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Annual Energy Outlook 1998

With Projections to 2020

December 1997

Energy Information Administration
Office of Integrated Analysis and Forecasting
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Washington, DC 20585

The *Annual Energy Outlook 1998 (AEO98)* 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 *AEO98* reference case. The next section, "Legislation and Regulations," describes the assumptions made with regard to laws that affect energy markets and discusses evolving legislative and regulatory issues. "Issues in Focus" discusses three current energy issues—electricity restructuring, renewable portfolio standards, and carbon emissions. It is followed by the analysis of energy market trends.

The analysis in *AEO98* 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 these cases are provided in Appendixes A through C. Appendixes D and E present a summary of the reference case forecasts in units of oil equivalence and household energy expenditures. Other cases explore the impacts of varying key assumptions in NEMS—generally, technology penetration. The major results are shown in Appendix F. Appendix G briefly describes NEMS and the *AEO98* assumptions, with a summary table of the cases. Appendix H provides tables of energy and metric conversion factors. *AEO98*, the detailed assumptions, and supplementary tables will be available on the EIA Home Page and on CD-ROM.

The *AEO98* projections are based on Federal, State, and local laws and regulations in effect on July 1, 1997. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the forecasts. Historical data used for the *AEO98* projections were the most current available as of July 31, 1997, when most 1996 data but only partial 1997 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official values. The *AEO98* projections for 1997 and 1998 incorporate the short-term projections from the August update of EIA's *Short-Term Energy Outlook* (*STEO*), Third Quarter 1997.

The *AEO98* 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 Administrator of EIA to prepare an annual report that contains trends and projections of energy consumption and supply.

The projections in *AEO98* 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 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 *AEO98* 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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The Energy Information Administration (EIA) presents its *Annual Energy Outlook 1998* (*AEO98*), the first *Annual Energy Outlook* to extend the projections to the year 2020. This extension is in keeping with our general philosophy of providing projections to a horizon of approximately 20 years.

As we extend the forecasts, the question of technology improvements for both energy production and energy use becomes even more important. Advances in the cost and performance of energy consumption technologies can help to moderate the growth in consumption even as the demand for energy equipment and services continues to increase. In addition, technology and productivity improvements in the production of energy can restrain the price impacts as production requirements increase or production moves to more expensive sources.

AEO98 incorporates ongoing technological improvements in its projections; however, the rate of technology improvement and penetration is highly uncertain. Consequently, we include a number of sensitivities within the report that present the impact of more rapid and slower improvements in costs, efficiency, productivity, and resources.

Carbon emissions and the role that energy consumption plays in contributing to emissions are among today's most critical and visible energy issues. The technology sensitivities indicate the extent to which carbon emissions might be mitigated by cost reductions that lead to faster market penetration of more efficient equipment or shifts to less carbon-intensive fuels.

The ongoing restructuring of the electricity industry and the trend to increased competition in the industry are also vital issues. Although last year's report included a number of assumptions on cost reductions indicated by the increasing competition in the industry, *AEO98* incorporates additional trends for lower production costs and changes to the financial requirements for construction, as a wider range of investors enter the competitive market. Also, the baseline includes the specific plans by California, New York, and New England to begin the transition to market-based pricing in 1998. In keeping with EIA's fundamental assumption that the *AEO* baseline incorporate only current laws and regulations, actions that might be taken by other States are not included because they have not been specifically formulated. Again, the report includes sensitivities exploring the impact of a transition to a fully competitive electricity market nationwide.

We recognize the importance of energy baselines to many users of the *AEO*. However, we also believe it is critically important that we continue to help inform the debate on current energy issues. The sensitivities and analyses of the key uncertainties and evolving issues included in the *AEO* are one way that EIA provides this service to policymakers and to the public.

Jay E. Hakes
Administrator
Energy Information Administration

Overview

Key Issues

The *Annual Energy Outlook 1998* (*AEO98*) is the first *AEO* with projections to 2020. Key issues for the forecast extension are trends in energy efficiency improvements, the effects of increasing production and productivity improvements on energy prices, and the reduction in nuclear generating capacity.

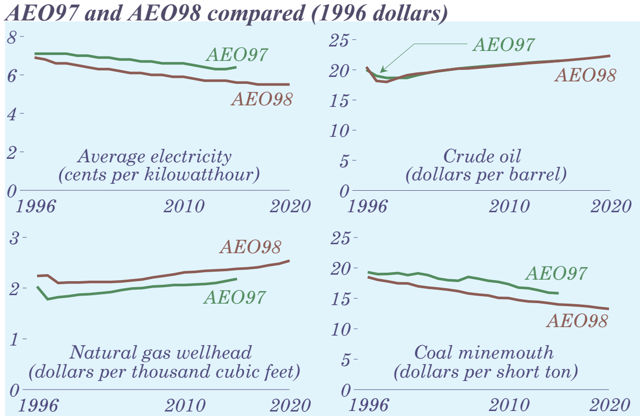
Projections in *AEO98* also reflect a greater shift to electricity market restructuring. Restructuring is addressed through several changes that are assumed to occur in the industry, including a shorter capital recovery period for capacity expansion decisions and a revised financial structure that features a higher cost of capital as the result of higher competitive risk. Both assumptions tend to favor less capital-intensive generation technologies, such as natural gas, over coal or baseload renewable technologies.

The forecasts include specific restructuring plans in those regions that have announced plans. California, New York, and New England are assumed to begin competitive pricing in 1998. The provisions of the California legislation for stranded cost recovery and price caps are incorporated. In New York and New England, stranded cost recovery is assumed to be phased out by 2008.

Prices

Average world crude oil prices in *AEO98* are projected to be similar to those in *AEO97* (Figure 1), $21.48 a barrel (all prices are in 1996 dollars) in 2015, rising to $22.32 a barrel in 2020. Worldwide demand for oil is expected to reach 116.6 million barrels per day in 2020. Because of higher assumed economic growth, the *AEO98* projection of world oil demand in 2015 is 3 percent higher than the *AEO97* projection—106.2 million barrels per day compared with 102.8 million barrels per day.

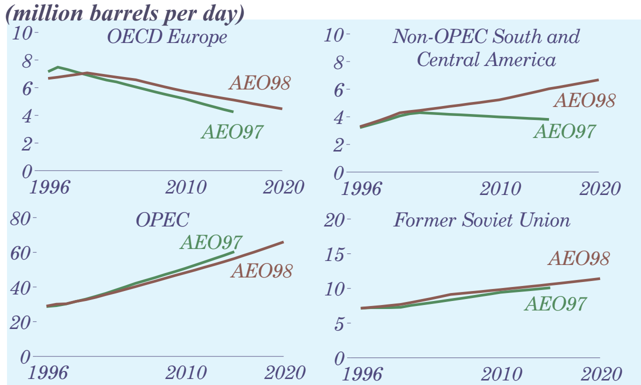
Figure 1. Fuel price projections, 1996--2020: AEO97 and AEO98 compared (1996 dollars)



Oil production in the Organization of Petroleum Exporting Countries (OPEC) continues to expand to 2020 in the *AEO98* projections, but OPEC production in 2015 is 7 percent lower than was projected in *AEO97* (Figure 2). Partially offsetting a lower outlook for Persian Gulf production are recent offshore discoveries in Nigeria and Algeria and capacity expansion in Venezuela. It is assumed that Iraqi oil production will not exceed sanction-approved levels until after 1998 and then will increase to full capacity within a decade. OPEC production capacity expansion in the Persian Gulf is lower than in *AEO97* because of a more optimistic assessment of oil production potential and technological advances in non-OPEC countries.

Higher expectations for non-OPEC oil production in *AEO98*, as compared with *AEO97*, maintain world oil prices at *AEO97* levels even with higher world demand. New fields in the North Sea slow the projected production decline in that area. Production in Central and South America increases, particularly in Mexico, Brazil, Colombia, and Argentina. In the oil-producing areas of the Former Soviet Union, current production increases through 2020, mostly due to the development of the Caspian Sea oil fields. Expectations for oil production in Canada and in the offshore areas of West Africa are also higher in *AEO98* than they were in *AEO97*.

Figure 2. Sources of world oil supply, 1996--2020: AEO97 and AEO98 compared (million barrels per day)



The average wellhead price of natural gas in *AEO98* is projected to increase to $2.38 per thousand cubic feet in 2015 (9 percent higher than the $2.18 in *AEO97*), increasing to $2.54 in 2020. Higher price projections are the result of a lower assessment of the expansion of the oil and gas resource base, higher drilling costs as indicated in more recent data, and higher projected demand for natural gas.

In *AEO98*, the average minemouth price of coal is projected to be $13.99 per ton in 2015, 12 percent lower than the $15.84 in *AEO97*. Prices are lower in *AEO98* due to analysis of more recent data showing a greater impact of productivity on mining costs and price, regional analysis of productivity improvements that reduce costs for western surface mines, and a higher share for western coal. By 2020, the price declines to $13.27 per ton as a result of increasing productivity, a continued shift to lower-cost western production, and competitive pressures on labor costs.

AEO97 represented increased competition in electricity markets by incorporating the Federal Energy Regulatory Commission actions on open access, lower costs for gas-fired technologies, and early retirements of higher cost coal-fired plants. In addition, *AEO98* assumes lower operating and maintenance costs as indicated by recent data, lower capital costs and improved efficiency for coal- and gas-fired generation technologies, lower general and administrative costs, early retirement of higher cost nuclear units, changes in financial structure, and transition to competitive prices in California, New York, and New England (as noted above). Average electricity prices decline to 5.5 cents per kilowatthour in 2020. Because of these assumptions and lower coal prices, electricity prices are 13 percent lower than in *AEO97*—5.6 cents per kilowatthour in 2015 in *AEO98*, compared to 6.4 cents in *AEO97*.

Currently evolving legislative actions that could shape the future of the electricity industry are discussed in the "Legislation and Regulations" section of this report (page 15). An analysis of the potential impacts of competitive pricing nationwide is included in "Issues in Focus" on page 20.

Consumption

Total U.S. energy consumption is projected to increase from 94.0 to 118.6 quadrillion British thermal units (Btu) between 1996 and 2020. In 2015 the *AEO98* projection is 4.7 quadrillion Btu (4 percent) higher than in *AEO97*, reflecting higher projected consumption levels in all end-use sectors.

Transportation demand grows at an average annual rate of 1.6 percent through 2020 and is 2.6 quadrillion Btu (8 percent) higher in 2015 compared with *AEO97*. Recent data indicate increased light-duty vehicle travel, particularly by the older age groups and women, and slower growth in efficiency of light-duty vehicles because of continuing consumer preference for improved performance and larger vehicles over efficiency. In 2015, motor gasoline demand is 10 percent (0.9 million barrels per day) higher than was projected in *AEO97*. In *AEO98*, jet fuel demand is 17 percent higher in 2015, reflecting an ongoing trend of more air travel, combined with slower sales of the more efficient wide-body aircraft.

In *AEO98*, residential and commercial demand is higher than in *AEO97* by a total of 1.5 quadrillion Btu (4 percent) in 2015, partly as the result of lower projected electricity prices. In the absence of additional efficiency standards beyond the new refrigerator and room air conditioner standards that were issued in 1997, penetration of more efficient technologies is assumed to occur more slowly than in *AEO97*. In the residential sector, there are also more mobile homes, a more disaggregated representation of end uses, and greater use of the more traditional heating technologies (as indicated by recent data), all contributing to higher projected demand in *AEO98*. Commercial floorspace increases at a faster rate than in *AEO97* early in the projection period, contributing to higher demand in *AEO98*. Industrial sector demand is 2 percent (0.6 quadrillion Btu) higher in 2015, with higher expected growth in some of the more energy-intensive industries partially offset by more rapid efficiency improvements.

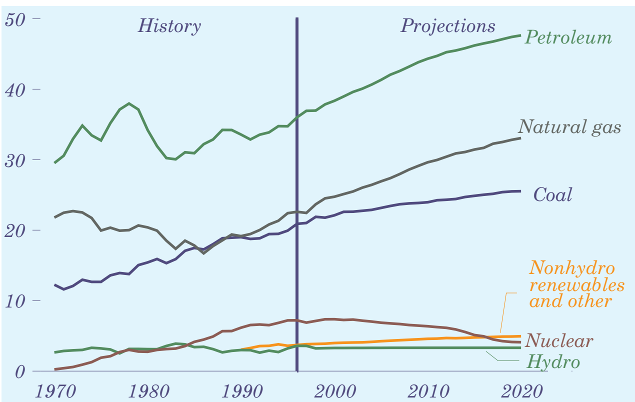
AEO98 incorporates the efficiency standards for new energy-using equipment in buildings and for motors mandated through 1994 by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992. Several alternative cases in *AEO98* examine the impacts of technology on the projections by assuming the penetration of more energy-efficient technologies in the end-use sectors beyond that projected in the reference case and, conversely, assuming slower penetration of technology improvements. Modifications to residential equipment standards are discussed on page 11.

Natural gas consumption increases by an average of 1.6 percent a year (Figure 3), with increased demand in all sectors. The most rapid growth is in consumption by electricity generators (excluding cogenerators), which is projected to increase from 3.0 to 10.1 quadrillion Btu between 1996 and 2020. Total gas consumption in 2015 is 0.5 quadrillion Btu (2 percent) higher than in *AEO97*, due to higher projected consumption in the residential, commercial, and industrial sectors.

Although coal-fired generation loses market share over the projection period, it accounts for more than one-half of electricity generation (excluding cogeneration). Total coal consumption increases from 20.9 to 25.6 quadrillion Btu between 1996 and 2020, an average annual rate of 0.9 percent. About 90 percent of U.S. coal consumption is used for electricity generation. Coal consumption is 5 percent (1.2 quadrillion Btu) higher than in *AEO97* in 2015, due to an increase in projected consumption for generation.

Demand for petroleum products is projected to grow by an average of 1.2 percent a year through 2020. In 2020, 72 percent of petroleum use is in the transportation sector, up from 66 percent in 1996. Increases in light-duty vehicle miles traveled more than offset the increases in vehicle efficiency throughout the projection period. Continued economic growth also increases petroleum use for air and freight travel and shipping over the forecast horizon. In 2015, total petroleum demand is 7 percent higher than in *AEO97*, due primarily to higher travel and slower efficiency inceases in the transportation sector.

Figure 3. Energy consumption by fuel, 1970--2020 (quadrillion Btu)



Renewable fuel use increases by an average of 0.5 percent a year. In 2020, 59 percent of the total is for electricity generation and the rest for dispersed heating and cooling, industrial uses, and blending in vehicle fuels. In 2015, renewables consumption is lower than in *AEO97* by 0.2 quadrillion Btu (3 percent) due to lower demand for renewables for electricity generation and for industrial sector cogeneration, as indicated by recent data.

Electricity consumption is projected to grow by 1.4 percent a year through 2020. Efficiency gains in electricity use partially offset the continued trend of electrification and the penetration of new electricity-using equipment. Compared to *AEO97*, electricity demand is 0.2 quadrillion Btu (2 percent) higher in 2015, due to slower efficiency improvements in the residential and commercial sectors and a more disaggregated treatment of residential end uses.

Energy Efficiency

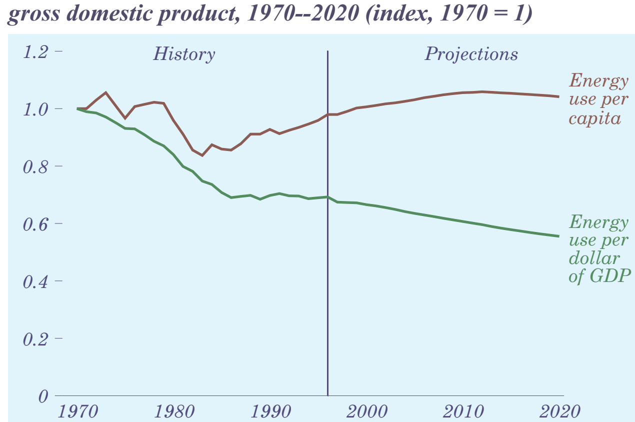
Energy intensity, measured as energy use per dollar of GDP, has generally declined since 1970, particularly during periods of rapid increases in energy prices (Figure 4). From 1970 to 1986, it declined on average by 2.3 percent a year, as the economy shifted to less energy-intensive industries and more efficient technologies. Energy intensity was relatively stable from 1986 to 1996 due to moderate price increases and the growth of more energy-intensive industries. From 1996 to 2020, intensity is projected to decline at an average annual rate of 0.9 percent.

Energy use per capita, which also declined from 1970 through the early 1980s, rose in the mid-1980s as energy prices declined. Per capita energy use is expected to remain relatively stable through 2020 and below the high in the early 1970s, as efficiency gains offset higher demand for energy services.

Electricity Generation

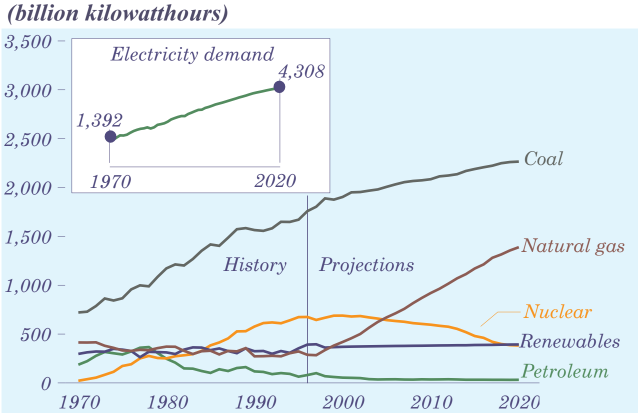
Electricity generation from nuclear power declines significantly over the projection period (Figure 5). Of the 101 gigawatts of nuclear capacity available in 1996, 52 gigawatts (65 units) are assumed to be retired by 2020, with no new plants constructed by 2020. In *AEO97*, it was assumed that nuclear plants would be retired at the end of their 40-year operating licenses; however, *AEO98* assumes that 24 units will be retired as early as 10 years before their licenses expire. The early retirement assumptions are based on utility announcements and on analysis of the ages and operating costs of the units.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1970--2020 (index, 1970 = 1)



Generation from both natural gas and coal is projected to increase significantly through 2020 to meet increased demand for electricity and offset the decline in nuclear power. With lower coal prices, lower capital costs for coal-fired generating technologies, and higher electricity demand, the projection for coal-fired generation is higher than the *AEO97* projection. The share of coal generation declines in the *AEO98* forecast to 2020, because the assumptions concerning the restructuring of the electricity industry favor the less capital-intensive gas technologies for new capacity additions. *AEO98* also incorporates a more optimistic assessment of ultimately recoverable natural gas resources, which affects capacity expansion decisions in favor of natural gas technologies. The natural-gas-fired share of electricity generation (excluding cogenerators) more than triples, from 9 percent to 31 percent, between 1996 and 2020.

Figure 5. Electricity generation by fuel, 1970--2020 (billion kilowatthours)



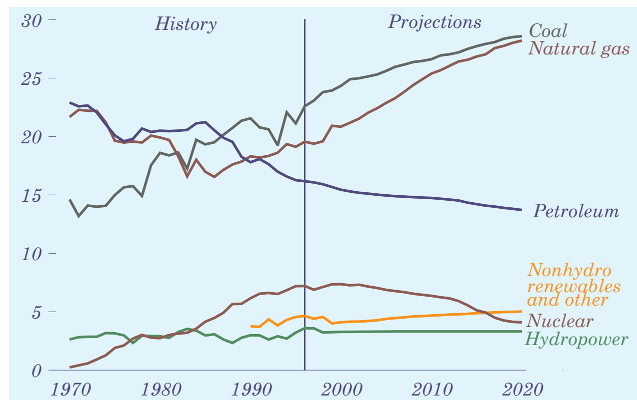
Generation from renewable energy sources remains nearly stable between 1996 and 2020. Compared with *AEO97*, renewable generation is 2 percent (6 billion kilowatthours) lower in 2015. Renewables penetrate more slowly than they did in *AEO97* due to competition with fossil fuel technologies. In addition, the shorter assumed capital recovery period for new projects weighs against more capital-intensive projects, such as coal and baseload renewables. Biomass generation is significantly lower than in *AEO97* because of lower coal prices and reduced costs for coal technologies, which compete with biomass.

In *AEO98*, hydropower, the main renewable source of electricity generation, is lower in 2020 than in 1996, primarily because regulatory actions limit capacity at existing sites and no large new sites are available for development. Generation from all other renewables increases to 2020, although at slower rates than in *AEO97*.

Production and Imports

U.S. crude oil production declines at an average rate of 1.1 percent a year between 1996 and 2020 to a projected level of 4.9 million barrels a day. Advances in oil exploration and production technologies are insufficient to offset declining resources. In 2015, projected world oil prices are the same in *AEO98* as those in *AEO97*, and domestic crude oil production is also the same at 5.2 million barrels a day. In projections of total petroleum production (Figure 6), increases in the production of natural gas plant liquids partially offset the decline in crude oil production.

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

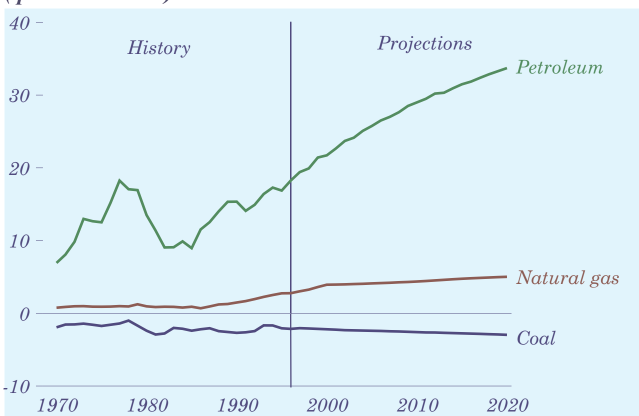


Declining production and rising consumption lead to increasing petroleum imports through 2020 (Figure 7). The share of petroleum consumption met by net imports rises from 46 percent in 1996 (measured in barrels per day) to 66 percent in 2020. Comparing *AEO97* to *AEO98*, the 2015 share increases from 61 to 63 percent as a result of higher demand and stable production.

In *AEO98*, dry natural gas production is projected to increase from 19.0 trillion cubic feet in 1996 to 27.4 trillion cubic feet in 2020, an average annual rate of 1.5 percent, to meet most of the growing demand for gas. Net imports of natural gas, primarily from Canada, increase from 2.7 to 4.9 trillion cubic feet between 1996 and 2020. It is assumed that pipeline capacity from Canada and pipeline utilization rates increase to encourage imports of competitively priced Canadian gas. Net imports of liquefied natural gas increase to 0.3 trillion cubic feet in 2020.

Coal production increases by an average of 1.1 percent a year, from 1,064 million tons in 1996 to 1,376 million tons in 2020, with increasing demand for domestic use and for exports. Exports of steam coal will primarily serve expanding markets for electricity generation in Asia, although exports to Europe and the Americas also increase. Total metallurgical coal exports are essentially unchanged from 1996 to 2020. In 2015, coal production in the *AEO98* projections is higher than in *AEO97* by 58 million tons (5 percent) due to increased con-

Figure 7. Net energy imports by fuel, 1970--2020 (quadrillion Btu)



sumption by electricity generators, which is offset slightly by a reduction in industrial demand.

Renewable energy production, including hydropower, is projected to increase from 6.9 to 7.7 quadrillion Btu between 1996 and 2020, primarily from industrial biomass, along with municipal solid waste, geothermal, wind, and biomass for electricity generation. With lower consumption in the industrial and generation sectors, the *AEO98* projection for renewable energy production is 0.2 quadrillion Btu (3 percent) lower in 2015 than in *AEO97*.

Carbon Emissions

Carbon emissions from energy use are projected to increase by 1.2 percent a year, to 1,956 million metric tons in 2020 (Figure 8). Projected emissions in 2015 are 5 percent higher than in *AEO97*—1,888 million metric tons compared with 1,799 million metric tons—due to higher energy consumption and lower penetration of renewables. About one-third of the increase over *AEO97* is attributable to increased electricity demand and the resulting increase in consumption of natural gas and coal for generation. Increased use of petroleum in the transportation sector contributes more than 50 percent of the increased emissions in *AEO98* compared to *AEO97*.

The Climate Change Action Plan (CCAP) is a collection of 44 actions developed by the Clinton Administration in 1993 to stabilize greenhouse gas emissions at 1990 levels in 2000. In 1990, carbon emissions from energy use were estimated to be about 1,346 million metric tons. *AEO98* incorporates the impacts of those CCAP provisions related to carbon emissions from energy use, including the Climate Challenge and Climate Wise programs, which foster voluntary reductions in emissions by electric utilities and industry; however, projected emissions exceed 1990 levels in 2000 by 17 percent and in 2020 by 45 percent. Further discussion of carbon emissions is presented on pages 25 and 74.

Figure 8. U.S. carbon emissions by sector and fuel, 1990--2020 (million metric tons)

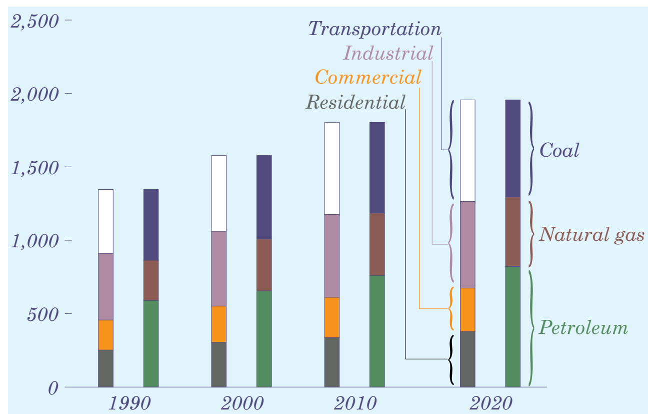


Table 1. Summary of results for five cases

Sensitivity Factors	1995	1996	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	16.26	16.17	13.71	13.13	14.28	11.47	16.03
Natural Gas	19.12	19.55	28.21	25.65	30.12	27.28	28.62
Coal	21.98	22.64	28.59	26.10	31.28	28.68	28.64
Nuclear Power	7.19	7.20	4.09	4.09	4.09	4.09	4.09
Renewable Energy	6.40	6.91	7.71	7.28	8.45	7.68	7.74
Other	1.36	1.33	0.47	0.46	0.51	0.46	0.48
Total Primary Production	**72.31**	**73.80**	**82.77**	**76.71**	**88.73**	**79.66**	**85.60**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	16.87	18.25	33.71	29.28	37.35	38.57	29.24
Natural Gas	2.75	2.77	5.02	4.70	5.48	4.91	5.23
Coal/Other (-- indicates export)	-1.73	-1.80	-2.68	-2.71	-2.65	-2.68	-2.68
Total Net Imports	**17.89**	**19.22**	**36.06**	**31.26**	**40.19**	**40.80**	**31.79**
Discrepancy	0.66	0.99	-0.25	-0.24	0.18	-0.48	0.36
Consumption (quadrillion Btu)							
Petroleum Products	34.74	36.01	47.64	42.65	52.31	50.02	46.12
Natural Gas	22.18	22.60	33.06	30.19	35.43	32.00	33.69
Coal	19.96	20.90	25.61	23.08	28.34	25.71	25.67
Nuclear Power	7.19	7.20	4.09	4.09	4.09	4.09	4.09
Renewable Energy	6.40	6.91	7.74	7.31	8.48	7.72	7.77
Other	0.39	0.39	0.43	0.42	0.45	0.44	0.42
Total Consumption	**90.86**	**94.01**	**118.58**	**107.74**	**129.10**	**119.98**	**117.75**
Prices (1996 dollars)							
World Oil Price (dollars per barrel)	17.58	20.48	22.32	21.24	23.44	14.43	28.71
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.61	2.24	2.54	1.91	2.97	2.45	2.58
Domestic Coal at Minemouth (dollars per short ton)	19.25	18.50	13.27	13.14	13.50	13.16	13.28
Average Electricity Price (cents per kilowatthour)	7.0	6.9	5.5	5.0	5.8	5.4	5.5
Economic Indicators							
Real Gross Domestic Product (billion 1992 dollars)	6,742	6,928	10,900	9,533	12,191	10,953	10,873
(annual change, 1996--2020)	--	--	1.9%	1.3%	2.4%	1.9%	1.9%
GDP Implicit Price Deflator (index, 1992=1.00)	1.08	1.10	2.26	3.20	1.69	2.27	2.25
(annual change, 1996--2020)	--	--	3.0%	4.5%	1.8%	3.1%	3.0%
Real Disposable Personal Income (billion 1992 dollars)	4,964	5,077	8,217	7,336	9,006	8,289	8,171
(annual change, 1996--2020)	--	--	2.0%	1.5%	2.4%	2.1%	2.0%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.264	1.299	2.125	1.761	2.444	2.124	2.121
(annual change, 1996--2020)	--	--	2.1%	1.3%	2.7%	2.1%	2.1%
Energy Intensity (thousand Btu per 1992 dollar of GDP)	13.52	13.57	10.89	11.31	10.60	10.96	10.84
(annual change, 1996--2020)	--	--	-0.9%	-0.8%	-1.0%	-0.9%	-0.9%
Carbon Emissions (million metric tons)	**1,411**	**1,463**	**1,956**	**1,770**	**2,134**	**1,990**	**1,940**

Notes: Assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections, beginning on page 34. 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 refin ery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Legislation and Regulations

Introduction

Because EIA analyses are required to be policy-neutral, the *AEO98* projections assume that Federal, State, and local laws and regulations in effect on July 1, 1997, remain unchanged through 2020. The potential impacts of pending or proposed legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the projections.

