Solar Thermal	0.87	0.96	0.96	0.96	1.05	1.05	1.05	1.12	1.12	1.12
Solar Photovoltaic	0.01	0.26	0.26	0.26	0.46	0.46	0.46	0.68	0.68	0.68
Wind	5.30	19.60	19.45	19.51	21.72	21.95	22.44	22.80	24.07	25.95
Total	**320.54**	**389.35**	**390.65**	**389.61**	**399.59**	**400.95**	**400.77**	**406.76**	**406.87**	**414.02**
Cogenerators[6]										
Net Summer Capability										
Municipal Solid Waste	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Biomass	5.26	6.40	6.64	7.05	7.09	7.62	8.26	7.53	8.43	9.41
Total	**5.77**	**6.91**	**7.15**	**7.56**	**7.60**	**8.13**	**8.77**	**8.04**	**8.94**	**9.92**
Generation (billion kilowatthours)										
Municipal Solid Waste	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
Biomass	29.63	36.57	38.04	40.56	40.74	44.04	47.95	43.40	48.99	55.01
Total	**32.93**	**39.86**	**41.34**	**43.85**	**44.03**	**47.33**	**51.25**	**46.70**	**52.28**	**58.31**
Other End-Use Generators[7]										
Net Summer Capability										
Conventional Hydropower[8]	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic[5]	0.02	0.39	0.39	0.39	0.42	0.42	0.42	0.46	0.46	0.47
Total	**0.99**	**1.36**	**1.36**	**1.36**	**1.40**	**1.40**	**1.40**	**1.44**	**1.44**	**1.44**
Generation (billion kilowatthours)										
Conventional Hydropower[8]	3.98	4.32	4.32	4.32	4.32	4.32	4.32	4.31	4.31	4.31
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.81	0.81	0.81	0.89	0.89	0.89	0.98	0.98	0.99
Total	**4.02**	**5.14**	**5.14**	**5.14**	**5.21**	**5.21**	**5.21**	**5.28**	**5.29**	**5.29**

[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]Does not include off-grid photovoltaics (PV). EIA estimates that another 76 megawatts of remote electricity generation PV applications were in service in 1999, plus an additional 205 megawatts in communications, transportation, and assorted other non-grid-connected applications.
[6]Cogenerators produce electricity and other useful thermal energy.
[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 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2002. Net summer capability 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 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 2000 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 2000 generation: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2000	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Marketed Renewable Energy[2]										
Residential	**0.43**	**0.43**	**0.43**	**0.44**	**0.43**	**0.44**	**0.45**	**0.43**	**0.45**	**0.46**
Wood	0.43	0.43	0.43	0.44	0.43	0.44	0.45	0.43	0.45	0.46
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.41**	**2.78**	**2.89**	**3.07**	**2.98**	**3.18**	**3.43**	**3.13**	**3.43**	**3.79**
Conventional Hydroelectric	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	2.21	2.58	2.69	2.87	2.78	2.98	3.23	2.93	3.23	3.59
Transportation	**0.14**	**0.23**	**0.24**	**0.24**	**0.25**	**0.26**	**0.27**	**0.27**	**0.28**	**0.29**
Ethanol used in E85[4]	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Ethanol used in Gasoline Blending	0.14	0.21	0.21	0.22	0.22	0.23	0.24	0.23	0.24	0.25
Electric Generators[5]	**3.55**	**4.43**	**4.46**	**4.45**	**4.70**	**4.74**	**4.72**	**4.91**	**4.94**	**5.00**
Conventional Hydroelectric	2.82	3.11	3.11	3.11	3.11	3.11	3.11	3.10	3.10	3.10
Geothermal	0.28	0.48	0.50	0.50	0.73	0.75	0.74	0.92	0.96	0.96
Municipal Solid Waste	0.28	0.37	0.38	0.39	0.40	0.41	0.41	0.41	0.42	0.42
Biomass	0.11	0.24	0.25	0.23	0.23	0.23	0.22	0.22	0.19	0.24
Dedicated Plants	0.10	0.12	0.12	0.12	0.12	0.12	0.14	0.13	0.14	0.19
Cofiring	0.01	0.13	0.13	0.11	0.11	0.10	0.09	0.09	0.05	0.04
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	0.05	0.20	0.20	0.20	0.22	0.23	0.23	0.23	0.25	0.27
Total Marketed Renewable Energy	**6.60**	**7.95**	**8.10**	**8.28**	**8.45**	**8.70**	**8.95**	**8.82**	**9.17**	**9.62**
Sources of Ethanol										
From Corn	0.14	0.22	0.22	0.23	0.22	0.23	0.24	0.21	0.22	0.23
From Cellulose	0.00	0.02	0.02	0.02	0.03	0.03	0.04	0.06	0.06	0.07
Total	**0.14**	**0.23**	**0.24**	**0.24**	**0.25**	**0.26**	**0.27**	**0.27**	**0.28**	**0.29**
Non-Marketed Renewable Energy[6] Selected Consumption										
Residential	**0.04**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**	**0.07**	**0.08**	**0.08**
Solar Hot Water Heating	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.05
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	0.00	0.00	0.00

[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 cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 2000 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 2000: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	27.5	24.6	24.6	24.5	23.5	23.3	23.3	22.7	22.6	22.6
Natural Gas	73.2	81.2	81.8	81.8	82.9	84.8	85.9	85.7	88.6	90.1
Coal	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	204.0	235.9	238.3	238.9	247.5	252.0	254.4	260.5	268.7	275.6
Total	**305.9**	**343.1**	**346.0**	**346.6**	**355.2**	**361.4**	**365.0**	**370.1**	**381.1**	**389.5**
Commercial										
Petroleum	14.2	13.5	13.6	13.8	13.7	13.8	14.1	13.7	14.0	14.4
Natural Gas	49.3	57.9	58.2	57.9	61.2	62.3	63.1	65.0	66.8	68.3
Coal	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0
Electricity	195.6	240.7	243.6	244.8	261.8	266.9	271.1	279.9	288.9	298.7
Total	**260.9**	**313.8**	**317.1**	**318.3**	**338.5**	**344.8**	**350.2**	**360.5**	**371.7**	**383.4**
Industrial[1]										
Petroleum	93.7	103.6	107.2	113.2	108.1	112.9	121.3	109.6	117.8	127.6
Natural Gas[2]	136.1	153.8	158.5	164.6	158.5	166.8	174.1	162.0	172.4	185.3
Coal	65.2	60.7	63.3	67.5	60.2	63.7	68.7	59.6	64.7	71.5
Electricity	183.0	194.1	203.1	217.4	202.3	215.5	235.2	207.6	227.4	258.6
Total	**478.1**	**512.3**	**532.1**	**562.8**	**529.0**	**558.9**	**599.2**	**538.8**	**582.3**	**643.1**
Transportation										
Petroleum[3]	502.5	608.5	621.8	641.6	654.6	680.3	711.4	689.8	730.7	776.1
Natural Gas[4]	11.4	13.3	13.7	14.1	14.8	15.4	16.0	15.9	16.7	17.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	3.0	3.8	3.8	3.9	4.3	4.4	4.4	5.0	5.1	5.3
Total[3]	**516.9**	**625.8**	**639.4**	**659.7**	**673.8**	**700.2**	**731.9**	**710.8**	**752.7**	**798.7**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	637.9	750.2	767.2	793.2	799.8	830.3	870.1	835.8	885.0	940.7
Natural Gas	270.0	306.3	312.2	318.5	317.4	329.3	339.1	328.6	344.5	360.9
Coal	68.2	63.8	66.4	70.7	63.4	66.9	71.9	62.8	67.9	74.8
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	585.6	674.5	688.8	705.1	715.8	738.7	765.2	753.0	790.2	838.2
Total[3]	**1561.7**	**1794.9**	**1834.7**	**1887.5**	**1896.5**	**1965.4**	**2046.4**	**1980.3**	**2087.8**	**2214.7**
Electric Generators[6]										
Petroleum	19.9	3.8	4.3	5.5	5.1	5.1	5.5	5.6	5.9	7.0
Natural Gas	61.1	95.3	100.6	108.9	123.1	130.7	139.5	141.6	151.1	152.1
Coal	504.6	575.4	583.9	590.6	587.7	602.9	620.2	605.8	633.2	679.1
Total	**585.6**	**674.5**	**688.8**	**705.1**	**715.8**	**738.7**	**765.2**	**753.0**	**790.2**	**838.2**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	657.8	754.1	771.5	798.7	804.9	835.4	875.6	841.4	890.9	947.7
Natural Gas	331.2	401.6	412.8	427.4	440.5	460.0	478.6	470.2	495.6	513.0
Coal	572.8	639.2	650.3	661.3	651.0	669.8	692.1	668.7	701.2	753.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1561.7**	**1794.9**	**1834.7**	**1887.5**	**1896.5**	**1965.4**	**2046.4**	**1980.3**	**2087.8**	**2214.7**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.7**	**6.1**	**6.1**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**	**6.4**	**6.5**

[1]Includes consumption by cogenerators.
[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 1998, international bunker fuels accounted for 25 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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2000,* DOE/EIA-0573(2000) (Washington, DC, November 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B20. Macroeconomic Indicators

(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2000	Projections								
		2010			2015			2020		
		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)	**1.070**	**1.443**	**1.369**	**1.269**	**1.709**	**1.561**	**1.417**	**2.067**	**1.826**	**1.608**
Real Gross Domestic Product	**9224**	**11759**	**12312**	**13021**	**13395**	**14399**	**15450**	**14901**	**16525**	**18102**
Real Consumption	6258	7935	8256	8612	8929	9545	10043	9970	10991	11754
Real Investment	1773	2313	2518	2764	2855	3252	3607	3257	3953	4532
Real Government Spending	1573	1796	1892	1947	1871	2016	2105	1947	2149	2279
Real Exports	1133	1856	1968	2140	2587	2840	3177	3507	4032	4620
Real Imports	1532	2093	2263	2339	2711	3090	3217	3586	4369	4631
Real Disposable Personal Income	**6539**	**8404**	**8742**	**9130**	**9604**	**10202**	**10803**	**10791**	**11698**	**12541**
AA Utility Bond Rate (percent)	**7.91**	**8.26**	**7.37**	**6.64**	**8.64**	**7.66**	**6.72**	**9.98**	**8.07**	**6.71**
Real Yield on Government 10 Year Bonds (percent)	**4.84**	**4.34**	**4.54**	**4.58**	**4.86**	**4.99**	**4.65**	**6.36**	**5.34**	**4.77**
Real Utility Bond Rate (percent)	**6.27**	**5.07**	**4.94**	**4.74**	**5.17**	**4.95**	**4.45**	**5.92**	**4.64**	**3.96**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	8.04	7.24	7.09	6.92	6.72	6.51	6.34	6.30	6.02	5.84
Total Energy	10.77	9.62	9.40	9.15	8.90	8.59	8.34	8.34	7.92	7.64
Consumer Price Index (1982-84=1.00)	**1.72**	**2.40**	**2.27**	**2.11**	**2.91**	**2.64**	**2.39**	**3.63**	**3.15**	**2.77**
Unemployment Rate (percent)	**4.01**	**4.89**	**4.49**	**3.85**	**5.14**	**4.56**	**4.35**	**4.78**	**4.04**	**3.94**
Housing Starts (millions)	**1.82**	**1.67**	**1.93**	**2.16**	**1.58**	**1.90**	**2.09**	**1.60**	**2.01**	**2.26**
Single-Family	1.23	1.14	1.33	1.50	1.07	1.32	1.46	1.04	1.36	1.54
Multifamily	0.34	0.25	0.29	0.35	0.26	0.30	0.35	0.30	0.36	0.43
Mobile Home Shipments	0.25	0.29	0.30	0.31	0.25	0.27	0.27	0.25	0.28	0.28
Commercial Floorspace, Total (billion square feet)	**64.5**	**76.3**	**77.5**	**78.9**	**81.5**	**83.8**	**86.1**	**86.0**	**89.6**	**93.0**
Gross Output (billion 1992 dollars)										
Total Industrial	5062	6298	6584	7085	7070	7535	8297	7767	8447	9610
Nonmanufacturing	1039	1148	1211	1284	1222	1325	1424	1293	1444	1587
Manufacturing	4022	5150	5373	5801	5848	6210	6874	6473	7003	8023
Energy-Intensive Manufacturing	1100	1200	1251	1319	1259	1340	1434	1294	1410	1538
Non-Energy-Intensive Manufacturing	2922	3950	4122	4482	4589	4870	5440	5180	5593	6484
Unit Sales of Light-Duty Vehicles (millions)	**17.36**	**16.50**	**17.34**	**18.27**	**16.75**	**17.81**	**18.87**	**16.34**	**18.24**	**20.27**
Population (millions)										
Population with Armed Forces Overseas)	275.7	294.0	300.2	306.5	302.9	312.7	322.4	311.9	325.3	338.7
Population (aged 16 and over)	213.1	232.0	236.6	241.2	239.7	246.7	253.8	246.7	256.5	266.3
Employment, Non-Agriculture	130.1	141.5	145.2	150.6	143.9	150.2	156.7	144.8	154.5	163.2
Employment, Manufacturing	17.5	15.8	16.3	17.3	14.8	15.5	16.7	14.3	15.3	16.8
Labor Force	140.9	153.3	156.9	161.3	155.9	161.4	167.4	157.5	165.3	173.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2000: DRI-WEFA, Simulation CTL0901. **Projections:** Energy Information Administration, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (2000 dollars per barrel)[1]	**27.72**	**22.75**	**23.36**	**23.87**	**23.09**	**24.00**	**24.82**	**23.45**	**24.68**	**25.81**
Production[2]										
OECD										
U.S. (50 states)	9.03	8.77	8.87	8.81	9.39	9.71	9.82	9.71	9.95	10.07
Canada	2.74	3.20	3.20	3.20	3.37	3.37	3.38	3.54	3.55	3.56
Mexico	3.54	4.23	4.24	4.24	4.38	4.39	4.40	4.42	4.44	4.45
OECD Europe[3]	7.06	7.19	7.20	7.20	6.91	6.92	6.93	6.63	6.65	6.66
Other OECD	0.98	0.92	0.92	0.92	0.90	0.90	0.90	0.88	0.88	0.88
Total OECD	**23.35**	**24.31**	**24.43**	**24.38**	**24.94**	**25.29**	**25.42**	**25.17**	**25.46**	**25.63**
Developing Countries										
Other South & Central America	3.78	4.81	4.82	4.83	5.57	5.58	5.60	6.45	6.48	6.50
Pacific Rim	2.31	2.62	2.63	2.63	2.58	2.59	2.60	2.54	2.55	2.56
OPEC	30.93	40.57	40.78	41.55	48.19	48.32	49.14	56.95	57.46	58.46
Other Developing Countries	4.96	6.24	6.25	6.26	7.21	7.23	7.25	8.34	8.38	8.41
Total Developing Countries	**41.98**	**54.25**	**54.48**	**55.27**	**63.56**	**63.73**	**64.58**	**74.28**	**74.86**	**75.93**
Eurasia										
Former Soviet Union	7.83	12.00	12.02	12.03	13.68	13.72	13.76	14.83	14.89	14.94
Eastern Europe	0.24	0.30	0.30	0.30	0.33	0.33	0.33	0.35	0.36	0.36
China	3.26	3.07	3.07	3.08	3.04	3.05	3.06	3.01	3.02	3.03
Total Eurasia	**11.33**	**15.37**	**15.39**	**15.42**	**17.05**	**17.10**	**17.14**	**18.19**	**18.26**	**18.33**
Total Production	**76.66**	**93.93**	**94.31**	**95.06**	**105.54**	**106.12**	**107.15**	**117.64**	**118.59**	**119.88**
Consumption										
OECD										
U.S. (50 states)	19.74	22.61	23.21	24.13	24.05	25.07	26.44	25.02	26.66	28.54
U.S. Territories	0.35	0.43	0.43	0.43	0.46	0.45	0.45	0.48	0.48	0.47
Canada	1.96	2.10	2.09	2.08	2.15	2.12	2.10	2.17	2.14	2.11
Mexico	2.03	2.76	2.75	2.74	3.36	3.33	3.31	4.16	4.11	4.06
Japan	5.54	5.66	5.62	5.59	5.72	5.64	5.58	5.74	5.62	5.52
Australia and New Zealand.	1.00	1.09	1.09	1.09	1.18	1.18	1.17	1.29	1.28	1.27
OECD Europe[3]	14.53	15.85	15.80	15.76	16.21	16.12	16.05	16.57	16.44	16.34
Total OECD	**45.16**	**50.50**	**50.98**	**51.80**	**53.11**	**53.91**	**55.09**	**55.43**	**56.72**	**58.32**
Developing Countries										
Other South and Central America	4.29	5.88	5.86	5.86	7.13	7.11	7.09	8.66	8.62	8.59
Pacific Rim	8.20	12.23	12.20	12.18	14.52	14.46	14.42	16.85	16.76	16.69
OPEC	5.81	7.55	7.55	7.55	8.72	8.72	8.72	10.08	10.08	10.08
Other Developing Countries	2.85	4.21	4.20	4.19	5.45	5.41	5.38	7.20	7.12	7.04
Total Developing Countries	**21.15**	**29.87**	**29.81**	**29.77**	**35.81**	**35.70**	**35.60**	**42.79**	**42.58**	**42.41**
Eurasia										
Former Soviet Union	3.66	5.57	5.56	5.55	6.82	6.79	6.76	7.74	7.69	7.65
Eastern Europe	1.54	1.63	1.63	1.63	1.68	1.68	1.67	1.70	1.69	1.69
China	4.53	6.65	6.62	6.59	8.42	8.35	8.30	10.29	10.18	10.10
Total Eurasia	**9.73**	**13.85**	**13.81**	**13.77**	**16.91**	**16.82**	**16.74**	**19.72**	**19.57**	**19.43**

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Consumption	**75.99**	**94.23**	**94.61**	**95.36**	**105.84**	**106.42**	**107.45**	**117.94**	**118.89**	**120.18**
Non-OPEC Production	45.73	53.36	53.52	53.51	57.35	57.80	58.01	60.69	61.12	61.42
Net Eurasia Exports	1.61	1.52	1.59	1.65	0.14	0.28	0.40	-1.53	-1.30	-1.11
OPEC Market Share	0.40	0.43	0.43	0.44	0.46	0.46	0.46	0.48	0.48	0.49

[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, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LM2002.D102001B, AEO2002.D102001B, HM2002.D102001B.

Oil Price Case Comparisons

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

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		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	12.33	10.05	10.76	11.61	10.42	11.76	12.91	10.46	11.92	13.62
Natural Gas Plant Liquids	2.71	3.35	3.37	3.40	3.68	3.74	3.79	3.93	4.03	4.11
Dry Natural Gas	19.59	23.93	24.12	24.31	26.57	27.03	27.46	28.54	29.25	30.03
Coal	22.58	26.27	26.23	26.34	26.65	26.91	27.47	27.58	28.11	29.04
Nuclear Power	8.03	7.87	7.87	7.95	7.37	7.55	7.63	7.31	7.49	7.58
Renewable Energy[1]	6.46	7.85	7.89	7.88	8.39	8.47	8.48	8.90	8.93	8.97
Other[2]	1.10	0.46	0.85	0.91	0.53	1.04	1.03	0.40	0.93	1.06
Total	**72.80**	**79.77**	**81.09**	**82.41**	**83.62**	**86.51**	**88.78**	**87.13**	**90.66**	**94.40**
Imports										
Crude Oil[3]	19.69	26.11	24.36	23.02	26.16	24.04	22.26	26.92	24.45	22.10
Petroleum Products[4]	4.73	7.92	7.83	7.49	11.14	10.31	9.66	13.83	12.69	11.54
Natural Gas	3.85	5.75	5.64	5.40	6.34	6.04	5.60	6.47	6.20	5.74
Other Imports[5]	0.76	0.94	0.95	0.98	1.08	1.07	1.09	1.07	1.09	1.10
Total	**29.04**	**40.72**	**38.79**	**36.89**	**44.71**	**41.46**	**38.61**	**48.29**	**44.44**	**40.47**
Exports										
Petroleum[6]	2.15	1.89	1.91	1.89	2.00	2.02	2.01	2.10	2.11	2.13
Natural Gas	0.25	0.63	0.63	0.63	0.66	0.66	0.66	0.56	0.56	0.56
Coal	1.53	1.41	1.36	1.44	1.34	1.34	1.34	1.38	1.38	1.38
Total	**3.93**	**3.93**	**3.90**	**3.96**	**3.99**	**4.01**	**4.01**	**4.05**	**4.05**	**4.08**
Discrepancy[7]	**-1.37**	**0.29**	**0.37**	**0.33**	**0.11**	**0.32**	**0.36**	**-0.04**	**0.20**	**0.51**
Consumption										
Petroleum Products[8]	38.63	46.00	45.20	44.56	50.12	48.85	47.93	53.78	51.99	50.96
Natural Gas	23.43	28.77	28.85	28.76	31.98	32.14	31.77	34.17	34.63	34.04
Coal	22.34	25.40	25.41	25.43	25.90	26.16	26.71	26.83	27.35	28.27
Nuclear Power	8.03	7.87	7.87	7.95	7.37	7.55	7.63	7.31	7.49	7.58
Renewable Energy[1]	6.48	7.86	7.90	7.88	8.40	8.48	8.49	8.91	8.94	8.98
Other[9]	0.38	0.37	0.38	0.42	0.46	0.46	0.49	0.42	0.44	0.46
Total	**99.29**	**116.28**	**115.61**	**115.01**	**124.23**	**123.64**	**123.02**	**131.42**	**130.85**	**130.29**
Net Imports - Petroleum	**22.28**	**32.14**	**30.29**	**28.62**	**35.30**	**32.33**	**29.91**	**38.65**	**35.04**	**31.51**
Prices (2000 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.72	17.64	23.36	30.01	17.64	24.00	30.44	17.64	24.68	30.58
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	2.70	2.85	3.05	2.97	3.07	3.25	3.07	3.26	3.40
Coal Minemouth Price (dollars per ton)	16.45	13.96	14.11	13.86	13.27	13.44	13.57	12.67	12.79	12.95
Average Electricity Price (cents per kilowatthour)	6.9	6.2	6.3	6.4	6.3	6.3	6.4	6.4	6.5	6.5