Federal legislation incorporated in the projections includes the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon to the Federal tax on highway fuels [1]; the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; and the Tax Payer Relief Act of 1997. *AEO98* also incorporates regulatory actions of the Federal Energy Regulatory Commission, including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other actions to foster more efficient natural gas markets.

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, annual emissions of sulfur dioxide by electricity generators are, in general, capped at 8.95 million short tons a year in 2000 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, leading to regulations that impose limits on electricity generators for NO_x emissions. The impacts of CAAA90 on electricity generators are discussed on page 76.

The provisions of EPACT focus primarily on reducing energy demand, requiring 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 owners of fleets of automobiles and trucks are required to phase in vehicles that do not rely on petroleum products.

Climate Change Action Plan

The *AEO98* projections include analysis of provisions of 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 signed by more than 160 countries in Rio de Janeiro on May 4, 1992. As part of the Rio Treaty, the economically developed countries, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels.

Energy combustion is the primary source of anthropogenic (human-caused) carbon emissions. *AEO98* estimates of emissions from fuel combustion 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, such as forests. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis. The projections do not include any other carbon mitigation actions that may be enacted as a result of the third Conference of the Parties (the signatories of the Framework Convention), which is scheduled for December 1997 in Kyoto, Japan, to consider carbon reduction goals beyond 2000.

Climate Wise and Climate Challenge are two programs cosponsored by EPA and the U.S. Department of Energy to foster voluntary reductions in emissions on the part of industry and electricity generators, as reported in the EIA publication *Mitigating Greenhouse Gas Emissions: Voluntary Reporting* [2]. *AEO98* includes analysis of the impacts of both programs (see Appendix G).

Tax Payer Relief Act

AEO98 includes the changes to excise taxes on propane and methanol produced from natural gas in the Tax Payer Relief Act signed on August 5, 1997. The Act also changed the excise taxes on liquefied natural gas (LNG); however, *AEO98* does not project a price for LNG. Taxes on these motor fuels had previously been set to be equivalent to the gasoline tax on a cents-per-gallon basis. This tax structure effectively gave a competitive advantage to gasoline because it has a much higher energy content— measured in British thermal units (Btu)—per gallon than the other fuels. Provisions of the Tax Payer Relief Act changed taxes on these special fuels to be equivalent with gasoline in terms of Btu content starting on September 30, 1997. The new tax structure reduces excise taxes on propane from 18.3 to 13.6 cents per gallon, on LNG from 18.4 to 11.9 cents per gallon, and on methanol from 11.4 to 9.15 cents per gallon.

Revisions to Appliance Efficiency Standards

In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which gave the U.S. Department of Energy (DOE) legal authority to promulgate minimum efficiency requirements for 13 classes of consumer products. The law also mandated that DOE revise and update standards through time, as technologies and economic conditions changed. From 1988 to 1995, DOE was active in establishing and updating standards for the consumer products it was assigned to evaluate. Table 2 shows the products and years in which standards were either established or revised under NAECA.

The standards that were established generally have been regarded as successful in terms of reducing energy requirements without substantial negative effects on appliance manufacturers or consumers. In the mid-1990s, however, the standards program came under public scrutiny, following the release of the Notice of Proposed Rulemaking (NOPR) for eight product categories in 1994. The 1994 NOPR issued standards that some considered too stringent on both appliance manufacturers and consumers. After intense public debate, focusing primarily on the adverse effects the standards could have on domestic ballast manufacturers, water heater manufacturers, and consumers—who would have been required to purchase more expensive heat pump water heaters in place of conventional electric resistance water heaters—DOE agreed to delete electric water heaters and ballasts from the original 1994 NOPR and to exempt color televisions from the standards process entirely. In 1995, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from issuing any new standards. DOE spent the better part of fiscal year 1996 reevaluating the standards process.

In July 1996, DOE formalized its new procedures and policies for appliance efficiency standards, creating a new process that is intended to provide for early input from stakeholders, increase the predictability of the rulemaking timetable, increase the use of outside technical experts, eliminate problematic or controversial design options, and encourage nonregulatory approaches. In January 1997, DOE established the Advisory Committee on Appliance Energy Efficiency Standards to review and participate in the standards process. The committee, representing government, industry, environmental, and public concerns, monitors and advises DOE on both the analytical and logistical aspects of the standards process.

The new process has yielded some tangible near-term results. For example, at the request of the Advisory Committee, DOE is developing computer software that allows users to vary important key inputs for the economic evaluation of appliance standards, such as future energy prices, discount

Table 2. Effective dates of appliance efficiency standards, 1988-1995

Product	1988	1990	1992	1993	1994	1995
Clothes dryers	X				X	
Clothes washers	X				X	
Dishwashers	X				X	
Refrigerators and freezers		X		X		
Kitchen ranges and ovens		X				
Room air conditioners		X				
Direct heating equipment		X				
Fluorescent lamp ballasts		X				
Water heaters		X				
Pool heaters		X				
Central air conditioners and heat pumps			X			
Furnaces						
Central (45,000 Btu per hour)			X			
Small (-,000 Btu per hour)			X			
Mobile home		X				
Boilers			X			
Fluorescent lamps, 8 foot					X	
Fluorescent lamps, 2 and 4 foot (U tube)						X

rates, and efficiency levels. To foster a greater level of trust between industry and government, this development has moved away from a "black box" approach to one that encourages interested parties to test the sensitivity of a proposed standard level to key inputs. DOE has also prioritized the standards process by characterizing each of the product classes as either high, medium, or low priority (Table 3). Thus, all interested parties will be able to focus their attention on products that have a more immediate likelihood of regulation.

Although the standards moratorium has brought about some sound changes to the standards process, it has also contributed to at least a 5-year delay in the issuance of new standards. By the end of 1997, DOE hopes to have released final actions for several product groups, including refrigerators and freezers, room air conditioners, and kitchen ranges, ovens, and microwaves. By "pre-negotiating" with industry and environmental concerns, DOE established a new standard for refrigerators that would require 30 percent less electricity by July 1, 2001. The standard still was not without controversy, precipitating protests from some manufacturers and environmental groups who believed that the original pre-negotiated arrangement, calling for a standard in 1998, was not honored.

In summary, the revised process should allow for more flexibility and public participation with respect to appliance efficiency standards. With the new process in place, DOE plans to take final action on its high-priority items over the next 2 years, setting the stage for numerous efficiency standards in the early 21st century, with the potential for greater energy savings over the next several decades. Given the historical uncertainty of the standards process, the *AEO98* projections take into account only the standards for which final actions have been taken. At the time the projections were finalized, the only product categories for which final action had been taken in the promulgation of new standards were room air conditioners and refrigerators and freezers. The *AEO98* projections reflect only these new standards and none of the other potential new appliance efficiency standards.

New National Ambient Air Quality Standards

In July 1997, the EPA finalized new attainment standards for ground-level ozone (smog) and fine particulate matter (PM). The new standards will have no immediate impact on energy markets; however, some impacts may be seen after 2004, to the extent that pollution control strategies focus on reducing emissions from electric utilities, industry, and motor fuels combustion. The potential energy impacts of the new standards have not been incorporated in *AEO98*, because noncompliance areas and control strategies have not yet been identified. Some possible impacts of the new standards are explored below.

Ground Level-Ozone Standards

The ambient air standards for ozone have been changed from a measurement of 0.12 parts per million (ppm) averaged over a 1-hour period to a new 0.08 ppm standard averaged over 8 hours. The revised standards also include some methodological differences for measuring exceedences. The current limit of "1 expected exceedence" (i.e., when the expected number of days above the standard per year, averaged over 3 years, is greater than 1) will be replaced by a "concentration-based" limit, calculated as the 3-year average of the annual fourth-highest daily maximum ozone concentration.

Table 3. Product categories and priority levels for new standards

Product	Priority	Product	Priority
Distribution transformers	*High*	*Clothes dryers*	*Low*
Clothes washers	*High*	*Dishwashers*	*Low*
Fluorescent lamp ballasts	*High*	*Furnaces and boilers*	*Low*
Water heaters	*High*	*Pool heaters*	*Low*
Kitchen ranges, ovens, and microwaves	*High*	*Direct heating equipment*	*Low*
Central air conditioning and heat pumps	*Medium*	*1- to 200-horsepower motors*	*Low*
Small electric motors	*Low*	*Fluorescent and incandescent lamps*	*Low*
High-intensity discharge lamps	*Low*		

The EPA estimates that 67 percent of the nonattainment areas under the new standards could be brought into compliance merely by continuing current pollution control strategies[3]. States will not be required to provide new attainment plans until 2003; however, areas that met the former standard but do not attain the current standard are encouraged by the EPA to achieve a "transitional status" by providing early attainment plans in 2000 [4].

Ground-level ozone is caused by the photochemical reaction of nitrogen oxides (NO_x) and volatile organic compounds (VOCs). NO_x emissions result when fuel is burned in motor vehicles, industrial plants, and electric utility plants. VOC emissions include unburned motor fuels and vapors that escape from petroleum products, paints, dyes, etc. [5].

Although State implementation plans (SIPs) will be unique to each State, all are likely to include strategies to reduce NO_x and VOC emissions from such key sources as electric utilities, industries, and motor fuels consumption. The EPA is relying heavily on States to adopt voluntary regional strategies for reducing the long-distance transport of ozone. In 1997 the Ozone Transport Assessment Group (OTAG), with representatives from 37 States, provided the EPA with recommendations for reducing ozone transport, including utility and nonutility NO_x controls, an NO_x trading program, implementation of a national low-emissions vehicle program, changes to vehicle emissions inspection and maintenance controls, changes to diesel fuel standards, and increased use of reformulated gasoline. Some of those strategies may play a role in ozone compliance.

Particulate Matter Standards

The previous standards for particulate matter were concerned with relatively coarse combustion particles, at least 10 microns (μm) in diameter (PM_{10}). The new standards change the methodology for measuring PM_{10} exceedences, from one expected exceedence per year of 150 micrograms per cubic meter ($\mu g/m^3$) in a 24-hour period and an annual mean standard of 50 $\mu g/m^3$, to a concentration-based form that preserves the 50 $\mu g/m^3$ annual standard but changes the 24-hour standard to a 99th percentile form averaged over 3 years. In addition, the major change is the creation of a new standard for fine particles, smaller than 2.5 μm in diameter ($PM_{2.5}$). The new health-based standard sets the exceedence limits for $PM_{2.5}$ at 15 $\mu g/m^3$ (3-year annual arithmetic mean) and a 24-hour standard of 65 $\mu g/m^3$ (99th percentile of concentrations in a year averaged over 3 years). The change will require tighter controls for fine ash and solid particles resulting from combustion. Controls for a new class of pollutants, nitrate and sulfate particles, will also become necessary [6].

Because fine particles are not currently monitored, the EPA is allowing States 5 years to gather and analyze the data for compliance. Areas not in compliance will have until 2005 to submit air quality plans, followed by another year and a half for review of the plans and several more years before compliance will be required.

Implications for Electric Utilities

The new attainment standards for NO_x and fine particulates could have a significant effect on the operating costs for electricity generating plants. Although the selection of an appropriate technology to control NO_x and particulates depends on the specific generating technology, configuration of the plant site, and economic considerations, utilities have successfully employed many pollution abatement systems. Low-NO_x burners, flue gas recirculation, staged combustion, and reduced oxygen concentration have already been used to control NO_x formation, and electrostatic precipitators, fabric filters, and cyclone separators have been used to control particulates. For compliance with the new standards, it is expected that utilities will need to install NO_x removal technologies that are more efficient than those widely used at present. Possibilities include selective catalytic reduction, switching from coal to gas as the generating fuel, and derating boilers to produce less steam and, hence, less NO_x. Similarly, utilities may need to install wet cyclone or wet ionizing scrubbers to capture particles as fine as $PM_{2.5}$.

Innovative technologies that are more efficient in removing NO_x and particulates than those that currently are widely employed are not without costs. Generally, they have high capital costs and, in addition, use a portion of the generating plant's output. The cost to utilities of new scrubbers to reduce soot alone could run into the billions of dollars. And, according to the EPA [7], a selective catalytic reduction (SCR) system for reducing NO_x has capital costs of $60 to $70 per kilowatt of capacity. Thus, adding an SCR unit to an existing 500-megawatt coal-fired generator would cost between $30 and $35 million. The additional costs, both investment and operating costs, of the SCR unit would increase the plant's generating costs by nearly 3 mills per kilowatthour—roughly 10 to 15 percent of its operating costs. It is not clear how many plants may have to add SCR systems. If a quarter to one-half of the existing U.S. coal-fired generating plants (75,000 to 150,000 megawatts) were required to do so, the capital costs would be between $5 billion and $10 billion. The impact on electricity prices would be between 0.8 and 1.5 mills per kilowatthour, or a 1- to 2-percent increase. For the average residential customer, this might amount to an increase of $1.00 to $1.50 in average monthly bills.

The cost of compliance with the new rules will not be distributed evenly across the country. Compliance costs are expected to be lower, for example, in the Northeast, where utilities have made significant reductions in nitrogen oxides in recent years, than in the Midwest and Southeast, which have large amounts of coal-fired baseload capacity.

In general, the extended time line for compliance with the new rules may help to dampen the costs. In the case of the new ozone rules, States will not need to submit their plans to EPA until 2003. Implementation of the plans can occur between 2005 and 2012. For $PM_{2.5}$ particulates, pollution monitors will need to be sited and the data collected and reviewed before compliance strategies are submitted. Implementation is not required until at least 2007 and can extend to 2016.

Implications for Industrial Energy Consumption

Typically, more stringent limits on emissions tend to favor natural gas over other fuels. In the industrial sector, however, there is little room for fuel switching. The *AEO98* projections do not indicate any significant increases in industrial use of either coal or petroleum. Thus, although there may be some modest amounts of shifting from coal to natural gas, the aggregate effect is likely to be small. The VOC standards could have the effect of increasing natural gas consumption in those industries engaged in coating and finishing, where fugitive VOCs often are controlled by combustion with natural gas. Since it is unclear what the energy consumption impacts of the new standards will be, no impact has been assumed in the *AEO98* energy forecast.

Implications for Motor Fuels Consumption

In the transportation sector, it is unclear what impacts the recent National Ambient Air Quality Standards (NAAQS) will have on fuel consumption. The EPA is currently evaluating the following compliance strategies: heavy-duty vehicle retrofits and/ or voluntary standards; heavy-duty in-use initiatives, especially with more inspection and maintenance programs; long-term research on emissions standards for heavy-duty vehicles; new truck and bus PM standards; lower tailpipe standards for all emissions; new vehicle technologies and clean fuels programs; nonroad diesel PM test procedures and standards; and research into further reductions in emissions from locomotives, aircraft, ships, and lawnmowers and other small engine equipment. In addition, some current fuel quality requirements could be extended, such as the Federal Reid vapor pressure regulation on gasoline, requirements for oxygenated and reformulated gasoline (RFG), and the Clean Air Act Amendments of 1990 (CAAA90) low-sulfur diesel fuel program, which reduces particulate emissions as well as some hydrocarbon and carbon monoxide emissions.

Ten of the areas with the worst ozone pollution currently are required to use RFG under the provisions of CAAA90. Areas with less severe ozone problems in 13 States have opted to use RFG as part of their States' attainment strategies. Under more stringent ozone standards, additional areas may adopt RFG requirements to reduce NO_x and VOC emissions.

Because the decision to join the RFG program is at the discretion of each State, the outlook for RFG demand is uncertain. In the *AEO98* projections, the possible impact of higher RFG demand in the regions with the most new nonattainment areas was explored in an alternative case, assuming a 10-percent increase in the RFG market share in areas east of the Rocky Mountains (Census Divisions 1, 2, 3, 4, 5, 6, and 7). Relative to gasoline price projections in the *AEO98* reference case, the overall impact of the shift toward RFG consumption on projected average U.S. gasoline prices in the alternative case was small. Higher RFG prices in the alternative case were offset in part by lower prices for conventional gasoline: RFG prices were 1 to 4 cents per gallon higher than in the reference case, depending on the region and year, whereas conventional gasoline prices were 1 to 3 cents per gallon lower. The net effect on national average gasoline prices was an increase of no more than 1 cent per gallon.

In its final recommendations to the EPA, OTAG included several fuel-related proposals for reducing ozone pollution. In addition to encouraging participation in the Federal RFG program, OTAG recommended that EPA adopt a lower (unspecified) sulfur standard for gasoline. OTAG also recommended that the EPA evaluate a change in the cetane standard for diesel fuel by 1999 and implement a new standard if appropriate, and that new diesel fuel standards be identified and implemented by 2004 if they are found to be beneficial and cost-effective. The new diesel fuel standards, implemented in conjunction with new diesel engine standards, would have the potential to reduce PM emissions significantly, as well as reducing NO_x and VOC emissions.

Electricity Deregulation

Throughout the United States, a march toward more competitive electricity markets is continuing. At the Federal level, several bills have been introduced in Congress to encourage competition in electricity markets. In addition, the Federal Energy Regulatory Commission (FERC) continues to work to ensure that transmission capacity will be available on equal terms to all market participants. At the local level, some State regulators and legislatures are moving toward competition very rapidly. In fact, some consumers will be able to choose among electricity suppliers in 1998.

The bills that have been introduced in Congress generally include provisions in one or all of the following key areas [8]. First, they require that all consumers have the right to choose their electricity suppliers within a specified time period—generally, 3 to 6 years. Second, they repeal portions of the Public Utility Regulatory Policies Act of 1978 (PURPA), releasing utilities from their obligation to purchase power from qualifying cogenerators and small power producers at specified costs. Third, they repeal portions of the Public Utility Holding Company Act of 1935 (PUHCA), allowing large utility holding companies more freedom to invest in businesses in multiple States. Fourth, they establish funds and/or portfolio standards to continue support for low income, energy efficiency, environmental protection, and renewable energy programs.

For example, H.R. 655, the "Electric Consumers' Power to Choose Act of 1997," introduced on February 10, 1997, calls for all consumers to have the right to choose their electricity suppliers by December 15, 2000. Once consumers in a State have the right to choose, the bill repeals the provisions of PUHCA and PURPA. It also establishes a renewable energy credit program, requiring that a certain percentage of power be generated from qualifying renewable energy sources. A more complete discussion of renewable portfolio standards is presented in the "Issues in Focus" section of this report, on pages 23-25. A similar bill, S. 237, the "Electric Consumers Protection Act of 1997," was introduced in the Senate on January 30, 1997. The major difference between S. 237 and H.R. 655 is that the Senate bill delays the requirement for consumers to have the right to choose electricity suppliers until December 15, 2003.

At the FERC, efforts continue to ensure that the electricity transmission system is available, under comparable terms, to all who wish to use it. In 1996, FERC issued Orders 888 and 889, which were designed to provide open access to the transmission system to all market participants. Open access is critical to the development of competitive electricity markets. Electricity transmission lines are the highways of the electricity market, carrying large quantities of high-voltage electricity from generating plants to the local distribution system that deliver it to homes and businesses. Currently, the system is owned and operated primarily by the same companies that generate power and sell it to consumers. Such a structure might cause problems in a competitive market. It is the equivalent of having one or a small number of trucking companies controlling access to all the roads over which trucks travel.

To overcome this problem, FERC Orders 888 and 889 require that electric utilities "unbundle" the different sectors of their business. In other words, they must separate the operation of transmission systems from the operation of generation and distribution systems. Essentially, they must operate their transmission systems as if they were independent businesses. Toward this end FERC required that transmission-owning utilities implement an Open Access Same-Time Information System (OASIS) and encouraged them to establish independent system operators (ISOs) for transmission systems.

The OASIS concept was devised because FERC realized that access to information about the transmission system is critical to the formation of a competitive electricity market. If the owners of transmission lines were the only ones who had this information, they would have a significant advantage in the market for wholesale and retail power. The OASIS is intended to provide all the information needed to use the transmission system, including the amount of available transmission capacity, the price for using it, and the availability and price of ancillary services [9]. In order to ensure that all OASIS nodes provide information in a similar fashion, FERC, working with the industry, has carefully defined the minimum data elements that must be included, the look and feel of the node, and the service levels required [10]. To date, 22 OASIS nodes are operating [11].

ISOs will be independent entities set up to maintain and operate utility-owned transmission facilities. In particular, they will be independent from the utilities that own the transmission lines. A variety of functions have been proposed for ISOs, but in general they would be responsible for operating and maintaining the transmission system and ensuring that proposed generator operating plans are consistent with consumer demands for power. In some cases, they would also operate a short-term market for electricity, taking power supply bids from generators and matching them to consumer power demands.

Like Congress at the Federal level and FERC at the wholesale level, many State regulators and legislatures are moving aggressively toward competitive electricity markets at the retail level. The list of States preparing to open their electricity markets to full competition continues to grow. A review of State plans indicates that between 15 and 20 States are planning to move to full retail choice by 2002 [12]. In fact, at least 5 States—California, Massachusetts, New York, New Hampshire, and Rhode Island—are expected to introduce some level of retail competition in 1998. The thorniest problem facing State regulators and legislatures continues to be dealing with utility stranded costs. Stranded costs occur when the competitive market price for power is below the price needed to recover the investment in an existing plant (or contract). In most regions of the country, competitive prices for power are expected to be below historical prices, and some utilities could see their market values fall.

In California, all consumers are to have the right to choose electricity suppliers starting on January 1, 1998. An ISO will operate the transmission system, and a separate entity, the power exchange (PE), will operate a short-term spot market for electricity. The existing utilities in California are required to sell off a portion of their fossil-fired generating capacity to ensure that there will be sufficient competition among electricity suppliers. In addition, existing utilities are required to sell all their power through the PE during the first few years of competition. Stranded costs are to be collected through a competitive transition charge (CTC) between 1998 and 2001. However, residential rates are capped at 10 percent below 1996 levels in 1998 and as much as 20 percent below 1996 levels in 2002. The rates will include a public benefits charge to support various programs. The required rate reductions are to be achieved in part through special financing arrangements supported by the State.

In Massachusetts, all consumers are expected to be able to choose their suppliers in 1998. As in California, an ISO and a PE will be set up to operate the transmission system and provide a short-term pool for energy transactions. Utilities are required to separate the operations of their different business sectors—generation, transmission, and distribution—and to operate them as separate companies. In fact, they are encouraged to divest themselves fully of their generating assets, and several utilities in the State have announced plans to sell their non-nuclear generating assets. A fee of 1 mill (0.1 cent) per kilowatthour will be collected to support renewable energy. Utilities are also required to make efforts to mitigate their potential stranded costs through cost reductions. They will be afforded the opportunity to recover any remaining stranded costs over a 10-year transition period through an access fee. Full recovery of stranded costs is not guaranteed.

In New York, full retail access is being phased in over 4 to 5 years. As in California and Massachusetts, an ISO will operate the State's transmission system. Large industrial customers will, in general, have access earlier, followed by commercial and residential customers in 2001 and 2002. Individual agreements are being negotiated with each of New York's major utilities to phase in retail access and recover stranded costs. Each of the proposed agreements calls for some level of rate reduction over the phase-in period, but the amount varies by company and customer class. The agreements also require each of the companies to sell off a portion of its generating assets to ensure that there will be enough suppliers to make the market competitive.

In New Hampshire, retail pilot programs were begun in 1996, bringing significant rate reductions to many customers. Retail access for all customers will begin in 1998. Utilities must functionally unbundle their different business sectors, and an ISO will run the transmission system. A fee of 1.5 mills per kilowatthour will be assessed to support energy efficiency and integrated resource planning programs. Initial stranded costs have been estimated by comparing each utility's rates with average regional rates. Final stranded costs will be determined when assets are sold off.

Finally, in Rhode Island, where industrial customers were given full retail access to electricity suppliers in July 1997, all customers are to have retail access by July 1, 1998. Utilities are required to provide a standard offer to their customers that is equal to their rates as of September 30, 1996, adjusted for 80 percent of the change in the consumer price index (CPI). Utilities are working on selling off their generating assets. A stranded cost fee has been established to recover regulatory assets, nuclear obligations (including decommissioning and costs independent of operation), above-market payments for purchased power, and net unrecovered costs of generating plants. The fee is set at 2.8 cents per kilowatthour between July 1, 1997, and December 31, 2000, and will be adjusted by the State's public utilities commission as needed between December 31, 2000, and December 31, 2009.

Issues in Focus

Electricity Pricing in a Competitive Environment

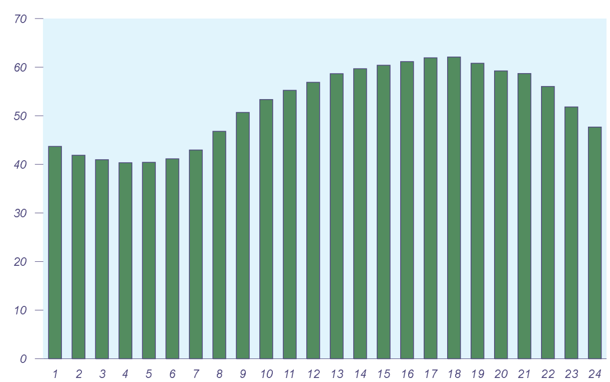
If State plans for the deregulation of electricity markets are implemented as expected, some consumers will soon have the ability to choose their electricity suppliers. While this by itself represents a significant market adjustment, there may be an even more profound change in the way electricity is priced. (This discussion refers to the price of generation services. It is assumed that prices for transmission and distribution services will continue to be set administratively.) For the past 60 years or so, electricity prices in the United States have not been determined in a competitive market. Rather, prices have been set administratively to the average cost of producing and delivering electricity to consumers. State regulators determine the average "embedded cost" of each kilowatthour of electricity sold, by adding all costs—including fuel, recovery of investment costs, operations and maintenance costs, and a regulated profit—and dividing by the number of kilowatthours sold.

In competitive markets, prices will not be equal to average embedded costs but will be determined freely by buyers and sellers in the marketplace. During most time periods the generation price of electricity will be set by the operating costs of the most expensive generating unit needed to meet demand, or what in economics is referred to as the "marginal cost" of production. In general, a supplier will not be willing to sell power below the market price of the most expensive facility operating at a given time, because consumers will be willing to pay the higher price. Similarly, consumers will be unwilling to pay more than the cost of the most expensive operating available generator, since other suppliers will be offering lower prices [13]. Thus, prices will tend to be set by the marginal costs during any given time period.

Only during periods of extremely high (peak) demand, typically on very hot summer (or cold winter) days, when the demand for electricity approaches the available generating capacity, might prices rise above the operating costs of the most expensive generator operating. Because the amount of capacity available at any point in time is fixed, and new generating capacity cannot be built quickly, the only way in which demand and supply can be kept in balance during extremely high demand periods is through an increase in the price, to a level that will encourage some consumers to reduce their usage.

The movement to prices based on marginal costs has several implications. First, electricity prices are likely to vary from hour to hour as consumer demand changes. In many regions of the country, consumer demand for electricity during a typical summer day is lowest in the early morning hours when people are asleep and businesses are closed. Through the day, demand rises as temperatures rise and homes and businesses use more air conditioning (Figure 9). As a result, in the early morning only generators with the lowest operating costs are running. Over the course of the day, more expensive generators are brought into service as demand grows. The competitive price

Figure 9. Hourly load curve for the South Atlantic region (megawatthours)



of electricity follows the operating costs of the marginal generator—that is, the last one brought on line. Another implication of the change in pricing of generation services is the sensitivity of electricity prices to the operating costs of the marginal generator. With average cost pricing, the impact of any underlying change in operating costs (such as higher fuel or operations and maintenance costs) on electricity prices tends to be muted, because it is averaged in with all the other costs that are not changing. With marginal cost pricing, any change that affects the operating costs of the generators setting the market clearing price will be fully seen in the price of electricity.

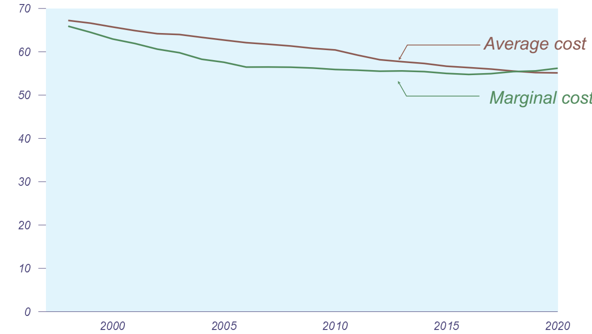
Consumer responses to price variations and new product offerings in competitive electricity markets are likely to vary, depending on such factors as the type of customer, the value placed on electricity-based services, the price and availability of alternative energy sources, and the availability of new technologies that will permit the levels and timing of electricity consumption to be altered with relative ease. For example, large, electricity-intensive industrial customers, who have a strong incentive to reduce their electricity expenditures, may be willing to alter work schedules to take advantage of lower electricity prices during periods of lower demand; residential customers may be willing to change home heating patterns to reduce consumption during high load hours while they are away from home; but commercial customers who rely on uninterrupted service during the prime business hours of the day may be unwilling or unable to change their consumption patterns to take advantage of price fluctuations unless storage or backup technologies become less expensive and more widely available.

In the long term, new technologies are likely to play a key role in determining the level of consumer response to changing prices. Faced with more volatile prices, equipment vendors will develop, and consumers will seek to purchase, equipment that allows for better control of electricity use. For example, intelligent electric meters, which monitor the electricity use of a household or business minute by minute, are already entering the marketplace. Combining this equipment with a real-time price signal and the ability to control key appliances or equipment may enable consumers to reduce electricity usage during high cost periods.

Many residential customers participating in demand-side management programs are already familiar with the boxes connected to their water heaters and/or air conditioners that allow local utilities to shut them off during periods of high demand. Similarly, some commercial establishments have cool storage systems that make ice during low cost periods and then use it for space cooling when prices are higher. Such systems may become more prevalent where competitive electricity prices and time-of-use rates are implemented. Ultimately, their success will depend on weighing the costs associated with new meters, equipment control boxes, and telecommunication devices for transmitting price signals against the potential savings from lowering the amount of electricity consumed or shifting consumption to lower cost periods.

The following analysis discusses the impacts of a movement to electricity prices based on marginal costs and their sensitivity to demand variations and the operating costs of the marginal generator. In the reference competitive pricing case, it is assumed that competition will be phased in over a 10-year period, with full competition and prices based entirely on marginal costs beginning in 2008. As shown in Figure 10, in most parts of the country today, marginal operating costs are below average embedded costs, because some of the plants that are operating have costs, including recovery of construction costs, that make them uncompetitive in today's market for power. As a result, competitive electricity prices (based on marginal operating costs) fall below the average-cost-based (regulated) prices until the end of the projection period in the reference case (Figure 10) [14]. The gap is fairly narrow, because it is assumed that the transition to competitive prices based on marginal costs will occur slowly over a 10-year period. If it occurs more rapidly, the gap in the early years could be much larger. Many factors have

Figure 10. Average and marginal costs of electricity generation in the reference case, 1998--2020 (1996 mills per kilowatthour)

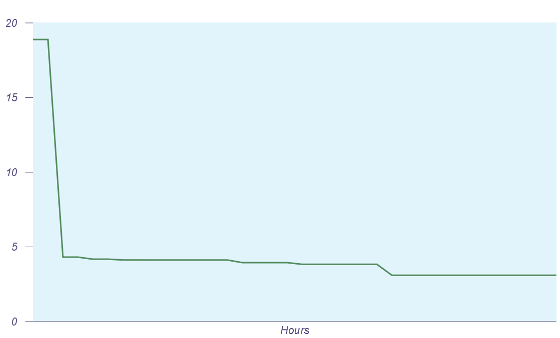


contributed to this situation, including lower-than-expected fossil fuel prices, the unexpected slowing of demand growth through the 1980s, and the development of new low-cost, high-efficiency generating technologies (gas combustion turbines and combined-cycle plants).

The difference between the two price lines in Figure 10 is the source of stranded costs. In a few regions of the country, where average costs already are relatively low, stranded costs may be negligible or actually negative. In most regions of the country, marginal-cost-based prices in 2010 are expected to be between 4 and 15 percent lower than average-cost-based prices. Only in the Northwest, where average-cost-based prices are very low, are marginal-cost-based prices expected to be higher— by 10 percent [15]. It is also possible that, in a competitive pricing environment, some costs could rise—such as the costs of sales, marketing, and system operations. The recovery of such costs in competitive prices might reduce the amount of stranded costs. At any rate, over time, the difference between costs and prices narrows, as stranded costs are paid off or written off [16].

Over the course of a day and year, competitive prices do vary with demand. In the fall and spring, when consumer needs for electricity are relatively low, prices are low. Conversely, in the summer, or when a large number of plants are out of service, prices rise as the most expensive generators—normally idle—are brought on line to meet demand. In the sample region and season shown in Figure 11, competitive prices in 2020 range from a high of 19 cents per kilowatthour to a low of just over 3 cents per kilowatthour in the reference case. Fortunately, the periods of high prices are expected to be limited to only a few hours during the season.

Figure 11. Generation price of electricity by hour for the January/February season (1996 cents per kilowatthour)



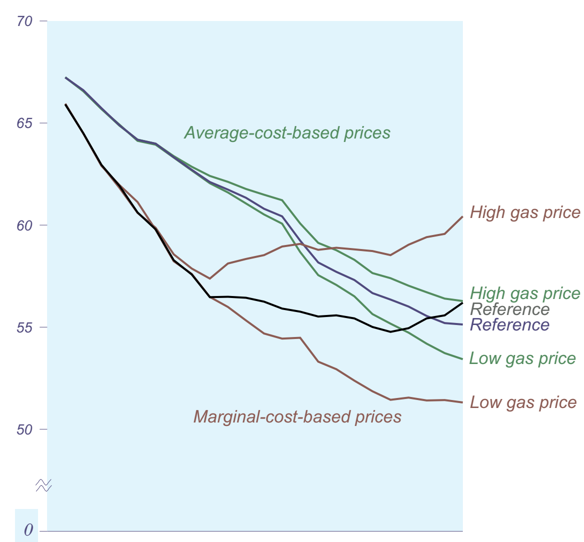
Two alternative competitive pricing cases—which incorporate alternative assumptions about improvements in natural gas recovery and distribution technology, leading to different gas price paths—are discussed. Gas prices are varied in these cases for illustrative purposes only, to demonstrate how marginal electricity prices might respond. The projections should not be seen as representing an expected outcome.

As in the reference competitive pricing case, it is assumed that competition will be phased in over a 10-year period, with full competition and prices based entirely on marginal costs beginning in 2008. Whereas the reference competitive pricing case assumed moderate improvement in natural gas availability, the low gas price competitive pricing case assumes rapid improvement; and the high gas price competitive pricing case assumes little improvement. Table 4 shows projected natural gas prices to

Table 4. Natural gas prices to electricity producers in three competitive pricing cases, 2000-2020 (1996 dollars per million Btu)

	2000	2010	2015	2020
Low gas price	2.48	2.72	2.64	2.65
Reference	2.50	2.92	3.07	3.25
High gas price	2.49	3.27	3.50	3.83

Figure 12. Average and marginal cost-based prices for electricity in three cases, 1998--2020 (1996 mills per kilowatthour)



electricity generators in the three cases.

Higher or lower gas prices have an impact both on prices that are based on average embedded costs and on prces based on margal costs; however, the magnitude of the impact is quite different (Figure 12). With 18 percent lower gas prices in 2020, average-cost--based prices are 3 percent lower than in the reference case, while marginal-cost-based prices are 9 percent lower than in the reference case. Similarly, with 18 percent higher gas prices in 2020, average-cost-based prices are 2 percent higher, while marginal-cost-based prices are 8 percent higher. In the high fuel price case, marginal-cost-based prices actually exceed average-cost-based prices by 7 percent. The difference is explained by the fact that prices based on marginal costs are much more sensitive to changes in the operating cost of the marginal unit than are prices based on average costs.

Stimulating Renewables in a Competitive Environment

As the price of electricity and the procurement of new generating resources become increasingly competitive, many are worried that some programs formerly sponsored by utilities will fall by the wayside. Such programs include low-income support programs, demand-side management (DSM) programs, and integrated resource planning programs, which have increased the penetration of renewable technologies. These programs were developed by utilities and regulators to achieve social goals, overcome barriers thought to prevent some technologies from penetrating the market, and incorporate the environmental externalities associated with power production in the resource selection process. In a competitive environment, where new resources are selected solely on the basis of their market economics, they may be hard to sustain.

Several approaches for continuing these, or similar, programs are being considered. Among the two most popular are the establishment of a public benefits fund (PBF) and a renewable portfolio standard (RPS). With a PBF, a small fee would be added to the price of each kilowatthour of electricity sold to support qualifying programs, typically including renewable energy, universal electric service, affordable electric service, and energy conservation and efficiency programs. A typical proposal—S. 687, the "Electric System Public Benefits Protection Act of 1997"—calls for a fee, not to exceed 2 mills per kilowatthour, to be established. For the typical residential consumer, such a fee would increase average monthly electricity bills by no more than $2.

The RPS would specify a percentage of total electricity generation (or sales) that must come from qualifying renewable generating sources, including wind, solar, landfill gas, geothermal, and biomass generating plants. Credits would be issued for each kilowatthour of qualifying renewable generation. The credits could then either be held or sold to electricity providers generating power from nonqualifying facilities. For example, with a 5-percent RPS, a coal or gas plant generating 100 megawatthours of power would have to purchase 5 megawatthours of renewable credits to meet the standard. New qualifying renewable facilities would be encouraged, because they would be able to make money both by selling power at market prices and by selling excess credits.

Several bills that include RPS provisions have been introduced in the U.S. Congress, including S. 237 (Senator Bumpers), S. 687 (Senator Jeffords), and H.R. 655 (Congressman Schaefer). The most significant differences among the bills are in the level of renewables required and the technologies that qualify for renewable credits. In S. 237, the RPS grows from 5 percent in 2003 to 12 percent in 2013. All renewable technologies other than municipal solid waste (MSW)—including new hydroelectric plants (the treatment of hydroelectric plants varies by the vintage of the plant)—are included. In S. 687, the RPS requirement is much higher, growing from 2.5 percent in 2000 to 20 percent in 2020. Neither incinerated MSW nor hydroelectric plants are included. In H.R. 655, the RPS grows from 2 percent to 4 percent between 2000 and 2010, and all renewable technologies other than hydroelectric plants are included.

Several States also may pursue RPS or similar requirements. Nevada's recently passed "Domestic Energy Portfolio Standard" (Assembly Bill 366) requires all retail sellers of electricity in the State to purchase or generate a percentage of their energy sales from biomass, geothermal, solar, or wind resources. Beginning at 0.2 percent of sales in 2001, the renewables standard rises to 1 percent in 2008.

The energy must come from new systems, at least half of it from solar energy, and at least half from systems located in Nevada. Vermont's proposed RPS (approved in the Vermont Senate and under consideration in the House) calls for increasing the State's use of "new" and "emerging" renewables, including solar and wind, starting in 1998 and reaching 4 percent of sales by 2008. California's restructuring legislation (Assembly Bill 1890), while not setting percentages for renewables, requires investor-owned utilities to collect $540 million from ratepayers from 1998 through 2002 for the support of renewables, with funds to support both operation of existing projects and also the development of new and emerging renewable energy technologies in the State.

The following analysis discusses the impacts on technology selection for new capacity, generation by fuel, average electricity prices, total expenditures on electricity, and carbon emissions of two alternative RPS cases—assuming a 5-percent RPS program and a 10-percent program. In both cases, the standard is assumed to begin in 2000 at 2 percent, growing linearly to 5 or 10 percent by 2020. Qualifying facilities include wind, solar, landfill gas, geothermal, and biomass generating plants. Hydroelectric plants and MSW plants are excluded.

Relative to the reference case, a 5- or 10-percent RPS would increase the amount of new renewable capacity built by 24 gigawatts and 59 gigawatts, respectively, in 2020 (Figure 13). The impacts in the 5-percent case are relatively small, because the amount of new renewable capacity that is built, above what is built in the reference case, is not large. Among the renewable technologies, biomass and wind plants are expected to account for most of the new additions. The technologies displaced are new gas- and coal-fired plants.

In the reference case, gas-fired combustion turbines and combined-cycle plants are projected to account for the vast majority of new plants built between 1996 and 2020, because their efficiency and low capital costs make them economically attractive. Few new coal-fired plants are expected to be built until after 2010. Imposition of the RPS reduces the number of new gas- and coal-fired plants projected to be built, although natural gas technologies still account for the vast majority of new builds. The percentage of new plants that are gas-fired falls from 85 percent in the reference case to 82 percent and 76 percent in the 5- and 10-percent RPS cases, respectively. A 5- or 10-percent RPS is not large enough to eliminate the growth expected for new gas-fired capacity.

Similar changes in generation by fuel are seen in the 5- and 10-percent RPS cases (Figure 14). Biomass and wind generation are higher, and gas- and coal-fired generation are lower, than in the reference case. One important difference is that biomass accounts for most of the increase in renewable generation. Even though a large number of new wind plants are projected in the RPS cases, they do not generate nearly as much electricity as do the

Figure 13. Generating capacity by fuel in three cases, 2020 (gigawatts)

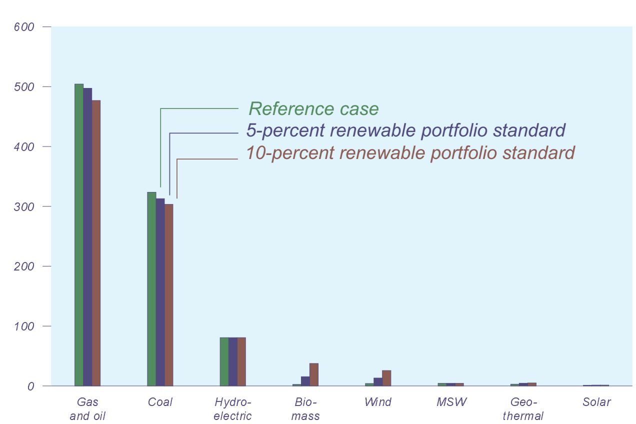
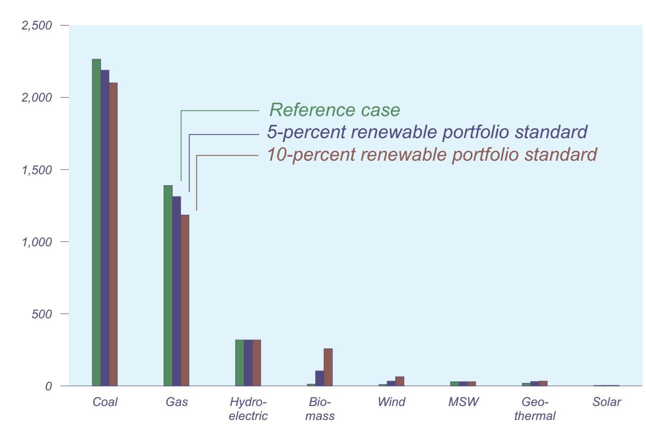


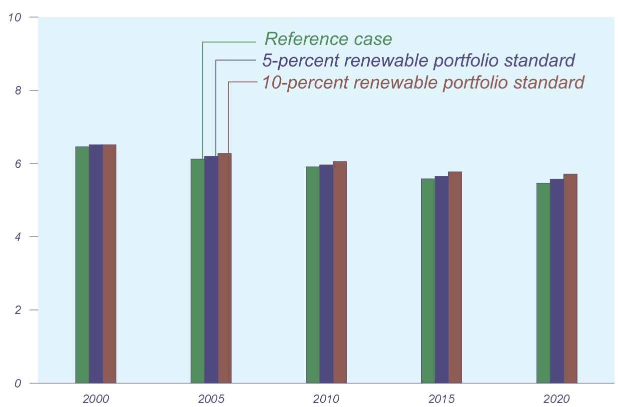
Figure 14. Electricity generation by fuel in three cases, 2020 (billion kilowatthours)



projected new biomass plants. New biomass plants are expected to operate at capacity factors of 70 to 80 percent, whereas new wind plants, because of their dependence on wind conditions, are expected to operate at 30 to 35 percent of capacity.

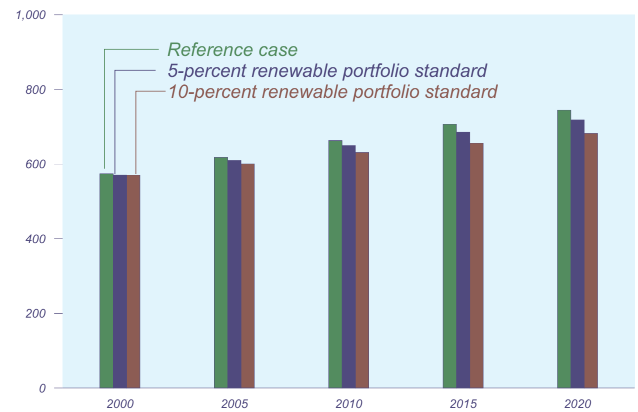
In the RPS cases, average regulated electricity prices are projected to be higher than those in the reference case (Figure 15). The higher cost of the small amounts of renewable capacity brought on line in the 5- and 10-percent RPS cases leads to prices that are 2 percent and 5 percent higher, respectively, in 2020

Figure 15. Projected electricity prices in three cases (1996 cents per kilowatthour)



than those in the reference case. For the average residential consumer, projected monthly electricity bills in 2020 would be $1 and $3 higher, respectively, than in the reference case. On a national scale, however, total expenditures for electricity in the 5-percent RPS case in 2020 would be $2 billion higher than those projected in the reference case, and in the 10-percent RPS case they would be $8 billion higher.
RPS programs would also affect revenues in the natural gas and coal industries, both of which—particularly the gas industry—are expected to see significant growth as the demand for electricity increases over the next 20 to 25 years. In the RPS cases, their projected growth is dampened. Relative to the reference case, the natural gas and coal industries are expected to have lower revenues in the 5-percent and 10-percent RPS cases. At the national level, the lower revenues in the gas and coal industries would be offset by increased revenues to renewable technology and fuel suppliers (biomass fuel); however, regional impacts could be significant.

Figure 16. Carbon emissions from electricity generation in three cases (million metric tons)



Carbon emissions are projected to be slightly lower in the RPS cases than in the reference case (Figure 16). In 2020, projected carbon emissions from the generation of electricity are 26 million metric tons (1 percent) and 62 million metric tons (3 percent) below the level in the reference case in the 5- and 10-percent RPS cases, respectively. Even with those reductions, however, U.S. carbon emissions from electricity generation would still be 201 and 165 million metric tons above the 1996 level.

Carbon Emissions

Background

Over the past several decades, rising concentrations of greenhouse gases have been detected in the Earth's atmosphere. The greenhouse gases include carbon dioxide, methane, nitrous oxide, chloro- fluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and others. Although there is not universal agreement within the scientific community on the impacts of increasing concentrations of greenhouse gases, there is concern that they may lead to rising temperatures and, in turn, a variety of changes in the global climate, sea level, agricultural patterns, and ecosystems that could be, on net, detrimental.

As a result of increasing warnings by members of the climatological and scientific community, the Intergovernmental Panel on Climate Change was established under the auspices of the United Nations in

1988 to provide advice on climate change issues to policymakers. This was followed by a series of international conferences, 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 Framework Convention on Climate Change was signed by more than 160 countries at the Earth Summit in Rio de Janeiro on May 4, 1992.

The purpose of the Framework Convention, or Rio Treaty, 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." The signatories of the Rio Treaty agreed to voluntary commitments to achieve the treaty objectives and to prepare national action plans and periodic emissions inventories for review. In addition, the developed country signatories, known as the Annexe I Countries [17], agreed to take actions that would reduce their national anthropogenic emissions of greenhouse gases to 1990 levels by 2000. Specifically excluded from the Convention are CFCs and HCFCs, which are controlled by the Montreal Protocol, signed in 1987.

On April 21, 1993, President Clinton committed the United States to the stabilization of greenhouse gas emissions by 2000 at 1990 levels. Specific steps to achieve the U.S. commitment were enumerated in the Climate Change Action Plan (CCAP), published in October 1993, which consists of a series of 44 actions to reduce emissions. The Energy Policy Act of 1992 (EPACT), Section 1605(a), provided for an annual inventory of U.S. greenhouse gas emissions, which is contained in the EIA publication series, *Emissions of Greenhouse Gases in the United States* [18].In addition, EPACT, Section 1605(b), established the Voluntary Reporting Program, permitting corporations, government agencies, households, and voluntary organizations to report to EIA on actions that have reduced or avoided emissions of greenhouse gases. The results of the Voluntary Reporting Program are reported annually by EIA, most recently in the *Mitigating Greenhouse Gas Emissions: Voluntary Reporting* [19], which reports 1995 activities. Entities providing data to the Voluntary Reporting Program include some participants in government-sponsored voluntary programs, such as the Climate Wise and Climate Challenge programs, which are cosponsored by the U.S. Environmental Protection Agency and the U.S. Department of Energy to foster reductions in greenhouse gas emissions by industry and electricity generators.

In 1995, the Conference of the Parties, which meets annually to review the implementation of the Framework Convention, met in Berlin and issued the Berlin mandate, an agreement to begin to negotiate the successor agreement to the Convention, addressing the period beyond 2000. The second Conference of the Parties, held in Geneva in July 1996, called for negotiations on legally binding measures to achieve specific emissions limitations and reductions in specified timeframes for adoption at the third Conference in Kyoto, Japan, in December 1997.

Several negotiating sessions leading to the Kyoto Conference have not yielded an agreement among the signatories. The European Union (EU) member nations have announced support of a 15-percent reduction in greenhouse gas emissions from 1990 levels by 2010. Under this proposal, nations outside the EU would be held to the 15-percent reduction individually, although the EU would achieve the target collectively.

Several countries, including Australia and Japan, have announced opposition to the EU proposal on the basis that it is too extreme and inequitable between the members and nonmembers of the EU. Other countries have joined Australia in calling for differential targets based on the potential impact to each country. Japan has proposed that developed countries reduce emissions by an average of 5 percent below 1990 levels between 2008 and 2012, with some flexibility of targets among the nations. Major oil-producing countries are concerned about the loss of revenue that would occur from the likely reduction in oil consumption. The Alliance of Small Island Nations has proposed an even more stringent target—to reduce emissions by 20 percent from 1990 levels by 2005—because of their concern that increasing emissions and rising temperatures could lead to melting ice caps and rising sea levels.

On October 22, 1997, President Clinton proposed a stabilization of emissions by developed countries at 1990 levels between 2008 and 2012, with reductions below 1990 levels in the following 5-year period, and a $5 billion program of tax cuts and research and development spending for energy-efficient and lower carbon technologies. In 2008, an emissions trading system would be put into place, with credit for early reductions. Electricity restructuring and reductions of emissions from Federal sources will also be pursued. Although the President indicated that developing countries must participate, proposals for reductions by those countries were not specified; however, joint implementation projects are favored.

Earlier, at the June 26, 1997, Earth Summit+5 Conference at the United Nations, President Clinton pledged support for binding emissions targets and announced three initiatives: a pledge of $1 billion over 5 years by the United States for the development of more energy-efficient and alternative energy technologies in developing countries; the strengthening of environmental guidelines for U.S. companies investing overseas; and a partnership with private industry to install solar panels on 1 million roofs in the United States by 2010.

In addition to the debates over the need for emissions reductions and the cost and economic impact of reductions, another key issue is the limitations, if any, to be placed on the developing countries in an international agreement. Two-thirds of the growth in world energy demand over the coming 20 years is likely to be in the developing countries and countries in transition to market economies, with attendant growth in emissions. Because such countries generally use far less energy per capita than do the developed countries, some proposals suggest that these countries should be exempt from emissions restrictions in order not to constrain their economic development. Such an exemption would likely lead to significant growth in emissions even if all the developed nations were successful in their stabilization efforts. In addition, an exemption could lead polluting industries to move from the developed to the developing countries, exacerbating the worldwide growth in emissions and restraining the economic growth of the developed countries through the loss of industry.

Carbon Emissions in the AEO98 *Reference Case*

The United States is the largest emitter of anthropogenic (human-caused) carbon in the world, producing about 23 percent of the energy-related carbon emissions worldwide [20]. In 1990, total greenhouse gas emissions in the United States were 1,618 million metric tons carbon equivalent [21]. Of this total, 1,346 million metric tons, or 83 percent, was due to carbon emissions from the combustion of energy fuels. By 1996, total U.S. greenhouse gas emissions had risen to 1,753 million metric tons carbon equivalent, including 1,463 million metric tons of carbon emissions from energy combustion.

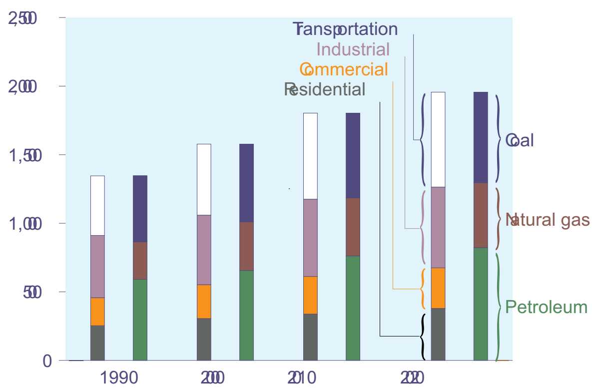
The initial estimates of the impacts of the CCAP programs projected stabilization of greenhouse gas emissions in 2000 at 1990 levels; however, a more recent review and update of CCAP significantly reduced the expected impact [22]. The projections of carbon emissions in the *AEO98* include EIA's analysis of the impacts of CCAP, but the projections do not take into account carbon-absorbing sinks, such as increased planting of forests, nor do they account for the 13 CCAP actions related to non-energy programs or greenhouse gases other than carbon dioxide. The remaining CCAP programs are represented in the *AEO98* projections but do not result in the reductions originally estimated by the developers of CCAP.

The *Annual Energy Outlook 1995* (*AEO95*) was the first *AEO* to include the impacts of CCAP in the projections. Even then, the goal of stabilizing carbon emissions in 2000 at 1990 levels seemed unlikely. *AEO95* projected that carbon emissions in 2000 from energy combustion would be 1,471 million metric tons—9 percent higher than the 1990 level of 1,346 million metric tons—a level nearly achieved in 1996, when emissions reached 1,463 million metric tons.

There are several reasons that the target specified by CCAP is unlikely to be realized. First, U.S. economic growth has been higher than assumed at the time the CCAP programs were formulated. Second, energy prices have increased at a more moderate

rate than initially assumed in the early 1990s. Both these factors have contributed to higher growth in energy consumption than earlier assumed, leading to higher emissions levels. Third, the funding levels for a number of the CCAP programs are lower than

Figure 17. U.S. carbon emissions by sector and fuel, 1990-2020 (million metric tons)



those initially requested, resulting in lower effective impacts. Subsequent *AEO*s have continued to raise the estimate of carbon emissions, primarily because of lower price projections that encourage energy use and reduce the penetration of renewable sources of energy.

In *AEO98*, carbon emissions from energy combustion are expected to reach 1,577 million metric tons in 2000, 17 percent above the 1990 level of 1,346 million metric tons. The projected emissions rise to 1,803 million metric tons in 2010 and 1,956 million metric tons in 2020 (Figure 17). Total emissions increase at an average annual rate of 1.2 percent between 1996 and 2020 in the reference case projections, and per capita emissions also increase at an average rate of 0.4 percent, as continued economic growth and moderate price increases encourage growth in energy services and energy consumption, and as electricity generation from nuclear power plants declines, particularly after 2010.

In 2020, electricity generation accounts for 38 percent of all carbon emissions, increasing from 35 percent in 1996. Electricity use increases at an average annual rate of 1.4 percent through the forecast horizon, and the growth in emissions from generation is mitigated somewhat by the increasing share of natural gas generation. Nuclear generation, which is carbon free, declines significantly over the forecast period, with plant retirements that total 52 gigawatts, or 51 percent of the current nuclear capacity. This loss of nuclear baseload capacity, as well as the additional capacity needed to meet demand growth, is in general met by new gas- or coal-fired generation.