[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, 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 and heat loss when natural gas 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.83	0.83	0.79	0.74	0.81	0.75	0.70	0.80	0.73	0.67
Kerosene	0.09	0.08	0.07	0.07	0.07	0.07	0.06	0.07	0.07	0.06
Liquefied Petroleum Gas	0.47	0.47	0.45	0.42	0.46	0.42	0.39	0.45	0.41	0.37
Petroleum Subtotal	1.38	1.37	1.30	1.23	1.33	1.24	1.16	1.32	1.20	1.11
Natural Gas	5.14	5.73	5.68	5.63	5.92	5.89	5.85	6.19	6.15	6.10
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.45	0.45	0.45
Electricity	4.07	4.94	4.92	4.90	5.31	5.30	5.28	5.72	5.70	5.69
Delivered Energy	**11.06**	**12.52**	**12.40**	**12.25**	**13.05**	**12.92**	**12.78**	**13.72**	**13.55**	**13.40**
Electricity Related Losses	8.79	9.93	9.85	9.79	10.28	10.25	10.27	10.71	10.72	10.77
Total	**19.85**	**22.45**	**22.24**	**22.04**	**23.32**	**23.17**	**23.05**	**24.43**	**24.27**	**24.16**
Commercial										
Distillate Fuel	0.38	0.47	0.42	0.39	0.49	0.42	0.39	0.50	0.42	0.39
Residual Fuel	0.14	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.13	0.13
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.65	0.74	0.69	0.66	0.78	0.70	0.67	0.80	0.71	0.68
Natural Gas	3.36	4.06	4.04	4.00	4.32	4.33	4.30	4.63	4.64	4.61
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.90	5.06	5.03	5.01	5.63	5.62	5.60	6.15	6.13	6.13
Delivered Energy	**8.07**	**10.01**	**9.91**	**9.81**	**10.88**	**10.80**	**10.71**	**11.74**	**11.64**	**11.57**
Electricity Related Losses	8.42	10.18	10.06	10.01	10.90	10.85	10.87	11.51	11.53	11.60
Total	**16.49**	**20.19**	**19.98**	**19.82**	**21.78**	**21.65**	**21.58**	**23.26**	**23.18**	**23.17**
Industrial[4]										
Distillate Fuel	1.11	1.24	1.22	1.20	1.32	1.29	1.28	1.41	1.38	1.36
Liquefied Petroleum Gas	2.36	2.69	2.66	2.57	2.85	2.85	2.77	3.01	3.00	2.91
Petrochemical Feedstock	1.32	1.46	1.45	1.44	1.55	1.54	1.53	1.60	1.59	1.58
Residual Fuel	0.27	0.28	0.23	0.22	0.29	0.26	0.21	0.31	0.27	0.23
Motor Gasoline[2]	0.22	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Other Petroleum[5]	3.96	4.79	4.77	4.76	5.07	4.99	4.96	5.32	5.17	5.18
Petroleum Subtotal	9.23	10.69	10.57	10.44	11.34	11.19	11.01	11.92	11.69	11.53
Natural Gas[6]	9.79	11.02	11.19	11.37	11.59	11.77	12.01	11.91	12.19	12.48
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	1.69	1.74	1.74	1.76	1.79	1.79	1.80	1.85	1.85	1.86
Net Coal Coke Imports	0.06	0.11	0.11	0.10	0.14	0.14	0.13	0.17	0.16	0.15
Coal Subtotal	2.53	2.49	2.50	2.50	2.52	2.51	2.51	2.55	2.55	2.54
Renewable Energy[7]	2.41	2.90	2.89	2.88	3.19	3.18	3.17	3.44	3.43	3.42
Electricity	3.65	4.21	4.20	4.20	4.54	4.53	4.53	4.84	4.83	4.83
Delivered Energy	**27.62**	**31.31**	**31.35**	**31.39**	**33.19**	**33.19**	**33.23**	**34.67**	**34.69**	**34.81**
Electricity Related Losses	7.89	8.46	8.39	8.39	8.80	8.76	8.81	9.07	9.08	9.15
Total	**35.50**	**39.77**	**39.74**	**39.79**	**41.99**	**41.96**	**42.04**	**43.74**	**43.76**	**43.96**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Transportation										
Distillate Fuell[8]	5.42	7.27	7.27	7.26	8.09	8.09	8.04	8.71	8.72	8.66
Jet Fuel[9]	3.58	4.48	4.46	4.42	5.15	5.12	5.07	5.86	5.82	5.78
Motor Gasoline[2]	16.05	19.51	19.32	19.07	21.12	20.86	20.45	22.47	22.12	21.60
Residual Fuel	1.14	1.08	1.08	1.08	1.09	1.09	1.09	1.10	1.10	1.11
Liquefied Petroleum Gas	0.02	0.03	0.04	0.04	0.04	0.04	0.05	0.04	0.05	0.05
Other Petroleum[10]	0.22	0.26	0.26	0.26	0.28	0.28	0.28	0.29	0.29	0.29
Petroleum Subtotal	26.42	32.64	32.43	32.13	35.76	35.48	34.97	38.49	38.11	37.49
Pipeline Fuel Natural Gas	0.79	0.86	0.86	0.86	0.94	0.95	0.94	1.00	1.02	1.00
Compressed Natural Gas	0.02	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.15
Renewable Energy (E85)[11]	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.08	0.08	0.08	0.09	0.09	0.09	0.11	0.11	0.11
Delivered Energy	**27.32**	**33.70**	**33.50**	**33.21**	**36.96**	**36.69**	**36.17**	**39.78**	**39.43**	**38.80**
Electricity Related Losses	0.13	0.16	0.16	0.16	0.18	0.18	0.18	0.20	0.21	0.21
Total	**27.45**	**33.86**	**33.66**	**33.36**	**37.13**	**36.87**	**36.35**	**39.99**	**39.64**	**39.01**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.73	9.81	9.70	9.59	10.70	10.55	10.40	11.42	11.24	11.09
Kerosene	0.14	0.13	0.13	0.12	0.13	0.12	0.12	0.13	0.12	0.12
Jet Fuel[9]	3.58	4.48	4.46	4.42	5.15	5.12	5.07	5.86	5.82	5.78
Liquefied Petroleum Gas	2.93	3.28	3.23	3.12	3.44	3.41	3.31	3.61	3.56	3.43
Motor Gasoline[2]	16.29	19.77	19.59	19.34	21.40	21.14	20.73	22.77	22.42	21.90
Petrochemical Feedstock	1.32	1.46	1.45	1.44	1.55	1.54	1.53	1.60	1.59	1.58
Residual Fuel	1.54	1.48	1.43	1.42	1.52	1.48	1.43	1.55	1.51	1.46
Other Petroleum[12]	4.16	5.03	5.01	5.00	5.33	5.25	5.21	5.59	5.44	5.45
Petroleum Subtotal	37.69	45.44	45.00	44.46	49.21	48.61	47.80	52.53	51.71	50.81
Natural Gas[6]	19.11	21.76	21.87	21.95	22.89	23.06	23.22	23.87	24.14	24.34
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	1.80	1.86	1.86	1.88	1.91	1.91	1.92	1.98	1.98	1.98
Net Coal Coke Imports	0.06	0.11	0.11	0.10	0.14	0.14	0.13	0.17	0.16	0.15
Coal Subtotal	2.64	2.61	2.62	2.63	2.64	2.64	2.64	2.68	2.68	2.67
Renewable Energy[13]	2.93	3.45	3.44	3.43	3.75	3.74	3.74	4.01	4.00	4.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.69	14.28	14.23	14.19	15.57	15.54	15.50	16.82	16.77	16.75
Delivered Energy	**74.06**	**87.54**	**87.15**	**86.66**	**94.07**	**93.60**	**92.89**	**99.92**	**99.31**	**98.58**
Electricity Related Losses	25.23	28.74	28.46	28.35	30.16	30.04	30.12	31.50	31.54	31.71
Total	**99.29**	**116.28**	**115.61**	**115.01**	**124.23**	**123.64**	**123.02**	**131.42**	**130.85**	**130.29**
Electric Generators[14]										
Distillate Fuel	0.08	0.07	0.05	0.04	0.27	0.05	0.05	0.58	0.06	0.05
Residual Fuel	0.86	0.49	0.16	0.06	0.64	0.19	0.09	0.68	0.22	0.10
Petroleum Subtotal	0.93	0.56	0.21	0.10	0.91	0.24	0.13	1.25	0.28	0.15
Natural Gas	4.32	7.02	6.98	6.81	9.09	9.08	8.55	10.30	10.49	9.70
Steam Coal	19.69	22.79	22.80	22.81	23.26	23.52	24.07	24.15	24.67	25.60
Nuclear Power	8.03	7.87	7.87	7.95	7.37	7.55	7.63	7.31	7.49	7.58
Renewable Energy[15]	3.55	4.41	4.46	4.45	4.65	4.74	4.75	4.89	4.94	4.99
Electricity Imports[16]	0.38	0.37	0.38	0.42	0.45	0.45	0.48	0.41	0.44	0.45
Total	**36.92**	**43.02**	**42.69**	**42.54**	**45.73**	**45.58**	**45.63**	**48.32**	**48.32**	**48.47**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		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	7.80	9.88	9.75	9.64	10.97	10.61	10.45	11.99	11.31	11.14
Kerosene	0.14	0.13	0.13	0.12	0.13	0.12	0.12	0.13	0.12	0.12
Jet Fuel[9]	3.58	4.48	4.46	4.42	5.15	5.12	5.07	5.86	5.82	5.78
Liquefied Petroleum Gas	2.93	3.28	3.23	3.12	3.44	3.41	3.31	3.61	3.56	3.43
Motor Gasoline[2]	16.29	19.77	19.59	19.34	21.40	21.14	20.73	22.77	22.42	21.90
Petrochemical Feedstock	1.32	1.46	1.45	1.44	1.55	1.54	1.53	1.60	1.59	1.58
Residual Fuel	2.40	1.97	1.59	1.48	2.15	1.67	1.52	2.23	1.72	1.57
Other Petroleum[12]	4.16	5.03	5.01	5.00	5.33	5.25	5.21	5.59	5.44	5.45
Petroleum Subtotal	38.63	46.00	45.20	44.56	50.12	48.85	47.93	53.78	51.99	50.96
Natural Gas	23.43	28.77	28.85	28.76	31.98	32.14	31.77	34.17	34.63	34.04
Metallurgical Coal	0.77	0.64	0.64	0.64	0.59	0.59	0.59	0.54	0.54	0.54
Steam Coal	21.50	24.65	24.66	24.68	25.17	25.43	25.99	26.13	26.65	27.58
Net Coal Coke Imports	0.06	0.11	0.11	0.10	0.14	0.14	0.13	0.17	0.16	0.15
Coal Subtotal	22.34	25.40	25.41	25.43	25.90	26.16	26.71	26.83	27.35	28.27
Nuclear Power	8.03	7.87	7.87	7.95	7.37	7.55	7.63	7.31	7.49	7.58
Renewable Energy[17]	6.48	7.86	7.90	7.88	8.40	8.48	8.49	8.91	8.94	8.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.38	0.37	0.38	0.42	0.45	0.45	0.48	0.41	0.44	0.45
Total	**99.29**	**116.28**	**115.61**	**115.01**	**124.23**	**123.64**	**123.02**	**131.42**	**130.85**	**130.29**
Energy Use and Related Statistics										
Delivered Energy Use	74.06	87.54	87.15	86.66	94.07	93.60	92.89	99.92	99.31	98.58
Total Energy Use	99.29	116.28	115.61	115.01	124.23	123.64	123.02	131.42	130.85	130.29
Population (millions)	275.69	300.24	300.24	300.24	312.66	312.66	312.66	325.33	325.33	325.33
Gross Domestic Product (billion 1996 dollars)	9224	12319	12312	12303	14417	14399	14372	16561	16525	16496
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1561.7	1849.1	1834.7	1822.0	1981.5	1965.4	1957.0	2103.2	2087.8	2083.4

[1]Includes wood used for residential heating. See Table C18 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 electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. 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 cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[0]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, 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 all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. 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 cogeneration. Excludes net electricity imports.
[16]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]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 2000 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 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1999, Volume 1,* DOE/EIA-0348(99)/1 (Washington, DC, August 2000). 2000 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C3. Energy Prices by Sector and Source
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		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	**14.42**	**13.14**	**13.50**	**13.89**	**13.39**	**13.68**	**14.03**	**13.67**	**14.04**	**14.31**
Primary Energy[1]	8.26	6.94	7.27	7.65	7.07	7.40	7.73	7.10	7.49	7.77
Petroleum Products[2]	10.78	8.81	9.84	11.06	8.96	10.29	11.41	8.99	10.41	11.55
Distillate Fuel	9.42	6.85	7.94	9.13	7.03	8.43	9.56	7.09	8.54	9.74
Liquefied Petroleum Gas	13.65	12.35	13.26	14.51	12.46	13.65	14.77	12.44	13.81	14.84
Natural Gas	7.64	6.54	6.73	6.97	6.69	6.84	7.06	6.75	6.97	7.13
Electricity	24.36	22.13	22.41	22.70	22.09	22.18	22.44	22.34	22.55	22.66
Commercial	**14.03**	**12.48**	**12.89**	**13.29**	**12.87**	**13.15**	**13.53**	**13.18**	**13.57**	**13.83**
Primary Energy[1]	6.31	5.26	5.57	5.93	5.46	5.77	6.09	5.56	5.93	6.20
Petroleum Products[2]	7.19	5.26	6.36	7.55	5.41	6.77	7.93	5.49	6.91	8.05
Distillate Fuel	7.08	4.60	5.73	6.92	4.82	6.25	7.39	4.94	6.39	7.57
Residual Fuel	3.46	2.97	3.83	4.86	2.98	3.92	4.92	2.97	4.02	4.93
Natural Gas[3]	6.23	5.33	5.51	5.74	5.53	5.68	5.88	5.64	5.86	6.00
Electricity	22.11	19.44	19.87	20.23	19.68	19.85	20.23	20.02	20.33	20.52
Industrial[4]	**6.88**	**5.50**	**5.97**	**6.49**	**5.73**	**6.27**	**6.76**	**5.88**	**6.49**	**6.94**
Primary Energy	5.69	4.24	4.76	5.32	4.41	5.05	5.59	4.50	5.19	5.70
Petroleum Products[2]	8.10	5.71	6.69	7.77	5.79	7.08	8.12	5.82	7.13	8.16
Distillate Fuel	7.21	4.72	5.89	7.07	5.03	6.52	7.65	5.29	6.70	7.81
Liquefied Petroleum Gas	11.73	7.82	8.60	9.69	7.82	8.98	10.01	7.82	9.11	10.08
Residual Fuel	3.27	2.81	3.65	4.67	2.82	3.74	4.73	2.82	3.86	4.77
Natural Gas[5]	4.31	3.31	3.47	3.68	3.57	3.69	3.86	3.72	3.90	4.03
Metallurgical Coal	1.62	1.54	1.56	1.57	1.50	1.52	1.53	1.45	1.46	1.48
Steam Coal	1.41	1.28	1.30	1.31	1.24	1.26	1.28	1.20	1.21	1.23
Electricity	13.50	12.27	12.54	12.81	12.57	12.62	12.89	12.85	13.04	13.20
Transportation	**10.88**	**8.88**	**9.98**	**11.27**	**8.76**	**10.04**	**11.52**	**8.54**	**9.99**	**11.28**
Primary Energy	10.86	8.86	9.96	11.25	8.73	10.02	11.50	8.52	9.96	11.26
Petroleum Products[2]	10.86	8.85	9.96	11.25	8.72	10.01	11.50	8.51	9.96	11.26
Distillate Fuel[6]	10.81	8.99	10.14	11.47	8.99	10.09	11.38	8.83	9.98	11.18
Jet Fuel[7]	7.36	4.69	5.87	7.12	4.99	6.32	7.49	5.08	6.37	7.45
Motor Gasoline[8]	12.20	10.17	11.27	12.57	9.90	11.28	12.98	9.63	11.28	12.72
Residual Fuel	4.38	2.59	3.48	4.54	2.58	3.57	4.59	2.57	3.67	4.61
Liquefied Petroleum Gas[9]	15.91	13.48	14.43	15.62	13.54	14.70	15.68	13.35	14.65	15.58
Natural Gas[10]	8.04	6.67	6.89	7.12	6.92	7.13	7.32	6.98	7.28	7.43
Ethanol (E85)[11]	17.33	20.85	20.59	21.53	21.43	21.71	22.29	20.40	21.19	21.86
Electricity	21.78	17.93	18.20	18.48	19.18	19.27	19.50	17.69	17.91	17.96
Average End-Use Energy	**10.40**	**8.84**	**9.53**	**10.31**	**8.96**	**9.73**	**10.57**	**9.02**	**9.90**	**10.63**
Primary Energy	8.41	6.85	7.61	8.48	6.91	7.81	8.77	6.88	7.89	8.74
Electricity	20.20	18.25	18.58	18.88	18.42	18.53	18.83	18.73	18.97	19.12
Electric Generators[12]										
Fossil Fuel Average	1.88	1.56	1.61	1.67	1.74	1.77	1.77	1.82	1.85	1.82
Petroleum Products	4.33	2.94	3.97	5.43	3.26	4.14	5.47	3.55	4.27	5.45
Distillate Fuel	6.89	4.06	5.23	6.40	4.31	5.73	6.89	4.40	5.87	6.99
Residual Fuel	4.11	2.78	3.60	4.72	2.81	3.69	4.71	2.82	3.81	4.71
Natural Gas	4.41	3.17	3.38	3.60	3.50	3.65	3.82	3.66	3.87	3.99
Steam Coal	1.20	1.04	1.05	1.07	1.00	1.01	1.02	0.95	0.97	0.97

Table C3. Energy Prices by Sector and Source (Continued)
(2000 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2000	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Average Price to All Users[13]										
Petroleum Products[2]	10.05	8.07	9.19	10.44	7.99	9.35	10.74	7.84	9.34	10.58
Distillate Fuel	9.93	8.03	9.22	10.53	8.07	9.37	10.63	7.93	9.33	10.54
Jet Fuel	7.36	4.69	5.87	7.12	4.99	6.32	7.49	5.08	6.37	7.45
Liquefied Petroleum Gas	12.06	8.59	9.37	10.48	8.56	9.70	10.72	8.53	9.79	10.75
Motor Gasoline[8]	12.20	10.17	11.27	12.57	9.90	11.28	12.98	9.63	11.28	12.72
Residual Fuel	4.11	2.69	3.54	4.59	2.71	3.64	4.65	2.71	3.75	4.66
Natural Gas	5.43	4.29	4.47	4.69	4.48	4.61	4.80	4.60	4.79	4.93
Coal	1.22	1.06	1.07	1.09	1.02	1.03	1.04	0.97	0.98	0.99
Ethanol (E85)[11]	17.33	20.85	20.59	21.53	21.43	21.71	22.29	20.40	21.19	21.86
Electricity	20.20	18.25	18.58	18.88	18.42	18.53	18.83	18.73	18.97	19.12
Non-Renewable Energy Expenditures by Sector (billion 2000 dollars)										
Residential	153.41	158.80	161.45	164.12	168.86	170.74	173.09	181.44	184.01	185.26
Commercial	112.06	123.99	126.73	129.33	139.03	140.90	143.87	153.78	156.92	158.91
Industrial	142.86	126.02	136.11	147.14	138.66	150.46	161.37	148.78	162.53	173.24
Transportation	288.38	291.00	325.09	363.67	314.50	357.95	404.92	330.40	382.65	425.17
Total Non-Renewable Expenditures	696.71	699.81	749.39	804.26	761.05	820.07	883.25	814.39	886.10	942.59
Transportation Renewable Expenditures	0.31	0.68	0.70	0.77	0.84	0.88	0.98	0.92	1.00	1.10
Total Expenditures	**697.01**	**700.49**	**750.09**	**805.03**	**761.89**	**820.95**	**884.24**	**815.32**	**887.11**	**943.69**

[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]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes use for lease and plant fuel.
[6] Diesel fuel containing 500 parts per million (ppm) or 15 pm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[13]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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline, distillate, and jet fuel are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/ data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf. 2000 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 2000 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial natural gas delivered prices: EIA,, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. 2000 electricity prices for commercial, industrial, and transportation: EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	76.57	85.97	85.88	85.78	90.69	90.55	90.38	95.50	95.27	95.01
Multifamily	21.97	23.17	23.15	23.12	23.79	23.77	23.74	24.62	24.58	24.55
Mobile Homes	6.61	6.96	6.95	6.95	7.14	7.14	7.13	7.27	7.27	7.26
Total	**105.15**	**116.09**	**115.98**	**115.85**	**121.62**	**121.46**	**121.26**	**127.39**	**127.12**	**126.82**
Average House Square Footage	**1678**	**1735**	**1735**	**1735**	**1763**	**1762**	**1761**	**1788**	**1787**	**1786**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	105.2	107.8	106.9	105.7	107.3	106.4	105.4	107.7	106.6	105.6
Total Energy Consumption	188.8	193.4	191.8	190.3	191.8	190.7	190.1	191.8	190.9	190.5
(thousand Btu per square foot)										
Delivered Energy Consumption	62.7	62.1	61.6	60.9	60.9	60.4	59.8	60.2	59.6	59.1
Total Energy Consumption	112.5	111.5	110.5	109.7	108.8	108.2	107.9	107.3	106.8	106.7
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.42	0.48	0.48	0.48	0.50	0.50	0.51	0.53	0.53	0.54
Space Cooling	0.56	0.64	0.63	0.63	0.68	0.68	0.68	0.75	0.75	0.75
Water Heating	0.41	0.42	0.41	0.41	0.40	0.41	0.41	0.39	0.39	0.40
Refrigeration	0.43	0.34	0.34	0.34	0.32	0.32	0.32	0.32	0.32	0.32
Cooking	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.23	0.26	0.25	0.25	0.27	0.26	0.26	0.28	0.28	0.27
Freezers	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.35	0.46	0.45	0.45	0.49	0.48	0.48	0.51	0.51	0.51
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	0.23	0.23	0.23	0.26	0.26	0.26
Personal Computers	0.04	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[2]	1.14	1.72	1.71	1.70	1.95	1.95	1.94	2.17	2.16	2.15
Delivered Energy	**4.07**	**4.94**	**4.92**	**4.90**	**5.31**	**5.30**	**5.28**	**5.72**	**5.70**	**5.69**
Natural Gas										
Space Heating	3.44	3.84	3.82	3.78	4.01	3.99	3.96	4.25	4.22	4.19
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.32	1.45	1.44	1.43	1.46	1.46	1.45	1.48	1.47	1.46
Cooking	0.20	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Clothes Dryers	0.07	0.09	0.09	0.09	0.10	0.10	0.09	0.10	0.10	0.10
Other Uses[3]	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**5.14**	**5.73**	**5.68**	**5.63**	**5.92**	**5.89**	**5.85**	**6.19**	**6.15**	**6.10**
Distillate										
Space Heating	0.70	0.71	0.67	0.63	0.69	0.64	0.60	0.69	0.63	0.58
Water Heating	0.12	0.12	0.12	0.11	0.12	0.11	0.10	0.11	0.10	0.09
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.83**	**0.83**	**0.79**	**0.74**	**0.81**	**0.75**	**0.70**	**0.80**	**0.73**	**0.67**
Liquefied Petroleum Gas										
Space Heating	0.33	0.33	0.31	0.29	0.32	0.30	0.27	0.32	0.29	0.26
Water Heating	0.10	0.10	0.09	0.09	0.09	0.09	0.08	0.09	0.08	0.07
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.47**	**0.47**	**0.45**	**0.42**	**0.46**	**0.42**	**0.39**	**0.45**	**0.41**	**0.37**
Marketed Renewables (wood)[5]	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.45	0.45	0.45
Other Fuels[6]	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	5.45	5.92	5.83	5.73	6.08	5.98	5.89	6.35	6.23	6.12
Space Cooling	0.56	0.64	0.64	0.63	0.68	0.68	0.68	0.76	0.75	0.75
Water Heating	1.95	2.09	2.07	2.04	2.08	2.06	2.04	2.07	2.04	2.02
Refrigeration	0.43	0.34	0.34	0.34	0.32	0.32	0.32	0.32	0.32	0.32
Cooking	0.33	0.37	0.37	0.37	0.39	0.39	0.39	0.41	0.41	0.41
Clothes Dryers	0.29	0.34	0.34	0.34	0.36	0.36	0.36	0.38	0.38	0.38
Freezers	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.35	0.46	0.45	0.45	0.49	0.48	0.48	0.51	0.51	0.51
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	0.23	0.23	0.23	0.26	0.26	0.26
Personal Computers	0.04	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[7]	1.27	1.84	1.83	1.82	2.07	2.07	2.06	2.29	2.28	2.27
Delivered Energy	**11.06**	**12.52**	**12.40**	**12.25**	**13.05**	**12.92**	**12.78**	**13.72**	**13.55**	**13.40**
Electricity Related Losses	**8.79**	**9.93**	**9.85**	**9.79**	**10.28**	**10.25**	**10.27**	**10.71**	**10.72**	**10.77**
Total Energy Consumption by End-Use										
Space Heating	6.36	6.87	6.78	6.68	7.05	6.96	6.87	7.35	7.23	7.14
Space Cooling	1.77	1.92	1.90	1.89	2.01	2.00	1.99	2.17	2.16	2.16
Water Heating	2.83	2.92	2.90	2.87	2.86	2.84	2.82	2.81	2.79	2.77
Refrigeration	1.36	1.03	1.03	1.03	0.95	0.95	0.95	0.93	0.93	0.93
Cooking	0.56	0.61	0.61	0.61	0.63	0.63	0.63	0.65	0.65	0.65
Clothes Dryers	0.78	0.86	0.85	0.85	0.87	0.87	0.87	0.90	0.90	0.90
Freezers	0.37	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.25	0.25
Lighting	1.11	1.37	1.36	1.35	1.43	1.42	1.42	1.47	1.47	1.46
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.09
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.42	0.60	0.60	0.59	0.67	0.66	0.66	0.75	0.74	0.75
Personal Computers	0.14	0.24	0.24	0.23	0.28	0.28	0.28	0.31	0.31	0.31
Furnace Fans	0.25	0.29	0.29	0.28	0.31	0.30	0.30	0.32	0.32	0.32
Other Uses[7]	3.73	5.29	5.26	5.22	5.85	5.83	5.82	6.35	6.34	6.35
Total	**19.85**	**22.45**	**22.24**	**22.04**	**23.32**	**23.17**	**23.05**	**24.43**	**24.27**	**24.16**
Non-Marketed Renewables										
Geothermal[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Solar[9]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Total	**0.04**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**	**0.08**	**0.08**	**0.08**

[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf.
Projections: EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	62.3	75.6	75.5	75.3	81.8	81.7	81.6	87.6	87.5	87.5
New Additions	2.2	2.0	2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.1
Total	**64.5**	**77.7**	**77.5**	**77.4**	**83.9**	**83.8**	**83.7**	**89.6**	**89.6**	**89.5**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	125.1	128.9	127.8	126.8	129.8	128.9	128.0	131.0	130.0	129.3
Electricity Related Losses	130.6	131.1	129.8	129.3	130.0	129.6	130.0	128.5	128.8	129.5
Total Energy Consumption	255.7	259.9	257.6	256.1	259.8	258.5	258.0	259.5	258.8	258.8
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Space Cooling[1]	0.45	0.51	0.50	0.50	0.53	0.53	0.52	0.55	0.54	0.54
Water Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Ventilation	0.18	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.23
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.24	1.44	1.42	1.41	1.51	1.50	1.49	1.54	1.53	1.53
Refrigeration	0.19	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24
Office Equipment (PC)	0.16	0.32	0.32	0.32	0.35	0.35	0.35	0.35	0.35	0.35
Office Equipment (non-PC)	0.32	0.52	0.52	0.52	0.65	0.65	0.65	0.78	0.78	0.78
Other Uses[2]	1.05	1.49	1.49	1.49	1.79	1.79	1.78	2.10	2.10	2.10
Delivered Energy	**3.90**	**5.06**	**5.03**	**5.01**	**5.63**	**5.62**	**5.60**	**6.15**	**6.13**	**6.13**
Natural Gas[3]										
Space Heating[1]	1.50	1.72	1.72	1.71	1.77	1.79	1.79	1.83	1.87	1.86
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]	0.65	0.80	0.79	0.78	0.86	0.85	0.84	0.91	0.91	0.90
Cooking	0.21	0.26	0.26	0.25	0.28	0.27	0.27	0.30	0.29	0.29
Other Uses[4]	0.99	1.27	1.25	1.24	1.39	1.37	1.36	1.55	1.54	1.52
Delivered Energy	**3.36**	**4.06**	**4.04**	**4.00**	**4.32**	**4.33**	**4.30**	**4.63**	**4.64**	**4.61**
Distillate										
Space Heating[1]	0.23	0.29	0.25	0.23	0.30	0.24	0.22	0.31	0.24	0.22
Water Heating[1]	0.08	0.09	0.08	0.08	0.09	0.08	0.08	0.09	0.08	0.08
Other Uses[5]	0.07	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.09	0.09
Delivered Energy	**0.38**	**0.47**	**0.42**	**0.39**	**0.49**	**0.42**	**0.39**	**0.50**	**0.42**	**0.39**
Other Fuels[6]	**0.34**	**0.34**	**0.34**	**0.33**	**0.36**	**0.36**	**0.35**	**0.38**	**0.37**	**0.36**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.88	2.16	2.13	2.09	2.24	2.20	2.17	2.31	2.27	2.25
Space Cooling[1]	0.47	0.53	0.53	0.52	0.56	0.56	0.55	0.58	0.58	0.58
Water Heating[1]	0.87	1.05	1.03	1.02	1.11	1.10	1.09	1.17	1.15	1.14
Ventilation	0.18	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.23
Cooking	0.24	0.29	0.29	0.28	0.31	0.30	0.30	0.33	0.32	0.32
Lighting	1.24	1.44	1.42	1.41	1.51	1.50	1.49	1.54	1.53	1.53
Refrigeration	0.19	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24
Office Equipment (PC)	0.16	0.32	0.32	0.32	0.35	0.35	0.35	0.35	0.35	0.35
Office Equipment (non-PC)	0.32	0.52	0.52	0.52	0.65	0.65	0.65	0.78	0.78	0.78
Other Uses[7]	2.53	3.28	3.25	3.23	3.71	3.69	3.66	4.21	4.18	4.16
Delivered Energy	**8.07**	**10.01**	**9.91**	**9.81**	**10.88**	**10.80**	**10.71**	**11.74**	**11.64**	**11.57**

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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	**8.42**	**10.18**	**10.06**	**10.01**	**10.90**	**10.85**	**10.87**	**11.51**	**11.53**	**11.60**
Total Energy Consumption by End-Use										
Space Heating[1]	2.20	2.49	2.45	2.41	2.56	2.52	2.49	2.62	2.58	2.56
Space Cooling[1]	1.45	1.55	1.53	1.52	1.57	1.57	1.57	1.60	1.60	1.61
Water Heating[1]	1.19	1.37	1.35	1.33	1.43	1.41	1.40	1.48	1.46	1.45
Ventilation	0.56	0.63	0.63	0.62	0.64	0.64	0.64	0.66	0.65	0.65
Cooking	0.31	0.35	0.35	0.34	0.37	0.36	0.36	0.38	0.38	0.37
Lighting	3.91	4.33	4.27	4.24	4.42	4.39	4.38	4.43	4.42	4.43
Refrigeration	0.59	0.66	0.65	0.65	0.67	0.67	0.67	0.69	0.69	0.69
Office Equipment (PC)	0.49	0.96	0.95	0.95	1.03	1.03	1.03	1.02	1.02	1.02
Office Equipment (non-PC)	1.00	1.58	1.57	1.56	1.91	1.91	1.91	2.24	2.24	2.25
Other Uses[7]	4.79	6.28	6.23	6.20	7.18	7.14	7.13	8.15	8.13	8.13
Total	**16.49**	**20.19**	**19.98**	**19.82**	**21.78**	**21.65**	**21.58**	**23.26**	**23.18**	**23.17**
Non-Marketed Renewable Fuels										
Solar[8]	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]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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 Gross Output (billion 1992 dollars)										
Manufacturing	4022	5,379	5,373	5,369	6,221	6,210	6,190	7,026	7,003	6,977
Nonmanufacturing	1039	1,210	1,211	1,212	1,321	1,325	1,327	1,441	1,444	1,451
Total	**5062**	**6,589**	**6,584**	**6,581**	**7,542**	**7,535**	**7,517**	**8,467**	**8,447**	**8,428**
Energy Prices (2000 dollars per million Btu)										
Electricity	13.50	12.27	12.54	12.81	12.57	12.62	12.89	12.85	13.04	13.20
Natural Gas	4.31	3.31	3.47	3.68	3.57	3.69	3.86	3.72	3.90	4.03
Steam Coal	1.41	1.28	1.30	1.31	1.24	1.26	1.28	1.20	1.21	1.23
Residual Oil	3.27	2.81	3.65	4.67	2.82	3.74	4.73	2.82	3.86	4.77
Distillate Oil	7.21	4.72	5.89	7.07	5.03	6.52	7.65	5.29	6.70	7.81
Liquefied Petroleum Gas	11.73	7.82	8.60	9.69	7.82	8.98	10.01	7.82	9.11	10.08
Motor Gasoline	12.18	10.13	11.22	12.52	9.86	11.24	12.96	9.59	11.24	12.70
Metallurgical Coal	1.62	1.54	1.56	1.57	1.50	1.52	1.53	1.45	1.46	1.48
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.65	4.21	4.20	4.20	4.54	4.53	4.53	4.84	4.83	4.83
Natural Gas[2]	9.79	11.02	11.19	11.37	11.59	11.77	12.01	11.91	12.19	12.48
Steam Coal	1.69	1.74	1.74	1.76	1.79	1.79	1.80	1.85	1.85	1.86
Metallurgical Coal and Coke[3]	0.84	0.76	0.75	0.75	0.73	0.72	0.72	0.70	0.70	0.69
Residual Fuel	0.27	0.28	0.23	0.22	0.29	0.26	0.21	0.31	0.27	0.23
Distillate	1.11	1.24	1.22	1.20	1.32	1.29	1.28	1.41	1.38	1.36
Liquefied Petroleum Gas	2.36	2.69	2.66	2.57	2.85	2.85	2.77	3.01	3.00	2.91
Petrochemical Feedstocks	1.32	1.46	1.45	1.44	1.55	1.54	1.53	1.60	1.59	1.58
Other Petroleum[4]	4.17	5.03	5.01	5.00	5.33	5.25	5.21	5.59	5.45	5.45
Renewables[5]	2.41	2.90	2.89	2.88	3.19	3.18	3.17	3.44	3.43	3.42
Delivered Energy	**27.62**	**31.31**	**31.35**	**31.39**	**33.19**	**33.19**	**33.23**	**34.67**	**34.69**	**34.81**
Electricity Related Losses	7.89	8.46	8.39	8.39	8.80	8.76	8.81	9.07	9.08	9.15
Total	**35.50**	**39.77**	**39.74**	**39.79**	**41.99**	**41.96**	**42.04**	**43.74**	**43.76**	**43.96**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)										
Purchased Electricity	0.72	0.64	0.64	0.64	0.60	0.60	0.60	0.57	0.57	0.57
Natural Gas[2]	1.93	1.67	1.70	1.73	1.54	1.56	1.60	1.41	1.44	1.48
Steam Coal	0.33	0.26	0.26	0.27	0.24	0.24	0.24	0.22	0.22	0.22
Metallurgical Coal and Coke[3]	0.17	0.11	0.11	0.11	0.10	0.10	0.10	0.08	0.08	0.08
Residual Fuel	0.05	0.04	0.04	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate	0.22	0.19	0.19	0.18	0.17	0.17	0.17	0.17	0.16	0.16
Liquefied Petroleum Gas	0.47	0.41	0.40	0.39	0.38	0.38	0.37	0.36	0.36	0.34
Petrochemical Feedstocks	0.26	0.22	0.22	0.22	0.21	0.20	0.20	0.19	0.19	0.19
Other Petroleum[4]	0.82	0.76	0.76	0.76	0.71	0.70	0.69	0.66	0.64	0.65
Renewables[5]	0.48	0.44	0.44	0.44	0.42	0.42	0.42	0.41	0.41	0.41
Delivered Energy	**5.46**	**4.75**	**4.76**	**4.77**	**4.40**	**4.41**	**4.42**	**4.10**	**4.11**	**4.13**
Electricity Related Losses	1.56	1.28	1.27	1.28	1.17	1.16	1.17	1.07	1.07	1.09
Total	**7.01**	**6.04**	**6.04**	**6.05**	**5.57**	**5.57**	**5.59**	**5.17**	**5.18**	**5.22**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, 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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline and distillate are based on the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_ annual/current/pdf/pmaall.pdf. 2000 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. 2000 electricity prices: EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. Other 2000 prices derived from EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001). Other 2000 values: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2000	Projections								
		2010			2015			2020		
		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)	2340	2996	2981	2955	3335	3318	3272	3649	3631	3586
Commercial Light Trucks (VMT)[1]	70	89	89	89	101	101	100	113	112	112
Freight Trucks >10,000 pounds (VMT)	214	286	285	284	324	323	322	362	360	359
Air (seat miles available)	1184	1614	1603	1592	1960	1949	1939	2354	2342	2333
Rail (ton miles traveled)	1415	1761	1757	1764	1903	1907	1919	2056	2066	2089
Domestic Shipping (ton miles traveled)	689	786	792	798	843	855	867	894	910	930
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.5	25.6	25.7	25.9	26.4	26.6	26.9	26.8	27.2	27.7
New Car (miles per gallon)[2]	28.6	30.0	30.2	30.5	30.7	31.0	31.3	31.2	31.7	32.3
New Light Truck (miles per gallon)[2]	21.1	22.2	22.3	22.4	23.1	23.3	23.5	23.5	23.8	24.2
Light-Duty Fleet (miles per gallon)[3]	19.8	20.0	20.1	20.1	20.4	20.5	20.6	20.8	21.0	21.2
New Commercial Light Truck (MPG)[1]	14.2	14.8	14.9	14.9	15.4	15.5	15.6	15.7	15.9	16.1
Stock Commercial Light Truck (MPG)[1]	13.6	14.4	14.4	14.5	14.8	14.9	14.9	15.3	15.4	15.5
Aircraft Efficiency (seat miles per gallon)	52.1	55.9	55.9	56.0	58.1	58.1	58.4	60.2	60.3	60.6
Freight Truck Efficiency (miles per gallon)	5.9	6.0	6.0	6.0	6.1	6.1	6.2	6.3	6.3	6.4
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.3	3.3	3.3	3.4	3.4	3.4
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	14.97	18.65	18.49	18.25	20.29	20.07	19.69	21.66	21.37	20.90
Commercial Light Trucks[1]	0.64	0.78	0.77	0.77	0.85	0.85	0.84	0.92	0.91	0.90
Freight Trucks[4]	4.80	6.26	6.24	6.22	6.94	6.91	6.84	7.46	7.42	7.32
Air[5]	3.62	4.54	4.51	4.48	5.22	5.19	5.14	5.95	5.91	5.86
Rail[6]	0.58	0.67	0.66	0.67	0.69	0.69	0.69	0.72	0.72	0.72
Marine[7]	1.73	1.72	1.73	1.73	1.77	1.78	1.78	1.82	1.82	1.83
Pipeline Fuel	0.79	0.86	0.86	0.86	0.94	0.95	0.94	1.00	1.02	1.00
Lubricants	0.18	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Total	**27.32**	**33.70**	**33.50**	**33.21**	**36.96**	**36.69**	**36.17**	**39.78**	**39.43**	**38.80**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	7.82	9.85	9.76	9.64	10.71	10.59	10.39	11.43	11.27	11.03
Commercial Light Trucks[1]	0.33	0.41	0.41	0.40	0.45	0.45	0.44	0.49	0.48	0.47
Freight Trucks[4]	2.14	2.81	2.81	2.80	3.13	3.12	3.09	3.37	3.35	3.31
Railroad	0.24	0.27	0.27	0.27	0.28	0.28	0.28	0.28	0.28	0.29
Domestic Shipping	0.14	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18
International Shipping	0.48	0.45	0.45	0.45	0.45	0.45	0.45	0.46	0.46	0.46
Air[5]	1.51	1.90	1.89	1.88	2.22	2.21	2.19	2.57	2.56	2.53
Military Use	0.30	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Bus Transportation	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.09
Rail Transportation[6]	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
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	0.11	0.11	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.40	0.43	0.44	0.43	0.48	0.48	0.47	0.50	0.52	0.50
Total	**13.73**	**17.05**	**16.95**	**16.80**	**18.69**	**18.55**	**18.28**	**20.11**	**19.92**	**19.60**

[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 recreation 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 are model results and may differ slightly from official EIA data reports.

Sources: 2000: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2000/1999* (Washington, DC, 2000); Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf; EIA, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0535(99) (Washington, DC, August 2000); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Generation by Fuel Type										
Electric Generators[1]										
Coal	1922	2213	2215	2223	2260	2292	2352	2363	2423	2529
Petroleum	93	64	28	18	106	33	22	156	38	25
Natural Gas[2]	417	879	893	871	1192	1202	1130	1391	1414	1303
Nuclear Power	752	737	737	745	690	707	715	685	702	710
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	321	388	391	390	396	401	401	405	407	410
Total	**3504**	**4280**	**4263**	**4247**	**4644**	**4634**	**4619**	**4999**	**4983**	**4976**
Nonutility Generation for Own Use	30	33	33	33	33	33	33	32	33	32
Distributed Generation	0	2	2	2	5	5	4	8	8	8
Cogenerators[4]										
Coal	46	49	49	49	49	49	49	49	49	49
Petroleum	9	10	10	10	12	10	10	15	11	10
Natural Gas[2]	209	259	260	261	285	286	289	315	318	320
Other Gaseous Fuels[5]	6	10	9	9	11	10	10	11	12	11
Renewable Sources[3]	33	41	41	41	47	47	47	52	52	52
Other[6]	4	4	4	4	4	4	4	4	4	4
Total	**307**	**374**	**374**	**375**	**408**	**408**	**410**	**447**	**447**	**447**
Other End-Use Generators[7]	**4**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	163	190	189	189	205	204	204	224	224	223
Generation for Own Use	147	190	190	190	208	208	210	228	228	229
Net Imports[8]	**35**	**33**	**35**	**38**	**41**	**41**	**44**	**38**	**40**	**41**
Electricity Sales by Sector										
Residential	1193	1447	1443	1436	1556	1554	1548	1676	1672	1667
Commercial	1144	1483	1475	1467	1650	1646	1640	1803	1798	1795
Industrial	1071	1232	1230	1231	1332	1329	1328	1420	1415	1416
Transportation	18	23	23	23	27	27	27	32	32	32
Total	**3426**	**4185**	**4170**	**4158**	**4565**	**4556**	**4544**	**4931**	**4916**	**4910**
End-Use Prices (2000 cents per kwh)[9]										
Residential	8.3	7.5	7.6	7.7	7.5	7.6	7.7	7.6	7.7	7.7
Commercial	7.5	6.6	6.8	6.9	6.7	6.8	6.9	6.8	6.9	7.0
Industrial	4.6	4.2	4.3	4.4	4.3	4.3	4.4	4.4	4.5	4.5
Transportation	7.4	6.1	6.2	6.3	6.5	6.6	6.7	6.0	6.1	6.1
All Sectors Average	**6.9**	**6.2**	**6.3**	**6.4**	**6.3**	**6.3**	**6.4**	**6.4**	**6.5**	**6.5**
Prices by Service Category[9] (2000 cents per kilowatthour)										
Generation	4.3	3.6	3.7	3.8	3.7	3.7	3.8	3.8	3.9	4.0
Transmission	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Emissions (million short tons)										
Sulfur Dioxide	11.05	9.68	9.70	9.70	8.94	8.95	8.95	8.94	8.95	8.95
Nitrogen Oxide	4.28	4.09	4.04	4.02	4.17	4.12	4.12	4.21	4.18	4.19

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[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]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Electric Generators[2]										
Capability										
Coal Steam	304.6	305.5	305.7	307.3	308.4	313.1	321.1	320.9	329.0	343.5
Other Fossil Steam[3]	135.0	117.3	115.6	114.6	115.9	114.4	112.9	112.6	113.3	111.9
Combined Cycle	30.6	125.8	139.9	139.0	173.1	182.4	176.7	216.6	213.8	205.1
Combustion Turbine/Diesel	77.7	143.5	128.9	126.3	163.4	149.6	146.1	189.6	177.9	170.8
Nuclear Power	97.5	94.3	94.3	95.4	86.4	88.8	89.9	85.6	88.0	89.1
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Renewable Sources[4]	89.1	97.0	97.2	97.3	98.9	99.5	99.8	100.5	101.2	101.9
Distributed Generation[5]	0.0	5.3	5.1	4.8	11.0	11.1	10.1	17.9	19.0	18.0
Total	**753.6**	**908.5**	**906.4**	**904.6**	**976.8**	**978.8**	**976.5**	**1063.6**	**1062.2**	**1060.1**
Cumulative Planned Additions[6]										
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[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Combustion Turbine/Diesel	0.0	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
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	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[4]	0.0	7.0	7.0	7.0	7.9	7.9	7.9	8.2	8.2	8.2
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**17.7**	**17.7**	**17.7**	**18.7**	**18.7**	**18.7**	**19.0**	**19.0**	**19.0**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	5.9	6.2	7.7	9.5	14.1	22.0	23.3	31.2	45.6
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	87.9	101.9	101.1	135.1	144.5	138.7	178.7	175.9	167.1
Combustion Turbine/Diesel	0.0	68.4	53.6	51.4	90.2	76.7	73.1	118.0	105.9	98.9
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[4]	0.0	0.4	0.6	0.7	1.4	1.9	2.3	2.7	3.4	4.1
Distributed Generation[5]	0.0	5.3	5.1	4.8	11.0	11.1	10.1	17.9	19.0	18.0
Total	**0.0**	**167.8**	**167.3**	**165.6**	**247.2**	**248.3**	**246.2**	**340.6**	**335.5**	**333.6**
Cumulative Total Additions	**0.0**	**185.5**	**185.0**	**183.3**	**265.9**	**267.1**	**264.9**	**359.6**	**354.5**	**352.6**
Cumulative Retirements[7]										
Coal Steam	0.0	5.2	5.2	5.1	5.9	5.8	5.7	7.1	7.0	6.9
Other Fossil Steam[3]	0.0	16.6	18.2	19.2	18.0	19.4	21.0	21.3	20.5	21.9
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combustion Turbine/Diesel	0.0	6.2	6.1	6.4	8.3	8.5	8.4	9.8	9.5	9.5
Nuclear Power	0.0	3.4	3.4	2.3	11.3	8.9	7.8	12.1	9.7	8.6
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[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**31.5**	**33.1**	**33.2**	**43.6**	**42.8**	**42.9**	**50.5**	**46.9**	**47.1**

Table C9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	2000	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Cogenerators[8]										
Capability										
Coal	8.9	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Petroleum	2.6	2.6	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6
Natural Gas	35.9	43.4	43.5	43.6	47.1	47.1	47.5	51.7	51.6	51.7
Other Gaseous Fuels	0.7	1.2	1.2	1.1	1.4	1.4	1.3	1.5	1.6	1.5
Renewable Sources[4]	5.8	7.2	7.1	7.1	8.2	8.1	8.1	9.0	8.9	8.9
Other	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**54.7**	**63.9**	**63.8**	**63.9**	**68.6**	**68.7**	**68.9**	**74.2**	**74.2**	**74.2**
Cumulative Additions[6]	**0.0**	**9.2**	**9.1**	**9.2**	**13.9**	**14.0**	**14.2**	**19.5**	**19.5**	**19.5**
Other End-Use Generators[9]										
Renewable Sources[10]	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Cumulative Additions	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 2000.
[7]Cumulative total retirements after December 31, 2000.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]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.
[10]See Table C17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model estimates and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Electricity Trade	2000	Projections								
		2010			2015			2020		
		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	156.9	102.9	102.9	102.9	45.7	45.7	45.7	0.0	0.0	0.0
Gross Domestic Economy Trade	151.0	186.3	189.5	193.3	189.6	198.2	208.9	190.5	205.1	211.6
Gross Domestic Trade	**307.8**	**289.2**	**292.4**	**296.2**	**235.4**	**243.9**	**254.6**	**190.5**	**205.1**	**211.6**
Gross Domestic Firm Power Sales (million 2000 dollars)	7576.3	4970.1	4970.1	4970.1	2208.9	2208.9	2208.9	0.0	0.0	0.0
Gross Domestic Economy Sales (million 2000 dollars)	6849.1	5555.6	5909.5	6373.0	6246.0	6711.2	7441.8	6407.6	7262.7	7703.9
Gross Domestic Sales (million 2000 dollars)	**14425.4**	**10525.**	**10879.**	**11343.**	**8455.0**	**8920.1**	**9650.7**	**6407.6**	**7262.7**	**7703.9**
International Electricity Trade										
Firm Power Imports From Canada & Mexico[1]	23.7	5.8	5.8	5.8	2.6	2.6	2.6	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	24.2	44.0	45.1	48.4	50.3	50.4	52.7	45.3	47.4	48.6
Gross Imports From Canada and Mexico[1]	**47.9**	**49.8**	**51.0**	**54.2**	**52.9**	**52.9**	**55.3**	**45.3**	**47.4**	**48.6**
Firm Power Exports To Canada and Mexico	6.6	8.7	8.7	8.7	3.9	3.9	3.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.4	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**13.0**	**16.4**	**16.4**	**16.4**	**11.5**	**11.5**	**11.5**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 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, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		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]	5.82	4.75	5.08	5.49	4.92	5.56	6.10	4.94	5.63	6.43
Alaska	0.97	0.69	0.70	0.72	0.89	0.90	0.92	1.08	1.10	1.12
Lower 48 States	4.85	4.06	4.38	4.77	4.04	4.65	5.18	3.86	4.53	5.32
Net Imports	9.02	12.00	11.18	10.55	12.02	11.01	10.17	12.37	11.20	10.08
Gross Imports	9.07	12.03	11.22	10.60	12.05	11.07	10.26	12.40	11.26	10.18
Exports	0.05	0.02	0.04	0.06	0.03	0.06	0.08	0.03	0.06	0.10
Other Crude Supply[2]	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.07**	**16.75**	**16.26**	**16.03**	**16.94**	**16.57**	**16.27**	**17.31**	**16.83**	**16.52**
Natural Gas Plant Liquids	**1.91**	**2.36**	**2.38**	**2.39**	**2.59**	**2.64**	**2.66**	**2.77**	**2.84**	**2.88**
Other Inputs[3]	**0.35**	**0.25**	**0.42**	**0.47**	**0.28**	**0.51**	**0.62**	**0.23**	**0.47**	**0.78**
Refinery Processing Gain[4]	**0.95**	**1.01**	**1.00**	**0.99**	**1.04**	**1.01**	**1.00**	**1.08**	**1.02**	**1.01**
Net Product Imports[5]	**1.40**	**3.16**	**3.09**	**2.93**	**4.74**	**4.29**	**4.00**	**6.06**	**5.44**	**4.89**
Gross Refined Product Imports[6]	2.04	3.23	3.21	3.09	4.71	4.31	4.07	6.04	5.49	4.96
Unfinished Oil Imports	0.27	0.81	0.75	0.69	0.95	0.88	0.80	0.98	0.90	0.85
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.99	0.88	0.87	0.84	0.92	0.90	0.88	0.97	0.94	0.92
Total Primary Supply[7]	**19.68**	**23.53**	**23.15**	**22.81**	**25.60**	**25.01**	**24.54**	**27.45**	**26.61**	**26.07**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.50	10.41	10.32	10.18	11.27	11.13	10.92	12.00	11.81	11.54
Jet Fuel[9]	1.73	2.16	2.15	2.14	2.49	2.47	2.45	2.83	2.81	2.79
Distillate Fuel[10]	3.67	4.65	4.58	4.53	5.16	4.99	4.91	5.64	5.32	5.24
Residual Fuel	1.05	0.86	0.69	0.64	0.94	0.73	0.66	0.97	0.75	0.68
Other[11]	4.80	5.52	5.46	5.37	5.82	5.75	5.65	6.08	5.97	5.87
Total	**19.74**	**23.60**	**23.21**	**22.87**	**25.67**	**25.07**	**24.59**	**27.52**	**26.66**	**26.12**
Refined Petroleum Products Supplied										
Residential and Commercial	1.12	1.15	1.09	1.03	1.15	1.06	1.00	1.16	1.04	0.98
Industrial[12]	4.96	5.72	5.66	5.57	6.07	6.00	5.89	6.38	6.27	6.17
Transportation	13.26	16.48	16.37	16.22	18.05	17.90	17.64	19.42	19.22	18.90
Electric Generators[13]	0.41	0.25	0.09	0.05	0.40	0.11	0.06	0.57	0.12	0.07
Total	**19.74**	**23.60**	**23.21**	**22.87**	**25.67**	**25.07**	**24.59**	**27.52**	**26.66**	**26.12**
Discrepancy[14]	**-0.07**	**-0.07**	**-0.06**	**-0.05**	**-0.07**	**-0.06**	**-0.04**	**-0.07**	**-0.05**	**-0.04**
World Oil Price (2000 dollars per barrel)[15]	**27.72**	**17.64**	**23.36**	**30.01**	**17.64**	**24.00**	**30.44**	**17.64**	**24.68**	**30.58**
Import Share of Product Supplied	**0.53**	**0.64**	**0.62**	**0.59**	**0.65**	**0.61**	**0.58**	**0.67**	**0.62**	**0.57**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2000 dollars)	**106.46**	**102.73**	**125.51**	**149.63**	**116.02**	**141.00**	**161.81**	**129.96**	**159.84**	**174.31**
Domestic Refinery Distillation Capacity[16]	**16.6**	**18.2**	**17.8**	**17.8**	**18.3**	**17.9**	**17.9**	**18.7**	**18.2**	**18.1**
Capacity Utilization Rate (percent)	**93.0**	**92.7**	**91.7**	**90.4**	**93.3**	**93.2**	**91.3**	**93.3**	**93.2**	**91.9**