Because of increased travel and slow growth in fuel efficiency, energy consumption and emissions for transportation grow the fastest of all end-use sectors—1.6 percent annually through 2020. In 2020, the transportation sector share of emissions is 35 percent. Over the forecast period, vehicle-miles traveled in light-duty vehicles increase at an annual rate of 1.5 percent, although the population over age 16 grows at a rate of only 0.9 percent. At the same time, the average efficiency of the light-duty fleet grows by only 0.2 percent annually, with the slow improvement exacerbated by the penetration of light-duty trucks, vans, and sport utility vehicles. Growth in air travel also contributes to the overall increase in transportation sector petroleum use and emissions.

Although the industrial sector contributes 30 percent of the emissions in 2020, including emissions from the generation of electricity used in the sector, industrial emissions grow by only 0.9 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate the growth in energy use. Emissions in the residential and commercial sectors grow by 1.2 and 1.1 percent a year, respectively, and their 2020 shares are 19 and 15 percent. In both sectors, continuing growth in electricity use and in the use of new appliances and energy services contributes to increasing consumption and emissions, dampened somewhat by efficiency improvements in both sectors.

Petroleum products are the leading source of carbon emissions from energy use, contributing approximately 42 percent of the emissions in 2020—822 million metric tons of the total of 1,956 million metric tons. About 80 percent of the petroleum-related emissions are from transportation uses.

Although natural gas has the fastest growth rate in consumption among all the fossil fuels in the projections—an average of 1.6 percent annually— natural gas is projected to produce only 24 percent of the carbon emissions in 2020, including the natural gas consumed for end uses and for electricity generation. Coal, which emits about twice as much carbon as natural gas per unit of input, is the second leading source of emissions, after petroleum. In 2020, coal emits 34 percent of the total carbon emissions, about 90 percent of which is from electricity generation.

Impact of Technology Improvements

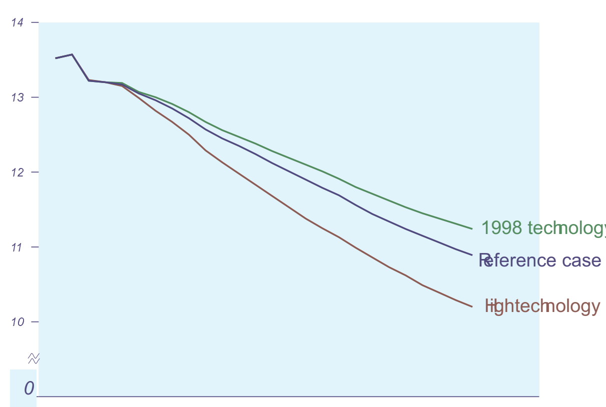
Energy intensity—defined as total energy consumption per dollar of gross domestic product (GDP)—decreased significantly in the 1970s and early 1980s. Approximately half the decline in energy intensity resulted from structural shifts in the economy (i.e., shifts to service industries and other less energy-intensive industries); however, the other half of the decline was due to the use of more energy-efficient technologies. Particularly from the mid-1970s through the mid-1980s, there was a period of rapid escalation in the price of energy. As the growth in energy prices moderated, growth in some energy-intensive industries resumed and the decline in energy intensity moderated. Recent improvements in energy efficiency are more a result of government-sponsored regulatory programs, including the Corporate Average Fleet Efficiency standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in EPACT and the National Appliance Energy Conservation Act of 1987, although the impacts of those programs are slowed by the pace of stock turnover.

In keeping with the general practice of considering only current policy and regulations, the *AEO98* reference case assumes no new efficiency standards or improvements in current efficiency standards, despite the likelihood that additional standards will be introduced over the nearly 25-year forecast horizon. Frozen standards, the modest increase in the price of energy in the reference case, and growing demand for certain energy services, such as appliances, office equipment, and travel, all slow further declines in energy intensity over the projection period. Energy intensity is projected to decline by an average of 0.9 percent annually between 1996 and 2020. The projected decline in energy intensity is significant but considerably less than the decline in the 1970s and early 1980s, which averaged 2.3 percent a year between 1970 and 1986.

The *AEO98* reference case includes continued improvement in technologies for both energy consumption and production—for example, improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. Technology improvements could reduce energy consumption, and therefore energy-related carbon emissions, below that in the reference case. Conversely, slower improvement than that assumed in the reference could increase both consumption and emissions. *AEO98* presents a range of alternative cases that vary key assumptions concerning technology improvement and penetration.

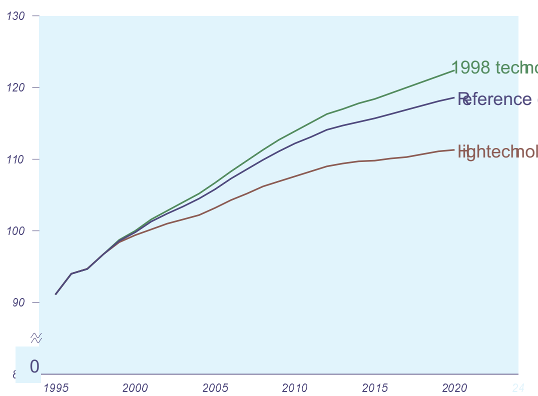
In the residential and commercial sectors, alternative technology cases assume that the cost of the most energy-efficient equipment and technologies will decline over time from their reference case values, and that building shell efficiencies will improve more rapidly. Appendix G contains further discussion of the assumptions for the alternative cases. In the 1998 technology cases, it is assumed that all

Figure 18. U.S. energy intensity in three cases, 1995-2020 (thousand Btu per dollar GDP)



future equipment purchases will be made only from the equipment available in 1998, and that building shell efficiencies will be frozen at 1998 levels.

Figure 19. U.S. energy consumption in three cases, 1995-2020 (quadrillion Btu)



For the advanced technology case in the transportation sector, advanced technologies are assumed to have lower costs and higher efficiencies than those assumed to be available in the reference case. Efficiencies for new equipment are fixed at 1998 levels for all travel modes in the 1998 technology case.

A high technology case is defined for the industrial sector by increasing the assumed rates of decline in energy intensity for the energy-intensive industries relative to those in the reference case. In this high technology case, energy intensity in the industrial sector declines at an average rate of 1.5 percent a year, compared with 1.1 percent a year in the reference case. In the 1998 technology case for the industrial sector, plant and equipment efficiencies are fixed at 1998 levels.

Figure 20. U.S. carbon emissions in three cases, 1995-2020 (million metric tons)

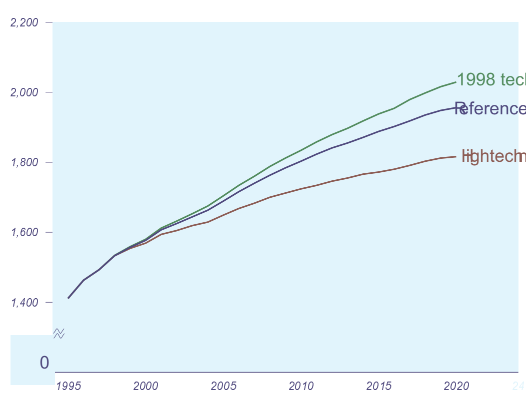


Figure 18 illustrates the change in aggregate energy intensity for the high technology and 1998 technology cases combined for the four end-use demand sectors. Through 2020, the high technology case projects an average annual decline of 1.2 percent in energy consumed per dollar of GDP, compared with 0.9 percent in the reference case. In the 1998 technology case, the average decline in intensity is only 0.8 percent a year. Energy consumption increases to 111.3 quadrillion Btu in 2020 in the high technology case, compared with 118.6 quadrillion Btu in the reference case (Figure 19), but increases to 122.4 quadrillion Btu in the 1998 technology case.
Even the adoption of more efficient technologies in the high technology case is insufficient to achieve carbon stabilization. The lower energy consumption in the high technology case serves to lower carbon emissions from 1,956 million metric tons in the reference case in 2020 to 1,816 million metric tons (Figure 20); however, in the 1998 technology case, emissions rise to 2,029 million metric tons. Approximately 39 percent, or 55 million metric tons, of the reduction in carbon emissions in 2020 in the high technology case compared to the reference case results from lower electricity demand and generation. An additional 51 million metric tons of the reduction, or 36 percent, is in the transportation sector, as a result of shifts to more efficient or alternatively fueled vehicles.

Options for Reducing Emissions

A wide range of options have been proposed to reduce carbon emissions. It is possible that some combination of these options may be selected to form the basis of national policy in the wake of an international agreement on carbon reduction.

Ultimately, there are three ways in which energy consumers can have an impact on emissions. First, selecting more energy-efficient equipment reduces the amount of energy required to meet the demand for energy services. Second, shifts to noncarbon or less carbon-intensive fuels reduces the carbon released per unit of energy consumed. Among the major categories of energy fuels, renewable fuels and nuclear power emit little or no carbon, and natural gas emits the lowest level of carbon per unit consumed of all the fossil fuels—about half that of coal. On average, petroleum products emit a level of carbon about halfway between natural gas and coal. Third, emissions can be reduced through reduction in the demand for energy services—for example, fewer vehicle miles traveled or smaller homes.

Although the primary focus of this discussion is on carbon emissions, an additional approach to carbon mitigation is carbon sequestration. The growth of forests and other vegetation serves to absorb carbon from the atmosphere (although, if the forests are eventually burned, the carbon is released and the overall level in the atmosphere is unchanged). Encouragement of forest growth, research, and development of additional sequestration techniques could reduce the atmospheric concentration of carbon and its detrimental effects.

An expansion of current voluntary reduction programs already included in the *AEO98* projections, coupled with increased public awareness of the need to reduce emissions, could lead to additional reductions in carbon emissions. Such programs serve to encourage consumers to make more energy-efficient choices when purchasing equipment or to select more renewable technologies, and they may also encourage industry and electricity generators to invest in more efficient or renewable technologies.

Consumer preferences may also indirectly influence choices made by generators, as shown by the reaction to differential pricing programs in several States, where some electricity consumers have expressed a willingness to pay more for electricity generated from renewable sources (although this has not been demonstrated in practice). Changes in the overall composition of the stock of energy-using equipment can be slow, however, and only in more extreme cases is it likely that equipment with remaining functional economic life would be prematurely retired from the capital stock. The high end-use technology cases described above represents a range for the reductions achievable through efficiency improvements in end-use technologies alone.

Increased efficiency standards would also serve to reduce the use of energy beyond that induced by voluntary measures. New or tightened standards could be applied to a range of appliances, building shell technologies, motors, and vehicles, but the penetration of the more efficient equipment would again be limited by the capital stock turnover rate. Additional standards have also been proposed to alter the composition of electricity generation. One example is S. 687, the “Electric System Public Benefits Protection Act of 1997,” which proposes a renewable portfolio standard for electric generators and also caps carbon emissions from electricity generators at 1990 levels by 2005.

Both the reference case and the high technology cases analyzed in *AEO98* include efficiency improvements that result from the penetration of newer technologies that either are available now or are assumed to be available within the forecast horizon. Additional research and development in energy-efficient or alternatively fueled technologies would serve to increase the slate of choices available to consumers, likely leading to further increases in efficiency and reductions in emissions.

Some European countries have considered imposition of carbon taxes as a means of reducing emissions. Under such proposals, energy fuels are generally assigned taxes relative to their carbon content. More widely favored as a way of achieving fixed emissions limits, however, is an emissions trading program. In the United States, the Clean Air Act Amendments of 1990 (CAAA90) established a trading program for emissions of sulfur dioxide (SO_2) by electric generators in order to reduce emissions to fixed specified levels. Permits issued to electricity generators allow them to emit a specified level of SO_2, with the total number of permits equal to the national limit on emissions. Generators have the option of reducing emissions through the use of lower sulfur coal or the installation of scrubbers and selling excess emissions permits, which can be purchased by other generators for whom it is more cost-effective to purchase permits at the prevailing market price than to reduce emissions. Emissions permits can also be banked for future use.

A similar trading scheme for carbon emissions could be formulated either internationally or within individual countries to achieve fixed emissions levels; however, implementing and enforcing such a plan internationally would be highly complex. Even within the United States, a carbon emissions trading plan would be far more complicated than the SO2 plan, in part because of the number of entities that emit carbon (households, commercial establishments, industries, vehicles, and generating stations) as opposed to the smaller number of sources (electricity generators) covered by the CAAA90. Further complexity could be introduced by consideration of non-energy sources and sinks of carbon.

The current EU proposal calls for emissions trading among the EU member nations. There are numerous ways in which an international trading plan could be devised; however, a likely outcome would be a flow of investment from developed to developing nations in the form of joint implementation projects for the development of energy-efficient and renewable technologies in those countries.

Within the United States, concern has been raised about the economic loss that could occur under an emissions trading plan as the result of an increase in the effective cost of energy. Estimates of the carbon fee necessary to achieve stabilization vary widely.

Lower estimates are suggested by those who believe that there are a number of low-cost options readily available to reduce the use of energy or to shift to low-carbon or noncarbon fuels. Higher estimates are suggested by analysts who think that the effective price of carbon-intensive fuels will have to be raised significantly to encourage changes in consumer choices and the development of additional alternative technologies.

A carbon trading system in the United States would likely reduce end-use energy consumption through the adoption of more energy-efficient equipment and alternative fuel technologies and through reductions in demand for energy services. In the electricity generation sector, there would likely be some reduction in emissions because of lower electricity demand by end-use consumers. In addition, there would likely be less coal-fired generation and more generation from natural gas and renewable fuels, which would capture a larger share of new generation capacity. Higher carbon fees could lead to premature retirements of some less efficient coal-fired facilities, extensions of the operating lives of some nuclear plants (if allowed), and the development and construction of additional nuclear and other non-carbon-emitting generation technologies.

In addition to producing the projections in the *AEO*, the National Energy Modeling System (NEMS) is frequently used for analytical studies for the U.S. Congress, other offices in the epartment of Energy, and other Government organizations. For such studies, requesting organizations specify their own assumptions for the alternative cases analyzed and frequently request modifications to the reference case as well. NEMS has been used in two recent studies on carbon emissions—*An Analysis of Carbon Mitigation Cases* for the U.S. Environmental Protection Agency [23] and Analysis of Carbon Stabilization Cases for the Office of Policy and International Affairs, U.S. Department of Energy [24]. Both studies, which used the assumptions of the requesting organizations, illustrate the capability of NEMS to represent technological change and penetration and a range of potential carbon policies, including carbon taxes and alternative trading and permit schemes that vary the level, timing, and phase-in of carbon emissions targets.

Approaching the Kyoto conference, there is no universally accepted goal for either stabilization or reduction of emissions. Having established a goal, the conference negotiators must agree on a process for achieving the goal, which could range from a voluntary process, such as the Rio agreement, to jointly implemented international targets, to legally binding emissions targets for each country. National targets, if established, might be universally or differentially specified and might either include or exempt the developing countries. As a result, there is considerable uncertainty about future carbon mitigation policies.

Because *AEO98* includes only policies, programs, legislation, and regulations as of July 1, 1997, and because the provisions of the President's October 22 emissions stabilization proposal are not precisely defined, it is not included in the reference case. Thus, U.S. carbon emissions are projected in the reference case to increase at an average rate of 1.2 percent per year from 1996 to 2020.

Market Trends

The projections in *AEO98* 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 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.

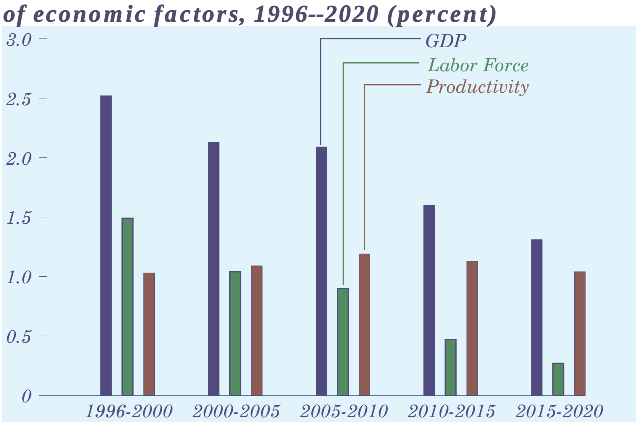
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 *AEO98* 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.

AEO98 Projects Strong Growth in Economic Output, Productivity

Figure 21. Average annual real growth rates of economic factors, 1996--2020 (percent)

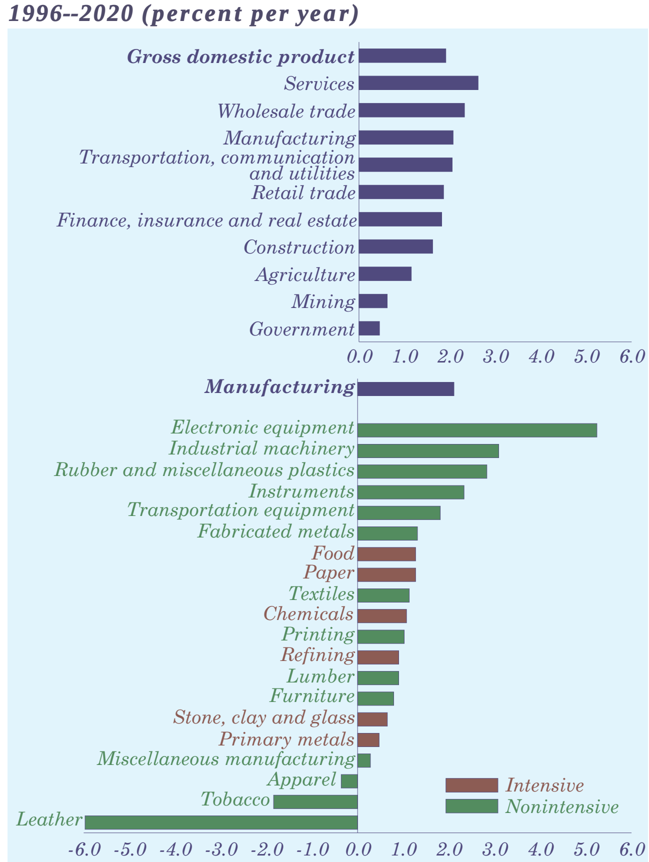


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 1.9 percent a year between 1996 and 2020 (with GDP based on 1992 chain-weighted dollars) (Figure 21). Through 2015, the forecast horizon for last year's *AEO*, the projected economic growth rate is 2.1 percent a year, slightly higher than the 1.9-percent growth in *AEO97*. The projected growth rate for the labor force is similar to last year's forecast through 2015; however, in the *AEO98* projection, productivity growth is 1.1 percent a year, up from 0.9 percent a year in *AEO97*.

The projected rate of growth in GDP slows in the latter half of the forecast period as the expansion of the labor force slows, but increases in labor productivity moderate the effects of lower labor force growth. The slowing growth in the size of the labor force is a result of slowing population growth after 2000. From 2010 to 2015, labor force growth slows to 0.5 percent, and from 2015 to 2020 it falls to 0.3 percent a year. Labor force productivity growth, however, remains at or near 1 percent a year throughout each of the 5-year periods. In addition, the labor force participation rate—the percentage of the population over 16 years of age actually holding or looking for employment—peaks in 2007 and then begins to decline as "baby boom" cohorts begin to retire.

More Rapid Growth Projected for Non-Energy-Intensive Industries

Figure 22. Sectoral composition of GDP growth, 1996--2020 (percent per year)

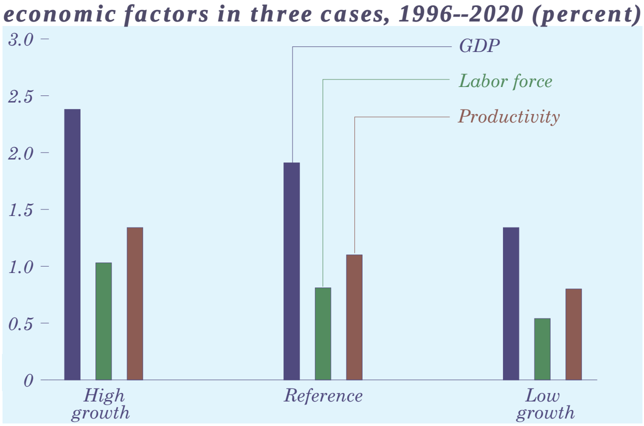


The projected growth rate for manufacturing production is 2.1 percent a year, just slightly higher than the growth of 1.9 percent a year for the aggregate economy. Energy-intensive industries, however, are projected to grow more slowly than non-energy-intensive industries (1.0 percent and 2.6 percent annual growth, respectively) [25], due in part to rising real energy prices.

The electronic equipment and industrial machinery sectors lead the expected growth in manufacturing, as semiconductors and computers find broader applications (Figure 22). 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. Higher growth is expected for the wholesale trade and services sectors than for the manufacturing sector, as in last year's forecast.

High and Low Growth Cases Show Effects of Economic Assumptions

Figure 23. Average annual real growth rates of economic factors in three cases, 1996--2020 (percent)



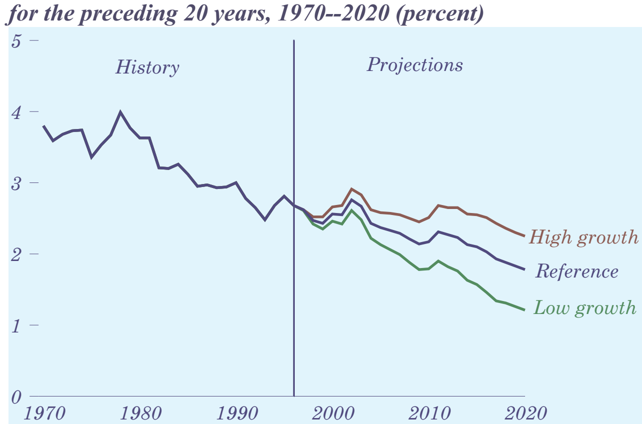
To reflect the uncertainty in forecasts of economic growth, *AEO98* includes high and low economic growth cases in addition to the reference case (Figure 23). The high and low growth cases show the effects of alternative growth assumptions on energy markets. All three economic growth cases are based on macroeconomic forecasts prepared by DRI/McGraw-Hill (DRI) [26]. The DRI forecasts used in *AEO98* are the August 1997 trend growth scenario and the optimistic and pessimistic growth projections. EIA has adjusted DRI's forecasts to incorporate the world oil price assumptions used in the *AEO98* reference case. With this change incorporated, the DRI projections are used as the starting point for the macroeconomic forecasts in the National Energy Modeling System (NEMS) simulations for *AEO98*. The macroeconomic activity module in NEMS incorporates energy price feedback effects on the aggregate economy.

The high economic growth case incorporates higher growth rates for population, labor force, and labor productivity. With higher productivity gains, inflation and interest rates are lower than in the reference case, and economic output is projected to increase by 2.4 percent a year. The low economic growth case assumes lower growth rates for population, labor force, and productivity, resulting in higher prices, higher interest rates, and lower industrial output growth. In the low growth case, economic output increases by 1.3 percent a year from 1996 through 2020.

Figure 24 shows the trend in the moving 20-year annual growth rate for GDP, including projections for three *AEO98* cases. The value for each year is calculated as the annual growth rate over the preceding 20 years. The pattern for the 20-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes. The trend is downward, reflecting lower rates of capital accumulation during the 1970s and 1980s, lower labor force growth rates, and shifts in the demographic makeup of the population. In addition, annual GDP growth has fluctuated considerably around the trend. The high and low growth cases are presented to capture the potential for different paths of long-term output growth in the forecast.

Investment Rates Are Key to Economic Growth Paths

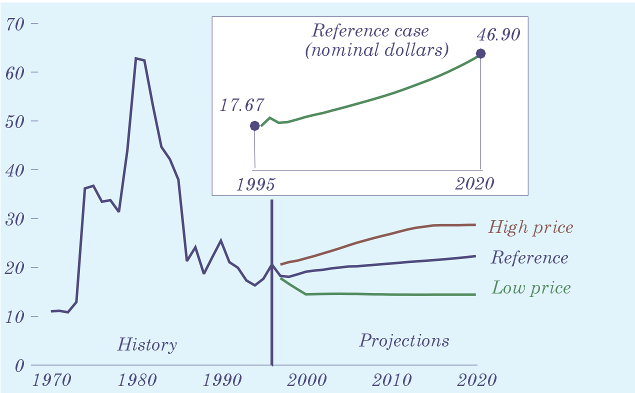
Figure 24. Change in annual GDP growth rate for the preceding 20 years, 1970--2020 (percent)



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 grows by 2.0 percent a year, while investment grows at a robust 2.9 percent. In the high growth case, growth in investment increases to 3.6 percent a year—a shift that is significant for overall economic growth. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, coupled with higher population and labor force growth, yield faster aggregate economic growth than in the reference case. In the low growth case, annual growth in investment expenditures slows to 2.1 percent. With the labor force also growing more slowly, aggregate economic growth slows considerably.

Alternative Cases Show Uncertainty in Future Oil Prices

Figure 25. World oil prices in three cases, 1970--2020 (1996 dollars per barrel)



Just as the historical record shows substantial variability in world oil prices, there is considerable uncertainty about future prices. Three *AEO98* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 25). For the reference case, prices rise by about 0.4 percent a year, reaching $22.32 in constant 1996 dollars in 2020. In nominal dollars, the reference case price reaches almost $47 in 2020. The low price case has prices falling to $14.47 by 2000 and remaining at about that level out to 2020. The high price case has a price rise of about 1.4 percent a year out to 2015 and then remains at $28.65 out to 2020. The leveling off at about $28.65 in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

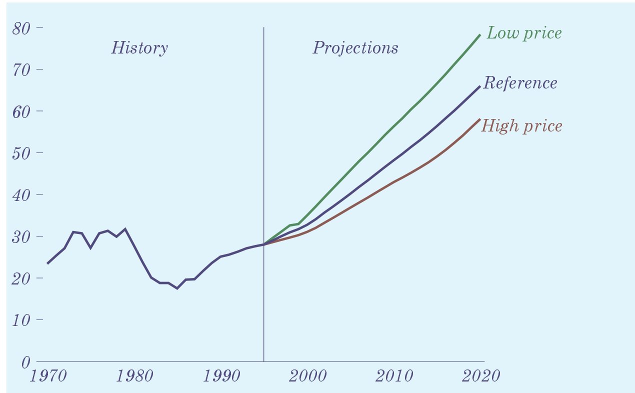
All three price cases out to 2015 are similar to the price projections in *AEO97*, reflecting considerable optimism about the potential for worldwide petroleum supply, even in the face of the substantial expected increase in demand. Production from countries outside OPEC is expected to show a steady increase, exceeding 45 million barrels per day by the turn of the century and increasing gradually thereafter to more than 50 million barrels per day by 2020.

Total worldwide demand for oil is expected to exceed 116 million barrels per day by 2020. Developing countries in Asia show the largest growth in demand, averaging almost 5 percent a year.

The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production 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 future incremental demand.

OPEC Oil Production Rises in the Three World Oil Price Cases

Figure 26. OPEC oil production in three cases, 1970--2020 (million barrels per day)

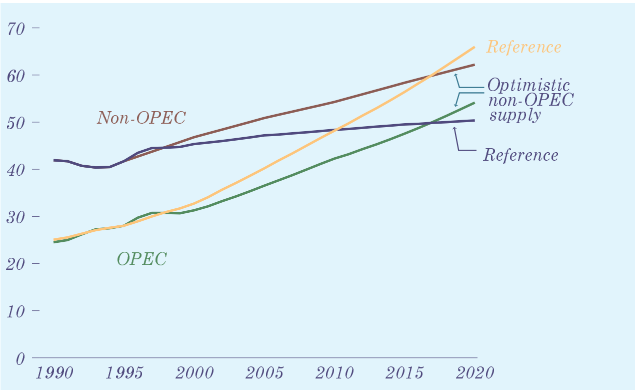


By 2000, OPEC supply in the reference case is almost 33 million barrels per day, consistent with announced plans for OPEC capacity expansion [*27*]. By 2020, OPEC production is almost 66 million barrels per day (more than twice its 1996 production) in the reference case, 58 million in the high case, and over 78 million in the low case (Figure 26). Worldwide demand for oil varies across the price cases in response to the price paths. Total world demand for oil ranges from 126.3 million barrels per day in the low price case to 111.0 in the high price case.

This variation 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 for the remainder of this decade. Recent discoveries offshore of Algeria and 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.