[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, and natural gas 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 blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[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 by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 product supplied data from Table C2. Other 2000 data: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C12. Petroleum Product Prices
(2000 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2000	Projections								
		2010			2015			2020		
		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 (2000 dollars per barrel)	**27.72**	**17.64**	**23.36**	**30.01**	**17.64**	**24.00**	**30.44**	**17.64**	**24.68**	**30.58**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	130.7	95.0	110.1	126.6	97.5	116.9	132.5	98.3	118.5	135.1
Liquefied Petroleum Gas	117.1	105.9	113.8	124.4	106.9	117.1	126.7	106.7	118.5	127.3
Commercial										
Distillate Fuel	98.2	63.7	79.4	95.9	66.8	86.7	102.5	68.5	88.6	105.0
Residual Fuel	51.8	44.5	57.3	72.7	44.6	58.7	73.7	44.4	60.2	73.9
Residual Fuel (2000 dollars per barrel)	21.77	18.68	24.08	30.55	18.72	24.67	30.93	18.65	25.29	31.02
Industrial[1]										
Distillate Fuel	99.9	65.5	81.7	98.1	69.8	90.4	106.1	73.3	93.0	108.4
Liquefied Petroleum Gas	100.6	67.1	73.7	83.1	67.1	77.1	85.8	67.0	78.2	86.5
Residual Fuel	48.9	42.1	54.7	69.9	42.2	56.1	70.7	42.2	57.9	71.4
Residual Fuel (2000 dollars per barrel)	20.55	17.68	22.97	29.37	17.72	23.54	29.71	17.71	24.30	29.97
Transportation										
Diesel Fuel (distillate)[2]	149.9	124.7	140.6	159.1	124.7	140.0	157.8	122.5	138.5	155.0
Jet Fuel[3]	99.3	63.4	79.2	96.1	67.4	85.4	101.2	68.5	86.0	100.6
Motor Gasoline[4]	152.6	126.1	139.6	155.8	122.7	139.8	160.9	119.3	139.7	157.6
Liquid Petroleum Gas	136.5	115.6	123.8	134.0	116.2	126.1	134.5	114.6	125.7	133.6
Residual Fuel	65.6	38.7	52.1	67.9	38.6	53.5	68.8	38.5	55.0	69.0
Residual Fuel (2000 dollars per barrel)	27.56	16.26	21.88	28.52	16.23	22.47	28.88	16.17	23.10	28.96
Ethanol (E85)	155.3	186.4	184.1	192.6	191.6	194.1	199.3	182.5	189.5	195.5
Electric Generators[5]										
Distillate Fuel	95.6	56.3	72.6	88.8	59.7	79.5	95.6	61.0	81.4	96.9
Residual Fuel	61.5	41.6	53.9	70.7	42.1	55.3	70.5	42.3	57.0	70.5
Residual Fuel (2000 dollars per barrel)	25.83	17.46	22.66	29.71	17.70	23.22	29.61	17.75	23.93	29.62
Refined Petroleum Product Prices[6]										
Distillate Fuel	137.7	111.4	127.8	146.1	112.0	129.9	147.5	109.9	129.5	146.1
Jet Fuel[3]	99.3	63.4	79.2	96.1	67.4	85.4	101.2	68.5	86.0	100.6
Liquefied Petroleum Gas	103.5	73.7	80.4	89.9	73.5	83.2	92.0	73.2	84.0	92.3
Motor Gasoline[4]	152.6	126.1	139.6	155.8	122.7	139.8	160.9	119.3	139.7	157.6
Residual Fuel	61.5	40.3	53.1	68.7	40.5	54.5	69.5	40.5	56.1	69.8
Residual Fuel (2000 dollars per barrel)	25.83	16.91	22.29	28.86	17.02	22.89	29.21	17.02	23.56	29.32
Average	**130.5**	**104.8**	**118.9**	**134.9**	**103.7**	**120.5**	**138.5**	**101.6**	**120.5**	**136.5**

[1]Includes cogenerators.
[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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 are model results and may differ slightly from official EIA data reports.
Sources: 2000 prices for gasoline, distillate, and jet fuel are based on prices in the preliminary *Petroleum Marketing Annual 2000*, http://www.eia.doe.gov/pub/ oil_gas/petroleum/ data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf. 2000 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2000	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Production										
Dry Gas Production[1]	19.08	23.30	23.48	23.67	25.87	26.32	26.74	27.79	28.48	29.24
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**3.52**	**5.00**	**4.89**	**4.66**	**5.55**	**5.26**	**4.83**	**5.77**	**5.51**	**5.05**
Canada	3.46	4.62	4.51	4.28	5.19	4.90	4.47	5.32	5.06	4.61
Mexico	-0.09	-0.45	-0.45	-0.45	-0.47	-0.47	-0.47	-0.38	-0.38	-0.38
Liquefied Natural Gas	0.16	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
Total Supply	**22.69**	**28.41**	**28.49**	**28.45**	**31.53**	**31.69**	**31.68**	**33.67**	**34.10**	**34.41**
Consumption by Sector										
Residential	5.00	5.57	5.53	5.48	5.76	5.73	5.69	6.02	5.98	5.94
Commercial	3.27	3.95	3.93	3.89	4.20	4.21	4.18	4.51	4.52	4.49
Industrial[3]	8.41	9.24	9.39	9.55	9.64	9.79	9.99	9.82	10.06	10.29
Electric Generators[4]	4.24	6.89	6.85	6.68	8.92	8.91	8.39	10.10	10.30	9.52
Transportation[5]	0.02	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Pipeline Fuel	0.77	0.83	0.84	0.84	0.92	0.93	0.91	0.97	0.99	0.97
Lease and Plant Fuel[6]	1.12	1.49	1.50	1.51	1.64	1.66	1.69	1.77	1.80	1.84
Total	**22.83**	**28.05**	**28.13**	**28.04**	**31.19**	**31.34**	**30.98**	**33.33**	**33.78**	**33.20**
Natural Gas to Liquids	**0.00**	**0.00**	**0.00**	**0.05**	**0.00**	**0.00**	**0.37**	**0.00**	**0.00**	**0.88**
Discrepancy[7]	**-0.13**	**0.35**	**0.36**	**0.36**	**0.34**	**0.35**	**0.33**	**0.34**	**0.32**	**0.34**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C14. Natural Gas Prices, Margins, and Revenue
(2000 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2000	Projections								
		2010			2015			2020		
		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]	3.60	2.70	2.85	3.05	2.97	3.07	3.25	3.07	3.26	3.40
Average Import Price	3.94	2.62	2.91	3.22	2.86	3.13	3.39	3.11	3.40	3.57
Average[2]	**3.66**	**2.68**	**2.86**	**3.08**	**2.95**	**3.08**	**3.27**	**3.08**	**3.28**	**3.42**
Delivered Prices										
Residential	7.85	6.72	6.92	7.16	6.88	7.04	7.25	6.94	7.16	7.33
Commercial	6.40	5.47	5.66	5.90	5.69	5.84	6.05	5.80	6.02	6.17
Industrial[3]	4.43	3.40	3.57	3.78	3.67	3.79	3.97	3.82	4.01	4.14
Electric Generators[4]	4.49	3.23	3.44	3.67	3.56	3.72	3.89	3.73	3.94	4.07
Transportation[5]	8.26	6.86	7.08	7.32	7.11	7.33	7.53	7.18	7.48	7.64
Average[6]	**5.58**	**4.41**	**4.59**	**4.81**	**4.60**	**4.74**	**4.93**	**4.72**	**4.92**	**5.07**
Transmission and Distribution Margins[7]										
Residential	4.19	4.04	4.05	4.08	3.94	3.95	3.98	3.86	3.88	3.91
Commercial	2.74	2.79	2.80	2.81	2.74	2.76	2.77	2.72	2.74	2.75
Industrial[3]	0.78	0.72	0.70	0.70	0.73	0.71	0.70	0.74	0.73	0.71
Electric Generators[4]	0.83	0.54	0.58	0.59	0.62	0.64	0.62	0.65	0.66	0.64
Transportation[5]	4.61	4.17	4.22	4.23	4.17	4.25	4.26	4.09	4.20	4.22
Average[6]	**1.92**	**1.73**	**1.73**	**1.73**	**1.66**	**1.66**	**1.66**	**1.64**	**1.63**	**1.64**
Transmission and Distribution Revenue (billion 2000 dollars)										
Residential	20.96	22.49	22.40	22.34	22.65	22.65	22.66	23.21	23.21	23.19
Commercial	8.98	11.03	11.00	10.95	11.53	11.59	11.59	12.27	12.35	12.32
Industrial[3]	6.55	6.62	6.62	6.68	7.00	6.95	6.96	7.31	7.33	7.34
Electric Generators[4]	3.53	3.75	3.98	3.91	5.50	5.71	5.19	6.60	6.80	6.11
Transportation[5]	0.10	0.37	0.37	0.38	0.49	0.51	0.51	0.55	0.58	0.60
Total	**40.12**	**44.25**	**44.37**	**44.26**	**47.16**	**47.41**	**46.91**	**49.94**	**50.28**	**49.56**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 are model results and may differ slightly from official EIA data reports.

Sources: 2000 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 2000 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). **Other 2000 values and projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C15. Oil and Gas Supply

Production and Supply	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (2000 dollars per barrel)	**27.59**	**17.41**	**22.70**	**29.40**	**17.02**	**23.15**	**29.47**	**17.06**	**23.79**	**29.58**
Production (million barrels per day)[2]										
U.S. Total	**5.82**	**4.75**	**5.08**	**5.49**	**4.92**	**5.56**	**6.10**	**4.94**	**5.63**	**6.43**
Lower 48 Onshore	3.25	2.39	2.64	2.94	2.26	2.64	3.07	2.27	2.70	3.18
Conventional	2.60	1.85	1.91	1.97	1.75	1.82	1.89	1.79	1.87	1.94
Enhanced Oil Recovery	0.65	0.53	0.73	0.97	0.51	0.82	1.18	0.48	0.83	1.24
Lower 48 Offshore	1.61	1.67	1.74	1.83	1.78	2.01	2.11	1.59	1.83	2.14
Alaska	0.97	0.69	0.70	0.72	0.89	0.90	0.92	1.08	1.10	1.12
Lower 48 End of Year Reserves (billion barrels)[2]	**18.29**	**13.05**	**14.23**	**16.09**	**12.63**	**14.63**	**16.82**	**12.03**	**14.45**	**17.10**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2000 dollars per thousand cubic feet)	**3.60**	**2.70**	**2.85**	**3.05**	**2.97**	**3.07**	**3.25**	**3.07**	**3.26**	**3.40**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.08**	**23.30**	**23.48**	**23.67**	**25.87**	**26.32**	**26.74**	**27.79**	**28.48**	**29.24**
Lower 48 Onshore	13.31	16.32	16.45	16.53	19.31	19.40	18.93	20.92	21.13	20.48
Associated-Dissolved[4]	1.79	1.40	1.43	1.46	1.33	1.37	1.41	1.33	1.36	1.40
Non-Associated	11.52	14.91	15.02	15.07	17.98	18.04	17.52	19.58	19.77	19.08
Conventional	6.89	8.14	7.89	7.99	10.10	9.94	9.40	10.73	10.77	10.14
Unconventional	4.63	6.77	7.13	7.08	7.88	8.09	8.12	8.86	8.99	8.94
Lower 48 Offshore	5.34	6.45	6.50	6.55	5.99	6.35	6.86	6.27	6.75	7.23
Associated-Dissolved[4]	1.16	1.21	1.22	1.24	1.22	1.27	1.31	1.20	1.25	1.31
Non-Associated	4.18	5.24	5.28	5.31	4.77	5.08	5.54	5.08	5.50	5.92
Alaska	0.43	0.53	0.53	0.59	0.57	0.57	0.96	0.60	0.60	1.53
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**162.31**	**163.49**	**174.09**	**180.36**	**168.17**	**181.49**	**191.63**	**175.20**	**187.79**	**204.64**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**24.05**	**22.54**	**24.32**	**26.67**	**24.53**	**25.55**	**26.82**	**30.79**	**33.08**	**34.94**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		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	430	432	428	418	417	417	424	401	406	414
Interior	144	155	158	141	140	146	147	137	143	153
West	510	699	698	734	754	762	784	830	848	879
East of the Mississippi	518	534	533	516	517	520	525	504	510	523
West of the Mississippi	566	751	751	777	793	805	830	864	887	924
Total	**1084**	**1285**	**1284**	**1293**	**1311**	**1325**	**1355**	**1368**	**1397**	**1447**
Net Imports										
Imports	13	19	19	19	19	19	19	20	20	20
Exports	58	56	54	57	53	53	53	55	55	55
Total	**-46**	**-37**	**-35**	**-38**	**-34**	**-34**	**-34**	**-35**	**-35**	**-35**
Total Supply[2]	**1038**	**1248**	**1249**	**1255**	**1277**	**1291**	**1321**	**1333**	**1362**	**1412**
Consumption by Sector										
Residential and Commercial	5	5	5	5	6	6	6	6	6	6
Industrial[3]	82	80	81	81	83	83	83	86	86	86
Coke Plants	29	24	24	24	22	22	22	20	20	20
Electric Generators[4]	965	1141	1141	1146	1169	1183	1213	1225	1254	1303
Total	**1081**	**1250**	**1251**	**1257**	**1280**	**1294**	**1324**	**1336**	**1365**	**1415**
Discrepancy and Stock Change[5]	**-43**	**-2**	**-2**	**-2**	**-3**	**-3**	**-3**	**-3**	**-3**	**-3**
Average Minemouth Price										
(2000 dollars per short ton)	16.45	13.96	14.11	13.86	13.27	13.44	13.57	12.67	12.79	12.95
(2000 dollars per million Btu)	0.79	0.68	0.69	0.68	0.65	0.66	0.67	0.63	0.64	0.65
Delivered Prices (2000 dollars per short ton)[6]										
Industrial	31.86	27.74	28.11	28.32	26.77	27.21	27.62	25.73	26.14	26.59
Coke Plants	44.41	41.25	41.86	42.06	40.19	40.71	40.92	38.97	39.22	39.56
Electric Generators										
(2000 dollars per short ton)	24.36	20.70	21.02	21.28	19.86	20.15	20.30	18.74	19.00	19.15
(2000 dollars per million Btu)	1.20	1.04	1.05	1.07	1.00	1.01	1.02	0.95	0.97	0.97
Average	**25.42**	**21.55**	**21.89**	**22.14**	**20.66**	**20.95**	**21.11**	**19.50**	**19.75**	**19.90**
Exports[7]	34.90	35.27	35.84	35.83	34.46	34.96	35.24	33.42	33.67	34.02

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 data based on Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000) and EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	79.29	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90	79.90
Geothermal[2]	2.85	3.50	3.57	3.57	4.35	4.52	4.62	5.15	5.32	5.41
Municipal Solid Waste[3]	2.84	3.71	3.88	3.91	3.92	4.18	4.15	4.23	4.30	4.33
Wood and Other Biomass[4]	1.39	1.73	1.73	1.73	1.78	1.82	1.83	1.97	1.97	2.12
Solar Thermal	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.41	0.41	0.41
Solar Photovoltaic[5]	0.01	0.11	0.11	0.11	0.19	0.19	0.19	0.27	0.27	0.27
Wind	2.42	7.65	7.65	7.72	8.39	8.46	8.76	8.63	9.06	9.42
Total	**89.13**	**96.95**	**97.19**	**97.28**	**98.92**	**99.46**	**99.83**	**100.55**	**101.22**	**101.85**
Generation (billion kilowatthours)										
Conventional Hydropower	272.33	301.14	301.14	301.14	300.55	300.54	300.54	300.00	300.00	300.00
Geothermal[2]	13.52	19.57	20.20	20.16	26.62	28.06	28.84	33.29	34.71	35.47
Municipal Solid Waste	20.15	26.46	27.78	28.00	28.00	30.05	29.77	30.39	30.98	31.16
Wood and Other Biomass[4]	8.37	20.28	20.86	20.10	18.03	18.84	17.51	17.38	15.32	16.34
Dedicated Plants	7.46	9.72	9.72	9.72	10.02	10.32	10.29	11.25	11.25	12.26
Cofiring	0.91	10.56	11.14	10.38	8.01	8.52	7.22	6.13	4.07	4.08
Solar Thermal	0.87	0.96	0.96	0.96	1.05	1.05	1.05	1.12	1.12	1.12
Solar Photovoltaic	0.01	0.26	0.26	0.26	0.46	0.46	0.46	0.68	0.68	0.68
Wind	5.30	19.45	19.45	19.68	21.71	21.95	22.95	22.60	24.07	25.32
Total	**320.54**	**388.13**	**390.65**	**390.29**	**396.42**	**400.95**	**401.12**	**405.46**	**406.87**	**410.09**
Cogenerators[6]										
Net Summer Capability										
Municipal Solid Waste	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Biomass	5.26	6.65	6.64	6.61	7.64	7.62	7.60	8.45	8.43	8.42
Total	**5.77**	**7.16**	**7.15**	**7.12**	**8.15**	**8.13**	**8.11**	**8.96**	**8.94**	**8.93**
Generation (billion kilowatthours)										
Municipal Solid Waste	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
Biomass	29.63	38.16	38.04	37.90	44.18	44.04	43.88	49.13	48.99	48.90
Total	**32.93**	**41.46**	**41.34**	**41.19**	**47.47**	**47.33**	**47.18**	**52.43**	**52.28**	**52.20**
Other End-Use Generators[7]										
Net Summer Capability										
Conventional Hydropower[8]	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic[5]	0.02	0.39	0.39	0.39	0.42	0.42	0.42	0.46	0.46	0.46
Total	**0.99**	**1.36**	**1.36**	**1.36**	**1.40**	**1.40**	**1.40**	**1.44**	**1.44**	**1.44**
Generation (billion kilowatthours)										
Conventional Hydropower[8]	3.98	4.32	4.32	4.32	4.32	4.32	4.32	4.31	4.31	4.31
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.81	0.81	0.81	0.89	0.89	0.89	0.98	0.98	0.98
Total	**4.02**	**5.14**	**5.14**	**5.14**	**5.21**	**5.21**	**5.21**	**5.29**	**5.29**	**5.29**

[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]Does not include off-grid photovoltaics (PV). EIA estimates that another 76 megawatts of remote electricity generation PV applications were in service in 1999, plus an additional 205 megawatts in communications, transportation, and assorted other non-grid-connected applications.
[6]Cogenerators produce electricity and other useful thermal energy.
[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 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2002. Net summer capability 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 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 2000 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 2000 generation: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2000	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Marketed Renewable Energy[2]										
Residential	**0.43**	**0.43**	**0.43**	**0.44**	**0.44**	**0.44**	**0.44**	**0.45**	**0.45**	**0.45**
Wood	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.45	0.45	0.45
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.41**	**2.90**	**2.89**	**2.88**	**3.19**	**3.18**	**3.17**	**3.44**	**3.43**	**3.42**
Conventional Hydroelectric	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	2.21	2.70	2.69	2.68	2.99	2.98	2.97	3.24	3.23	3.22
Transportation	**0.14**	**0.24**	**0.24**	**0.26**	**0.26**	**0.26**	**0.27**	**0.27**	**0.28**	**0.30**
Ethanol used in E85[4]	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Ethanol used in Gasoline Blending	0.14	0.21	0.21	0.23	0.23	0.23	0.24	0.24	0.24	0.26
Electric Generators[5]	**3.55**	**4.41**	**4.46**	**4.45**	**4.65**	**4.74**	**4.75**	**4.89**	**4.94**	**4.99**
Conventional Hydroelectric	2.82	3.11	3.11	3.11	3.11	3.11	3.11	3.10	3.10	3.10
Geothermal	0.28	0.48	0.50	0.50	0.71	0.75	0.78	0.92	0.96	0.98
Municipal Solid Waste[6]	0.28	0.36	0.38	0.38	0.38	0.41	0.40	0.41	0.42	0.42
Biomass	0.11	0.24	0.25	0.24	0.22	0.23	0.21	0.21	0.19	0.20
Dedicated Plants	0.10	0.12	0.12	0.12	0.12	0.12	0.13	0.14	0.14	0.15
Cofiring	0.01	0.13	0.13	0.12	0.10	0.10	0.09	0.07	0.05	0.05
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	0.05	0.20	0.20	0.20	0.22	0.23	0.24	0.23	0.25	0.26
Total Marketed Renewable Energy	**6.60**	**8.06**	**8.10**	**8.10**	**8.62**	**8.70**	**8.72**	**9.13**	**9.17**	**9.23**
Sources of Ethanol										
From Corn	0.14	0.22	0.22	0.24	0.23	0.23	0.24	0.21	0.22	0.24
From Cellulose	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.06	0.06	0.06
Total	**0.14**	**0.24**	**0.24**	**0.26**	**0.26**	**0.26**	**0.27**	**0.27**	**0.28**	**0.30**
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	**0.04**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**	**0.08**	**0.08**	**0.08**
Solar Hot Water Heating	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
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	0.00	0.00	0.00

[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 cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 2000 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 2000: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2000	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Residential										
Petroleum	27.5	25.8	24.6	23.1	25.1	23.3	21.8	24.8	22.6	20.9
Natural Gas	73.2	82.4	81.8	81.1	85.2	84.8	84.2	89.1	88.6	87.9
Coal	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	204.0	240.8	238.3	236.6	254.2	252.0	253.2	269.9	268.7	271.6
Total	**305.9**	**350.4**	**346.0**	**342.1**	**365.8**	**361.4**	**360.6**	**385.1**	**381.1**	**381.7**
Commercial										
Petroleum	14.2	14.6	13.6	12.9	15.3	13.8	13.1	15.8	14.0	13.3
Natural Gas	49.3	58.5	58.2	57.6	62.2	62.3	61.9	66.7	66.8	66.4
Coal	1.8	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	195.6	246.8	243.6	241.7	269.7	266.9	268.2	290.2	288.9	292.5
Total	**260.9**	**321.7**	**317.1**	**314.0**	**349.1**	**344.8**	**345.1**	**374.7**	**371.7**	**374.2**
Industrial[1]										
Petroleum	93.7	109.4	107.2	105.2	115.6	112.9	110.3	121.7	117.8	115.1
Natural Gas[2]	136.1	156.0	158.5	161.0	164.1	166.8	170.0	168.7	172.4	176.8
Coal	65.2	63.2	63.3	63.5	63.8	63.7	63.7	64.7	64.7	64.5
Electricity	183.0	205.2	203.1	202.7	217.7	215.5	217.3	228.6	227.4	230.7
Total	**478.1**	**533.7**	**532.1**	**532.4**	**561.2**	**558.9**	**561.3**	**583.7**	**582.3**	**587.2**
Transportation										
Petroleum[3]	502.5	625.7	621.8	615.9	685.6	680.3	670.3	738.0	730.7	718.6
Natural Gas[4]	11.4	13.6	13.7	13.7	15.3	15.4	15.3	16.4	16.7	16.5
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	3.0	3.9	3.8	3.8	4.4	4.4	4.4	5.2	5.1	5.2
Total[3]	**516.9**	**643.3**	**639.4**	**633.5**	**705.4**	**700.2**	**690.0**	**759.6**	**752.7**	**740.3**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	637.9	775.5	767.2	757.1	841.6	830.3	815.4	900.3	885.0	867.9
Natural Gas	270.0	310.6	312.2	313.4	326.8	329.3	331.4	340.9	344.5	347.6
Coal	68.2	66.3	66.4	66.6	67.0	66.9	66.9	68.0	67.9	67.8
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	585.6	696.7	688.8	684.8	746.1	738.7	743.1	793.9	790.2	800.0
Total[3]	**1561.7**	**1849.1**	**1834.7**	**1822.0**	**1981.5**	**1965.4**	**1957.0**	**2103.2**	**2087.8**	**2083.4**
Electric Generators[6]										
Petroleum	19.9	11.9	4.3	2.2	18.9	5.1	2.8	25.8	5.9	3.2
Natural Gas	61.1	101.0	100.6	98.1	130.9	130.7	123.2	148.3	151.1	139.7
Coal	504.6	583.8	583.9	584.5	596.3	602.9	617.2	619.8	633.2	657.2
Total	**585.6**	**696.7**	**688.8**	**684.8**	**746.1**	**738.7**	**743.1**	**793.9**	**790.2**	**800.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	657.8	787.4	771.5	759.2	860.5	835.4	818.2	926.1	890.9	871.1
Natural Gas	331.2	411.6	412.8	411.5	457.7	460.0	454.6	489.2	495.6	487.3
Coal	572.8	650.1	650.3	651.2	663.3	669.8	684.1	687.8	701.2	724.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1561.7**	**1849.1**	**1834.7**	**1822.0**	**1981.5**	**1965.4**	**1957.0**	**2103.2**	**2087.8**	**2083.4**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.7**	**6.2**	**6.1**	**6.1**	**6.3**	**6.3**	**6.3**	**6.5**	**6.4**	**6.4**