OPEC Production Is Lower in the Optimistic Non-OPEC Supply Case

Figure 27. OPEC and non-OPEC oil production in two cases, 1990--2020 (million barrels per day)



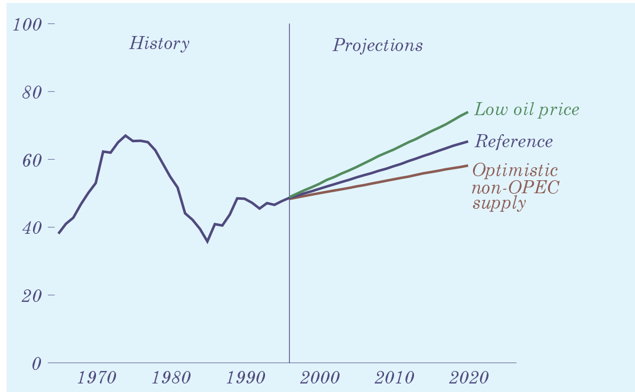
The growth and diversity in non-OPEC oil supply has played a significant role in the erosion of OPEC's market share over the past two decades. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers, who have demonstrated surprising resilience even in the low price environment of this decade. In the reference case, the OPEC market share of worldwide production does not begin to exceed that of non-OPEC suppliers until the year 2011 (Figure 27). Non-OPEC production rises to over 45 million barrels per day by the year 2000 and continues a gradual increase, exceeding 50 million barrels per day by the year 2019.

While the oil price cases make alternative assumptions about OPEC supply, it is also possible that non-OPEC supply could expand beyond the levels assumed for the reference case. In an optimistic non-OPEC supply case—in which one-third of the world's undiscovered oil is assumed to be economical to develop over the forecast period at reference case prices—OPEC would not regain the majority market share throughout the forecast period. In this case, non-OPEC production would increase steadily to more than 60 million barrels a day. While significant production increases are anticipated from the world's developing countries (especially those of Latin America and Asia), much of the increase in non-OPEC supply over the next decade is expected to come from the former Soviet Union.

Considering the world market in 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 oil traded in world markets (Figure 28). 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 oil traded in 1985 came from Persian Gulf suppliers. Following the 1985 oil price collapse, the Persian Gulf export percentage has been steadily increasing. For the first time since the early 1980s, Persian Gulf producers are expected to account for more than 50 percent of worldwide trade. This is expected to occur before the end of this decade.

Persian Gulf Could Supply Half of World Oil Exports by 2020

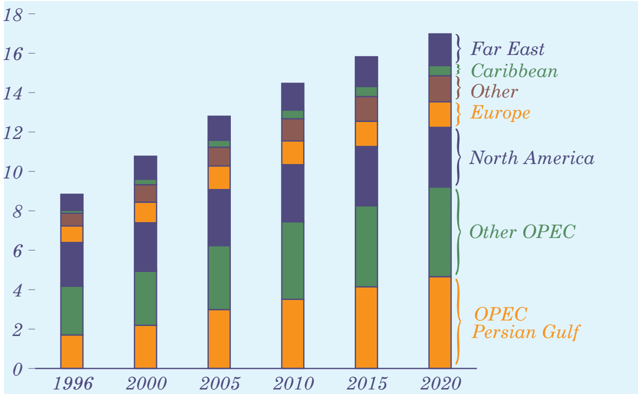
Figure 28. Persian Gulf share of worldwide oil exports, 1965--2020 (percent)



In the reference case, the Persian Gulf share of total exports is expected to exceed 52 percent shortly after the turn of the century and gradually increase to over 65 percent by the year 2020. In the *AEO98* low oil price case, the Persian Gulf share of worldwide petroleum exports is expected to exceed 54 percent shortly after the turn of the century and steadily increase to almost 74 percent by 2020. In the optimistic non-OPEC supply case, the Persian Gulf share of oil exports does not return to its historical peak during the forecast period. While all Persian Gulf producers are expected to increase their oil production capacity significantly over the forecast period, both Saudi Arabia and Iraq are expected to more than double their current production capacity levels.

U.S. Oil Imports Continue To Rise in the AEO98 Projections

Figure 29. U.S. gross petroleum imports by source, 1996--2020 (million barrels per day)



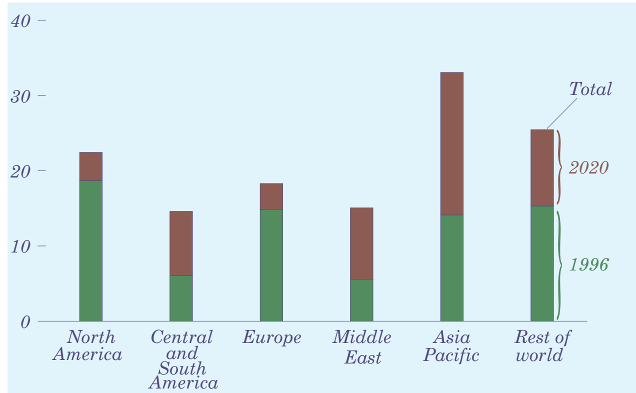
In the reference case, total U.S. gross oil imports increase from 9.5 million barrels per day in 1996 to 16.1 million in 2020 (Figure 29). Crude oil accounts for most of the increase before 2000, whereas imports of petroleum products make up a larger share after 2000. Product imports increase more rapidly, as U.S. production stabilizes and U.S. refineries lack the capacity to process a larger quantity of imported crude oil.

By 2010, OPEC accounts for more than one-half of total projected U.S. petroleum imports. After 2010, the OPEC share increases steadily, to more than 54 percent in 2020. The Persian Gulf share of U.S. imports from OPEC increases from about 38 percent in 1996 to more than 50 percent in 2020. Crude oil imports from the North Sea increase slightly through 2000, then level off as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico continue, and West Coast refiners are expected to import crude oil from the Far East to replace the modest volumes of Alaskan crude oil that will be exported.

Imports of light products are expected to more than double by 2020, to nearly 2.8 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.

World Refining Capacity Is Expected To Increase by More Than Half

Figure 30. Worldwide refining capacity by region, 1996 and 2020 (million barrels per day)



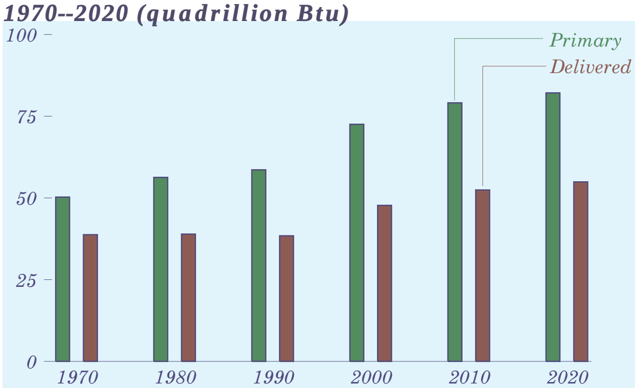
Worldwide crude oil distillation capacity was 74.5 million barrels per day at the beginning of 1996. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by more than half—to almost 129 million barrels per day—by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 30).

The Asia/Pacific region has been the fastest growing refining center in the 1990s. It has recently passed Western Europe as the world's second largest refining center and, in terms of distillation capacity, is expected to surpass the United States by 2010. 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.

Gap Between Primary and Delivered Energy Is Expected To Stabilize

Figure 31. ***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 [*28*].

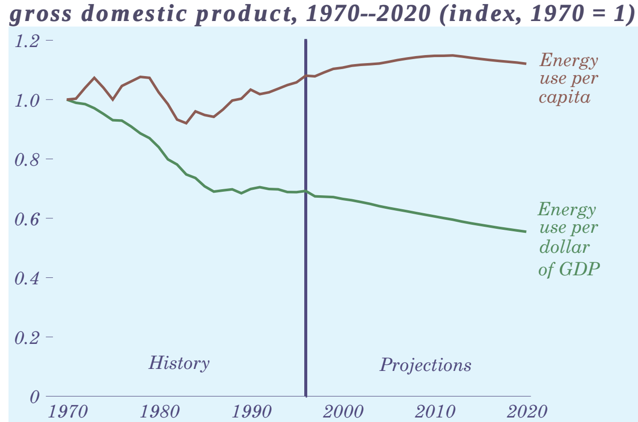
How energy consumption is measured has become more important over time, as reliance on electricity has expanded. In 1970 electricity accounted for only 12 percent of energy delivered to the end-use sectors, excluding transportation. Since then, the growth in electricity use for applications such as space conditioning, consumer appliances, telecommunication equipment, and industrial machinery has resulted in greater divergence between total and delivered energy consumption (Figure 31). This trend is expected to stabilize over the forecast horizon, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption and delivered energy consumption grow by 0.7 percent and 0.8 percent a year, respectively, excluding transportation use.

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

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-

A Slower Rate of Decline in Energy Intensity Is Projected

Figure 32. ***Energy use per capita and per dollar of gross domestic product, 1970--2020 (index, 1970 = 1)***

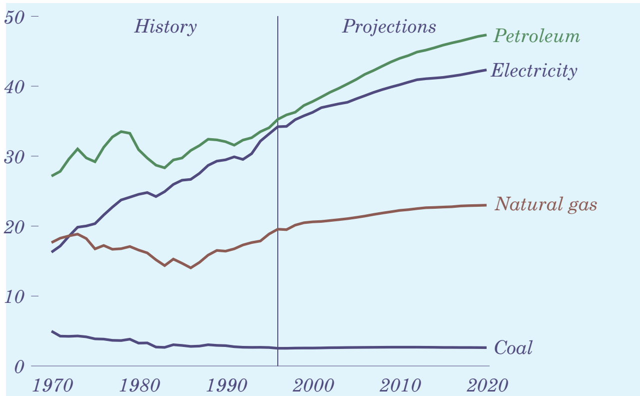


1980s (Figure 32). While the overall GDP-based energy intensity of the economy is projected to continue declining between 1996 and 2020, the rate of decline is expected to diminish, as a result of relatively stable projected energy prices and increased use of electricity-based energy services. As electricity claims a greater share of energy use, projected consumption per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption. Between 1996 and 2020, GDP is estimated to increase by 57 percent, compared with a 26-percent increase in primary energy use.

In the *AEO98* forecast, the demand for energy services increases markedly over current levels. The average home in 2020 is expected to be 5 percent larger and to rely more heavily on electricity-based technologies. Annual highway travel and air travel per capita in 2020 are expected to be 18 and 99 percent higher, respectively, than their current levels. Growth in demand for energy services notwithstanding, primary energy intensity on a per capita basis will remain essentially static through 2020, with efficiency improvements in many end-use energy applications making it possible to provide higher levels of service without significant increases in energy use per capita.

Oil and Electricity Fuel Projected Growth in End-Use Energy Demand

Figure 33. Primary energy use by fuel, 1970--2020 (quadrillion Btu)



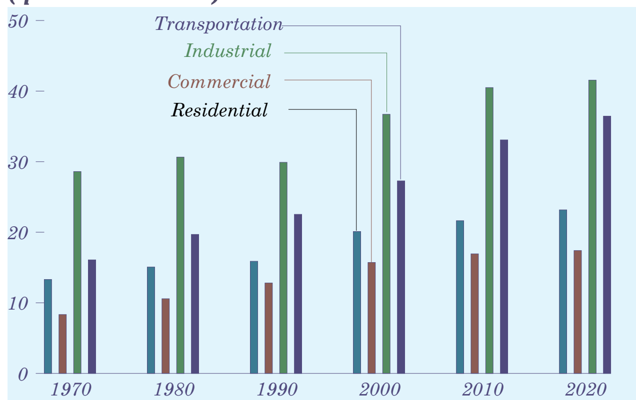
Petroleum products, mainly for transportation, claim the greatest share of primary energy consumption in the *AEO98* forecast (Figure 33). Growth in energy demand in the transportation sector, which averaged 2.0 percent a year during the 1970s, was diminished in the 1980s by rising fuel prices and by new Federal vehicle efficiency standards, which led to an unprecedented 2.1-percent annual increase in average vehicle fuel economy. In the *AEO98* forecast, fuel economy gains slow as a result of stable fuel prices and the absence of new legislative mandates. A growing population and increased travel per capita lead to increases in demand for gasoline throughout the forecast.

Increased competition and technological advances in electricity generation and distribution are expected to reduce the real cost of electricity. Despite low projected prices, however, growth in electricity use is slower than the rapid growth seen in the 1970s. End-use demand for natural gas grows at a slightly slower rate than overall 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 19.4 percent of all end-use energy demand requirements in 2020.

End-use demand for renewable energy from sources such as wood, wood wastes, and ethanol increases by 1.1 percent a year. The use of geothermal and solar thermal energy in buildings increases by about 5.6 percent a year but does not exceed 1 percent of energy consumption for space and water heating.

The Fastest Growth in Energy Use Is Projected for Transportation

Figure 34. Primary energy use by sector, 1970--2020 (quadrillion Btu)



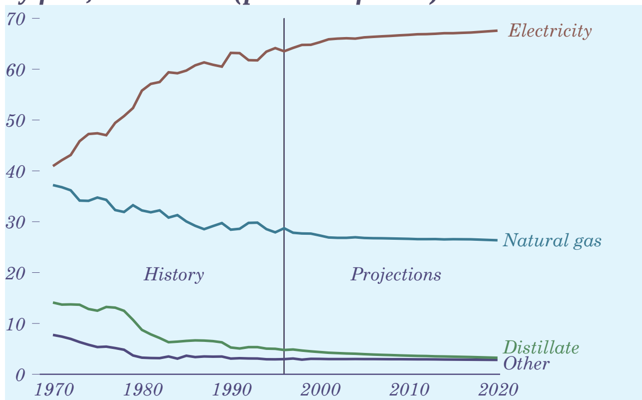
Primary energy use in the reference case is projected to reach 119 quadrillion Btu by 2020, 27 percent higher than the 1996 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 34). Between 1985 and 1996, however, stable energy prices contributed to a marked increase in sectoral energy consumption.

In the forecast, energy demand in the residential and commercial sectors grows at about the same rate as population. Demand for energy in the transportation sector grows more rapidly, driven by estimates 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 help bracket the uncertainty inherent in any long-term forecast, alternative assumptions were used to highlight the sensitivity of the *AEO98* forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Oil use for transportation in the high world oil price case is 5.6 percent lower than in the low world oil price case in 2020, as consumer choices favor more fuel-efficient vehicles and a slightly reduced demand for travel services. Varying economic growth affects overall energy demand in each of the end-use sectors to a greater extent [*29*]. By 2020, high economic growth assumptions result in a 20-percent increase in total annual energy use over its projected level in the low growth case.

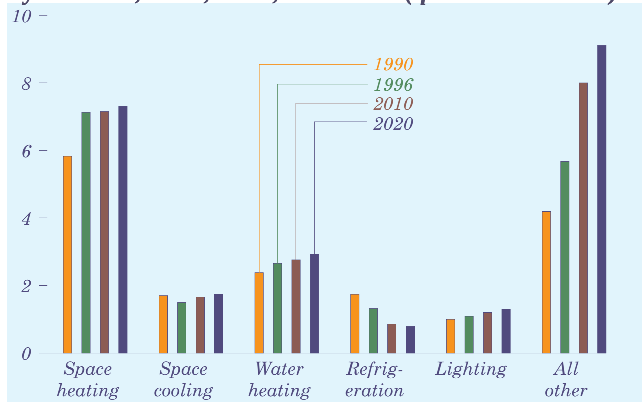
Electricity Supplies Most of the Projected U.S. Residential Energy Use

Figure 35. ***Residential primary energy consumption by fuel, 1970--2020 (percent of total)***



"Other" Residential Energy Uses Increase Rapidly in the Projections

Figure 36. ***Residential primary energy consumption by end use, 1990, 1996, and 2020 (quadrillion Btu)***



Residential energy consumption is projected to increase by 20 percent overall between 1996 and 2020. Most (87 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 35).

While its share declines slightly, natural gas use in the residential sector is projected to grow by 0.4 percent a year through 2020. Natural gas prices to residential customers decline in the forecast and are lower than the prices of other fuels, such as heating oil. The number of homes heated by natural gas increases more than the number heated by electricity and oil. Liquefied petroleum gas (LPG) use is projected to rise, as mobile homes—which tend to use LPG more intensively than multifamily units— provide a larger share of new housing.

Newly built homes are, on average, 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.

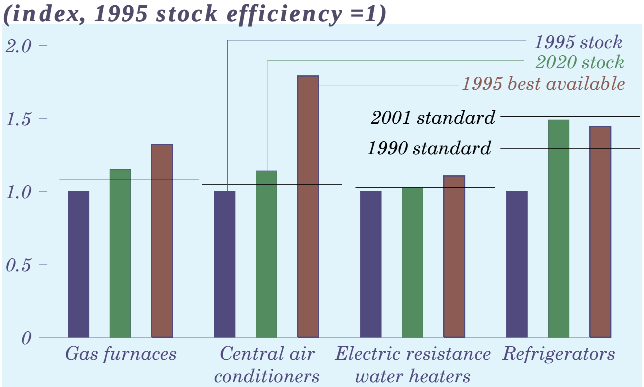
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 3.4 percent a year from 1990 to 1996 (Figure 36). Future growth should be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand in new homes by over 25 percent per household in 2020 relative to the demand in 1996.

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 limit electricity use to 690 kilowatthours a year, and revised standards are expected to reduce consumption by another 30 percent by 2002. Energy use for refrigeration has declined by 4.5 percent annually since 1990 and is projected to decline by about 2.1 percent a 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 a year since 1990 (Figure 36) and now accounts for 29 percent of total residential energy use. It is projected to account for 39 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 expected to exceed other components of residential demand by 2020.

Efficiency Improvements Are Projected for Residential Appliances

Figure 37. ***Efficiency indicators for selected residential appliances, 1995 and 2020 (index, 1995 stock efficiency =1)***

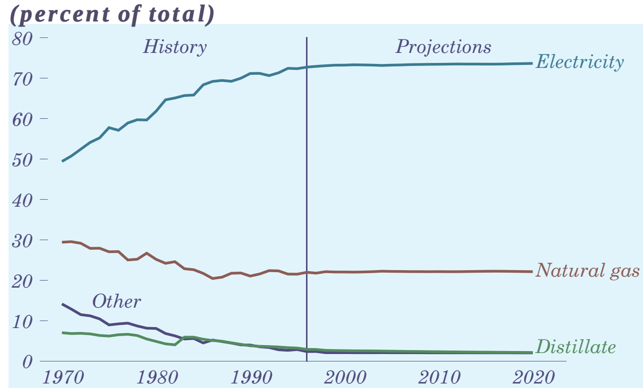


The *AEO98* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services combine to reduce residential energy intensity over time. For most appliances, recent Federal efficiency standards are at least 5 percent higher than the 1995 stock, ensuring an increase in stock efficiency (Figure 37). Future updates to the Federal standards can have a significant effect on residential energy consumption. (See "Legislation and Regulations," page 11, for details on the priorities established by the U.S. Department of Energy for appliances covered under the National Appliance Energy Conservation Act of 1987.)

For almost all end-use services, technologies now exist that 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 cost tends to restrict their market penetration. For natural gas furnaces, for example, condensing technology, which reclaims most of the heat in exhaust gases, can increase efficiency by more than 20 percent over the current standard. The use of variable-speed compressors in air conditioners and refrigerators can increase their efficiency by 50 percent or more over the current standard. On the other hand, there is little room for improvement in the efficiency of electric resistance water heaters, because the technology is approaching its thermal limit. (See page 48 for additional analysis of technology improvements for residential appliances.)

Slower Growth Is Projected for Commercial Energy Use Overall

Figure 38. ***Commercial nonrenewable primary energy consumption by fuel, 1970--2020 (percent of total)***

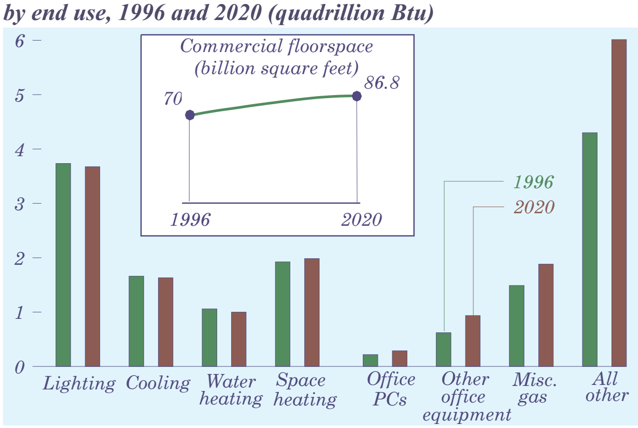


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past two decades (Figure 38). Slow growth (0.6 percent a year) is expected in the commercial sector, for two reasons. Commercial floorspace is projected to grow by only 0.8 percent a year between 1996 and 2020, compared with an average of 1.5 percent a year over the past two decades. Lower growth in floorspace reflects the slowing population growth expected after 2000. Additionally, energy consumption per square foot is projected to decline by 0.2 percent a year, as a result of efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements.

Electricity accounts for nearly three-fourths of commercial primary energy consumption throughout the forecast. Expected efficiency gains in electric equipment are offset by continuing penetration of new technologies and greater use of office equipment. Natural gas accounts for 22 percent of commercial energy consumption in 1996 and maintains that share throughout the forecast. Distillate fuel oil makes up only 3 percent of commercial demand in 1996, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate drops to 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.

Electricity Use for New Types of Equipment Grows Rapidly

Figure 39. Commercial primary energy consumption by end use, 1996 and 2020 (quadrillion Btu)

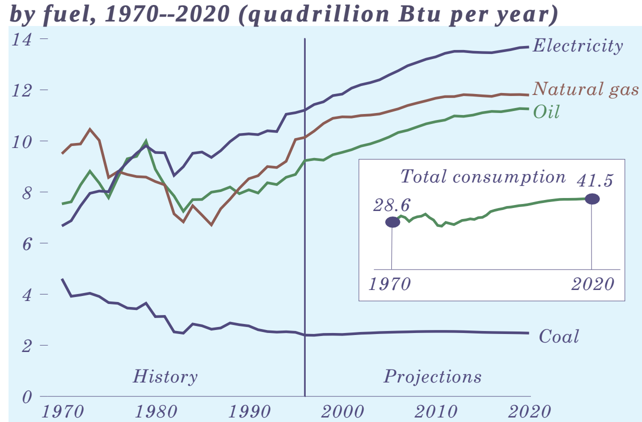


Through 2020, commercial lighting remains the most important individual end use in the commercial sector. Energy consumption for lighting is projected to decline slightly in the forecast, as more energy-efficient lighting equipment and more efficient generating technologies are adopted. Efficiency gains are also expected for space heating, space cooling, and water heating equipment, moderating the growth in overall commercial sector energy demand. Increasing building shell efficiency, which affects the energy required for space heating and cooling, also contributes to the trend (Figure 39).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers grows by 1.2 percent annually, and consumption for other office equipment, such as fax machines and copiers, grows by about 1.7 percent a year. Miscellaneous natural gas consumption for such uses as cooking, district heating, and self-generated electricity is expected to grow by 1.0 percent a year. New telecommunications technologies and medical imaging equipment increase the demand for electricity in the “all other” end-use category, which also includes ventilation, refrigeration, minor fuel consumption, and such varied uses of energy as service station equipment and vending machines. Growth in the “all other” category is expected to be especially vigorous during the first half of the forecast period and to slow somewhat in later years as emerging technologies achieve greater market penetration.

Industrial Use of All Energy Fuels Is Projected To Increase

Figure 40. Industrial primary energy consumption by fuel, 1970--2020 (quadrillion Btu per year)

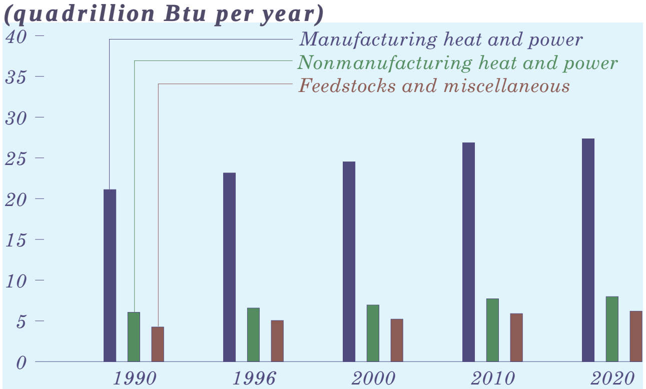


From 1970 to 1986, electricity's share of industrial energy use increased, as demand for coking coal was reduced by declines in steel production and electricity-intensive industries grew rapidly. The electric share of industrial total energy consumption rose from 23 percent to 35 percent, natural gas fell from 33 percent to 25 percent, and coal fell from 16 percent to 10 percent. After 1986, natural gas began to recover its share as end-use regulations were lifted and supplies became more certain and less costly. Over the forecast horizon, expectations of plentiful supplies and stable prices allow natural gas to maintain its current share of industrial energy consumption.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—increases by 0.7 percent a year in the forecast (Figure 40). 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 electricity use is projected to increase by 22.1 percent, as competition in the generation market keeps electricity prices low. Relatively low prices are also expected for natural gas, resulting in consumption that is 16.4 percent over its 1996 level by 2020. Industrial petroleum use grows by 22.0 percent over the same period. Coal consumption is stable over the forecast, as new steelmaking technologies continue to reduce demand for metallurgical coal, offsetting modest growth (0.6 percent a year) in coal use for boiler fuel.

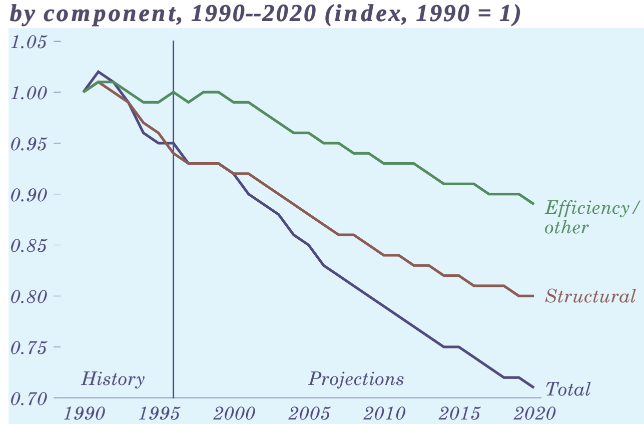
Manufacturing Industries Continue To Claim Major Share of Energy Use

Figure 41. ***Industrial primary energy consumption by industry category, 1990--2020 (quadrillion Btu per year)***



Manufacturing Energy Intensity Is Projected To Decline by One-Fourth

Figure 42. ***Manufacturing primary energy intensity by component, 1990--2020 (index, 1990 = 1)***



More than two-thirds of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing; the remainder is approximately equally distributed among nonmanufacturing heat and power and consumption as feedstocks (raw materials) and other miscellaneous uses (Figure 41).

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 7.9 quadrillion Btu in 1996. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for more than half of the energy consumed for heat and power. The pulp and paper industry consumes the most renewables, in the form of wood and spent liquor.

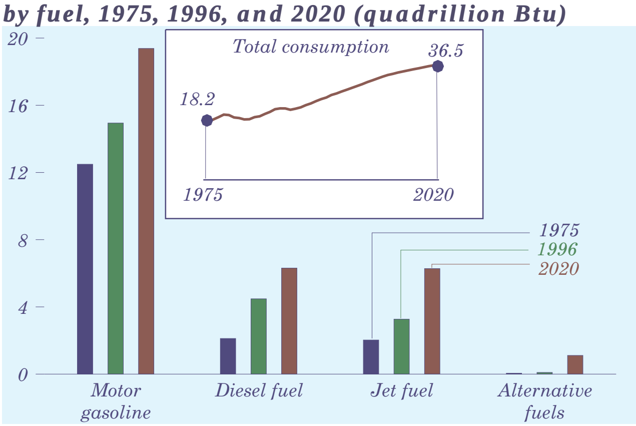
A major use of energy in the nonmanufacturing industries is for diesel-powered off-road equipment, such as mine excavation equipment, farm tractors, and bulldozers. The construction industry uses asphalt and road oil for paving and roofing. By 2020, nonmanufacturing output is expected to be 37.1 percent higher and delivered energy consumption (including asphalt and road oil) 28.7 percent higher than their 1996 levels. Total feedstock use is expected to increase by 17.6 percent. Natural gas is the fastest growing feedstock, increasing by 18.4 percent between 1996 and 2020.

Changes in manufacturing 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 moderated growth in industrial energy consumption. Thus, despite higher industrial output, total energy consumption in the sector has been virtually unchanged for the past 20 years. These basic trends are expected to continue.

The share of total manufacturing output attributed to the energy-intensive industries falls from 30 percent to 24 percent from 1996 to 2020. Thus, even if no specific industry experienced a decline in intensity, aggregate manufacturing intensity would decline. Figure 42 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*30*]. Over the forecast period, total manufacturing intensity drops by 27 percent, and the changing composition of manufacturing output alone results in approximately a 16-percent drop. Thus, more than half of the change in total energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with increases in equipment and production efficiencies.

Petroleum Products Dominate Energy Use for Transportation

Figure 43. Transportation energy consumption by fuel, 1975, 1996, and 2020 (quadrillion Btu)



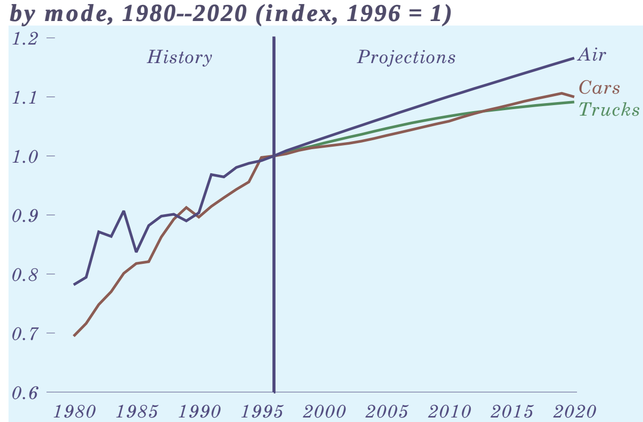
By 2020, total energy demand for transportation is expected to be 36.5 quadrillion Btu, compared with 24.8 quadrillion Btu in 1996 (Figure 43). Petroleum products dominate energy use in the sector. Motor gasoline use accounts for more than half of transportation energy demand, increasing by 1.1 percent a year in the reference case. Alternative fuels are projected to displace about 500,000 barrels of oil equivalent a day [*31*] by 2020, in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is sustained, however, by low projected gasoline prices and a slower pace of fuel efficiency gains in conventional light-duty vehicles (cars, vans, pickup trucks, and utility vehicles) than was achieved during the 1980s.

Assumed economic growth of 1.9 percent a year through 2020 leads to an increase in freight transport, with a corresponding increase in diesel use of 1.4 percent a year. Economic growth and low projected jet fuel prices yield a 3.7-percent annual increase in air travel, causing jet fuel use to increase by 2.8 percent a year.

In the forecast, energy prices directly affect the level of oil use through travel costs and average vehicle fuel efficiency. Most of the projected 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 only 1.0 percent a year, compared with 1.3 percent a year in the low oil price case.

Transportation Fuel Efficiency Grows More Slowly in the Forecast

Figure 44. Transportation stock fuel efficiency by mode, 1980--2020 (index, 1996 = 1)



Projected fuel efficiency improves at a slower rate through 2020 than in the 1980s (Figure 44). Light-duty vehicle efficiency standards are assumed to stay at current levels. Projected low fuel prices and higher disposable personal income [*32*] increase demand for more powerful and larger vehicles, although aging of the car-buying population is likely to moderate this trend later in the forecast. Projected average horsepower increases by two-thirds in 2020, but the use of advanced technologies and materials keeps new vehicle fuel economy from declining. Low fuel prices and slow stock turnover limit efficiency gains for freight trucks to 0.4 percent a year. Aircraft efficiency grows by 0.6 percent a year, with increasing sales of new wide-body aircraft.

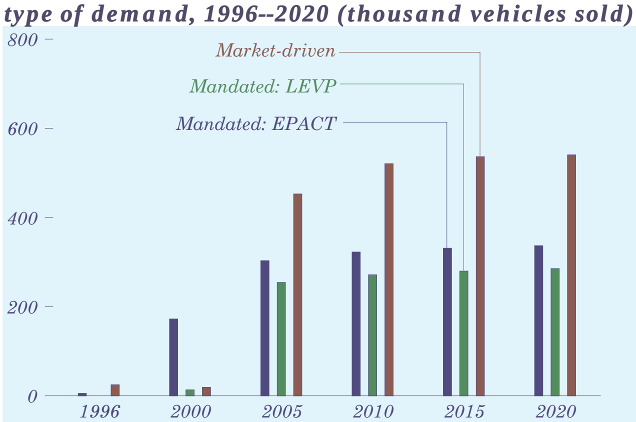
If vehicle horsepower increased by 1 percent a year through 2020, as compared with 2.1 percent in the reference case, new car fuel efficiency could be 13 percent higher than in the reference case in 2020 (Table 5). The improvement would cut fuel consumption by light-duty vehicles by 7.3 percent, or 1.4 quadrillion Btu, by 2020 and reduce total carbon emissions by 27 million metric tons.

Table 5. Changes in efficiency, fuel consumption, and carbon emissions with changes in horsepower, 2000-2020 (percent change from the reference case)

Year	Average horsepower	New car fuel efficiency (mpg)	Light-duty vehicle fuel consumption	Total carbon emissions
2000	-6.9	2.9	-0.6	-0.1
2010	-16.6	8.3	-3.5	-0.7
2020	-21.8	13.0	-7.3	-1.4

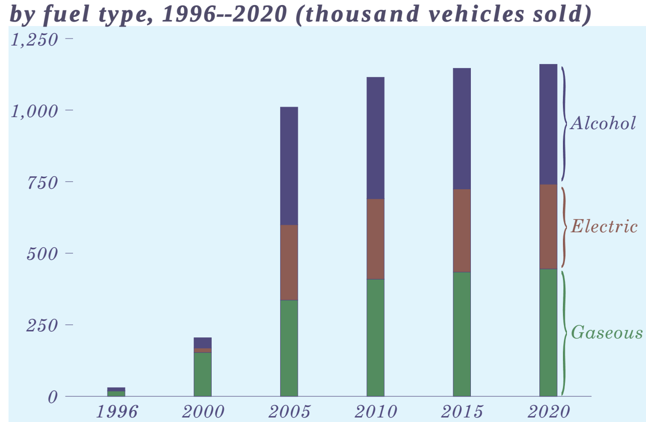
Market for Alternative-Fuel Vehicles Grows in the 21st Century

*Figure 45. **Alternative-fuel vehicle sales by type of demand, 1996--2020 (thousand vehicles sold)***



AFV Market Share in 2020 Projected To Be 8 Percent of All Vehicle Sales

*Figure 46. **Alternative-fuel light-duty vehicle sales by fuel type, 1996--2020 (thousand vehicles sold)***



Sales of alternative-fuel vehicles (AFVs) as a result of legislative mandates at the Federal level—under the Energy Policy Act of 1992 (EPACT)—and at the State level—under the Low Emission Vehicle Program (LEVP)—are expected to reach about 0.62 million units in 2020 (Figure 45). AFV acquisitions mandated for fleets under EPACT, predominantly fueled by compressed natural gas (CNG) or liquefied petroleum gas, represent the earliest legislated sales. Vehicles that use gaseous fuels continue to capture a large share of the AFV market through 2020 (Table 6).

Implementation of LEVP regulations is assumed to begin in New York in 1998, with California and Massachusetts mandates following in 2003. LEVP legislated sales are expected to total 285,000 units in 2020, boosting electric and electric hybrid vehicles to about 25 percent of AFV sales. With relatively low gasoline prices and the lack of an infrastructure to support AFVs, mandated sales will outpace market-driven sales of AFVs [*33*] until around 2005.

In the reference case, total AFV sales reach approximately 1.16 million units, or 8.0 percent of all vehicle sales, in 2020 (Figure 46). The use of light-duty AFVs is expected to reduce carbon emissions by 1 million metric tons of carbon by 2020. Vehicles that use gaseous fuels—already being sold by manufacturers at prices $1,000 to $1,500 above those for gasoline vehicles—dominate pre-2000 sales. Their limited range (about two-thirds that of gasoline vehicles) makes them good candidates for centrally fueled fleet applications. Because the large fuel tanks required to maintain vehicle range restrict both trunk and passenger space, the market potential for gaseous fuel AFVs for private use is limited to larger vehicles.

Electric vehicles are currently being developed by several automobile manufacturers, but large numbers of sales are not expected until LEVP mandates begin. Sales of dedicated and hybrid electric vehicles—96 percent of which originate from LEVP mandates—are projected to reach nearly 296,000 units in 2020.

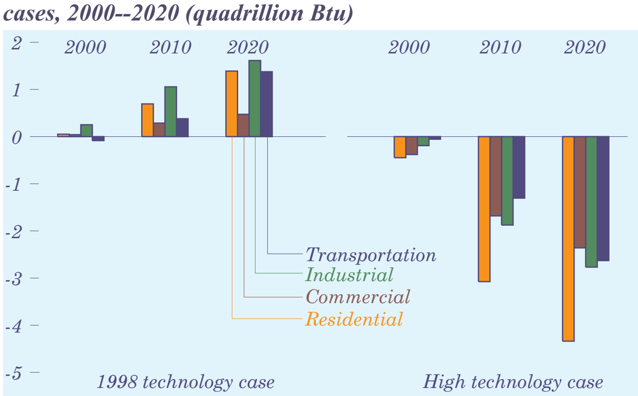
“Flex fuel” vehicles, which can use any combination of ethanol, methanol, and gasoline, are expected to make up 26 percent of AFV sales in 2020. The range, fuel efficiency, and performance of these vehicles are similar to those of conventional gasoline vehicles, and their incremental production cost is expected to be less than $500 by 2020. Unlike AFVs that use gaseous fuels, “flex-fuel” vehicles would be suitable for applications in all vehicle size classes.

Table 6. Market shares of alternative-fuel ***light-duty vehicles by technology type, 2020 (percent)***

Technology	Market share	Technology	Market share
Dedicated internal combustion		*Flex fuel internal combustion*	
Alcohol	*10.0*	*Alcohol*	*26.0*
CNG	*16.8*	*CNG*	*3.8*
LPG	*13.1*	*LPG*	*4.6*
Electric	*24.5*	*Electric hybrid*	*1.0*
Fuel cell	*0.0*	*Gas turbine*	*0.2*

More Efficient Technologies Could Reduce Total Energy Use

Figure 47. Variation from reference case primary energy use by sector in two alternative technology cases, 2000--2020 (quadrillion Btu)



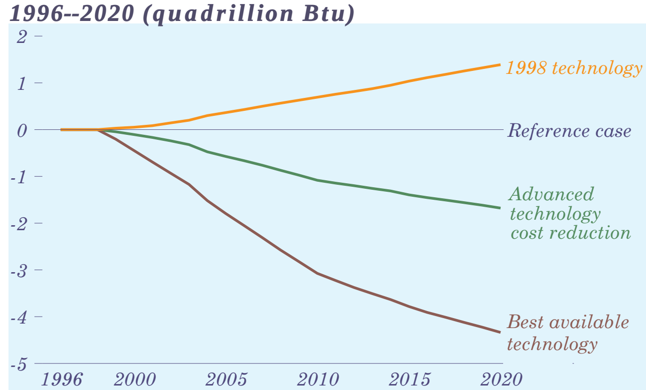
Adoption rates for new, more efficient technologies are uncertain. Alternative cases for each sector (see Appendix G), based on a range of assumptions about technological progress, show the effects of the assumptions (Figure 47). The alternative technology cases assume that existing equipment and building standards will be met, but they do not include feedback effects on energy prices or on economic growth.

Three cases are examined for the residential and commercial sectors. The 1998 technology case holds equipment efficiencies at 1998 levels. The best available technology case assumes that the most energy-efficient technologies available each year will be chosen, regardless of cost. The advanced technology cost reduction case permits choices based on cost, but over time the costs for the most efficient technologies decline from their reference case values.

For the industrial and transportation sectors, 1998 technology cases parallel the buildings sector case. A high technology case for the industrial sector assumes a more rapid, 1.5-percent annual decline in aggregate industrial energy intensity, compared with 1.1 percent in the reference case. The advanced technology case for the transportation sector includes reduced costs for advanced technologies and improved fuel efficiencies, comparable to levels assumed in a recent Department of Energy (DOE) interlaboratory study for air, rail, marine, and freight travel and provided by the DOE Office of Energy Efficiency and Renewable Energy for light-duty vehicles [*34*].

Lower Costs for New Technologies Could Cut Residential Energy Use

Figure 48. Variation from reference case primary residential energy use in three alternative cases, 1996--2020 (quadrillion Btu)



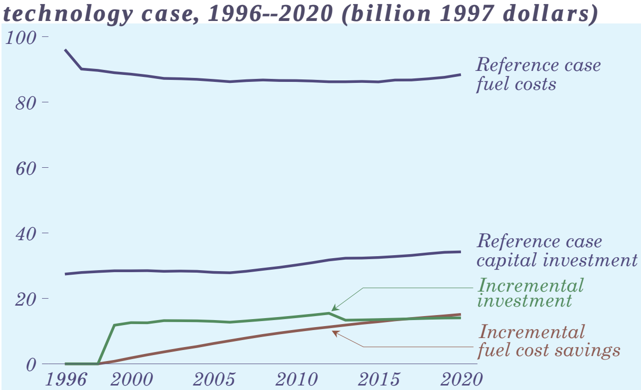
The *AEO98* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 1998 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 1998, 6.0 percent more energy would be required in 2020 (Figure 48).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, energy use is 18.7 percent lower than in the reference case in 2020, and household primary energy use is 23.3 percent lower than in the 1998 technology case in 2020.

The advanced technology cost reduction case does not constrain consumer choices. Instead, costs for the most energy-efficient technologies are assumed to decline by as much as 35 percent from reference case costs by 2020, as manufacturers gain experience. The consumer discount rates used to determine the purchased efficiency of all residential appliances in the advanced technology cost reduction 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 reach 7.2 percent in 2020; however, the savings are not as great as those in the best available technology case.

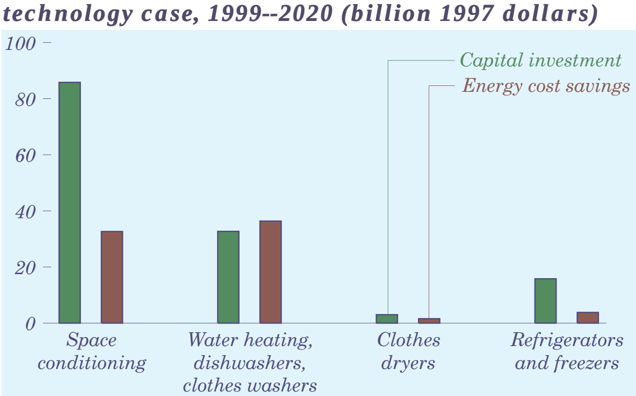
Efficient Home Water Heaters Could Give Significant Energy Cost Savings

Figure 49. ***Cost and investment changes for selected residential appliances in the best available technology case, 1996--2020 (billion 1997 dollars)***



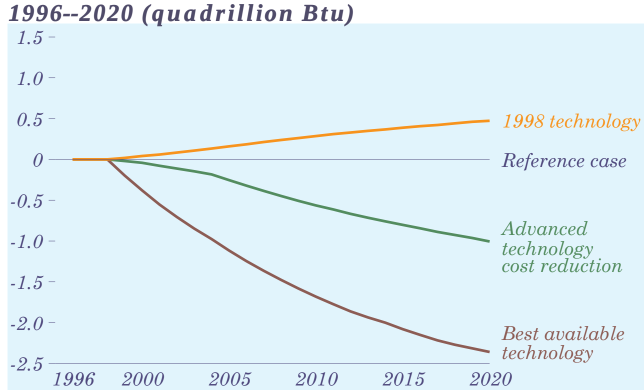
In the best available technology case, which requires the purchase of the most efficient equipment available, residential energy expenditures are lower but capital investment costs are higher (Figures 49 and 50). This case captures the effects of installing the most efficient (usually the most expensive) equipment at reference case turnover rates, regardless of economic considerations. An incremental investment of $137 billion [*35*] reduces residential delivered energy use by more than 16 quadrillion Btu—saving consumers $74 billion in energy expenditures—through 2020. Water heating has the greatest potential for savings relative to investment. In place of conventional technologies, such as electric resistance water heaters, condensing natural gas and electric heat pump water heaters and horizontal-axis washing machines can substantially cut the amount of energy needed to provide hot water services.

Figure 50. ***Present value of investment and savings for residential appliances in the best available technology case, 1999--2020 (billion 1997 dollars)***



Projected Energy Use Is Lowest Using Best Available Technologies

Figure 51. ***Variation from reference case primary commercial energy use in three alternative cases, 1996--2020 (quadrillion Btu)***

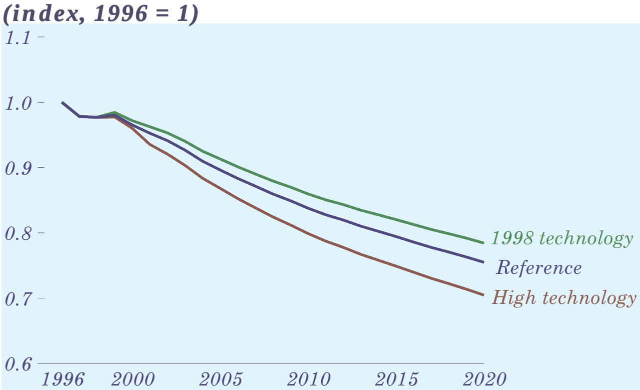


The *AEO98* reference case incorporates efficiency improvements for commercial equipment and building shells, contributing to a decline in commercial energy intensity of 0.2 percent a year over the forecast. The 1998 technology case assumes that future equipment and building shells will be no more efficient than those available in 1998. In comparison, the best available technology case assumes that only the most efficient technologies considered in *AEO98* will be chosen, regardless of cost, and that building shells will improve at a faster rate than in the reference case. The advanced technology cost reduction case assumes the same range of available technologies as in the reference case, but costs for the most energy-efficient technologies are assumed to decline over time more than they do in the reference case.

Energy use in the 1998 technology case is 2.7 percent higher than in the reference case by 2020 (Figure 51), with commercial primary energy intensity declining by 0.1 percent a year. In the best available technology case there is an additional 13.6-percent energy savings in 2020, and primary energy intensity falls by 0.8 percent a year from 1996 to 2020. Allowing the cost of efficiency advances to decline in the advanced technology cost reduction case yields energy use that is 5.8 percent lower than energy use in the reference case by 2020. Commercial primary energy intensity declines more slowly in this case than in the best available technology case, by 0.5 percent a year.

Changes in Technology Assumptions Alter Industrial Energy Intensity

Figure 52. ***Industrial primary energy intensity in two alternative technology cases, 1996--2020 (index, 1996 = 1)***



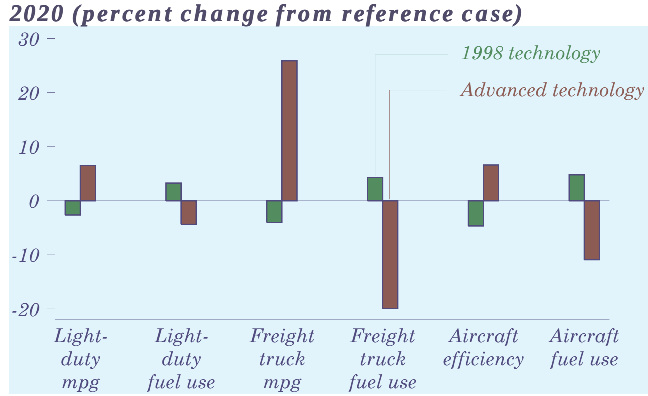
Expected efficiency gains in both energy-intensive and non-energy-intensive industries provide improvement in energy intensity. The growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor: these less energy-intensive industries grow 48 percent faster than the manufacturing average (3.1 percent vs. 2.1 percent a year).

In the high technology case, 2.8 quadrillion Btu less energy is used in 2020 than for the same level of output in the reference case. Industrial energy intensity declines by 1.5 percent a year through 2020 in this case, compared with a 1.2-percent annual decline in the reference case (Figure 52). While the individual industry intensities decline about twice as rapidly in the high technology case as in the reference case, the aggregate intensity falls less rapidly, because the composition of industrial output is the same in the two cases.

In the 1998 technology case, industry consumes 1.6 quadrillion Btu more energy in 2020 than in the reference case. Energy efficiency remains at the level achieved in 1998 new plants, but average efficiency still improves as old technology is retired and replaced by new 1998 technology. Aggregate industrial energy intensity declines by only about 1.0 percent a year because of reduced efficiency gains and changes in industrial structure. The composition of industrial output accounts for 69 percent of the change in aggregate industrial energy intensity, compared with 59 percent in the reference case.

Major Fuel Efficiency Gains Are Possible for Freight Trucks

Figure 53. ***Changes in key components of the transportation sector in two alternative cases, 2020 (percent change from reference case)***

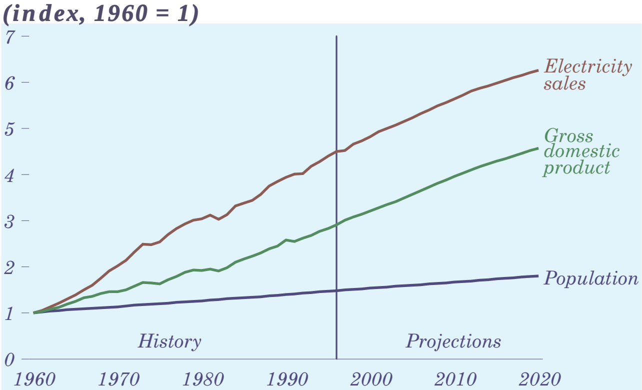


Two alternative cases were examined to bracket the potential impacts of technology improvements in the transportation sector. The 1998 technology case held new fuel efficiencies for light-duty vehicles, freight trucks, and aircraft at 1998 levels throughout the forecast, resulting in average stock efficiencies for light-duty vehicles that were as much as 2.6 percent lower than those in the reference case in 2020. As a result, fuel use in 2020 was 1.4 quadrillion Btu (3.8 percent) higher than in the reference case (Figure 53). The increase in fuel use was attributable primarily to light-duty vehicles (55 percent of the total increase), followed by aircraft (25 percent) and freight trucks (20 percent).

The advanced technology case assumes cost and performance criteria provided by the DOE Office of Energy Efficiency and Renewable Energy for light-duty vehicles and from the efficiency case of the recent interlaboratory study [*36*] for air, freight, marine, and rail travel, including high-efficiency advanced light-duty diesel vehicles; electric, electric hybrid, and fuel cell light-duty vehicles with higher efficiencies and earlier introduction dates; advanced drag reduction, reduced vehicle weights, and advanced diesel engines for freight trucks, with shorter market penetration times and lower cost-effectiveness criteria; and aircraft with higher load factors and higher fuel efficiency. In the advanced technology case, total fuel consumption for the transportation sector was 2.6 quadrillion Btu (7.2 percent) lower than the reference case level in 2020.

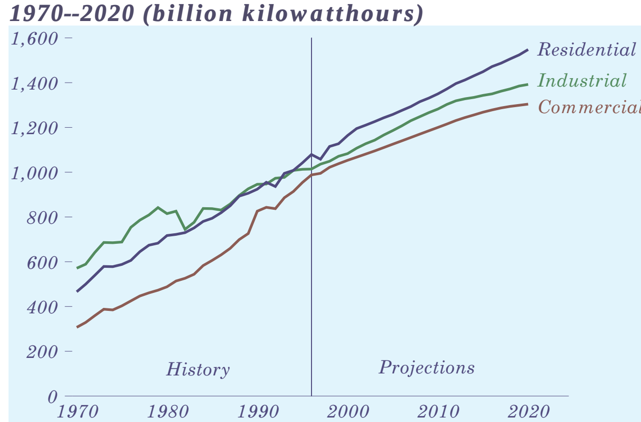
Slower Growth Is Projected for U.S. Electricity Sales

Figure 54. ***Population, gross domestic product, and electricity sales growth, 1960--2020 (index, 1960 = 1)***



Residential Electricity Sales Lead the Projected Increase

Figure 55. ***Annual electricity sales by sector, 1970--2020 (billion kilowatthours)***



While generators and cogenerators try to adjust to the evolving structure of the electricity market, they are also faced with slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. This positive relationship will continue, but the magnitude of the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent a year, nearly twice the rate of economic growth (Figure 54). 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 legislation establishing more stringent equipment efficiency standards. For similar reasons, a continued decline is expected throughout the forecast.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. Only a few years ago, no one foresaw the growth in home computers, facsimile machines, copiers, and security systems, all powered by electricity. If new uses of electricity are more substantial than currently expected, they could partially offset future efficiency gains.

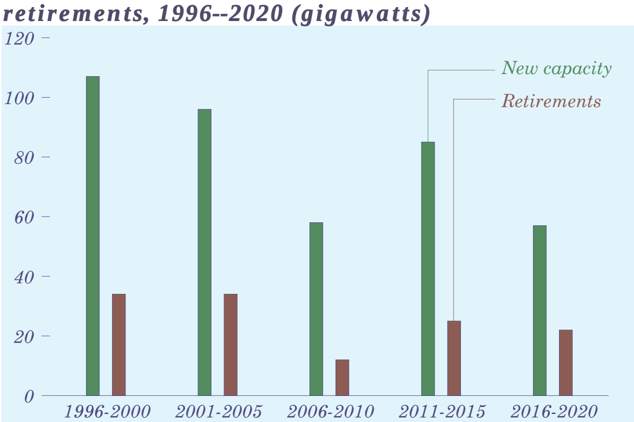
With the number of U.S. households projected to rise by 1.0 percent a year between 1996 and 2020, residential demand for electricity grows by 1.5 percent annually (Figure 55). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks 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 satisfy peak demand. Although many regions currently have surplus baseload capacity, strong growth in the residential sector will result in a need for more "peaking" capacity. Between 1996 and 2020, generating capacity from gas turbines and internal combustion engines is expected to more than triple.

Electricity demand in the commercial and industrial sectors grows by 1.2 and 1.3 percent a year, respectively, between 1996 and 2020. Annual commercial floorspace growth of 0.8 percent and industrial output growth of 1.9 percent drive the increase.

In addition to sectoral sales, cogenerators in 1996 produced 149 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, these producers are expected to maintain about the same share of total generation, increasing their own-use generation to 165 billion kilowatthours as demand for manufactured products increases.

New Capacity Will Be Needed
To Replace Retirements, Meet Demand

Figure 56. New generating capacity and retirements, 1996--2020 (gigawatts)



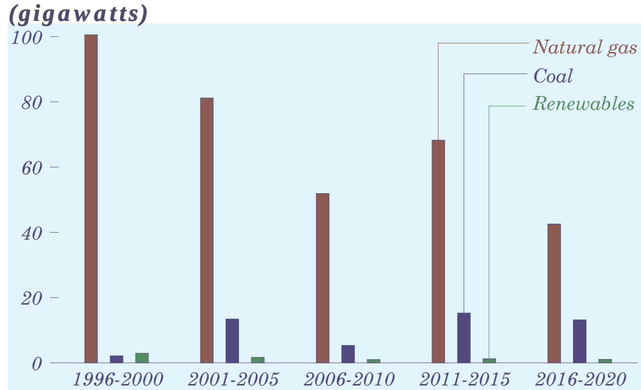
Despite slower demand growth, 403 gigawatts of new generating capacity will be needed by 2020 to meet growing demand and to replace retiring units. The reference case assumes that fossil-steam plants with operating costs above 4 cents per kilowatthour will be retired in the next decade. Between 1996 and 2020, 52 gigawatts (51 percent) of current nuclear capacity and 73 gigawatts (16 percent) of current fossil-steam capacity [*37*] are expected to be retired. Of the 142 gigawatts of new capacity needed after 2010 (Figure 56), 22 percent will replace retired nuclear capacity.

The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010: 47 percent of the new combined-cycle and 58 percent of the new coal capacity projected in the entire forecast are brought on line between 2010 and 2020. Before the advent of natural gas combined-cycle plants, fossil-fired baseload capacity additions were limited primarily to pulverized-coal steam units; however, efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared to 38 percent for coal-steam units, with construction costs only about 37 percent those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, more than one-half of currently operating nuclear capacity is expected to retire by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the need for new fossil-based capacity and reduce fossil fuel prices.

Natural Gas Is Projected
To Fuel Most New Capacity

Figure 57. Electricity generation and cogeneration capacity additions by fuel type, 1996--2020 (gigawatts)

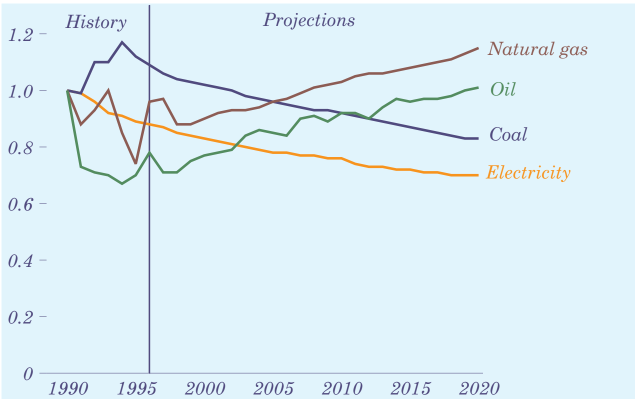


Before building new capacity, utilities are expected to use other options to meet demand growth—life extension and repowering of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 1,344 new plants with a total of 403 gigawatts of capacity will be needed by 2020 to meet growing demand and to offset retirements. Of the new capacity, 85 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas (Figure 57). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

More than 49 gigawatts of new coal-fired capacity is projected to come on line between 1996 and 2020, accounting for more than 12 percent of all capacity expansion. Competition with low-cost gas-turbine-based technologies has 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 the remaining 2 percent of capacity expansion by 2020—primarily, wind and biomass gasification units. Oil-fired steam plants, with higher fuel costs and lower efficiencies, account for less than 0.5 percent of new capacity in the forecast.