[1]Includes consumption by cogenerators.
[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 1998, international bunker fuels accounted for 25 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 all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2000,* DOE/EIA-0573(2000) (Washington, DC, November 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2000	Projections								
		2010			2015			2020		
		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)	**1.070**	**1.362**	**1.369**	**1.379**	**1.545**	**1.561**	**1.581**	**1.797**	**1.826**	**1.859**
Real Gross Domestic Product	**9224**	**12319**	**12312**	**12303**	**14417**	**14399**	**14372**	**16561**	**16525**	**16496**
Real Consumption	6258	8290	8256	8216	9591	9545	9492	11053	10991	10941
Real Investment	1773	2525	2518	2508	3267	3252	3235	3978	3953	3931
Real Government Spending	1573	1895	1892	1889	2019	2016	2013	2152	2149	2146
Real Exports	1133	1948	1968	1992	2816	2840	2863	4010	4032	4046
Real Imports	1532	2292	2263	2231	3132	3090	3050	4435	4369	4311
Real Disposable Personal Income	**6539**	**8758**	**8742**	**8726**	**10204**	**10202**	**10199**	**11685**	**11698**	**11723**
AA Utility Bond Rate (percent)	**7.91**	**7.16**	**7.37**	**7.63**	**7.31**	**7.66**	**8.06**	**7.55**	**8.07**	**8.62**
Real Yield on Government 10 Year Bonds (percent)	**4.84**	**4.37**	**4.54**	**4.74**	**4.73**	**4.99**	**5.29**	**4.93**	**5.34**	**5.79**
Real Utility Bond Rate (percent)	**6.27**	**4.80**	**4.94**	**5.11**	**4.72**	**4.95**	**5.22**	**4.24**	**4.64**	**5.10**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	8.04	7.11	7.09	7.05	6.53	6.51	6.47	6.04	6.02	5.98
Total Energy	10.77	9.45	9.40	9.36	8.62	8.59	8.57	7.94	7.92	7.90
Consumer Price Index (1982-84=1.00)	**1.72**	**2.26**	**2.27**	**2.30**	**2.60**	**2.64**	**2.68**	**3.08**	**3.15**	**3.21**
Unemployment Rate (percent)	**4.01**	**4.52**	**4.49**	**4.46**	**4.58**	**4.56**	**4.56**	**4.03**	**4.04**	**4.04**
Housing Starts (millions)	**1.82**	**1.94**	**1.93**	**1.92**	**1.91**	**1.90**	**1.88**	**2.03**	**2.01**	**1.99**
Single-Family	1.23	1.34	1.33	1.32	1.33	1.32	1.30	1.38	1.36	1.34
Multifamily	0.34	0.29	0.29	0.30	0.30	0.30	0.30	0.37	0.36	0.36
Mobile Home Shipments	0.25	0.30	0.30	0.30	0.27	0.27	0.27	0.28	0.28	0.28
Commercial Floorspace, Total (billion square feet)	**64.5**	**77.7**	**77.5**	**77.4**	**83.9**	**83.8**	**83.7**	**89.6**	**89.6**	**89.5**
Gross Output (billion 1992 dollars)										
Total Industrial	5062	6589	6584	6581	7542	7535	7517	8467	8447	8428
Nonmanufacturing	1039	1210	1211	1212	1321	1325	1327	1441	1444	1451
Manufacturing	4022	5379	5373	5369	6221	6210	6190	7026	7003	6977
Energy-Intensive Manufacturing	1100	1256	1251	1246	1343	1340	1333	1414	1410	1406
Non-Energy-Intensive Manufacturing	2922	4122	4122	4124	4878	4870	4857	5612	5593	5571
Unit Sales of Light-Duty Vehicles (millions)	**17.36**	**17.37**	**17.34**	**17.34**	**17.90**	**17.81**	**17.64**	**18.40**	**18.24**	**18.09**
Population (millions)										
Population with Armed Forces Overseas)	275.7	300.2	300.2	300.2	312.7	312.7	312.7	325.3	325.3	325.3
Population (aged 16 and over)	213.1	236.6	236.6	236.6	246.7	246.7	246.7	256.5	256.5	256.5
Employment, Non-Agriculture	130.1	145.5	145.2	144.8	150.6	150.2	149.8	154.9	154.5	154.3
Employment, Manufacturing	17.5	16.3	16.3	16.2	15.6	15.5	15.5	15.3	15.3	15.2
Labor Force	140.9	156.9	156.9	156.9	161.4	161.4	161.4	165.3	165.3	165.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2000: DRI-WEFA, Simulation CTL0901. **Projections:** Energy Information Administration, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		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 (2000 dollars per barrel)[1]	**27.72**	**17.64**	**23.36**	**30.01**	**17.64**	**24.00**	**30.44**	**17.64**	**24.68**	**30.58**
Production[2]										
OECD										
U.S. (50 states)	9.03	8.32	8.87	9.32	8.79	9.71	10.27	9.03	9.95	10.85
Canada	2.74	3.14	3.20	3.43	3.29	3.37	3.67	3.45	3.55	3.89
Mexico	3.54	4.09	4.24	4.78	4.22	4.39	5.04	4.25	4.44	5.13
OECD Europe[3]	7.06	7.07	7.20	7.64	6.78	6.92	7.42	6.50	6.65	7.15
Other OECD	0.98	0.88	0.92	1.07	0.85	0.90	1.10	0.83	0.88	1.11
Total OECD	**23.35**	**23.50**	**24.43**	**26.25**	**23.92**	**25.29**	**27.50**	**24.05**	**25.46**	**28.13**
Developing Countries										
Other South & Central America	3.78	4.66	4.82	5.44	5.36	5.58	6.41	6.20	6.48	7.49
Pacific Rim	2.31	2.54	2.63	2.96	2.49	2.59	2.97	2.44	2.55	2.94
OPEC	30.93	46.27	40.78	32.16	55.94	48.32	37.43	66.89	57.46	44.87
Other Developing Countries	4.96	6.04	6.25	7.05	6.95	7.23	8.31	8.02	8.38	9.68
Total Developing Countries	**41.98**	**59.50**	**54.48**	**47.61**	**70.73**	**63.73**	**55.12**	**83.54**	**74.86**	**64.98**
Eurasia										
Former Soviet Union	7.83	11.61	12.02	13.56	13.18	13.72	15.76	14.25	14.89	17.21
Eastern Europe	0.24	0.29	0.30	0.34	0.31	0.33	0.38	0.34	0.36	0.41
China	3.26	2.97	3.07	3.47	2.93	3.05	3.50	2.89	3.02	3.49
Total Eurasia	**11.33**	**14.87**	**15.39**	**17.36**	**16.42**	**17.10**	**19.64**	**17.48**	**18.26**	**21.11**
Total Production	**76.66**	**97.86**	**94.31**	**91.23**	**111.08**	**106.12**	**102.26**	**125.07**	**118.59**	**114.22**
Consumption										
OECD										
U.S. (50 states)	19.74	23.60	23.21	22.87	25.67	25.07	24.59	27.52	26.66	26.12
U.S. Territories	0.35	0.47	0.43	0.39	0.51	0.45	0.41	0.54	0.48	0.44
Canada	1.96	2.28	2.09	1.92	2.36	2.12	1.94	2.40	2.14	1.96
Mexico	2.03	2.94	2.75	2.60	3.61	3.33	3.10	4.52	4.11	3.82
Japan	5.54	6.26	5.62	5.09	6.53	5.64	4.97	6.73	5.62	4.89
Australia and New Zealand	1.00	1.13	1.09	1.05	1.23	1.18	1.14	1.34	1.28	1.24
OECD Europe[3]	14.53	16.47	15.80	15.20	16.91	16.12	15.50	17.34	16.44	15.84
Total OECD	**45.16**	**53.15**	**50.98**	**49.12**	**56.83**	**53.91**	**51.64**	**60.39**	**56.72**	**54.30**
Developing Countries										
Other South and Central America	4.29	6.01	5.86	5.73	7.31	7.11	6.95	8.89	8.62	8.44
Pacific Rim	8.20	12.56	12.20	11.89	14.95	14.46	14.08	17.38	16.76	16.34
OPEC	5.81	7.55	7.55	7.55	8.72	8.72	8.72	10.08	10.08	10.08
Other Developing Countries	2.85	4.46	4.20	3.97	5.90	5.41	5.03	7.93	7.12	6.54
Total Developing Countries	**21.15**	**30.58**	**29.81**	**29.14**	**36.86**	**35.70**	**34.77**	**44.28**	**42.58**	**41.40**
Eurasia										
Former Soviet Union	3.66	5.75	5.56	5.39	7.05	6.79	6.58	8.02	7.69	7.47
Eastern Europe	1.54	1.67	1.63	1.60	1.72	1.68	1.65	1.74	1.69	1.66
China	4.53	7.01	6.62	6.28	8.92	8.35	7.92	10.95	10.18	9.69
Total Eurasia	**9.73**	**14.42**	**13.81**	**13.26**	**17.69**	**16.82**	**16.14**	**20.70**	**19.57**	**18.82**

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2000	Projections								
		2010			2015			2020		
		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 Consumption	**75.99**	**98.16**	**94.61**	**91.53**	**111.38**	**106.42**	**102.56**	**125.37**	**118.89**	**114.52**
Non-OPEC Production	45.73	51.59	53.52	59.07	55.14	57.80	64.84	58.18	61.12	69.36
Net Eurasia Exports	1.61	0.44	1.59	4.10	-1.26	0.28	3.50	-3.22	-1.30	2.29
OPEC Market Share	0.40	0.47	0.43	0.35	0.50	0.46	0.37	0.53	0.48	0.39

[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, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf. **Projections:** EIA, AEO2002 National Energy Modeling System runs LW2002.D102001B, AEO2002.D102001B, HW2002.D102001B.

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 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	5.87	5.82	5.38	5.08	5.56	5.63	-0.2%
Natural Gas Plant Liquids	1.24	1.28	1.43	1.59	1.77	1.90	2.0%
Dry Natural Gas	9.07	9.23	10.06	11.39	12.77	13.78	2.0%
Coal	10.94	10.64	11.79	12.39	12.71	13.24	1.1%
Nuclear Power	3.66	3.78	3.83	3.72	3.57	3.53	-0.3%
Renewable Energy[1]	3.16	3.04	3.48	3.73	4.00	4.21	1.6%
Other[2]	0.78	0.52	0.32	0.40	0.49	0.44	-0.8%
Total	**34.72**	**34.32**	**36.27**	**38.31**	**40.86**	**42.73**	**1.1%**
Imports							
Crude Oil[3]	8.73	9.07	10.42	11.22	11.07	11.26	1.1%
Petroleum Products[4]	1.98	2.24	2.68	3.70	4.87	6.00	5.1%
Natural Gas	1.73	1.81	2.37	2.66	2.85	2.92	2.4%
Other Imports[5]	0.27	0.36	0.50	0.45	0.51	0.51	1.8%
Total	**12.71**	**13.48**	**15.98**	**18.03**	**19.30**	**20.69**	**2.2%**
Exports							
Petroleum[6]	0.92	1.02	0.80	0.90	0.95	1.00	-0.1%
Natural Gas	0.08	0.12	0.19	0.30	0.31	0.27	4.2%
Coal	0.72	0.72	0.67	0.64	0.63	0.65	-0.5%
Total	**1.72**	**1.85**	**1.66**	**1.84**	**1.90**	**1.91**	**0.2%**
Discrepancy[7]	**0.14**	**0.80**	**0.21**	**0.06**	**0.07**	**0.05**	**N/A**
Consumption							
Petroleum Products[8]	18.07	18.20	19.55	21.35	23.08	24.49	1.5%
Natural Gas	10.66	11.04	12.36	13.63	15.18	16.32	2.0%
Coal	10.16	10.49	11.32	11.95	12.29	12.81	1.0%
Nuclear Power	3.66	3.78	3.83	3.72	3.57	3.53	-0.3%
Renewable Energy[1]	3.17	3.05	3.48	3.73	4.01	4.21	1.6%
Other[9]	0.13	0.18	0.26	0.18	0.22	0.21	0.7%
Total	**45.84**	**46.74**	**50.80**	**54.56**	**58.34**	**61.57**	**1.4%**
Net Imports - Petroleum	**10.01**	**10.49**	**12.57**	**14.31**	**15.27**	**16.51**	**2.3%**
Prices (2000 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.60	27.72	22.73	23.36	24.00	24.68	-0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.27	3.60	2.66	2.85	3.07	3.26	-0.5%
Coal Minemouth Price (dollars per ton)	17.01	16.45	14.99	14.11	13.44	12.79	-1.3%
Average Electricity Price (cents per kilowatthour)	6.7	6.9	6.4	6.3	6.3	6.5	-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, 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 and heat loss when natural gas 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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 coal minemouth prices: EIA, *Coal Industry Annual 1999*, DOE/EIA-0584(99) (Washington, DC, June 2001). Other 1999 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 2000 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table D2. Total Energy Supply and Disposition Summary
(Million Tons of Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2000-2020 (percent)
	1999	2000	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	313.31	310.63	286.77	271.18	296.44	300.31	-0.2%
Natural Gas Plant Liquids	66.09	68.27	76.04	84.99	94.29	101.62	2.0%
Dry Natural Gas	483.82	493.70	536.50	607.74	681.24	737.05	2.0%
Coal	583.38	569.02	628.74	661.12	678.15	708.25	1.1%
Nuclear Power	195.10	202.47	204.18	198.28	190.28	188.83	-0.3%
Renewable Energy[1]	168.60	162.82	185.70	198.78	213.45	225.09	1.6%
Other[2]	41.80	27.74	17.20	21.43	26.15	23.53	-0.8%
Total	**1852.11**	**1834.64**	**1935.13**	**2043.53**	**2180.00**	**2284.68**	**1.1%**
Imports							
Crude Oil[3]	477.67	496.22	570.22	613.88	605.69	616.18	1.1%
Petroleum Products[4]	105.66	119.31	143.19	197.38	259.93	319.84	5.1%
Natural Gas	92.27	97.02	126.34	142.12	152.19	156.35	2.4%
Other Imports[5]	14.19	19.18	26.91	24.02	26.98	27.46	1.8%
Total	**689.80**	**731.73**	**866.66**	**977.40**	**1044.79**	**1119.83**	**2.2%**
Exports							
Petroleum[6]	49.27	54.18	42.93	48.05	50.86	53.09	-0.1%
Natural Gas	4.14	6.23	10.21	15.90	16.55	14.21	4.2%
Coal	38.43	38.51	35.64	34.31	33.76	34.79	-0.5%
Total	**91.84**	**98.92**	**88.78**	**98.26**	**101.17**	**102.08**	**0.2%**
Discrepancy[7]	**3.19**	**-34.59**	**1.13**	**9.22**	**7.95**	**4.99**	**N/A**
Consumption							
Petroleum Products[8]	963.84	973.35	1043.18	1139.08	1231.09	1310.13	1.5%
Natural Gas	568.71	590.40	659.27	727.01	809.90	872.77	2.0%
Coal	543.30	562.86	605.66	640.42	659.15	689.23	1.0%
Nuclear Power	195.10	202.47	204.18	198.28	190.28	188.83	-0.3%
Renewable Energy[1]	168.89	163.26	185.83	198.96	213.66	225.32	1.6%
Other[9]	7.03	9.70	13.77	9.69	11.59	11.15	0.7%
Total	**2446.87**	**2502.05**	**2711.88**	**2913.46**	**3115.67**	**3297.44**	**1.4%**
Net Imports - Petroleum	**534.06**	**561.35**	**670.49**	**763.21**	**814.76**	**882.94**	**2.3%**
Prices (2000 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.60	27.72	22.73	23.36	24.00	24.68	-0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.27	3.60	2.66	2.85	3.07	3.26	-0.5%
Coal Minemouth Price (dollars per ton)	17.01	16.45	14.99	14.11	13.44	12.79	-1.3%
Average Electricity Price (cents per kilowatthour)	6.7	6.9	6.4	6.3	6.3	6.5	-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, 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, and net storage withdrawals.
[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 1999 and 2000 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000). 1999 coal minemouth prices: EIA, *Coal Industry Annual 1999*, DOE/EIA-0584(99) (Washington, DC, June 2001). Other 1999 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001). 2000 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table E1. 2000 Average Household Expenditures for Energy by Household Characteristic
(2000 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2868.07**	**1375.72**	**909.88**	**382.52**	**83.33**	**1492.35**
Households by Income Quintile						
1st	1676.73	1026.23	648.96	304.08	73.19	650.49
2nd	2415.44	1174.88	799.53	318.87	56.47	1240.56
3rd	2815.15	1321.09	873.32	359.82	87.96	1494.07
4th	3171.84	1434.31	950.89	410.23	73.18	1737.53
5th	3858.15	1759.59	1166.44	481.23	111.92	2098.56
Households by Census Division						
New England	3281.76	1710.45	871.94	308.93	529.59	1571.30
Middle Atlantic	2891.79	1663.08	848.77	518.54	295.76	1228.72
South Atlantic	3059.00	1372.28	731.19	614.32	26.77	1686.72
East North Central	3208.73	1341.87	807.21	496.52	38.14	1866.86
East South Central	2785.28	1369.39	1120.76	216.01	32.62	1415.89
West North Central	2873.63	1444.02	1220.15	221.41	2.46	1429.62
West South Central	2851.34	1457.98	1130.85	327.13	0.00	1393.36
Mountain	2623.04	1086.61	737.24	342.92	6.45	1536.43
Pacific	2555.28	1061.17	743.54	307.77	9.86	1494.11

Source: Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table E2. 2005 Average Household Expenditures for Energy by Household Characteristic
(2000 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2732.50**	**1321.76**	**902.43**	**352.45**	**66.88**	**1410.75**
Households by Income Quintile						
1st	1606.59	984.83	646.57	279.45	58.81	621.76
2nd	2311.28	1132.24	793.53	293.31	45.40	1179.04
3rd	2681.81	1266.62	864.06	331.92	70.65	1415.18
4th	3016.59	1379.22	942.57	378.11	58.54	1637.36
5th	3655.33	1686.47	1153.77	443.04	89.65	1968.87
Households by Census Division						
New England	3114.07	1626.82	886.77	294.16	445.88	1487.25
Middle Atlantic	2761.91	1561.42	828.54	488.25	244.63	1200.49
South Atlantic	2844.65	1309.95	726.72	561.65	21.58	1534.70
East North Central	3003.30	1262.04	773.54	456.87	31.63	1741.26
East South Central	2621.29	1309.20	1098.29	186.94	23.97	1312.09
West North Central	2716.69	1370.93	1159.00	210.04	1.89	1345.76
West South Central	2726.05	1390.39	1087.38	303.00	0.00	1335.66
Mountain	2605.05	1142.82	797.78	339.81	5.23	1462.23
Pacific	2543.89	1073.09	774.26	290.60	8.23	1470.80

Source: Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table E3. 2010 Average Household Expenditures for Energy by Household Characteristic
(2000 Dollars)

Household Characteristics	Fuels: Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2813.93**	**1314.67**	**914.67**	**339.10**	**60.90**	**1499.26**
Households by Income Quintile						
1st	1647.33	979.60	657.13	268.94	53.53	667.73
2nd	2384.65	1126.73	803.12	282.30	41.32	1257.92
3rd	2763.64	1258.32	874.44	319.57	64.31	1505.33
4th	3107.60	1371.69	955.36	363.02	53.31	1735.91
5th	3756.32	1675.73	1168.21	425.89	81.63	2080.60
Households by Census Division						
New England	3165.32	1589.96	880.16	284.85	424.95	1575.36
Middle Atlantic	2812.66	1541.37	842.84	470.63	227.89	1271.29
South Atlantic	2917.99	1307.00	747.53	539.52	19.95	1610.99
East North Central	3117.39	1275.24	804.91	441.02	29.31	1842.16
East South Central	2690.18	1305.29	1100.51	183.61	21.16	1384.88
West North Central	2773.18	1359.09	1149.84	207.57	1.67	1414.09
West South Central	2797.11	1373.91	1080.49	293.42	0.00	1423.20
Mountain	2737.18	1152.05	820.30	327.31	4.45	1585.12
Pacific	2678.52	1081.74	792.22	281.84	7.67	1596.78

Source: Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table E4. 2015 Average Household Expenditures for Energy by Household Characteristic
(2000 Dollars)

Household Characteristics	Fuels: Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2874.65**	**1329.36**	**929.80**	**341.06**	**58.51**	**1545.28**
Households by Income Quintile						
1st	1684.39	989.26	667.27	270.64	51.35	695.13
2nd	2439.58	1136.88	812.96	284.19	39.74	1302.69
3rd	2823.89	1270.92	887.40	321.74	61.79	1552.97
4th	3169.49	1385.02	969.39	364.43	51.21	1784.47
5th	3829.12	1696.79	1190.73	427.70	78.36	2132.34
Households by Census Division						
New England	3251.56	1632.16	921.18	286.08	424.90	1619.40
Middle Atlantic	2873.20	1574.56	880.21	471.43	222.92	1298.64
South Atlantic	2970.19	1337.47	773.65	544.18	19.64	1632.71
East North Central	3162.14	1280.87	807.52	444.39	28.95	1881.27
East South Central	2732.72	1310.36	1103.51	187.09	19.76	1422.37
West North Central	2789.40	1353.80	1139.32	212.87	1.60	1435.61
West South Central	2883.14	1413.14	1119.08	294.06	0.00	1470.00
Mountain	2845.18	1177.93	837.99	335.87	4.07	1667.25
Pacific	2759.17	1067.33	773.30	286.41	7.62	1691.84

Source: Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Table E5. 2020 Average Household Expenditures for Energy by Household Characteristic
(2000 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2930.11**	**1367.43**	**967.41**	**345.26**	**54.75**	**1562.68**
Households by Income Quintile						
1st	1723.71	1015.70	693.67	274.29	47.74	708.01
2nd	2491.51	1168.84	843.58	288.04	37.22	1322.67
3rd	2878.44	1305.34	921.35	326.18	57.81	1573.10
4th	3222.96	1422.59	1006.55	368.11	47.93	1800.37
5th	3894.09	1747.77	1242.07	432.25	73.44	2146.32
Households by Census Division						
New England	3301.63	1664.18	958.96	292.23	413.00	1637.45
Middle Atlantic	2920.27	1613.05	924.75	475.97	212.32	1307.22
South Atlantic	3012.30	1382.95	812.44	551.82	18.69	1629.35
East North Central	3205.47	1315.78	837.05	451.16	27.57	1889.68
East South Central	2786.95	1345.47	1135.12	192.36	18.00	1441.47
West North Central	2832.07	1391.64	1169.17	221.00	1.47	1440.43
West South Central	2992.02	1498.35	1199.48	298.87	0.00	1493.66
Mountain	2925.02	1200.13	851.92	344.65	3.56	1724.89
Pacific	2805.66	1087.14	791.11	288.60	7.43	1718.53

Source: Energy Information Administration, AEO2002 National Energy Modeling System run AEO2002.D102001B.