Competition, Lower Coal Prices Are Expected To Reduce Electricity Prices

Figure 58. Fuel prices to electricity suppliers and electricity price, 1990--2020 (index, 1990 = 1)



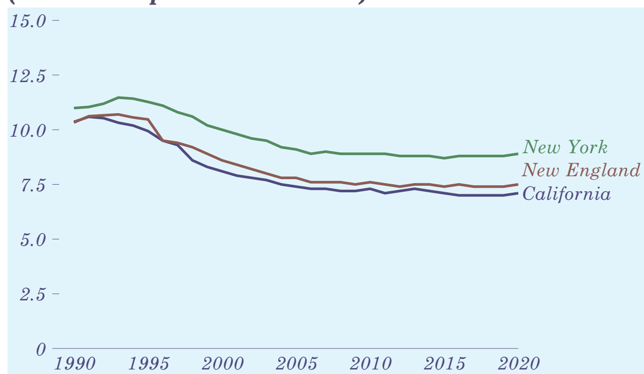
Between 1996 and 2020, the average price of electricity in real 1996 dollars is projected to decline by 1.0 percent a year as a result of competition among electricity suppliers (Figure 58). By sector, projected prices in 2020 are 19, 21, and 24 percent lower than 1996 prices for residential, commercial, and industrial customers.

The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. For existing plants, fuel costs typically represent $24 million annually or 79 percent of the total operational costs (fuel and operating and maintenance) for a 300-megawatt coal-fired plant and $31 million annually or 93 percent of the total operational costs for a gas-fired combined-cycle plant of the same size in 1996.

Natural gas prices to electricity suppliers rise by 0.7 percent a year in the forecast, from $2.70 per thousand cubic feet in 1996 to $3.22 in 2020. Gas-fired electricity generation increases by 376 percent, from 462 to 1,583 billion kilowatthours. Offsetting these increases are declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Oil prices to utilities are expected to increase by 29 percent. As a result, oil-fired generation is expected to decline by more than 56 percent between 1996 and 2020. However, oil currently accounts for only 2.5 percent of total generation, and that share is expected to decline to 0.8 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Three Regions Illustrate Projected Effects of Market Competition

Figure 59. Electricity prices in the New England, New York, and California regions, 1990--2020 (1996 cents per kilowatthour)



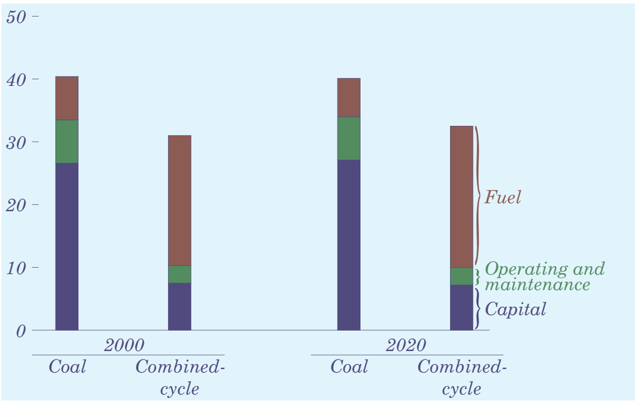
The reference case assumes a transition to competitive pricing in California, New York, and the New England States. It is assumed that electricity prices in California will remain constant at nominal 1996 levels between 1998 and 2001 for commercial and industrial customers, whereas residential customers will see a 10-percent reduction from 1996 prices in 1998; that there will be a transition from regulated to competitive prices between 2002 and 2007; and that the market will be fully competitive by 2008. Similarly, in New York and New England, the transition period is assumed to be from 1998 through 2007, with fully competitive pricing of electricity beginning in 2008.

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 competitive prices in these regions will be the marginal cost of generation, and the distribution of prices across economic sectors is the same as that for regulated prices.

As a result of the moves toward competition in California, New York, and New England electricity prices in those regions are expected to fall rapidly from 1996 to 2005—by 2 to 3 percent a year (Figure 59). Over the longer term, prices in the three regions are projected to decline at approximately the same rate as the national average—1 percent a year—as electricity prices in all regions approach the cost of building and operating new power plants.

Lower Projected Capital Costs Give Gas Technologies a Competitive Edge

Figure 60. Electricity generation costs, 2005 and 2020 (1996 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 levelized costs (Figure 60). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is increased by 1 percentage point, to account for the competitive risk of siting new units.

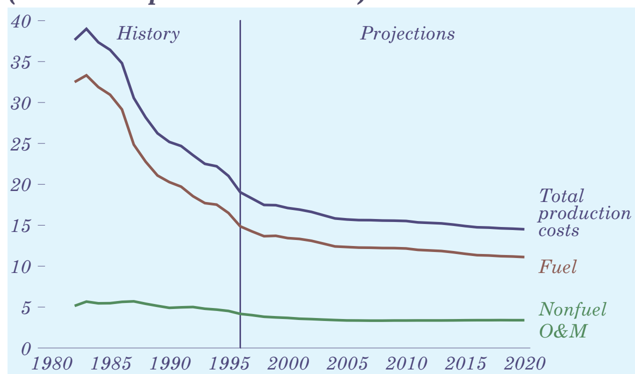
In the *AEO98* forecasts, capital costs of conventional technologies are assumed to decline by 2.5 percent for each doubling of new capacity. For advanced technologies, after an initial upward adjustment to account for technological optimism, capital costs decline by 10 percent for each doubling of capacity for the first 5 units, 5 percent for the 6th through 40th units, and 2.5 percent after 40 units. Heat rates for both advanced and conventional fossil-fired technologies decline annually from 1995 until 2010. In 2020, levelized costs for gas-fired combined-cycle capacity are 19.2 percent lower than those for coal (Table 7).

Table 7. Costs of producing electricity from new plants, 2005 and 2020

Item	2005 Conventional pulverized coal	2005 Advanced combined cycle	2020 Conventional pulverized coal	2020 Advanced combined cycle
	1996 mills per kilowatthour			
Capital	26.6	7.5	27.1	7.2
O&M	6.9	2.8	6.9	2.8
Fuel	6.9	20.7	6.1	22.5
Total	40.3	31.0	40.1	32.4
	Btu per kilowatthour			
Heat rate	9,386	6,812	9,087	6,350

Projected Electricity Production Costs Continue To Decline

Figure 61. Production costs for coal- and gas-fired generating plants, 1982--2020 (1996 mills per kilowatthour)

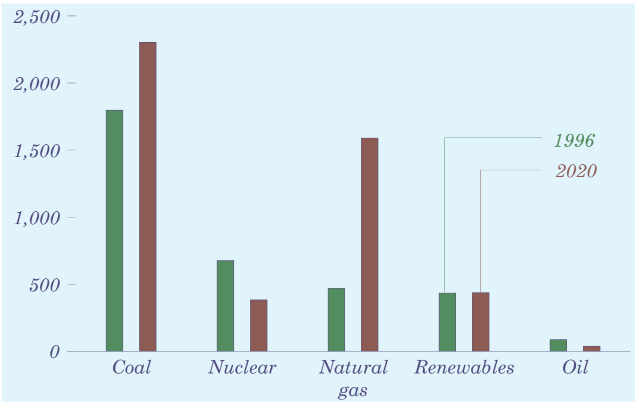


Since 1982, nonfuel operating and maintenance expenses for coal- and gas-fired steam generating plants have declined by 1.8 percent annually in real terms (Figure 61). These expenses include operation and maintenance of the boiler and electric plant, supervisory and engineering expenses, steam production expenses, and rents. The decline is the result of more energy-efficient plant components, more exacting engineering methods, demand growth, and reductions in staff. In addition, fuel expenses for these plants have declined by 5.5 percent a year, mirroring the falling prices of natural gas and coal during the period. As a result, total production expenses for coal- and gas-fired steam plants have declined by 5.1 percent annually since 1982.

The same trend is expected to continue but at a slower pace than the decline seen over the past decade. In 1982, coal-fired steam plants used 250 employees per gigawatt of installed capacity, and utilities were able to reduce that number to 200 by 1995. Gas-fired steam plants employed more than 138 staff per gigawatt in 1982 and fewer than 100 in 1995. Much of the incentive to cut staff and reduce operating costs came from the anticipation of competitive electricity markets. The amount by which utilities can continue to cut costs is uncertain, but many analysts agree that further reductions are possible, if not inevitable, in a competitive environment. Between 1996 and 2020, operating and maintenance costs for coal- and gas-fired steam generating plants are expected to decline by 0.8 percent a year and fuel costs by 1.2 percent a year.

Coal Continues as the Leading Electricity Fuel in the Projections

Figure 62. Electricity generation by fuel, 1996--2020 (billion kilowatthours)



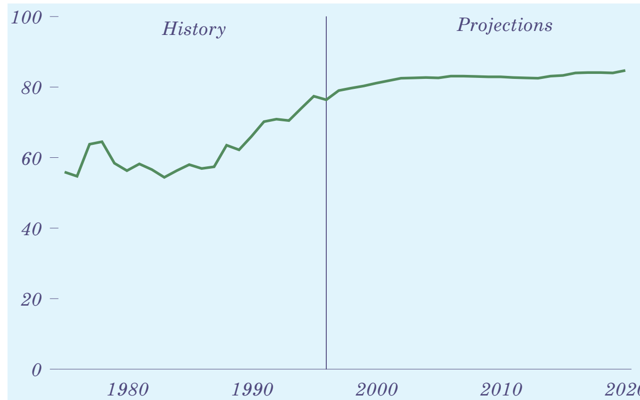
As they have since early in this century, coal-fired power plants are expected to remain the dominant source of electricity through 2020 (Figure 62). In 1996, coal accounted for 1,797 billion kilowatthours or 52 percent of total generation. Although coal-fired generation is projected to increase to 2,304 billion kilowatthours, increases in natural gas generation will lower coal's share to 49 percent in 2020. Concerns about the environmental impacts of coal plants, combined with their relatively long construction leadtimes and the availability of economical natural gas, make it unlikely that many new coal plants will be built before 2000. Nevertheless, slow demand growth and the huge investment in existing plants will keep coal in its dominant position.

The large investment in existing plants will also make nuclear power a growing source of electricity at least through 2000. In recent years, the performance of nuclear power plants has improved substantially. As a result, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, generation from gas-fired power plants shows the largest increase in the forecast, growing from 14 percent of generation in 1996 to 33 percent in 2020. As a result, by 2003, gas-fired generation overtakes nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants remains fairly small throughout the forecast.

Nuclear Power Plant Capacity Factor of 85 Percent Is Projected by 2020

Figure 63. Nuclear power plant capacity factors, 1975--2020 (percent)

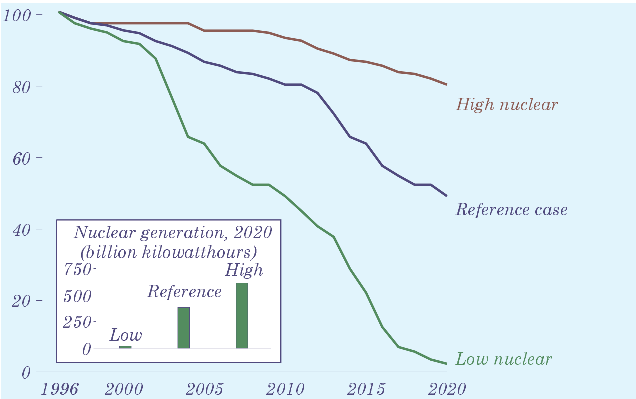


The *AEO98* reference case forecast assumes that 24 nuclear units will be retired before their license expiration dates, based on utility announcements and an analysis of the operating costs and aging degradation of the oldest vintage of plants. The remaining nuclear units are assumed to operate to the end of their current 40-year license terms, with 65 units (51 percent of current nuclear capacity) retiring between 1996 and 2020. Sixty percent of the projected retirements occur in the last 10 years of the forecast. (One new unit, Watts Bar 1, became operable in 1996.) Given these assumptions, 45 nuclear units are projected to provide 8 percent of total electricity generation in 2020, down from 19 percent in 1996. No new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical.

Nuclear generation forecasts depend on both operating capacity and assumed capacity factors. The national average capacity factor, which was below 65 percent in the 1970s and 1980s, has surpassed 70 percent since 1991 (Figure 63), achieving 76 percent in 1996. *AEO98* assumes that individual reactor performance improves for the first 20 or 25 years of operation, maintains this level for several years, then declines slightly just before retirement. As a result, the national average capacity factor increases fairly steadily throughout the forecast, reaching 85 percent in 2020.

Nuclear Capacity Is Projected To Decline in All Cases

Figure 64. Operable nuclear capacity in three cases, 1996--2020 (gigawatts)

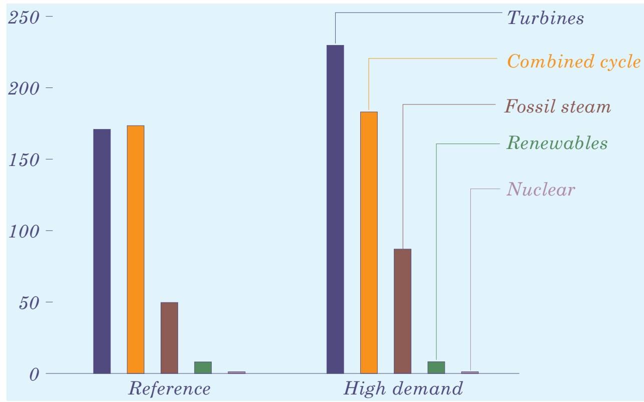


Two alternative *AEO98* analyses—the high and low nuclear cases—show how changing assumptions about the operating lifetimes of nuclear plants affect the reference case forecast of nuclear capacity (Figure 64). The low nuclear case assumes that, on average, all units are retired 10 years before the end of their 40-year license periods—108 units (all but 2) by 2020. Early shutdowns could be caused by unfavorable economics, in conjunction with waste disposal problems or age-related degradation of the units. The high nuclear case assumes 10 additional years of operation for each unit beyond the reference case retirement date (only 28 units retired by 2020), suggesting that license renewals would be permitted. Conditions favoring that outcome could include continued performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities.

In the low nuclear case, more than 170 new fossil-fueled units (assuming an average size of 300 megawatts) would be built to replace additional retiring nuclear units. The new capacity would mainly be split between coal-fired (73 percent) and combined-cycle (22 percent) units. The additional fossil-fueled capacity would produce 74 million metric tons of carbon emissions above those in the *AEO98* reference case in 2020. In the high nuclear case, 31 gigawatts of new capacity additions—mostly fossil-fueled plants—are avoided, as compared with those in the *AEO98* reference case, and carbon emissions are reduced by 42 million metric tons (6 percent of total emissions by electricity generators) in 2020.

High Demand Case Projects a Significant Increase in New Capacity

Figure 65. Cumulative new generating capacity by type in two cases, 1996--2020 (gigawatts)

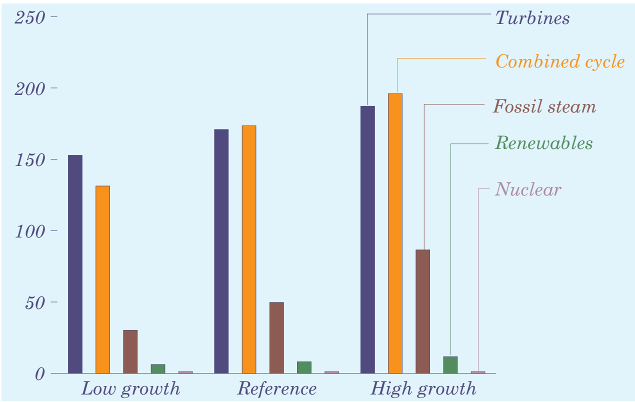


Electricity consumption grows in the forecast, but the rate of increase lags behind historical levels as a result of assumptions regarding efficiency improvements in end-use technologies, demand-side management programs, and population and economic growth. Deviations from these assumptions could result in substantial changes in electricity demand. For example, if electric vehicles enter the market faster than expected, the demand for electricity would also increase more rapidly. Lower electricity prices due to the effect of competitive markets could lead to increased consumption and less concern for conservation. In a high demand case, electricity demand is assumed to grow by 2.0 percent a year between 1996 and 2020, comparable to the annual growth rate of 2.2 percent between 1990 and 1996. In the reference case, electricity demand is projected to grow by 1.4 percent a year.

In the high demand case, 106 gigawatts more new generating capacity is built than in the reference case between 1996 and 2020—equivalent to 353 new 300-megawatt generating plants (Figure 65). The shares of coal- and gas-fired generation are about the same—12 and 85 percent, respectively, in the reference case and 17 and 81 percent in the high demand case. Relative to the reference case, there is a 12-percent increase in coal consumption and a 23-percent increase in natural gas consumption in the high demand case, and carbon emissions from electricity generation are 114 million metric tons (15 percent) higher.

Plant Refurbishment Is an Attractive Option for Electricity Generators

Figure 66. ***Cumulative new generating capacity by type in three cases, 1996--2020 (gigawatts)***



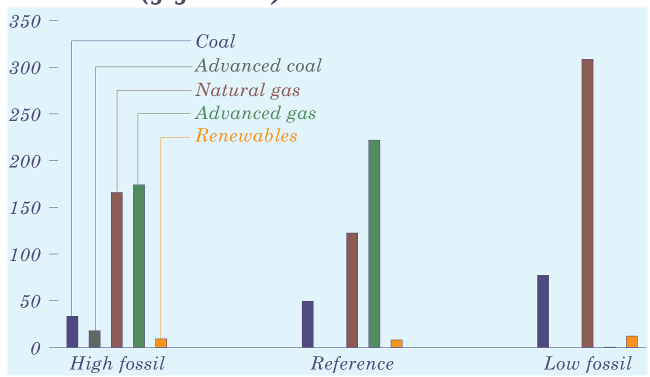
From 1996 to 2020, the annual average growth rate for GDP ranges between 2.4 and 1.3 percent in the high and low economic growth cases, respectively. The difference of a percentage point in the economic growth rate leads to a 21-percent change in electricity demand in 2020, with a corresponding difference of 161 gigawatts of new capacity required in the high and low economic growth cases. In both cases, utilities are expected to retire 17 percent of their current generating capacity (equivalent to 423 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

In the reference case, electricity suppliers are expected to add 403 gigawatts of new capacity, equivalent to 1,344 new 300-megawatt power plants. Of the new capacity, 12 percent is expected to be coal-steam, 85 percent gas turbine and combined-cycle, and 2 percent renewable technologies (Figure 66). In addition, between 1996 and 2020, utilities are expected to repower or life-extend 232 gigawatts or 30 percent of current capacity.

Current construction costs for a typical 400-megawatt plant range from $400 per kilowatt for combined-cycle technologies to $1,079 per kilowatt for coal-steam technologies. These costs, combined with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option for utility resource planners. Between 1996 and 2020, utilities are expected to refurbish 381 coal-, 190 gas-, and 40 oil-fired generating units.

New Capacity Types Change with Different Technology Assumptions

Figure 67. ***Cumulative new electricity generating capacity by technology type in three cases, 1996--2020 (gigawatts)***

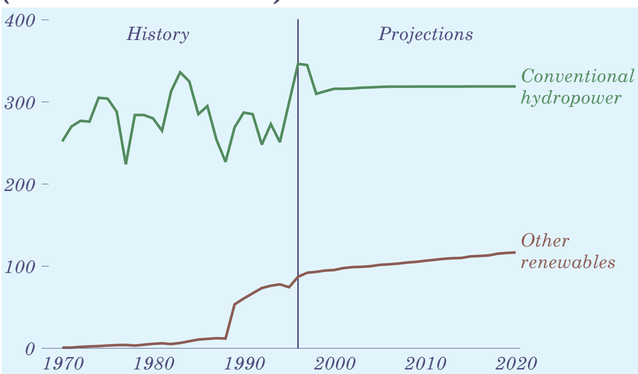


The *AEO98* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs, operating costs, and heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, advanced combustion turbine, and molten carbonate fuel cell) were revised to reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that no advanced technologies will come on line during the projection period.

Because of their high initial capital costs, no integrated coal gasification combined cycle (IGCC) units are projected between 1996 and 2020 in the reference case. In the high fossil fuel case, which assumes lower initial capital costs and higher efficiencies for the IGCC technology, 18 gigawatts of IGCC capacity are projected. The low fossil fuel case, as compared with the reference case, projects 36 gigawatts less gas-fired capacity additions, 28 gigawatts more coal-fired capacity additions, and 4 gigawatts more renewable capacity additions between 1996 and 2020 (Figure 67).

Modest Gains Are Projected for Nonhydroelectric Renewables

Figure 68. Grid-connected electricity generation from renewable energy sources, 1970--2020 (billion kilowatthours)



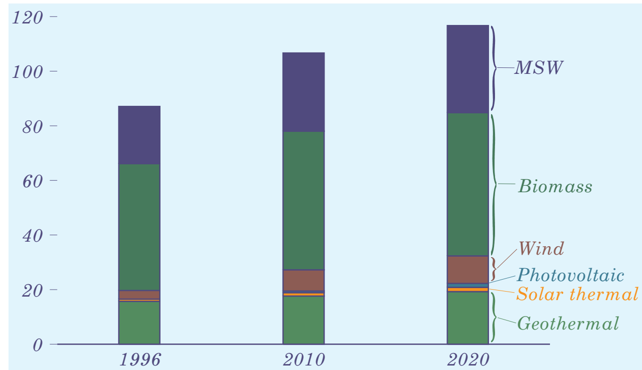
Total grid-connected electricity generation from renewable resources, including hydropower, increases only slightly in the forecast, from 433 billion kilowatthours in 1996 to 436 billion in 2020 (Figure 68). A 34-percent increase (30 billion kilowatthours) in generation from other renewables is offset by a decline in hydroelectricity to normal long-term levels after 1996. In addition, because fossil-fueled capacity increases substantially while conventional hydroelectric capacity remains almost unchanged, the total renewable share of U.S. generation (including utilities, nonutilities, and industrial cogenerators) drops from 12.5 percent in 1996 to 9.2 percent in 2020.

The largest source of renewable energy, conventional hydroelectric power—which in 1996 provided 80 percent of renewable electricity generation—is projected to show almost no growth in the forecast. Hydropower generation in 1996 was unusually high as a result of higher than normal precipitation. The growth of hydroelectric generation is constrained by a lack of available new sites, high construction costs, growing environmental concerns, and competing uses for water resources.

Expectations vary for nonhydroelectric renewables, including biomass, geothermal, municipal solid waste (MSW), solar (thermal and photovoltaic), and wind technologies. By 2020, electricity generation from renewable resources other than hydroelectricity is projected to provide about 117 billion kilowatthours a year, or about 2.5 percent of the U.S. grid-connected electricity supply.

Biomass, Municipal Solid Waste, Wind Show Increases in the Projections

Figure 69. Nonhydroelectric renewable electricity generation by energy source, 1996, 2010, and 2020 (billion kilowatthours)

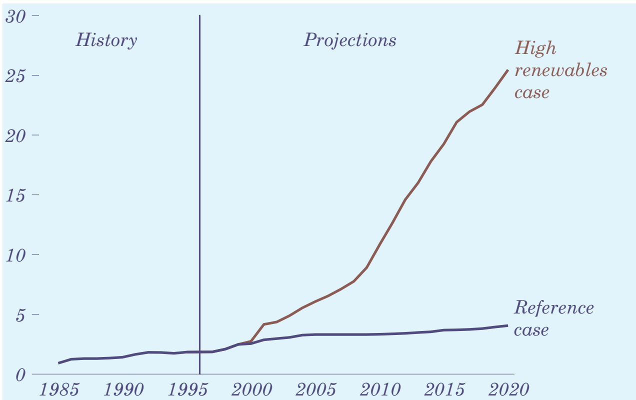


Most of the growth in renewable electricity generation is projected for MSW (including landfill gas), wind, and biomass (Figure 69). Growth in grid-connected solar power generation reflects only currently planned or mandated new capacity, or minimum estimates reflecting experimentation and commercialization programs. These technologies are not expected to be competitive in the reference case. Continued rapid growth is expected for small, off-grid applications of highly valued photovoltaic technologies, but those sources are not included in the *AEO98* projections. New geothermal capacity in the western United States is more than offset by retirements at The Geysers power station; however, efficiency gains yield a slight increase in geothermal generation. The growth in electricity generation from biomass is nearly equally divided between industrial cogeneration and gasification combined-cycle units owned by electricity generating firms. The increase in MSW generation comes largely from the recovery and use of landfill gas (methane) for electricity generation.

Overall, electricity generation from renewable energy sources could accelerate if efforts to emphasize their use gain public favor. If successful, programs such as renewable portfolio standards and voluntary consumer investments through "green pricing" programs could, in combination with heightened environmental concerns, lead to more rapid growth in the use of renewable energy resources—probably at the cost of higher electricity prices.

Wind-Powered Generating Capacity Is Expected To Increase Through 2020

Figure 70. ***Wind-powered electricity generating capacity in two cases, 1985--2020 (gigawatts)***

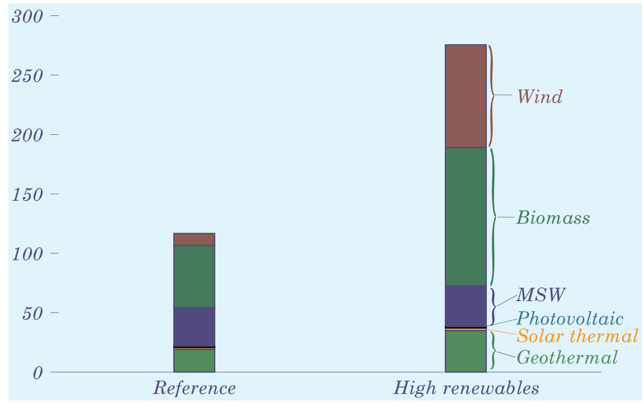


Improvements in wind power technology are expected over the forecast period, including larger, more efficient turbines and improved turbine siting. As a result, U.S. wind capacity is projected to increase from 1.8 gigawatts in 1996 to 4.1 gigawatts in 2020 (Figure 70), penetrating more deeply into regions outside California, including the Northern Plains, Midwest, Southwest, and Northwest. Little new wind power capacity is expected in the Northeast or the Southeast, where wind resources are less favorable. Nationwide, wind-powered electricity generation is projected to grow from 3.2 billion kilowatthours in 1996 to 10.1 billion kilowatthours in 2020, contributing about 0.2 percent of all U.S. grid-connected electricity generation. Growth in wind power capacity reflects both improved economics and other influences, including State mandates for renewable generation, “green pricing” initiatives, and environmental objectives. In the near term, new capacity is eligible for subsidies under the Energy Policy Act of 1992, which apply to units entering service by June 30, 1999.

Use of wind energy could increase more rapidly if additional technological improvements made it viable as a fuel saver in competition with the variable operating and fuel costs of natural-gas-fired generating units. On the other hand, many wind resources are located far from consumers; in some cases, installations would require modifications to the transmission network; and at many potential sites the land is more highly valued for recreational, aesthetic, or environmental reasons.

Improved Technologies Could Raise Generation From Renewable Fuels

Figure 71. ***Nonhydroelectric renewable electricity generation in two cases, 2020 (billion kilowatthours)***

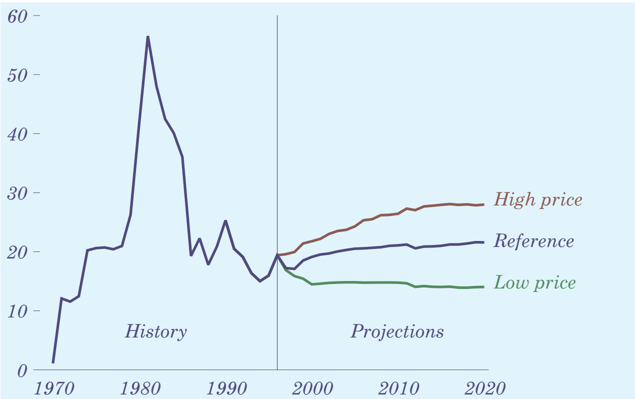


To examine more rapid improvements in renewable technologies, the high renewables case replaces the *AEO98* reference case assumptions for capital costs, variable operations and maintenance expenses, and capacity factors for nonhydroelectric renewables with more optimistic Department of Energy renewable energy assumptions, with no change in the assumptions for nuclear and fossil fuel technologies. In addition, the high renewables case assumes that 305 megawatts of capacity at The Geysers geothermal station continue in operation after their projected retirement in the reference case, and that the share of landfill gas captured for energy production increases to 50 percent in 2020, compared with 40 percent in the reference case.