Results from Side Cases

Table F1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2000	2005				2010			
		2002 Technology	Reference Case	High Technology	Best Available Technology	2002 Technology	Reference Case	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.83	0.85	0.85	0.84	0.83	0.79	0.79	0.78	0.73
Kerosene	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07
Liquefied Petroleum Gas	0.47	0.44	0.44	0.44	0.43	0.45	0.45	0.44	0.41
Petroleum Subtotal	1.38	1.38	1.37	1.36	1.33	1.32	1.30	1.29	1.21
Natural Gas	5.14	5.54	5.53	5.48	5.21	5.71	5.68	5.53	4.82
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy	0.43	0.43	0.43	0.43	0.42	0.44	0.43	0.43	0.42
Electricity	4.07	4.63	4.62	4.59	4.44	4.95	4.92	4.84	4.45
Delivered Energy	**11.06**	**12.03**	**11.99**	**11.91**	**11.44**	**12.47**	**12.40**	**12.14**	**10.95**
Electricity Related Losses	8.79	9.74	9.72	9.66	9.34	9.89	9.85	9.69	8.90
Total	**19.85**	**21.77**	**21.71**	**21.57**	**20.78**	**22.37**	**22.24**	**21.83**	**19.85**
Delivered Energy Consumption per Household (million Btu per household)	**105.2**	**109.0**	**108.6**	**107.9**	**103.7**	**107.5**	**106.9**	**104.7**	**94.4**
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.04**	**0.05**	**0.05**	**0.06**	**0.07**	**0.06**	**0.06**	**0.10**	**0.18**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.38	0.42	0.42	0.42	0.41	0.43	0.42	0.42	0.42
Residual Fuel	0.14	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09
Motor Gasoline	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.65	0.67	0.67	0.67	0.67	0.70	0.69	0.69	0.69
Natural Gas	3.36	3.78	3.77	3.77	3.71	4.05	4.04	4.03	3.90
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.90	4.46	4.46	4.44	4.20	5.07	5.03	4.94	4.42
Delivered Energy	**8.07**	**9.06**	**9.05**	**9.02**	**8.72**	**9.97**	**9.91**	**9.80**	**9.15**
Electricity Related Losses	8.42	9.39	9.38	9.33	8.83	10.15	10.06	9.88	8.85
Total	**16.49**	**18.45**	**18.42**	**18.35**	**17.56**	**20.12**	**19.98**	**19.68**	**18.00**
Delivered Energy Consumption per Square Foot (thousand Btu per square foot)	**125.1**	**126.4**	**126.2**	**125.9**	**121.7**	**128.6**	**127.8**	**126.4**	**118.0**
Net Summer Generation Capability (megawatts)									
Natural Gas	510	564	578	581	588	627	770	812	908
Solar Photovoltaic	15	89	89	89	89	258	258	258	258
Generation (billion kilowatthours)									
Natural Gas	3.63	4.01	4.11	4.13	4.19	4.46	5.48	5.79	6.46
Solar Photovoltaic	0.04	0.19	0.19	0.19	0.19	0.54	0.54	0.54	0.54
Non-Marketed Renewables Consumption (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 2000 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, AEO2002 National Energy Modeling System, runs BLDFRZN.D102201A, AEO2002.D102001B, BLDHIGH.D102201A, BLDBEST.D102301A

2015				2020				Annual Growth 2000-2020			
2002 Technology	Reference Case	High Technology	Best Available Technology	2002 Technology	Reference Case	High Technology	Best Available Technology	2002 Technology	Reference Case	High Technology	Best Available Technology
0.77	0.75	0.73	0.67	0.75	0.73	0.70	0.63	-0.5%	-0.6%	-0.8%	-1.3%
0.07	0.07	0.07	0.06	0.07	0.07	0.06	0.06	-1.2%	-1.5%	-1.7%	-2.0%
0.44	0.42	0.41	0.36	0.43	0.41	0.39	0.33	-0.5%	-0.7%	-0.8%	-1.7%
1.27	1.24	1.21	1.10	1.25	1.20	1.16	1.02	-0.5%	-0.7%	-0.9%	-1.5%
5.94	5.89	5.65	4.52	6.23	6.15	5.81	4.37	1.0%	0.9%	0.6%	-0.8%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.7%	0.6%	0.4%	0.3%
0.45	0.44	0.43	0.41	0.46	0.45	0.43	0.41	0.4%	0.2%	0.1%	-0.2%
5.37	5.30	5.15	4.56	5.78	5.70	5.50	4.81	1.8%	1.7%	1.5%	0.8%
13.09	**12.92**	**12.48**	**10.64**	**13.77**	**13.55**	**12.96**	**10.66**	**1.1%**	**1.0%**	**0.8%**	**-0.2%**
10.38	10.25	9.95	8.81	10.87	10.72	10.35	9.05	1.1%	1.0%	0.8%	0.1%
23.47	**23.17**	**22.43**	**19.45**	**24.64**	**24.27**	**23.30**	**19.71**	**1.1%**	**1.0%**	**0.8%**	**-0.0%**
107.7	**106.4**	**102.8**	**87.6**	**108.3**	**106.6**	**101.9**	**83.8**	**0.1%**	**0.1%**	**-0.2%**	**-1.1%**
0.06	**0.07**	**0.14**	**0.25**	**0.07**	**0.08**	**0.19**	**0.32**	**2.5%**	**3.2%**	**7.8%**	**10.7%**
0.43	0.42	0.41	0.41	0.43	0.42	0.41	0.41	0.7%	0.5%	0.5%	0.4%
0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-0.1%	-0.1%	-0.1%	-0.1%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	1.2%	1.2%	1.2%	1.2%
0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.9%	0.9%	0.9%	0.9%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%	-0.5%	-0.5%	-0.5%
0.71	0.70	0.70	0.69	0.72	0.71	0.71	0.70	0.5%	0.4%	0.4%	0.4%
4.32	4.33	4.33	4.17	4.58	4.64	4.68	4.52	1.6%	1.6%	1.7%	1.5%
0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.7%	0.7%	0.7%	0.7%
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.0%	0.0%	0.0%	0.0%
5.74	5.62	5.43	4.71	6.39	6.13	5.84	5.00	2.5%	2.3%	2.0%	1.2%
10.92	**10.80**	**10.60**	**9.72**	**11.85**	**11.64**	**11.39**	**10.38**	**1.9%**	**1.9%**	**1.7%**	**1.3%**
11.08	10.85	10.49	9.10	12.01	11.53	10.99	9.40	1.8%	1.6%	1.3%	0.6%
22.01	**21.65**	**21.09**	**18.82**	**23.86**	**23.18**	**22.38**	**19.78**	**1.9%**	**1.7%**	**1.5%**	**0.9%**
130.4	**128.9**	**126.6**	**116.1**	**132.3**	**130.0**	**127.2**	**115.9**	**0.3%**	**0.2%**	**0.1%**	**-0.4%**
728	1464	1947	2459	853	3047	4559	5828	2.6%	9.3%	11.6%	13.0%
283	283	283	288	309	311	315	368	16.5%	16.5%	20.7%	17.5%
5.17	10.48	13.97	17.67	6.07	21.91	32.88	42.05	2.6%	9.4%	11.6%	13.0%
0.59	0.59	0.59	0.61	0.65	0.65	0.66	0.78	16.7%	16.7%	16.8%	17.8%
0.03	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**1.4%**	**1.2%**	**1.0%**	**1.1%**

Table F2. Key Results for Industrial Sector Technology Cases

Consumption	2000	2010			2015			2020		
		2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.11	1.24	1.22	1.21	1.33	1.29	1.28	1.43	1.38	1.35
Liquefied Petroleum Gas	2.36	2.70	2.66	2.64	2.90	2.85	2.82	3.07	3.00	2.96
Petrochemical Feedstocks	1.32	1.47	1.45	1.45	1.57	1.54	1.53	1.62	1.59	1.57
Residual Fuel	0.27	0.25	0.23	0.22	0.28	0.26	0.23	0.31	0.27	0.25
Motor Gasoline	0.22	0.24	0.24	0.24	0.26	0.26	0.25	0.28	0.27	0.27
Other Petroleum	3.96	4.82	4.77	4.75	5.07	4.99	4.96	5.28	5.17	5.12
Petroleum Subtotal	9.23	10.72	10.57	10.51	11.42	11.19	11.07	11.99	11.69	11.52
Natural Gas	9.79	11.51	11.19	10.99	12.25	11.77	11.47	12.78	12.19	11.76
Metallurgical Coal[1]	0.84	0.81	0.75	0.66	0.81	0.72	0.59	0.80	0.70	0.53
Steam Coal	1.69	1.86	1.74	1.69	1.97	1.79	1.73	2.08	1.85	1.75
Coal Subtotal	2.53	2.67	2.50	2.35	2.78	2.51	2.32	2.89	2.55	2.28
Renewable Energy	2.41	2.85	2.89	3.09	3.11	3.18	3.54	3.32	3.43	3.96
Electricity	3.65	4.34	4.20	4.02	4.76	4.53	4.25	5.14	4.83	4.43
Delivered Energy	**27.62**	**32.09**	**31.35**	**30.97**	**34.32**	**33.19**	**32.64**	**36.11**	**34.69**	**33.96**
Electricity Related Losses	7.89	8.69	8.39	8.05	9.21	8.76	8.21	9.66	9.08	8.33
Total	**35.50**	**40.78**	**39.74**	**39.02**	**43.52**	**41.96**	**40.86**	**45.78**	**43.76**	**42.29**
Delivered Energy Use per Dollar of Output (thousand Btu per 1992 dollar)	**5.46**	**4.87**	**4.76**	**4.70**	**4.55**	**4.41**	**4.33**	**4.28**	**4.11**	**4.02**
Onsite Industrial Cogeneration										
Capacity (gigawatts)	21.40	27.21	27.84	31.42	30.39	31.28	36.87	33.61	34.69	42.23
Generation (billion kilowatthours)	116.30	157.80	161.49	186.39	180.61	185.60	224.22	203.92	209.76	261.36

[1]Includes net coal coke imports.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 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, AEO2002 National Energy Modeling System runs INDFRZN.D102201A, AEO2002.D102001B, INDHIGH.D102501A.

Table F3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2000	2010			2015			2020		
		2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	5.42	7.38	7.27	7.15	8.43	8.09	7.82	9.43	8.72	8.29
Jet Fuel	3.58	4.50	4.46	4.41	5.24	5.12	4.94	6.07	5.82	5.44
Motor Gasoline	16.05	19.68	19.32	18.32	21.66	20.86	19.03	23.47	22.12	19.52
Residual Fuel	1.14	1.08	1.08	1.07	1.10	1.09	1.08	1.11	1.10	1.09
Liquefied Petroleum Gas	0.02	0.04	0.04	0.03	0.04	0.04	0.04	0.05	0.05	0.04
Other Petroleum	0.22	0.26	0.26	0.26	0.28	0.28	0.28	0.29	0.29	0.29
Petroleum Subtotal	26.42	32.94	32.43	31.25	36.75	35.48	33.20	40.43	38.11	34.68
Pipeline Fuel Natural Gas	0.79	0.86	0.86	0.86	0.95	0.95	0.95	1.02	1.02	1.02
Compressed Natural Gas	0.02	0.09	0.09	0.09	0.13	0.12	0.12	0.16	0.14	0.14
Renewables (E85)	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.04
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.08	0.08	0.08	0.09	0.09	0.10	0.11	0.11	0.12
Delivered Energy	**27.32**	**34.01**	**33.50**	**32.32**	**37.97**	**36.69**	**34.40**	**41.77**	**39.43**	**35.99**
Electricity Related Losses	0.13	0.16	0.16	0.17	0.17	0.18	0.19	0.20	0.21	0.22
Total	**27.45**	**34.17**	**33.66**	**32.49**	**38.14**	**36.87**	**34.59**	**41.98**	**39.64**	**36.21**
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[1]	24.5	24.6	25.7	29.3	24.6	26.6	31.2	24.6	27.2	32.8
New Car (miles per gallon)[1]	28.6	28.9	30.2	32.7	29.0	31.0	35.2	29.0	31.7	37.2
New Light Truck (miles per gallon)[1]	21.1	21.2	22.3	26.5	21.3	23.3	28.0	21.4	23.8	29.3
Light-Duty Fleet (miles per gallon)[2]	19.8	19.7	20.1	21.2	19.7	20.5	22.6	19.7	21.0	24.0
New Commercial Light Truck (MPG)[3]	14.2	14.1	14.9	17.7	14.1	15.5	18.8	14.1	15.9	19.7
Stock Commercial Light Truck (MPG)[3]	13.6	14.1	14.4	15.8	14.1	14.9	17.2	14.1	15.4	18.4
Aircraft Efficiency (seat miles per gallon)	52.1	55.3	55.9	56.6	56.6	58.1	60.4	57.5	60.3	65.1
Freight Truck Efficiency (miles per gallon)	5.9	6.0	6.0	6.1	6.0	6.1	6.3	6.0	6.3	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	2.9	3.1	3.3	2.9	3.3	3.5	2.9	3.4	3.8
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.3	2.4	2.4	2.3	2.4	2.5
Light-Duty Vehicles Less Than 8500 Pounds (vehicle miles traveled)	**2340**	**2979**	**2981**	**2988**	**3313**	**3318**	**3331**	**3622**	**3631**	**3648**

[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 2000 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, AEO2002 National Energy Modeling System runs FROZEN.D102401C, AEO2002.D102001B, HIGHTECH.D102401A

Table F4. Key Results for Integrated Technology Cases

Consumption and Emissions	2000	2010			2015			2020		
		2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology	2002 Technology	Reference Case	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	19.8	22.3	22.2	21.9	23.5	23.2	22.6	24.7	24.3	23.3
Commercial	16.5	20.1	20.0	19.8	22.0	21.6	21.2	24.0	23.2	22.3
Industrial	35.5	40.8	39.7	38.8	43.7	42.0	40.5	46.1	43.8	41.6
Transportation	27.4	34.2	33.7	32.5	38.2	36.9	34.6	42.1	39.6	36.3
Total	**99.3**	**117.4**	**115.6**	**113.0**	**127.4**	**123.6**	**118.9**	**136.9**	**130.9**	**123.5**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	38.6	46.0	45.2	43.8	50.6	48.9	46.3	55.0	52.0	48.1
Natural Gas	23.4	29.4	28.9	27.9	32.8	32.1	29.9	34.6	34.6	31.6
Coal	22.3	25.8	25.4	24.9	27.5	26.2	25.9	30.4	27.4	26.5
Nuclear Power	8.0	7.9	7.9	7.9	7.6	7.6	7.4	7.5	7.5	7.1
Renewable Energy	6.5	7.9	7.9	8.2	8.4	8.5	9.2	9.0	8.9	9.9
Other	0.4	0.4	0.4	0.3	0.5	0.5	0.3	0.5	0.4	0.3
Total	**99.3**	**117.4**	**115.6**	**113.0**	**127.4**	**123.6**	**118.9**	**136.9**	**130.9**	**123.5**
Energy Intensity (thousand Btu per 1996 dollar of GDP)	**10.8**	**9.5**	**9.4**	**9.2**	**8.8**	**8.6**	**8.3**	**8.3**	**7.9**	**7.5**
Carbon Dioxide Emissions by Sector (million metric tons carbon equivalent)										
Residential	305.9	347.3	346.0	339.8	369.4	361.4	352.7	396.7	381.1	365.5
Commercial	260.9	319.2	317.1	312.5	354.6	344.8	338.2	394.7	371.7	357.6
Industrial	478.1	551.6	532.1	512.8	591.6	558.9	529.8	630.2	582.3	538.0
Transportation	516.9	649.7	639.4	617.2	726.0	700.2	657.4	799.2	752.7	688.5
Total	**1,561.7**	**1,867.8**	**1,834.7**	**1,782.3**	**2,041.6**	**1,965.4**	**1,878.1**	**2,220.8**	**2,087.8**	**1,949.6**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons carbon equivalent)										
Petroleum	637.9	780.0	767.2	742.0	860.9	830.3	784.0	938.2	885.0	814.8
Natural Gas	270.0	316.2	312.2	307.8	334.7	329.3	321.0	351.0	344.5	334.6
Coal	68.2	71.2	66.4	62.5	74.1	66.9	61.5	76.8	67.9	60.3
Other	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	585.6	700.4	688.8	669.9	771.8	738.7	711.5	854.6	790.2	739.9
Total	**1,561.7**	**1,867.8**	**1,834.7**	**1,782.3**	**2,041.6**	**1,965.4**	**1,878.1**	**2,220.8**	**2,087.8**	**1,949.6**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)										
Petroleum	19.9	5.2	4.3	3.2	7.0	5.1	3.4	7.8	5.9	2.9
Natural Gas	61.1	105.1	100.6	90.7	135.3	130.7	106.4	144.1	151.1	117.2
Coal	504.6	590.1	583.9	576.0	629.5	602.9	601.7	702.7	633.2	619.8
Total	**585.6**	**700.4**	**688.8**	**669.9**	**771.8**	**738.7**	**711.5**	**854.6**	**790.2**	**739.9**
Carbon Dioxide Emissions by Primary Fuel (million metric tons carbon equivalent)										
Petroleum	657.8	785.2	771.5	745.1	867.8	835.4	787.5	946.0	890.9	817.6
Natural Gas	331.2	421.3	412.8	398.6	470.1	460.0	427.4	495.1	495.6	451.8
Coal	572.8	661.2	650.3	638.5	703.6	669.8	663.2	779.5	701.2	680.1
Other	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**1,561.7**	**1,867.8**	**1,834.7**	**1,782.3**	**2,041.6**	**1,965.4**	**1,878.1**	**2,220.8**	**2,087.8**	**1,949.6**

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 2000 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LTRKITEN.D102501A, AEO2002.D102001B, HTRKITEN.D102501A.

Table F5. Key Results for Nuclear Generation Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, Generation, Emissions, and Fuel Prices	2000	Projections 2010 Reference	2010 Low Nuclear	2010 High Nuclear	2010 Advanced Nuclear Cost	2020 Reference	2020 Low Nuclear	2020 High Nuclear	2020 Advanced Nuclear Cost
Capability									
Coal Steam	304.6	305.7	306.0	305.8	305.9	329.0	331.9	330.2	329.1
Other Fossil Steam	135.0	115.6	115.7	115.8	115.5	113.3	113.4	113.5	113.2
Combined Cycle	30.6	139.9	141.7	140.4	139.6	213.8	219.6	209.8	215.6
Combustion Turbine/Diesel	77.7	128.9	130.4	129.0	129.1	177.9	177.8	176.3	176.8
Nuclear Power	97.5	94.3	94.3	96.3	94.3	88.0	81.3	92.4	89.0
Pumped Storage	19.2	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Renewable Sources	89.1	97.2	97.2	97.3	97.2	101.2	101.4	101.2	101.2
Distributed Generation	0.0	5.1	5.1	4.9	5.0	19.0	18.3	18.6	18.7
Cogenerators/Other Generators[1]	55.7	65.2	65.2	65.2	65.2	75.6	75.6	75.6	75.6
Total	**809.3**	**971.6**	**975.5**	**974.4**	**971.7**	**1137.8**	**1139.0**	**1137.4**	**1139.0**
Cumulative Additions									
Coal Steam	0.0	6.2	6.4	6.2	6.4	31.2	34.2	32.5	31.4
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	108.5	110.4	109.0	108.3	182.5	188.2	178.4	184.2
Combustion Turbine/Diesel	0.0	57.2	58.9	57.3	57.5	109.6	109.8	108.1	109.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Renewable Sources	0.0	7.6	7.6	7.6	7.5	11.6	11.7	11.5	11.5
Distributed Generation	0.0	5.1	5.1	4.9	5.0	19.0	18.3	18.6	18.7
Cogenerators/Other Generators[1]	0.0	9.5	9.5	9.5	9.5	19.9	19.9	19.9	19.9
Total	**0.0**	**194.5**	**198.4**	**195.1**	**194.7**	**374.4**	**382.7**	**369.7**	**376.3**
Cumulative Retirements	**0.0**	**33.1**	**33.1**	**30.9**	**33.2**	**46.9**	**53.9**	**42.5**	**47.6**
Generation by Fuel (billion kilowatthours)									
Coal	1922	2215	2214	2208	2212	2423	2446	2427	2422
Petroleum	93	28	26	28	28	38	38	38	37
Natural Gas	417	893	896	886	895	1414	1437	1377	1408
Nuclear Power	752	737	737	752	737	702	655	734	709
Pumped Power	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources	321	391	391	391	391	407	407	409	409
Distributed Generation	0	2	2	2	2	8	8	8	8
Cogenerators/Other Generators[1]	311	379	379	379	379	452	452	452	452
Total	**3815**	**4644**	**4645**	**4645**	**4644**	**5444**	**5442**	**5445**	**5444**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	19.9	4.3	3.9	4.1	4.1	5.9	5.9	5.9	5.6
Natural Gas	61.1	100.6	100.7	99.5	100.9	151.1	152.7	147.5	149.9
Coal	504.6	583.9	582.7	581.0	582.2	633.2	637.6	633.5	632.7
Total	**585.6**	**688.8**	**687.2**	**684.5**	**687.3**	**790.2**	**796.2**	**786.8**	**788.2**
Prices to Electric Generators (2000 dollars per million Btu)									
Petroleum	4.33	3.97	3.99	3.99	4.00	4.27	4.29	4.27	4.25
Natural Gas	4.41	3.38	3.38	3.37	3.39	3.87	3.90	3.81	3.85
Coal	1.20	1.05	1.05	1.05	1.06	0.97	0.97	0.97	0.97

[1] 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 cogenerators and other generators.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with electric utility capability estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs AEO2002.D102001B, LNUC02.D102201A, HNUC02.D102201A, ADVNUC02.D102301B.

Table F6. Key Results for Electricity Demand Case

Net Summer Capability, Generation, Consumption, Emissions, and Prices	2000	2005		2010		2020		Annual Growth 2000-2020	
		Reference	High Demand	Reference	High Demand	Reference	High Demand	Reference	High Demand
Electricity Sales (billion kilowatthours)	**3426**	**3793**	**3938**	**4170**	**4468**	**4916**	**5642**	**1.8%**	**2.5%**
Electricity Prices									
(2000 cents per kilowatthour)	**6.9**	**6.4**	**6.7**	**6.3**	**6.5**	**6.5**	**6.6**	**-0.3%**	**-0.2%**
Capability (gigawatts)									
Coal Steam	304.6	303.7	303.7	305.7	314.1	329.0	413.2	0.4%	1.5%
Other Fossil Steam	135.0	127.4	127.4	115.6	119.3	113.3	115.4	-0.9%	-0.8%
Combined Cycle	30.6	59.6	64.5	139.9	167.7	213.8	247.6	10.2%	11.0%
Combustion Turbine/Diesel	77.7	104.9	113.8	128.9	150.9	177.9	200.5	4.2%	4.9%
Nuclear Power	97.5	97.7	97.7	94.3	96.3	88.0	92.4	-0.5%	-0.3%
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.3	0.3	35.2%	35.2%
Renewable Sources/Pumped Storage	108.3	114.8	114.8	116.8	117.0	120.9	122.4	0.5%	0.6%
Distributed Generation	0.0	0.9	1.3	5.1	6.9	19.0	25.3	N/A	N/A
Cogenerators/Other Generators[1]	55.7	61.1	61.1	65.2	65.4	75.6	75.6	1.5%	1.5%
Total	**809.3**	**870.2**	**884.4**	**971.6**	**1037.9**	**1137.8**	**1292.6**	**1.7%**	**2.4%**
Cumulative Additions (gigawatts)									
Coal Steam	0.0	1.0	1.0	6.2	14.0	31.2	115.5	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	28.3	33.1	108.5	136.4	182.5	216.2	N/A	N/A
Combustion Turbine/Diesel	0.0	31.8	40.8	57.2	79.4	109.6	130.7	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	6.0	6.0	7.9	8.1	11.9	13.4	N/A	N/A
Distributed Generation	0.0	0.9	1.3	5.1	6.9	19.0	25.3	N/A	N/A
Cogenerators/Other Generators[1]	0.0	5.4	5.4	9.5	9.7	19.9	19.9	N/A	N/A
Total	**0.0**	**73.4**	**87.6**	**194.5**	**254.7**	**374.4**	**521.2**	**N/A**	**N/A**
Generation by Fuel (billion kilowatthours)									
Coal	1922	2086	2111	2215	2297	2423	3042	1.2%	2.3%
Petroleum	93	39	55	28	43	38	44	-4.4%	-3.8%
Natural Gas	417	607	711	893	1088	1414	1515	6.3%	6.5%
Nuclear Power	752	759	759	737	752	702	734	-0.3%	-0.1%
Renewable Sources/Pumped Storage	320	374	372	390	391	406	413	1.2%	1.3%
Distributed Generation	0	0	1	2	3	8	11	N/A	N/A
Cogenerators/Other	311	352	353	379	379	452	451	1.9%	1.9%
Total	**3815**	**4218**	**4362**	**4644**	**4953**	**5444**	**6210**	**1.8%**	**2.4%**
Fossil Fuel Consumption by Electric Generators (quadrillion Btu)[2]									
Petroleum	0.93	0.32	0.48	0.21	0.36	0.28	0.33	-5.9%	-5.3%
Natural Gas	4.32	5.58	6.56	6.98	8.34	10.49	11.10	4.5%	4.6%
Coal	19.69	21.44	21.77	22.80	23.59	24.67	29.39	1.1%	2.0%
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	19.9	6.8	10.2	4.3	7.5	5.9	6.9	-5.9%	-5.3%
Natural Gas	61.1	80.4	94.5	100.6	120.1	151.1	159.8	4.6%	4.8%
Coal	504.6	548.5	556.6	583.9	604.1	633.2	754.3	1.1%	2.0%
Total	**585.6**	**635.7**	**661.2**	**688.8**	**731.7**	**790.2**	**920.9**	**1.5%**	**2.3%**
Prices to Electric Generators (2000 dollars per million Btu)									
Petroleum	4.33	3.80	3.78	3.97	3.89	4.27	4.25	-0.1%	-0.1%
Natural Gas	4.41	3.19	3.48	3.38	3.89	3.87	4.10	-0.6%	-0.4%
Coal	1.20	1.13	1.13	1.05	1.06	0.97	0.99	-1.1%	-1.0%

[1] 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 cogenerators 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 2000 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, AEO2002 National Energy Modeling System runs AEO2002.D102001B, HDEM02.D102201A.

Table F7. Key Results for Electricity Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, Generation Consumption, and Emissions	2000	2005			2010			2020		
		Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil
Capability										
Pulverized Coal	304.1	303.2	303.2	303.2	305.8	304.9	304.1	344.1	322.6	302.5
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	0.9	0.8	3.1	4.3	6.4	59.4
Conventional Natural Gas Combined-Cycle	30.6	52.9	52.9	52.9	117.6	95.6	71.6	175.7	108.0	71.6
Advanced Natural Gas Combined-Cycle	0.00	6.8	6.7	6.7	21.0	44.3	62.9	21.6	105.9	141.5
Conventional Combustion Turbine	77.7	102.5	102.4	101.8	124.3	120.2	122.0	166.9	150.1	135.8
Advanced Combustion Turbine	0.00	2.4	2.5	2.7	5.3	8.6	11.9	5.4	27.7	31.8
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
Nuclear	97.5	97.7	97.7	97.7	94.3	94.3	94.3	88.0	88.0	85.5
Oil and Gas Steam	135.0	127.5	127.4	127.5	115.5	115.6	115.5	113.3	113.3	109.2
Renewable Sources/Pumped Storage	108.3	114.8	114.8	114.8	116.8	116.8	116.7	122.4	120.9	118.8
Distributed Generation	0.0	0.9	0.9	0.9	4.9	5.1	4.7	19.0	19.0	14.9
Cogenerators/Other Generators[1]	55.7	61.1	61.1	61.1	65.2	65.2	65.2	75.6	75.6	75.5
Total	**809.3**	**870.4**	**870.2**	**870.0**	**971.8**	**971.6**	**972.2**	**1136.7**	**1137.8**	**1146.7**
Cumulative Additions										
Pulverized Coal	0.0	1.0	1.0	1.0	6.6	5.8	5.0	46.8	25.4	5.2
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	0.4	0.4	2.6	3.8	5.9	58.9
Conventional Natural Gas Combined-Cycle	0.0	21.5	21.6	21.6	86.3	64.3	40.3	144.4	76.6	40.3
Advanced Natural Gas Combined-Cycle	0.0	6.8	6.7	6.7	21.0	44.3	62.9	21.6	105.9	141.5
Conventional Combustion Turbine	0.0	29.5	29.3	28.8	52.7	48.6	50.4	99.0	81.9	68.2
Advanced Combustion Turbine	0.0	2.4	2.5	2.7	5.3	8.6	11.9	5.4	27.7	31.8
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
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	6.0	6.0	6.0	7.9	7.9	7.7	13.5	11.9	9.8
Distributed Generation	0.0	0.9	0.9	0.9	4.9	5.1	4.7	19.0	19.0	14.9
Cogenerators/Other Generators[1]	0.0	5.4	5.4	5.4	9.5	9.5	9.5	19.9	19.9	19.8
Total	**0.0**	**73.5**	**73.4**	**73.1**	**194.7**	**194.5**	**195.2**	**373.7**	**374.4**	**390.5**
Cumulative Retirements	**0.0**	**13.2**	**13.3**	**13.2**	**33.1**	**33.1**	**33.2**	**47.2**	**46.9**	**54.0**
Generation by Fuel (billion kilowatthours)										
Coal	1922	2087	2086	2087	2219	2215	2217	2564	2423	2632
Petroleum	93	39	39	40	29	28	28	40	38	27
Natural Gas	417	607	607	607	886	893	895	1262	1414	1261
Nuclear Power	752	759	759	759	737	737	737	702	702	684
Renewable Sources/Pumped Storage	320	373	374	373	390	390	389	413	406	393
Distributed Generation	0	0	0	0	2	2	2	8	8	7
Cogenerators/Other Generators[1]	311	352	352	352	379	379	379	453	452	450
Total	**3815**	**4218**	**4218**	**4218**	**4643**	**4644**	**4647**	**5443**	**5444**	**5454**
Fuel Consumption by Electric Generators (quadrillion Btu)[2]										
Coal	19.69	21.45	21.44	21.46	22.79	22.80	22.73	26.00	24.67	25.46
Petroleum	0.93	0.33	0.32	0.33	0.21	0.21	0.20	0.31	0.28	0.16
Natural Gas	4.32	5.58	5.58	5.57	7.09	6.98	6.82	9.93	10.49	8.29
Nuclear Power	8.03	8.10	8.10	8.10	7.87	7.87	7.87	7.49	7.49	7.31
Renewable Sources	3.55	4.18	4.18	4.18	4.46	4.46	4.44	5.03	4.94	4.67
Total	**36.53**	**39.63**	**39.62**	**39.64**	**42.41**	**42.31**	**42.06**	**48.76**	**47.88**	**45.89**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]										
Petroleum	19.9	6.8	6.8	6.9	4.3	4.3	4.1	6.4	5.9	3.4
Natural Gas	61.1	80.3	80.4	80.2	102.0	100.6	98.2	143.0	151.1	119.4
Coal	504.6	548.8	548.5	549.0	584.0	583.9	582.3	667.4	633.2	653.2
Total	**585.6**	**635.9**	**635.7**	**636.2**	**690.4**	**688.8**	**684.6**	**816.8**	**790.2**	**776.0**

[1] 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 cogenerators and other generators.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with electric utility capability estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LFOSS02.D102401A, AEO2002.D102001B, HFOSS02.D102301A.

Table F8. Key Results for High Renewable Energy Case

Capacity, Generation, and Emissions	2000	2010		2020	
		Reference	High Renewables	Reference	High Renewables
Renewable Capability (gigawatts)					
Net Summer Capability					
Electric Generators[1]					
Conventional Hydropower	79.29	79.90	79.90	79.90	79.90
Geothermal[2]	2.85	3.57	4.03	5.32	7.99
Municipal Solid Waste[3]	2.84	3.88	3.88	4.30	4.30
Wood and Other Biomass[4]	1.39	1.73	1.73	1.97	2.09
Solar Thermal	0.33	0.36	0.36	0.41	0.41
Solar Photovoltaic[5]	0.01	0.11	0.11	0.27	0.27
Wind	2.42	7.65	8.72	9.06	25.27
Total	**89.13**	**97.19**	**98.72**	**101.22**	**120.23**
Cogenerators[6]					
Municipal Solid Waste	0.51	0.51	0.51	0.51	0.51
Wood and Other Biomass	5.26	6.64	7.27	8.43	10.21
Total	**5.77**	**7.15**	**7.78**	**8.94**	**10.72**
Other End-Use Generators[7]					
Conventional Hydropower	0.98	0.98	0.98	0.98	0.98
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic[5]	0.02	0.39	0.39	0.46	1.01
Total	**0.99**	**1.36**	**1.36**	**1.44**	**1.99**
Generation (billion kilowatthours)					
Electric Generators					
Coal	1922	2215	2213	2423	2395
Petroleum	93	28	27	38	35
Natural Gas	417	893	887	1414	1354
Total Fossil	**2432**	**3136**	**3126**	**3876**	**3784**
Conventional Hydropower	272.33	301.14	301.14	300.00	300.00
Geothermal	13.52	20.20	24.01	34.71	56.52
Municipal Solid Waste[3]	20.15	27.78	27.78	30.98	30.98
Wood and Other Biomass[4]	8.37	20.86	21.15	15.32	16.06
Dedicated Plants	7.46	9.72	9.72	11.25	12.09
Cofiring	0.91	11.14	11.43	4.07	3.97
Solar Thermal	0.87	0.96	0.96	1.12	1.12
Solar Photovoltaic	0.01	0.26	0.26	0.68	0.68
Wind	5.30	19.45	23.44	24.07	87.06
Total Renewable	**320.54**	**390.65**	**398.74**	**406.87**	**492.40**
Cogenerators[6]					
Total Fossil	**264**	**319**	**319**	**378**	**377**
Municipal Solid Waste	3.29	3.29	3.29	3.29	3.29
Wood and Other Biomass	29.63	38.04	41.85	48.99	59.92
Total Renewables	**32.93**	**41.34**	**45.14**	**52.28**	**63.22**
Other End-Use Generators[7]					
Conventional Hydropower[8]	3.98	4.32	4.32	4.31	4.31
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.81	0.81	0.98	2.13
Total	**4.02**	**5.14**	**5.14**	**5.29**	**6.44**
Sources of Ethanol					
From Corn	0.14	0.22	0.22	0.22	0.11
From Cellulose	0.00	0.02	0.02	0.06	0.17
Total	**0.14**	**0.24**	**0.24**	**0.28**	**0.28**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[9]					
Petroleum	19.9	4.3	4.0	5.9	5.2
Natural Gas	61.1	100.6	99.9	151.1	144.5
Coal	504.6	583.9	582.3	633.2	625.7
Total	**585.6**	**688.8**	**686.1**	**790.2**	**775.5**

[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]Does not include off-grid photovoltaics (PV). EIA estimates that another 76 megawatts of remote electricity generation PV applications were in service in 1999, plus an additional 205 megawatts in communications, transportation, and assorted other non-grid-connected applications.
[6]Cogenerators produce electricity and other useful thermal energy.
[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.
[9]Excludes cogenerators and other generators.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs AEO2002.D102001B, HIRENEW02.D102301A.

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	2000	Projections								
		2010			2015			2020		
		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	12.33	10.06	10.76	11.31	10.76	11.76	12.50	11.28	11.92	12.67
Natural Gas Plant Liquids	2.71	3.29	3.37	3.42	3.54	3.74	3.82	3.67	4.03	4.20
Dry Natural Gas	19.59	23.51	24.12	24.49	25.58	27.03	27.60	26.59	29.25	30.46
Coal	22.58	26.41	26.23	26.15	27.45	26.91	26.70	29.29	28.11	27.47
Nuclear Power	8.03	7.87	7.87	7.87	7.55	7.55	7.55	7.49	7.49	7.49
Renewable Energy[1]	6.46	7.88	7.89	7.89	8.49	8.47	8.42	8.96	8.93	8.91
Other[2]	1.10	0.80	0.85	0.86	0.45	1.04	1.06	0.42	0.93	1.06
Total	**72.80**	**79.82**	**81.09**	**81.99**	**83.83**	**86.51**	**87.66**	**87.70**	**90.66**	**92.26**
Imports										
Crude Oil[3]	19.69	25.09	24.36	23.87	25.12	24.04	23.31	25.41	24.45	23.73
Petroleum Products[4]	4.73	7.99	7.83	7.68	11.05	10.31	10.18	13.57	12.69	12.28
Natural Gas	3.85	5.61	5.64	5.64	6.05	6.04	6.08	6.19	6.20	6.35
Other Imports[5]	0.76	1.00	0.95	0.91	1.14	1.07	1.02	1.15	1.09	1.02
Total	**29.04**	**39.69**	**38.79**	**38.09**	**43.37**	**41.46**	**40.59**	**46.32**	**44.44**	**43.38**
Exports										
Petroleum[6]	2.15	1.88	1.91	1.92	1.98	2.02	2.04	2.08	2.11	2.13
Natural Gas	0.25	0.63	0.63	0.63	0.66	0.66	0.66	0.56	0.56	0.56
Coal	1.53	1.44	1.36	1.44	1.34	1.34	1.33	1.37	1.38	1.38
Total	**3.93**	**3.95**	**3.90**	**3.99**	**3.97**	**4.01**	**4.03**	**4.02**	**4.05**	**4.07**
Consumption										
Petroleum Products[8]	38.63	45.27	45.20	45.16	49.17	48.85	48.83	52.56	51.99	51.88
Natural Gas	23.43	28.25	28.85	29.20	30.71	32.14	32.73	31.94	34.63	35.97
Coal	22.34	25.51	25.41	25.26	26.70	26.16	25.95	28.55	27.35	26.72
Nuclear Power	8.03	7.87	7.87	7.87	7.55	7.55	7.55	7.49	7.49	7.49
Renewable Energy[1]	6.48	7.89	7.90	7.90	8.50	8.48	8.43	8.97	8.94	8.92
Other[9]	0.38	0.43	0.38	0.34	0.53	0.46	0.41	0.50	0.44	0.37
Total	**99.29**	**115.22**	**115.61**	**115.74**	**123.16**	**123.64**	**123.90**	**130.02**	**130.85**	**131.35**
Net Imports - Petroleum	**22.28**	**31.20**	**30.29**	**29.62**	**34.20**	**32.33**	**31.45**	**36.89**	**35.04**	**33.88**
Prices (2000 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.72	23.36	23.36	23.36	24.00	24.00	24.00	24.68	24.68	24.68
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	3.22	2.85	2.62	3.54	3.07	2.75	4.06	3.26	2.73
Coal Minemouth Price (dollars per ton)	16.45	13.93	14.11	13.61	13.36	13.44	13.16	12.94	12.79	12.64
Average Electricity Price (cents per kilowatthour)	6.9	6.5	6.3	6.3	6.6	6.3	6.2	6.8	6.5	6.2
Carbon Dioxide Emissions (million metric tons carbon equivalent)	**1561.7**	**1830.0**	**1834.7**	**1835.5**	**1964.9**	**1965.4**	**1968.2**	**2091.1**	**2087.8**	**2088.5**

[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, and net storage withdrawals.
[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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs OGLTEC02.D102501A, AEO2002.D102001B, OGHTEC02.D102501A.

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	2000	Projections								
		2010			2015			2020		
		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 (2000 dollars per thousand cubic feet)	**3.60**	**3.22**	**2.85**	**2.62**	**3.54**	**3.07**	**2.75**	**4.06**	**3.26**	**2.73**
Dry Gas Production[1]										
U.S. Total	**19.08**	**22.89**	**23.48**	**23.84**	**24.91**	**26.32**	**26.88**	**25.89**	**28.48**	**29.65**
Lower 48 Onshore	13.31	15.86	16.45	16.80	18.00	19.40	19.87	18.62	21.13	22.56
Associated-Dissolved	1.79	1.41	1.43	1.45	1.33	1.37	1.41	1.31	1.36	1.41
Non-Associated	11.52	14.45	15.02	15.35	16.67	18.04	18.46	17.31	19.77	21.14
Conventional	6.89	7.65	7.89	7.94	9.04	9.94	9.60	9.81	10.77	10.84
Unconventional	4.63	6.79	7.13	7.41	7.63	8.09	8.86	7.50	8.99	10.30
Lower 48 Offshore	5.34	6.50	6.50	6.51	6.34	6.35	6.43	6.67	6.75	6.49
Associated-Dissolved	1.16	1.18	1.22	1.26	1.21	1.27	1.31	1.25	1.25	1.25
Non-Associated	4.18	5.32	5.28	5.25	5.12	5.08	5.12	5.42	5.50	5.24
Alaska	0.43	0.53	0.53	0.53	0.57	0.57	0.57	0.60	0.60	0.60
Supplemental Natural Gas[2]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Net Imports	**3.52**	**4.86**	**4.89**	**4.89**	**5.27**	**5.26**	**5.29**	**5.49**	**5.51**	**5.65**
Canada	3.46	4.50	4.51	4.53	4.92	4.90	4.94	4.93	5.06	5.20
Mexico	-0.09	-0.45	-0.45	-0.45	-0.47	-0.47	-0.47	-0.26	-0.38	-0.38
Liquefied Natural Gas	0.16	0.81	0.83	0.81	0.83	0.83	0.83	0.83	0.83	0.83
Total Supply	**22.69**	**27.86**	**28.49**	**28.84**	**30.29**	**31.69**	**32.28**	**31.50**	**34.10**	**35.42**
Consumption by Sector										
Residential	5.00	5.45	5.53	5.58	5.61	5.73	5.81	5.77	5.98	6.13
Commercial	3.27	3.87	3.93	3.97	4.11	4.21	4.28	4.35	4.52	4.63
Industrial[3]	8.41	9.26	9.39	9.45	9.38	9.79	9.86	9.51	10.06	10.26
Electric Generators[4]	4.24	6.59	6.85	7.01	8.24	8.91	9.22	8.80	10.30	11.03
Transportation[6]	0.02	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Pipeline Fuel	0.77	0.82	0.84	0.85	0.88	0.93	0.95	0.91	0.99	1.03
Lease and Plant Fuel[5]	1.12	1.47	1.50	1.51	1.59	1.66	1.69	1.67	1.80	1.85
Total	**22.83**	**27.54**	**28.13**	**28.47**	**29.95**	**31.34**	**31.92**	**31.15**	**33.78**	**35.09**
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]	**-0.14**	**0.33**	**0.36**	**0.37**	**0.34**	**0.35**	**0.36**	**0.35**	**0.32**	**0.33**
Lower 48 End of Year Reserves	**162.31**	**162.44**	**174.09**	**188.58**	**161.07**	**181.49**	**216.13**	**152.47**	**187.79**	**238.66**

[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 by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[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 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 transportation sector consumption: Energy Information Administration (EIA), AEO2002 National Energy Modeling System runs OGLTEC02.D102501A, AEO2002.D102001B, OGHTEC02.D102501A. 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System runs OGLTEC02.D102501A, AEO2002.D102001B, OGHTEC02.D102501A. **Other 2000 values and projections:** EIA, AEO2002 National Energy Modeling System runs OGLTEC02.D102501A, AEO2002.D102001B, OGHTEC02.D102501A.

Table F11. Crude Oil Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000	Projections								
		2010			2015			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
World Oil Price										
(2000 dollars per barrel)	**27.72**	**23.36**	**23.36**	**23.36**	**24.00**	**24.00**	**24.00**	**24.68**	**24.68**	**24.68**
Production[1]										
U.S. Total	**5.82**	**4.75**	**5.08**	**5.34**	**5.08**	**5.56**	**5.91**	**5.33**	**5.63**	**5.98**
Lower 48 Onshore	3.25	2.49	2.64	2.73	2.41	2.64	2.83	2.41	2.70	2.90
Conventional	2.60	1.87	1.91	1.95	1.74	1.82	1.91	1.75	1.87	1.98
Enhanced Oil Recovery	0.65	0.63	0.73	0.78	0.67	0.82	0.92	0.66	0.83	0.91
Lower 48 Offshore	1.61	1.59	1.74	1.87	1.82	2.01	2.13	1.86	1.83	1.93
Alaska	0.97	0.67	0.70	0.74	0.86	0.90	0.95	1.06	1.10	1.15
Net Crude Imports	**9.02**	**11.53**	**11.18**	**10.94**	**11.53**	**11.01**	**10.66**	**11.65**	**11.20**	**10.85**
Other Crude Supply	**0.23**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total Crude Supply	**15.07**	**16.29**	**16.26**	**16.28**	**16.61**	**16.57**	**16.57**	**16.98**	**16.83**	**16.83**
Natural Gas Plant Liquids	**1.91**	**2.32**	**2.38**	**2.41**	**2.49**	**2.64**	**2.69**	**2.58**	**2.84**	**2.96**
Other Inputs[2]	**0.35**	**0.39**	**0.42**	**0.42**	**0.25**	**0.51**	**0.52**	**0.24**	**0.47**	**0.52**
Refinery Processing Gain[3]	**0.95**	**1.01**	**1.00**	**1.00**	**1.03**	**1.01**	**1.01**	**1.04**	**1.02**	**1.03**
Net Product Imports[4]	**1.40**	**3.18**	**3.09**	**3.02**	**4.82**	**4.29**	**4.22**	**6.06**	**5.44**	**5.20**
Total Primary Supply[5]	**19.68**	**23.18**	**23.15**	**23.13**	**25.20**	**25.01**	**25.00**	**26.91**	**26.61**	**26.55**
Refined Petroleum Products Supplied										
Residential and Commercial	1.12	1.09	1.09	1.09	1.07	1.06	1.06	1.05	1.04	1.04
Industrial[6]	4.96	5.69	5.66	5.65	6.16	6.00	6.00	6.47	6.27	6.23
Transportation	13.26	16.35	16.37	16.38	17.89	17.90	17.92	19.20	19.22	19.24
Electric Generators[7]	0.41	0.11	0.09	0.07	0.16	0.11	0.08	0.24	0.12	0.08
Total	**19.74**	**23.25**	**23.21**	**23.19**	**25.26**	**25.07**	**25.06**	**26.96**	**26.66**	**26.59**
Discrepancy[8]	**-0.07**	**-0.06**	**-0.06**	**-0.06**	**-0.06**	**-0.06**	**-0.06**	**-0.05**	**-0.05**	**-0.05**
Lower 48 End of Year Reserves										
(billion barrels)[1]	**18.29**	**13.39**	**14.23**	**14.66**	**13.50**	**14.63**	**15.31**	**13.24**	**14.45**	**15.25**

[1]Includes lease condensate.
[2]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and natural gas 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 petroleum imports.
[6]Includes consumption by cogenerators.
[7]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. 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 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 product supplied data from Table A2. Other 2000 data: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). **Projections:** EIA, AEO2002 National Energy Modeling System runs OGLTEC02.D102501A, AEO2002.D102001B, OGHTEC02.D102501A.

Table F12. Key Results for Federal MTBE Ban Case

Supply, Disposition, and Prices	2000	Projections									
		2006		2007		2008		2009		2010	
		Reference	MTBE Ban	Reference	MTBE Ban	Reference	MTBE Ban	Reference	MTBE Ban	Reference	MTBE Ban
MTBE Blended with Gasoline (thousand barrels per day)	**247**	**123**	**0**	**128**	**0**	**118**	**0**	**120**	**0**	**125**	**0**
Ethanol Blended with Gasoline (thousand barrels per day)	**106**	**178**	**257**	**180**	**260**	**181**	**265**	**183**	**271**	**187**	**276**
Gasoline Consumption (million barrels per day)	**8.50**	**9.59**	**9.53**	**9.75**	**9.68**	**9.94**	**9.87**	**10.13**	**10.06**	**10.32**	**10.24**
Gasoline Prices (2000 cents per gallon)											
National Average	153	139	142	139	142	139	143	140	143	140	143
Reformulated National Average	161	145	154	145	154	146	156	147	157	146	155
World Oil Price (2000 dollars per barrel)	**27.72**	**22.85**	**22.85**	**22.99**	**22.99**	**23.11**	**23.11**	**23.24**	**23.24**	**23.36**	**23.36**

MTBE = Methyl tertiary butyl ether.
RFG = Reformulated gasoline.
Note: The oxygen requirement on RFG is assumed to continue. Side case was run without the fully integrated modeling system, so not all potential feedbacks were captured. Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, AEO2002 National Energy Modeling System runs AEO2002.D102001B, MTBEB02.D102201A.

Table F13. Key Results for Coal Mining Cost Cases

Prices, Productivity, Wages, and Emissions	2000	2005			2010			2020		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (2000 dollars per short ton)	**16.45**	**14.23**	**14.99**	**15.53**	**12.71**	**14.11**	**15.16**	**10.76**	**12.79**	**15.74**
Delivered Price to Electric Generators (2000 dollars per million Btu)	**1.20**	**1.09**	**1.13**	**1.16**	**1.00**	**1.05**	**1.12**	**0.85**	**0.97**	**1.11**
Labor Productivity (short tons per miner per hour)	**6.99**	**9.12**	**8.40**	**7.84**	**10.97**	**9.31**	**8.17**	**14.56**	**10.76**	**7.85**
Labor Productivity (average annual growth from 2000)	**N/A**	**5.5**	**3.7**	**2.3**	**4.6**	**2.9**	**1.6**	**3.7**	**2.2**	**0.6**
Average Coal Miner Wage (2000 dollars per hour)	**19.09**	**18.62**	**19.09**	**19.57**	**18.16**	**19.09**	**20.07**	**17.27**	**19.09**	**21.09**
Average Coal Miner Wage (average annual growth from 2000)	**N/A**	**-0.5**	**0.0**	**0.5**	**-0.5**	**0.0**	**0.5**	**-0.5**	**0.0**	**0.5**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[1]										
Petroleum	19.9	6.8	6.8	6.9	4.0	4.3	4.3	5.5	5.9	6.6
Natural Gas	61.1	80.3	80.4	80.5	100.4	100.6	101.5	145.5	151.1	154.4
Coal	504.6	548.8	548.5	548.5	583.2	583.9	580.7	645.3	633.2	623.0
Total	**585.6**	**635.9**	**635.7**	**635.9**	**687.7**	**688.8**	**686.5**	**796.3**	**790.2**	**784.0**

[1] Excludes cogenerators and other generators.
Btu = British thermal unit.
N/A = Not applicable.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured. Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2002 National Energy Modeling System runs LMCST02.D102201A, AEO2002.D102001B, HMCST02.D102201A.

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2002* (*AEO2002*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). In addition to 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 in 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 regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data 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, 2001, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

In general, the *AEO2002* projections were prepared by using the most current data available as of July 31, 2001. At that time, most 2000 data were available, but only partial 2001 data were available. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2000*, published in November 2001 [*1*].

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 *AEO2002* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Also, the *State Energy Data Report* classifies energy consumed by independent power producers, exempt wholesale generators, and cogenerators as industrial consumption, whereas *AEO2002* includes cogeneration in the industrial or commercial sector and other nonutility generators in the electricity sector. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2002* projections for 2001 and 2002 incorporate short-term projections from EIA's October 2001

Short-Term Energy Outlook (*STEO*). For short- term energy projections, readers are referred to the monthly updates of the *STEO* [*2*].

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 DRI-WEFA Macroeconomic Model of the U.S. Economy.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as the changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Average expenditures estimates are provided for households by income group 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 output 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 that provide the representation of the supply response for biomass (including wood, energy crops, and biomass co-firing), geothermal, municipal solid waste (including landfill gas), solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports with Canada and Mexico and liquefied natural gas imports and exports. 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 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. *AEO2002* 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, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington [*3*].

Because the *AEO2002* 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 also 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. *AEO2002* 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 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 2002*

Table G1 provides a summary of the cases used to derive the *AEO2002* 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 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 the EIA's *International Energy Outlook 2001*.

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, 2001. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) and are part of its "Worldwide Petroleum Assessment 2001." Technology factors are derived from the DESTINY forecast software and are a part of the International Energy Services of Petroconsultants, Inc.

Table G1. Summary of the *AEO2002* 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 2.4 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 57	—
High Economic Growth	Gross domestic product grows at an average annual rate of 3.4 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 57	—
Low World Oil Price	World oil prices are $17.64 per barrel in 2020, compared to $24.68 per barrel in the reference case.	Fully integrated	p. 58	—
High World Oil Price	World oil prices are $30.58 per barrel in 2020, compared to $24.68 per barrel in the reference case.	Fully integrated	p. 58	—
Residential: 2002 Technology	Future equipment purchases based on equipment available in 2002. Existing building shell efficiencies fixed at 2002 levels.	With commercial	p. 69	p. 233
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 8 percent from 1997 values by 2020.	With commercial	p. 69	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 2020.	With commercial	p. 69	p. 233
Commercial: 2002 Technology	Future equipment purchases based on equipment available in 2002. Building shell efficiencies fixed at 2002 levels.	With residential	p. 70	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. 70	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. 70	p. 235
Industrial: 2002 Technology	Efficiency of plant and equipment fixed at 2002 levels.	Standalone	p. 71	p. 236
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 71	p. 236
Transportation: 2002 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2002 levels.	Standalone	p. 71	p. 237
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 71	p. 237
Consumption: 2002 Technology	Combination of the residential, commercial, industrial, and transportation 2002 technology cases and electricity low fossil technology case.	Fully integrated	p. 99	—
Consumption: High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, and high renewables case.	Fully integrated	p. 99	—

Table G1. Summary of the *AEO2002* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Low Nuclear	Relative to the reference case, greater increases in operating costs are assumed to be required after 40 years of operation.	Partially integrated	p. 76	p. 239
Electricity: High Nuclear	No increases in operating costs due to plant aging.	Partially integrated	p. 76	p. 239
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have both lower capital costs than in the reference case and a shorter (3-year) construction lead time.	Partially integrated	p. 77	p. 239
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. 77	p. 240
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2002.	Partially integrated	p. 78	p. 240
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values.	Partially integrated	p. 78	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 2020. 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. 80	p. 241
Renewables: Production Tax Credit Extension	Production tax credit for wind and closed-loop biomass power plants assumed to be extended through 2006, with coverage expanded to open-loop biomass and landfill gas power plants.	Partially integrated	p. 14	p. 242
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for slower improvement.	Fully integrated	p. 85, p. 87	p. 242
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for more rapid improvement.	Fully integrated	p. 85, p. 87	p. 242
Oil and Gas: Federal MTBE Ban	MTBE and other ethers blended with gasoline are banned from all gasoline starting in 2006. The Federal requirement for 2.0 percent oxygen in reformulated gasoline is not changed.	Partially integrated	p. 36	p. 245
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.7 percent, compared to the reference case growth of 2.2 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.	Partially integrated	p. 93	p. 246
Coal: High Mining Cost	Productivity increases at an annual rate of 0.6 percent, compared to the reference case growth of 2.2 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.	Partially integrated	p. 93	p. 246

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) 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 [*4*] 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 2002
- 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 2001
- 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 *AEO2002* version of the NEMS Residential Demand Module is based on EIA’s Residential Energy Consumption Survey (RECS) [*5*]. This survey, last conducted in 1997, 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 [*6*].

Beginning with *AEO2001*, a combined heating, ventilation, and air conditioning (HVAC)/shell module replaces the methodology for modeling building shells in new construction that was used for *AEO2000*. The new 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 [*7*])
- 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 *AEO2002* 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 residential sector:

- The *2002 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2002. Existing building shell efficiencies are assumed to be fixed at 2002 levels.
- 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 2020.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*8*]. Heating shell efficiency is projected to increase by 8 percent over 1997 levels by 2020.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*9*]. 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 4 percent and 6 percent, respectively, by 2020 relative to the 1995 averages.

Among the energy efficiency programs recognized in the *AEO2002* reference case are the expansion of the EPA Green Lights and Energy Star Buildings programs 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 such as Green Lights, which target particular end uses, the *AEO2002* 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 *AEO2002* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS) [*10*]. Parking garages and commercial buildings on multibuilding manufacturing sites, included in the previous CBECS, were eliminated from the target building population for 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 [*11*].

Due to the change in the target population and the variability caused by nonsampling and sampling errors, the estimates of commercial floorspace for the 1995 CBECS are lower than previous CBECS estimates. For example, the 1995 CBECS reports 13 percent less commercial floorspace in the United States than was reported in the 1992 CBECS. The most notable effect on *AEO2002* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO2002* is significantly higher than in *AEO*s before *AEO99*, not because energy consumption is higher but because the 1995 floorspace estimates are lower. 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 *AEO2002* projections for fuel consumption within each end use. For example, the 1995 CBECS end-use intensities report more fuel used for heating and less for cooling than the end-use intensities based on the 1992 CBECS.

In addition to the *AEO2002* 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 *2002 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2002. Building shell efficiencies are assumed to be fixed at 2002 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*12*]. 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 news releases and the Utility PhotoVoltaic Group web site. 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 2020 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies [*13*]. 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 has been recalibrated to be consistent with the data from EIA's 1998 Manufacturing Energy Consumption Survey [*14*]. In addition, the nonmanufacturing portion of the module has been updated on the basis of information from EIA, the U.S. Department of Agriculture, and the U.S. Census Bureau [*15*]. Compared to the building sector, there are relatively few regulations that target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1999 [*16*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use. Thus, these standards, incorporated into the Industrial Demand Module through the analysis of efficiencies for new industrial processes, are expected to lead to significant improvements in efficiency.

High technology, 2002 technology, and high renewables cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*17*]. 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 1.7 percent annually. In the reference case, primary energy intensity falls by 1.5 percent annually between 2000 and 2020.

The *2002 technology case* holds the energy efficiency of plant and equipment constant at the 2002 level over the forecast. In this case, primary energy intensity falls by 1.3 percent annually. Because the level and composition of industrial output are the same in the reference, high technology, and 2002 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* 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. This case was 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 *AEO2002* 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., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*18*]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 1999. Purchases of alternative-fuel vehicles by State governments must reach 25 percent of total purchases by 1999 and 75 percent by 2001. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1998, increasing to 90 percent by 2001. Fuel provider exemptions for electric utilities are assumed to follow the electric utility provisions, beginning in 1998 at 30 percent and reaching 90 percent by 2001. The municipal and private business fleet mandates, which are proposed to begin in 2002 at 20 percent and scale up to 70 percent by 2005, are not included in *AEO2002*.

In addition to these requirements, the State of California has recently upheld its Low Emission Vehicle Program, which requires that 10 percent of all new vehicles sold by 2003 meet the requirements for zero-emission vehicles (ZEVs). California recently passed legislation to allow 60 percent of the ZEV mandate to be met by ZEV credits from advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate must be achieved with "true ZEVs," which include only electric vehicles and hydrogen fuel cell vehicles [*19*]. In September 2000, further modifications were proposed for the ZEV mandate. The proposal was designed to maintain progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. The proposal by the California Air Resources Board removed ZEV sales requirements before 2003 but maintained the 2003 required ZEV sales goal of 10 percent and the required gradual increase of ZEV sales to 16 percent by 2018. The number of vehicles included in the estimation of required ZEV sales was also increased, to include small light-duty trucks. Originally, Massachusetts and New York, and more recently Maine and

Vermont, also adopted the California program. The projections currently assume that California, Massachusetts, New York, Maine, and Vermont will formally begin the Low Emission Vehicle Program in 2003.

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 52 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*20*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable.

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 [*21*]. When the fuel price exceeds this price, the technology will begin to penetrate the market. 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 [*22*].

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 [*23*].

Travel. Projections for both personal travel [*24*] and freight travel [*25*] 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 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 [*26*]. 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.

2002 technology case. The *2002 technology case* assumes that new fuel efficiency levels are held constant at 2002 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 originate from the DOE Office of Energy Efficiency and Renewable Energy, and conventional light-duty vehicle fuel-saving technology characteristics are from the American Council for an Energy-Efficient Economy [*27*]. New technologies in this case include a high-efficiency advanced light-duty direct injection diesel vehicle with attributes similar to gasoline engines; electric and electric hybrid (gasoline and diesel) vehicles with higher efficiencies than in the reference case; and fuel cell gasoline, methanol, and hydrogen light-duty vehicles. In the air travel sector, the high technology case assumes 40-percent efficiency improvement from new aircraft technologies by 2020, as concluded by the Aeronautics and Space Engineering Board of the National Research Council. Based on an analysis by the Federal Aviation Administration, the 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 [*28*]. 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 macro-economic 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. There are 29 fossil, renewable, and nuclear generating technologies included in the *AEO2002* projections. Technologies represented 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 costs for FGD equipment average approximately $400 per kilowatt, in 2000 dollars, including cost estimates for very small, possibly uneconomical, units. The average cost for units of 500 megawatts capacity or larger is $234 per kilowatt, although they vary widely 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.

The EPA has issued rules to limit emissions of nitrogen oxide, 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 NEMS, electricity generators in those 19 States must comply with the limit either by reducing their own emissions or 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, competition is phased in until 2002, when a return to complete cost-of-service regulation is assumed.

In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2002* 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. The reference case assumes that the competitive price in these regions will be 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. *AEO2002* assumes a ratio of 60 percent debt and 40 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. Furthermore, 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.

Energy efficiency and demand-side management. Improvements in energy efficiency induced by growing energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. Utilities reported spending more than $1.4 billion for demand-side management programs in 1999.

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 were addressable in NEMS. Programs such as tree planting and emissions offset purchasing are not addressable in NEMS. The other programs are, for the most part, captured in NEMS. 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 NEMS 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. Each 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 could 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 the technology represented by the Westinghouse AP600 advanced passive reactor design.

Two alternative cases were developed to incorporate the effects of uncertainty about the aging process for nuclear power plants. In the *low nuclear case* the capital investment was increased to $100 per kilowatt after 40 years. In the *high nuclear case* no aging-related cost increases were assumed. These are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules.

The average nuclear capacity factor in 2000 was 88 percent, the highest annual average ever in the United States. The average annual capacity factor generally increases throughout the forecast, to a maximum of about 90 percent. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

For nuclear power plants, an *advanced nuclear cost case* analyzes the sensitivity of the projections to lower costs and construction times for new plants. The cost assumptions for the advanced nuclear case are consistent with goals endorsed by DOE's Office of Nuclear Energy for Generation III nuclear power plants, including progressively lower overnight construction costs—by 23 percent initially compared with the reference case and by 33 percent in 2020—and shorter lead times. 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 2015. The advanced nuclear case assumes a 3-year lead time, the goal of the Office of Nuclear Energy. Cost and performance characteristics for all other technologies are as assumed in the reference case. These are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Individual plants are assumed to be able replace up to 5 percent of their total consumption with biomass, assuming that sufficient residue fuel is available in the State where the plant is located. Because of regional limitations on available biomass supply, the maximum national average co-firing share throughout the forecast is assumed to be 4 percent.

Distributed generation. AEO2002 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 50 percent of such "growth related" transmission and distribution costs could be avoided by adding distributed generators. In order to account for the uncertainty in the projections for delivered costs of natural gas, it was assumed that distributed generators would pay a premium of $2 per million Btu above the price incurred by electricity producers.

International learning. For *AEO2002*, capital costs for all new fossil-fueled electricity generating technologies decrease in response to foreign as well as domestic experience, to the extent that the new plants reflect technologies and firms also competing in the United States. *AEO2002* includes 1,811 megawatts of advanced coal gasification combined-cycle capacity and 5,244 megawatts of advanced combined-cycle natural gas capacity to be built outside the United States from 2000 through 2003.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 2000 and 2020, 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 2020 is 6.6 cents per kilowatthour in the high demand case, as compared with 6.5 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 coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units 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 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 of 1.5 cents per kilowatthour (now adjusted for inflation to 1.7 cents) for new wind plants originally expired on June 30, 1999, but was extended through December 31, 2001. *AEO2002* applies the credit to all wind plants built through 2001; EIA does not enumerate planned new wind units after 2001 where construction is contingent on the extension of the production tax credit [*29*]. The 10-percent investment tax credit for solar and geothermal technologies that generate electric power is continued.

Supplemental additions. AEO2002 includes 7,865 megawatts of new central station generating capacity using renewable resources, as reported by utilities and independent power producers or identified by EIA to be built from 2001 through 2020. Of the total, 7,034 megawatts results from mandates, State renewable portfolio standards (RPS), and system benefits charges, and 831 megawatts result from voluntary programs. The total includes 5,709 megawatts of wind capacity, 1,182 megawatts of landfill gas capacity, 530 megawatts of geothermal steam capacity, 405 megawatts of biomass capacity (excluding co-firing capacity, which is included with coal), and 39 megawatts of central station solar capacity (thermal and photovoltaic). It includes the 5,129 megawatts of wind capacity expected to be added after 2000 as a result of State RPS and other mandates, plus an additional 580 megawatts of wind capacity expected to result from voluntary initiatives by utilities and other generators.

In instances where a State RPS defines the percentage of State electricity supply to be reached by renewables before 2020, the additional renewables capacity needed to maintain the percentage through 2020 is estimated. EIA does not estimate new renewables capacity for States highly uncertain of the technologies likely to be chosen. The projections also include 54.5 megawatts of central-station solar thermal-electric and 250 megawatts of central-station photovoltaic (PV) generating capacity ("floors") assumed by EIA to be installed for reasons other than least-cost electricity supply from 2001 through 2020.

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 [*30*], 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 *AEO2002* reference case incorporates capital cost adjustment factors (proxies for supply elasticities) 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 costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences. These factors have little or no effect on the *AEO2002* reference case results but can affect results in cases assuming rapid growth in demand for renewable energy technologies.

AEO2002 includes revisions to some renewable energy submodules. Geothermal resources were reduced at each of the 51 identified U.S. resource sites to reflect quantities more likely to be available for development within the next 20 years, and upper limits were established for annual additions at each site. In addition, the wind energy submodule incorporates updated wind technology assumptions. As a consequence of assumed increased energy capture, estimates of U.S. wind supplies are slightly higher in *AEO2002* than they were in *AEO2001*.

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 by 2020, in order to approximate DOE's Office of Energy Efficiency and Renewable Energy December 1997 *Renewable Energy Technology Characterizations* [*31*]. 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. 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.

Production tax credit extension case. The *production tax credit extension case* examines the impact of a possible extension and expansion of a key subsidy to certain renewable energy technologies. Originally authorized in 1992, and extended once to December 31, 2001, the production tax credit (PTC) has not, as of November 2001, been extended further. Several proposals before Congress would extend the program for various durations and expand coverage to a wider variety of technologies. The extension and expansion assumed in this case conform to provisions of the Securing America's Future Energy Act (H.R. 4), passed by the U.S. House of Representatives in August 2001. The proposed legislation would extend the program to December 31, 2006, and expand coverage to include open-loop biomass and landfill gas technologies. The value of the subsidy is 1.5 cents per kilowatthour in 1992 dollars, adjusted for inflation. It is worth approximately 1.7 cents per kilowatthour in current dollars. The PTC applies to all energy produced in the first 10 years of operation from a qualifying plant placed in service before the expiration of the PTC (assumed to be December 31, 2006, in this case).

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2002* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior, with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm [*32*].

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. These 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 6.7 to 8.5 percent per year, and finding rates are expected to improve by 0.4 to 7.4 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 25 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 25 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.

Two impacts of technology improvements were modeled to determine the economics for development of inferred enhanced oil recovery reserves: (1) an overall reduction in the costs of drilling, completing, and equipping production wells and (2) the field-specific penetration of horizontal well technology. The corresponding cost decline and penetration rates assumed in the reference case were varied to reflect slower and more rapid penetration for the technology cases. The remaining undiscovered recoverable resource base determined to be technically amenable to gas miscible recovery methods was assumed to increase over the forecast period with advances in technology, at assumed rates dependent on the region and the technology case.

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 the *Assumptions to the Annual Energy Outlook 2002*, which is available on the Internet at web site 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 requires that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska and LNG imports. A natural gas pipeline from Alaska into Alberta, Canada, is assumed to carry an initial capitalization of $10 billion (2001 dollars). It assumed that the pipeline will require 4 years to construct, will not be completed before 2008, and will deliver 4 billion cubic feet per day when first opened. The wellhead price of natural gas from Alaska to be delivered through the pipeline is assumed to be $0.80 per thousand cubic feet (2000 dollars). A risk premium of $0.35 per thousand cubic feet is also assumed, above and beyond the expected cost of delivery into Alberta. On average, the price in Alberta would need to be maintained for 3 years at prices above $3.00 per thousand cubic feet (or $3.50 per thousand cubic feet in the United States), depending on GDP growth, for construction to commence.

The liquefied natural gas (LNG) facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have a combined sustainable sendout of 332 billion cubic feet per year. LNG facilities at Elba Island, Georgia, and Cove Point, Maryland, are assumed to reopen in 2002, bringing maximum sustainable sendout to 718 billion cubic feet per year. An additional combined expansion capability of 274 billion cubic feet per year brings the maximum to 992 billion cubic feet per year. The combined maximum load factor for all LNG facilities is assumed to be 90 percent.

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, capital expenditures for refurbishment over and above those included in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety. (Refurbishment costs include any expenditures for repair or replacement of existing pipe.) 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.

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 VNG taxes. The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $3 (1987 dollars) dispensing charge plus taxes. Federal taxes are set and held at $0.49 in nominal dollars per thousand cubic feet.

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 [*33*] 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 traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 2000 market shares in each Census division. The expected oxygenated gasoline market shares 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), although it is not a refinery process. Ethanol is produced in dedicated plants from corn or cellulose feedstocks. Most ethanol is produced from corn in the Midwest (Census Regions 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 West South Central (Census Region 7) and Pacific (Census Region 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 [*34*]. 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 *AEO2002* 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 2003. The *AEO2002* projections also reflect legislation in 13 States, including California, that would restrict or ban the use of MTBE in gasoline between 2003 and 2004 [*35*]. 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, *AEO2002* assumes that 80 percent of RFG in the State will continue to require 2.0 percent oxygen after MTBE is banned.

AEO2002 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by 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 the years 2004 and 2007. *AEO2002* assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between 2000 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.

AEO2002 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 the distribution system will become more efficient at handling ULSD with experience.

- Demand for highway-grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total transportation distillate demand. 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.

- 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.

- The capital costs for new distillate hydrotreaters reflected in *AEO2002* are $1,690 to $2,545 (2000 dollars) per barrel per day. The lower estimate is for a 25,000 barrel per day unit processing low-sulfur feed streams with incidental dearomatization. The higher estimate is for a 10,000 barrel per day unit processing higher sulfur feed streams with greater aromatics improvement.

- 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 $1,034 million each (2000 dollars). Operating costs are assumed to be $3.90 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.60 to $4.10 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 $0.80 per million cubic feet (2000 dollars).

State taxes on gasoline, diesel, jet fuel, M85, and E85 are assumed to increase with inflation, as they have tended to in the past. Federal taxes, which have increased sporadically in the past, are assumed to stay at 2000 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 54 cents per gallon by 1 cent per gallon in 2001, 2003, and 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2020 at the nominal level of 51 cents per gallon (a decline in real terms).

Federal MTBE ban case. The *Federal MTBE ban case* reflects a nationwide ban on MTBE and other ethers starting in 2006. Political impetus for restricting MTBE use has developed because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Thus far, 13 States have passed legislation to ban or reduce the use of MTBE, and there have been similar proposals in other States. Numerous legislative proposals in the U.S. Congress, focused on MTBE removal in all States, have been linked to a waiver of the oxygen requirement on RFG and/or a renewable fuels mandate that would require that ethanol represent a specified percentage of the gasoline pool.

It was not possible to provide analysis for all the variations of MTBE ban legislative proposals. The MTBE ban case provides a very severe scenario in terms of gasoline blending, because the oxygen requirement on RFG is assumed to remain unchanged. In addition, the PMM does not account for the possible conversion of MTBE units to alkylation or iso-octane processes that would lower the cost of making gasoline relative to that in the MTBE ban case. The MTBE ban case assumes that bans or restrictions currently scheduled between 2003 and 2004 in 13 States will be implemented as planned. Other than the ban on ethers in gasoline, all model inputs and assumptions remain the same as in the *AEO2002* reference case. It is assumed that imports of reformulated gasoline blendstock for oxygenate blending (RBOB) will be available.

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 assumed 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 2.2 percent per year, declining from an estimated annual improvement rate of 5.7 percent achieved in 2000 to approximately 1.5 percent over the 2010 to 2020 period.

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 *AEO2002* 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 2020 (in short tons per hour) were 14.56 in the *low mining cost case* and 7.85 in the *high mining cost case*, compared with 10.76 in the reference case. These are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or 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 alternative low and high mining cost cases, wages and equipment costs were assumed to decline and increase by 0.5 percent per year in real terms, respectively. With the exception of the electricity generation sector, the mining cost cases were run without allowing demands to shift in response to changing prices. If demands also had been allowed to shift in the energy end-use sectors, the price changes would be smaller, because minemouth prices vary with the levels of production required to meet demand.

Notes

[*1*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001).

[*2*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html.

[*3*] Maine has passed legislation that provides a goal of phasing out MTBE.

[*4*] 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.

[*5*] Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0321(97) (Washington, DC, 1999).

[*6*] For additional information on green programs see web site www.energystar.gov.

[*7*] For further information see web site www.pathnet.org/about/about.html.

[*8*] 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).

[*9*] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[*10*] Energy Information Administration, 1995 CBECS Micro-Data Files (February 17, 1998), web site www.eia.doe.gov/emeu/cbecs/.

[*11*] 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, web site www.eia.doe.gov/emeu/cbecs/.

[*12*] 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).

[*13*] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/pv/.

[*14*] Energy Information Administration, 1998 Manufacturing Energy Consumption Survey, web site www. eia. doe. gov/ emeu/ mecs/ mecs98/ datatables/ contents.html.

[*15*] The data sources and methodology used to develop the nonmanufacturing portion of the Industrial Demand Module will be described in EIA's forthcoming model documentation.

[*16*] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[*17*] 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).

[*18*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*19*] California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*20*] Energy and Environmental Analysis, *2001 Updates to the Fuel Economy Model (FEM) Portion of the National Energy Modeling System (NEMS) Transportation Model*, prepared for the Energy Information Administration (Washington, DC, September 2001).

[*21*] 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).

[*22*] 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).

[*23*] 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.

[*24*] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[*25*] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[*26*] 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).

[*27*] 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); and 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).

[*28*] 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).

[*29*] 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, December 1999).

[*30*] 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).

[*31*] 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).

[*32*] 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).

[*33*] 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.

[*34*] 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.

[*35*] Arizona, California, Colorado, Connecticut, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington. The State of Maine has passed legislation that provides a goal of phasing out MTBE.

Appendix H

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.070
Consumption	million Btu per short ton	20.753
Coke Plants	million Btu per short ton	27.426
Industrial	million Btu per short ton	22.489
Residential and Commercial	million Btu per short ton	23.880
Electric Utilities	million Btu per short ton	20.401
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.081
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	5.336
Motor Gasoline[2]	million Btu per barrel	5.204
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	5.326
Exports[2]	million Btu per barrel	5.749
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.887
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 1999 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 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), and EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B.

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 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001).

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 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table B2.

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The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook Conference

Crystal Gateway Marriott, Arlington, VA *March 12, 2002*

Morning Program

8:30 a.m. - 8:45 **Opening Remarks -** *Administrator*, Energy Information Administration

8:45 a.m. - 9:15 **Overview of the *Annual Energy Outlook 2002* - *Mary J. Hutzler,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration

9:15 a.m. - 10:00 **Keynote Address: What We Do and Do Not Know About How Electricity Markets Work -** ***James Bushnell***, *Research Director*, University of California Energy Institute

10:15 a.m. - 12:00 **Concurrent Sessions A**

1. **Electricity Deregulation after California: Status and Future Prospects**
2. **Future Natural Gas Price Uncertainty and the Financing of New Investments**
3. **IT Sector Growth and Electricity Demand in Buildings**

1:15 p.m. - 3:00 **Concurrent Sessions B**

1. **New Developments in International Energy Modeling**
2. **Ethanol on the Brink: Significant Growth and New Technology**
3. **Challenges in Transportation Services: Will Railroads, Pipelines, and Transmission Systems Meet the Needs?**

3:15 p.m. - 5:00 **Concurrent Sessions C**

1. **Potential Markets for Alternative Fuel and Advanced Technology Vehicles**
2. **Prospects for Industrial Energy Demand: Alternative Views**
3. **Prospects for Renewables in U.S. Electricity Supply: Opportunities and Barriers through 2020**

Hotel

The conference will be held at the *Crystal Gateway Marriott*, (703) 920-3230. The *Crystal Gateway Marriott* is located near the Crystal City Metro station at 1700 Jefferson Davis Highway, Arlington, VA. A block of rooms has been reserved at the *Residence Inn Arlington-Pentagon City*, (703) 413-6630 or (800) 331-3131, in the name of the NEMS conference and will be held until February 4, 2002. The *Residence Inn* is located at 550 Army Navy Drive, Arlington, VA, near the Pentagon City Metro station.

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, 2002, 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, 2002.

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.

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❒ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

❒ Electricity Deregulation after California
❒ Future Natural Gas Price Uncertainty
❒ IT Sector Growth and Electricity Demand in Buildings

Concurrent Sessions B

❒ New Developments in International Energy Modeling
❒ Ethanol on the Brink
❒ Challenges in Transportation Services

Concurrent Sessions C

❒ Potential Markets for Alternative Fuel and Advanced Technology Vehicles
❒ Prospects for Industrial Energy Demand
❒ Prospects for Renewables in U.S. Electricity Supply

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March 12, 2002

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