The results of the high renewables case suggest that technology improvements would increase generation from some renewable sources (Figure 71) but would not alter the dominant role of fossil fuels in the U.S. fuel mix overall. Generation from nonhydroelectric renewables is projected at 275 billion kilowatthours in 2020, compared with 117 billion in the reference case. The increment in generation is mostly from wind, biomass, and geothermal resources, which displace coal and natural gas. Wind capacity in 2020 is over 25 gigawatts, compared with 4 gigawatts in the reference case (Figure 70). As a result, the share of total electricity generation from nonhydroelectric renewables increases to 5.8 percent, compared with 2.5 percent in the reference case, and carbon emissions in 2020 are reduced by 30 million tons, or 2 percent.

Stable Oil Prices Are Projected, Despite Rising Consumption

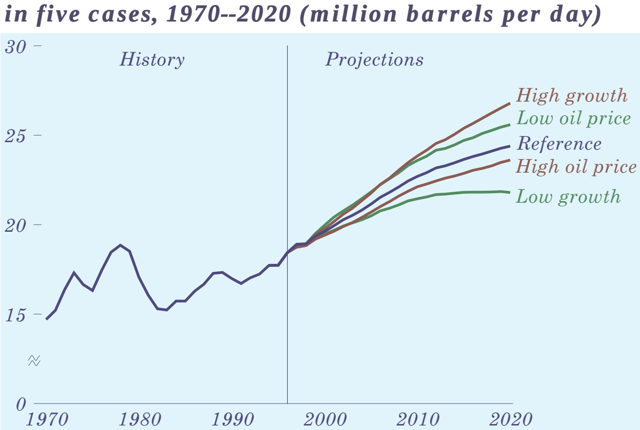
Figure 72. Lower 48 crude oil wellhead prices, 1970--2020 (1996 dollars per barrel)



From 1996 to 2020, wellhead prices for crude oil in the lower 48 States are projected to fall by 1.3 percent a year in the low world oil price case, and to grow by 0.4 and 1.5 percent a year in the reference and high price cases, respectively (Figure 72). The variation in world oil price assumptions leads to similar variation in projected domestic prices, which are determined largely by the international market.

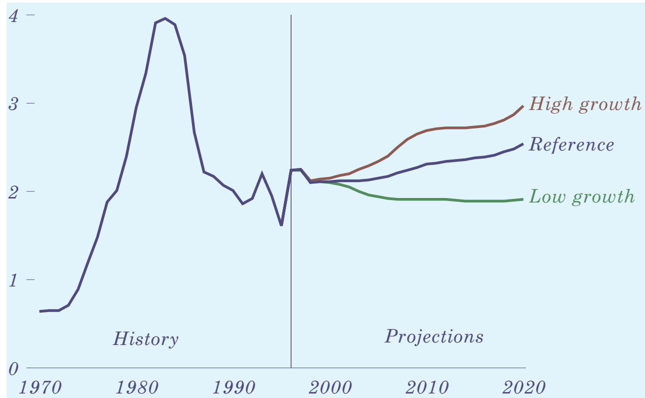
U.S. petroleum consumption continues to rise in all the *AEO98* cases (Figure 73). Total petroleum product supplied ranges from 21.8 million barrels per day in the low economic growth case to 26.8 million in the high growth case, as compared with 18.4 million in 1996. Petroleum continues as the primary source of energy in the United States, growing from 38 percent of total U.S. energy consumption in 1996 to 40 percent in 2020.

Figure 73. U.S. petroleum consumption in five cases, 1970--2020 (million barrels per day)



Projected Technology Improvements Moderate Gas Price Increases

Figure 74. Lower 48 natural gas wellhead prices, 1970--2020 (1996 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States increase by 0.5 and 1.2 percent a year in the reference and high economic growth cases, respectively, compared with a 0.7-percent annual decline in the low economic growth case (Figure 74). The increases reflect rising demand for natural gas and its impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. Price increases also reflect more production from higher cost sources, such as unconventional gas recovery. Lower 48 unconventional gas production grows by 2.2 percent a year in the reference case, compared with 1.8-percent annual growth for conventional sources.

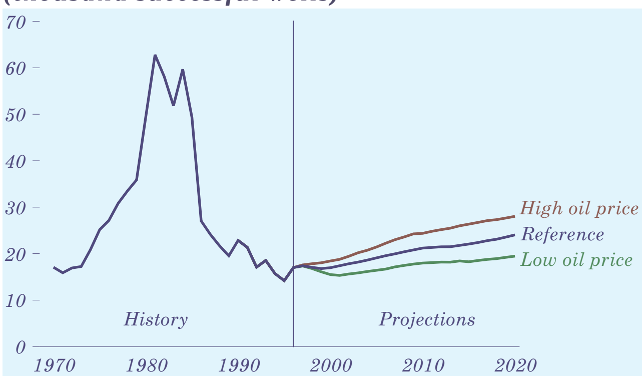
Although the demand for natural gas rises in all three cases, the rise in the low economic growth case is gradual enough for price increases due to rising demand to be overshadowed by the beneficial impacts of technological progress on the discovery process (Table 8). In the reference and high growth cases, the impacts of technological progress are able only to moderate the resulting price increases.

Table 8. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions

	Crude oil (billion barrels)		Natural gas (trillion cubic feet)	
Total U.S. resources	**1990 technology**	**2020 technology**	**1990 technology**	**2020 technology**
Proved	26	26	169	169
Unproved	92	102	870	1,186
Total	**119**	**128**	**1,040**	**1,355**

Drilling Levels Generally Increase in the AEO98 Projections

Figure 75. ***Successful new lower 48 natural gas and oil wells in three cases, 1970--2020 (thousand successful wells)***



Both exploratory and developmental drilling generally increase in the forecast. With rising prices and generally declining drilling costs, crude oil and natural gas well completions increase on average by 0.7 and 2.2 percent a year in the low and high oil price cases, respectively, compared with 1.6 percent in the reference case (Figure 75). Changes in world oil price assumptions have a more pronounced effect on projected oil drilling than on gas drilling (Table 9).

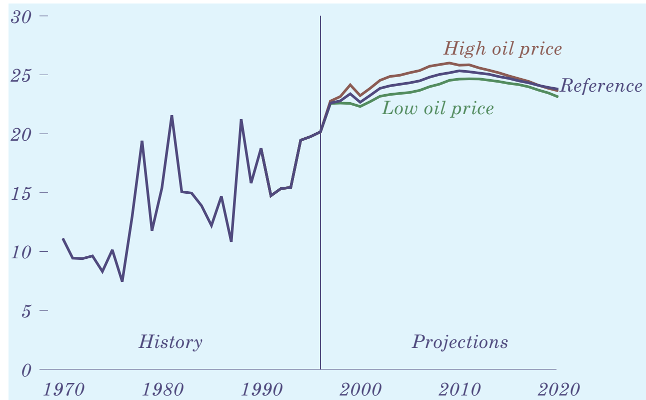
The productivity of natural gas drilling does not decline as much as that of oil drilling, because remaining recoverable gas resources are more abundant than oil resources by current estimates. At projected levels of productivity, the remaining recoverable resources of conventional natural gas decline rapidly, particularly in the onshore Southwest and offshore Gulf of Mexico regions. The future overall productivity of both oil and gas drilling is uncertain, however, because of the high degree of uncertainty that surrounds such factors as the extent of the Nation's oil and gas resources [*38*].

Table 9. Natural gas and crude oil drilling in three cases, 1996-2020 (thousands of successful wells)

	1996	2000	2010	2020
Natural gas				
Low oil price case		9.3	11.0	12.0
Reference case	9.4	9.4	11.3	12.4
High oil price case		9.5	11.5	12.7
Crude oil				
Low oil price case		6.2	7.0	7.5
Reference case	7.6	7.6	9.9	11.6
High oil price case		9.0	12.9	15.4

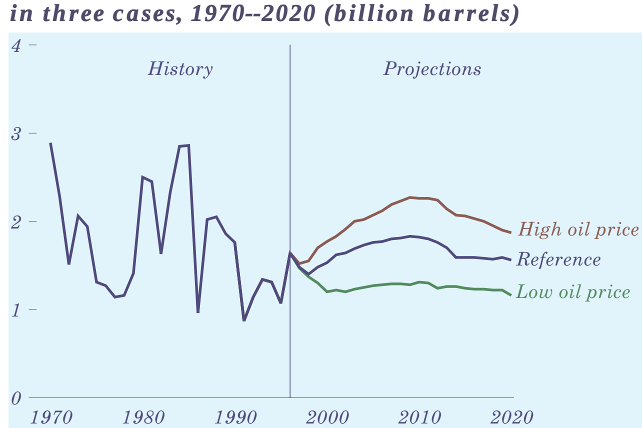
Oil and Gas Reserve Additions Are Expected To Slow After 2010

Figure 76. ***Lower 48 natural gas reserve additions in three cases, 1970--2020 (trillion cubic feet)***



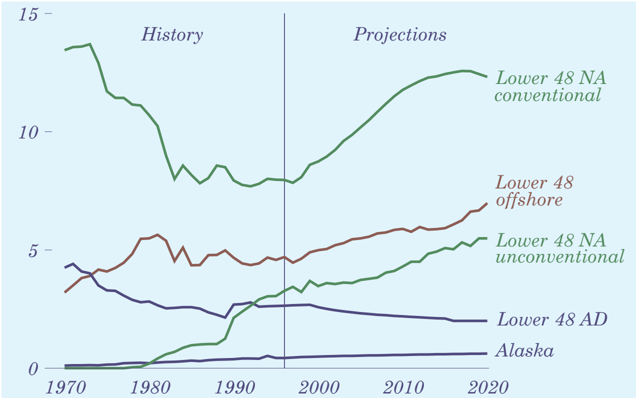
Historically, for both crude oil and natural gas, lower 48 production has generally exceeded reserve additions. The recent reversal of that pattern for natural gas is projected to continue as supply grows to meet expected increases in demand, primarily for electricity generation. The relatively high levels of annual gas reserve additions through 2020 reflect an extension of recent technological improvements affecting exploration and development for a sustained period of unprecedented duration (Figure 76). As a result, more than 85 percent of the lower 48 nonassociated natural gas resources assumed to be technically recoverable from conventional sources (based on current technology) are projected to be discovered by 2020. In contrast, despite varying patterns of lower 48 oil reserve additions (Figure 77), lower 48 crude oil production generally exceeds reserve additions in all cases.

Figure 77. ***Lower 48 crude oil reserve additions in three cases, 1970--2020 (billion barrels)***



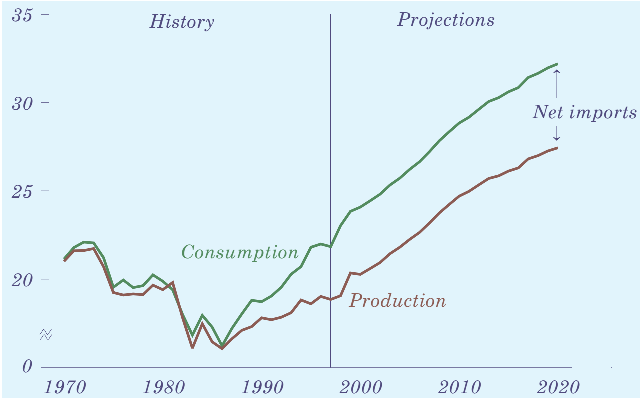
Significant Increases Are Projected for Most Sources of Natural Gas

Figure 78. Natural gas production by source, 1970--2020 (trillion cubic feet)



Natural Gas Imports Continue To Grow in the Projections

Figure 79. Natural gas production, consumption, and imports, 1970--2020 (trillion cubic feet)



The continuing increase in domestic natural gas production in the forecast comes primarily from lower 48 onshore nonassociated (NA) sources (Figure 78). Conventional onshore production, which accounted for 41.9 percent of total U.S. domestic production in 1996, increases in share to 44.9 percent of the total in 2020. Unconventional sources also increase in share, and gas from offshore wells in the Gulf of Mexico contributes significantly to production. The innovative use of cost-saving technology and the expected continuation of recent huge finds, particularly in the deep water off the Gulf of Mexico, have encouraged greater interest in this area.

Natural gas production from Alaska rises gradually in the forecast. Currently, all production is either consumed in the State, reinjected, or exported to Japan as liquefied natural gas (LNG). Alaskan gas is not expected to be transported to the lower 48 States, because the projected lower 48 prices are not high enough to support the required transport system in the forecast period. Expected Alaskan natural gas production does not include gas from the North Slope, which primarily is being reinjected to support oil production. In the future, North Slope gas may be marketed as LNG to Pacific Rim markets [*39*].

Production of associated/dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines, following the expected pattern of domestic crude oil production. AD gas accounts for 7.4 percent of total lower 48 production in 2020, compared with 13.9 percent in 1996.

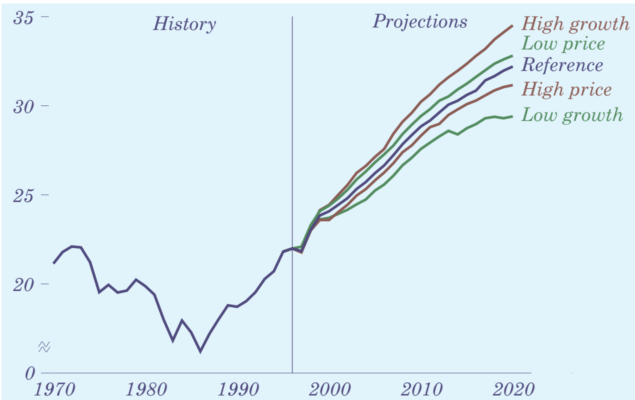
Net natural gas imports are expected to grow in the forecast (Figure 79) from 12.4 percent of total gas consumption in 1996 to 15.2 percent in 2020. Most of the increase is attributable to imports from Canada, which are projected to grow substantially as considerable new pipeline capacity comes on line. While most of the new capacity provides access to supplies from western Canada through the Midwest, new capacity is also expected to provide access to Sable Island supplies in the offshore Atlantic [*40*].

Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, with exports increasing as mandated conversion of power plants from heavy fuel oil to natural gas commences in 1998, in compliance with Mexico's new environmental regulations. Mexico has a considerable natural gas resource base, but there is uncertainty as to whether production can be increased sufficiently to satisfy rising demand.

LNG provides another source of gas imports; however, given the projected low natural gas prices in the lower 48 markets, LNG is not expected to become a significant source of U.S. supply. LNG imports into Everett, Massachusetts, and Lake Charles, Louisiana, are projected to increase over the forecast, reaching a level of 0.36 trillion cubic feet in 2020, compared with 0.04 trillion cubic feet in 1996 [*41*].

Natural Gas Consumption Increases in All the AEO98 Cases

Figure 80. Natural gas consumption in five cases, 1970--2020 (trillion cubic feet)

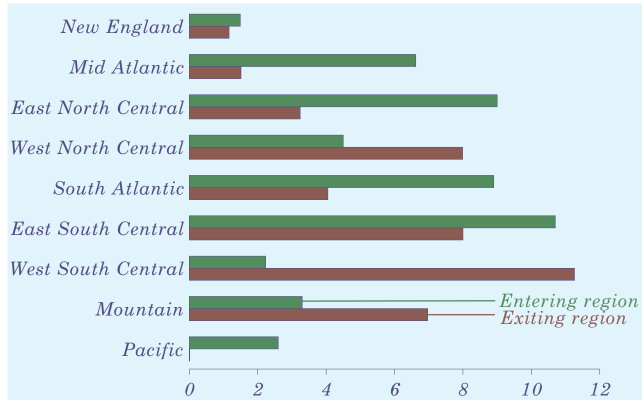


Natural gas consumption increases from 1996 to 2020 in all the *AEO98* cases (Figure 80). Domestic consumption ranges from 29.4 trillion cubic feet per year in the low economic growth case to 34.5 trillion in the high growth case in 2020, as compared with 22.0 trillion cubic feet in 1996. Growth is seen in all end-use sectors, with more than half of the growth as a result of rising demand for electricity, including industrial cogeneration.

Natural gas consumption in the electricity generation sector (excluding cogeneration) grows steadily throughout the forecast. In the reference case it more than triples, from 3.0 trillion cubic feet a year in 1996 to 9.9 trillion in 2020. Restructuring of the electric utility industry is expected to open up new opportunities for gas-fired generation. In addition, growth is spurred by increased utilization of existing gas-fired power plants in the forecast and the addition of new turbines and combined-cycle facilities, which are less capital-intensive than coal, nuclear, or renewable electricity generation plants. Although projected coal prices to the electricity generation sector fall throughout the forecast, the natural gas share of new capacity is nearly six times the coal share. Lower capital costs, projected improvements in gas turbine heat rates, and an assumed increase in the service life of gas-fired plants to 20 years make the overall cost of gas-generated electricity per kilowatthour competitive with the cost of electricity from new coal-burning generators.

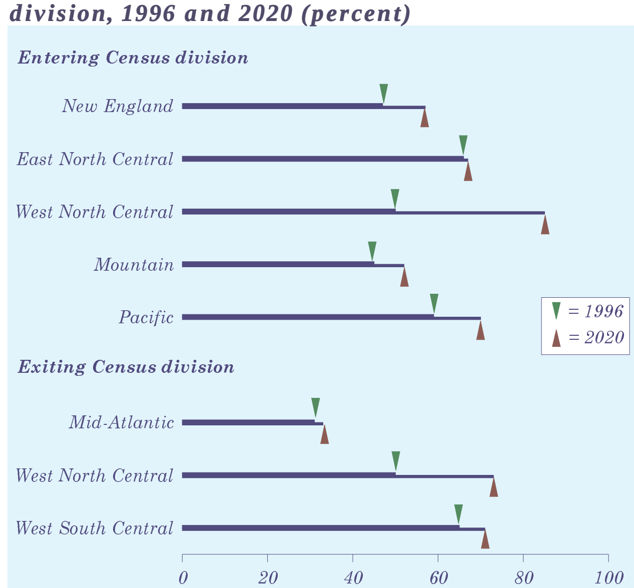
Growing Demand for Natural Gas Spurs Pipeline Capacity Expansion

Figure 81. Pipeline capacity expansion by Census division, 1996--2020 (billion cubic feet per day)



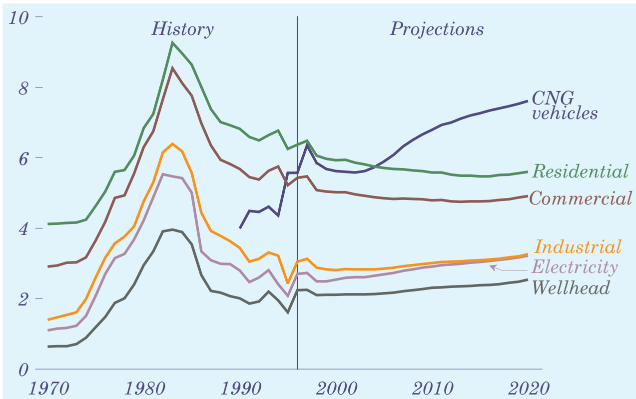
Demand for natural gas is projected to outstrip existing pipeline capacity. Expansion of interstate capacity (Figure 81) will be needed to provide access to new supplies and to serve expanding markets. Expansion is projected to proceed at a rate of 1.5 percent a year through the forecast. The greatest increases are projected along the corridors that move Canadian and Gulf Coast supplies to markets in the eastern half of the United States. Natural gas deliverability is also augmented by new storage capacity which is projected to increase in most regions over the forecast period. In several regions, growth in new pipeline construction is tempered by higher utilization of pipeline capacity (Figure 82).

Figure 82. Pipeline capacity utilization by Census division, 1996 and 2020 (percent)



Residential, Commercial Prices for Natural Gas Are Projected To Fall

Figure 83. Natural gas end--use prices by sector, 1970--2020 (1996 dollars per thousand cubic feet)



While consumer prices to the industrial, electricity, and transportation sectors generally increase throughout the forecast period, prices to the residential and commercial sectors decline (Figure 83). The decreases reflect declining distribution margins to these sectors due to anticipated efficiency improvements in an increasingly competitive market. In the industrial sector, a modest decrease in margins is overshadowed by an increase in wellhead prices, and the overall trend is a slight rise in prices. In the electricity generation sector, increases in pipeline margins and wellhead prices combine to yield an average 0.7-percent annual rise in end-use prices. A significant part of the increase in national average prices results from higher consumption increases in the regions with the highest prices.

Compared with their rise and decline over the 1970-1996 period, transmission and distribution revenues in the natural gas industry are relatively stable in the forecast through 2010, when they begin a gradual increase (Table 10). Declines in margins are balanced by higher volumes.

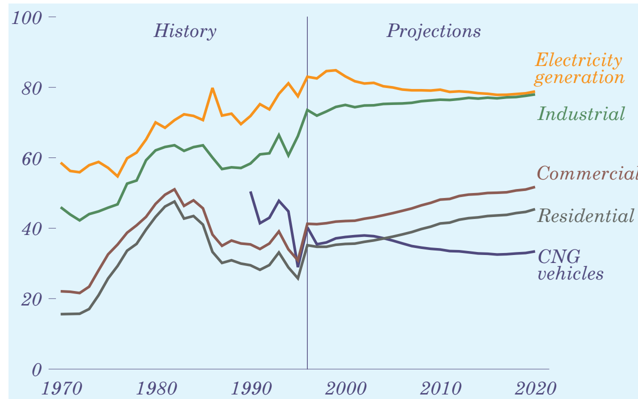
Table 10. Transmission and distribution revenues and margins, 1970--2020

	1970	1985	1996	2010	2015	2020
T&D revenues (billion 1996 dollars)	29.64	48.69	40.88	39.21	40.29	41.87
End-use consumption (trillion cubic feet)	19.02	15.81	21.99	28.84	30.61	32.20
Average margin* (1996 dollars per thousand cubic feet)	1.56	3.08	2.04	1.49	1.44	1.43

*Revenue divided by end-use consumption.

Reduced Margins Compensate for the Projected Rise in Wellhead Prices

Figure 84. Wellhead share of natural gas end-use prices by sector, 1970--2020 (percent)



With distribution margins declining, the wellhead shares of end-use prices generally increase in the forecast (Figure 84). The greatest impact is in the residential and commercial markets, where most customers purchase gas through local distribution companies (LDCs). In the electricity generation sector, which has a declining share, the majority of customers do not purchase from distributors.

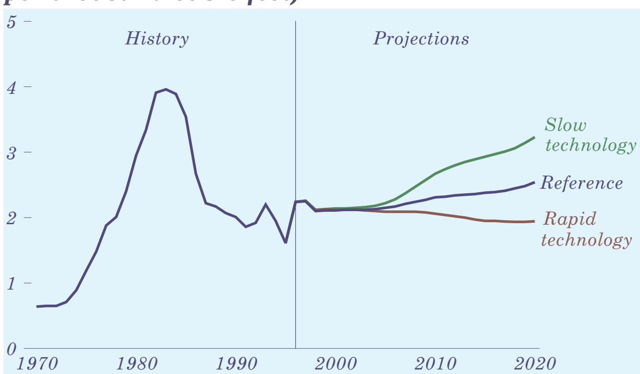
Changes have been seen historically in all components of end-use prices (Table 11). Pipeline margins fell markedly between 1985 and 1996 with industry restructuring. Modest decreases are projected to continue through the early part of the forecast, followed by increases that reflect the cost of interstate pipeline expansion. Although LDC margins in the residential and commercial sectors have seen only modest decreases since 1985, efficiency improvements and other impacts of restructuring are exerting downward pressure on distribution costs, and reduced margins are projected for these sectors.

Table 11. Components of residential and commercial natural gas end-use prices, 1985--2020 (1996 dollars per thousand cubic feet)

Price Component	1985	1996	2000	2010	2020
Wellhead price	3.54	2.24	2.11	2.31	2.54
Citygate price	5.22	3.21	3.04	3.19	3.46
Pipeline margin	1.69	0.97	0.93	0.89	0.92
LDC margin					
Residential	3.30	3.15	2.88	2.38	2.13
Commercial	2.44	2.23	1.99	1.61	1.46
End-use price					
Residential	8.52	6.37	5.93	5.58	5.60
Commercial	7.66	5.43	5.02	4.79	4.91

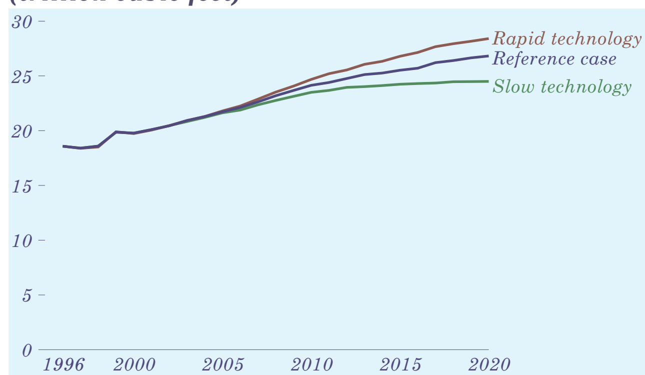
Price Projections Vary With Different Technology Assumptions

Figure 85. Lower 48 natural gas wellhead prices in three cases, 1970--2020 (1996 dollars per thousand cubic feet)



Gas Share of Fossil Fuel Use Follows Technology Assumptions

Figure 86. Lower 48 natural gas production in alternative technology cases, 1996--2020 (trillion cubic feet)



Rapid and slow technology cases were created to assess the sensitivity of the *AEO98* projections to changes in the economically recoverable oil and gas resource base, exploration and development costs, and finding rates as a result of technological progress. Representative values for the affected parameters are shown in Table 12 [*42*].

As shown in Figure 85, natural gas prices are highly sensitive to changes in assumptions about technological progress. For the first decade of the forecast, both price and production levels for lower 48 oil and natural gas are almost identical in the reference case and the two technological progress cases. By the year 2020, however, natural gas prices are 27.9 percent higher (at $3.28 per thousand cubic feet) in the slow technology case and 24.4 percent lower (at $1.92) in the rapid technology case than the reference case price of $2.54 per thousand cubic feet.

Changes in production in the alternative technology cases are more significant in the second half of the forecast than in the earlier years, as new investments in the industrial sector and in electric power generation facilities respond to changes in natural gas prices (Figure 86).

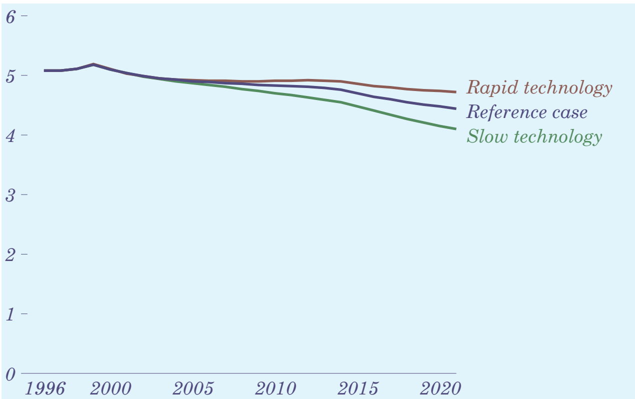
In the rapid technology case, the natural gas share of fossil fuel inputs to electricity generation facilities in 2020 is 33.9 percent, compared with 25.3 percent in the slow technology case. The higher level of gas consumption comes largely at the expense of coal. There is little additional displacement of petroleum products in the rapid technology case, since natural gas captures the bulk of the dual-fired boiler market in the reference case. In contrast, in the slow technology case, natural gas loses market share to both coal and petroleum products in the electricity generation sector.

Table 12. Representative average annual rates of technological progress in alternative technology cases (percent)

	Natural gas						Crude oil					
	Slow technology		Reference		Rapid technology		Slow technology		Reference		Rapid technology	
Technology area	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Costs												
Drilling	1.1	1.9	1.3	2.3	1.5	2.7	1.1	1.9	1.3	2.3	1.5	2.7
Lease equipment	1.0	1.1	1.3	1.9	1.6	2.6	1.0	1.1	1.3	1.9	1.6	2.6
Operating	0.4	0.9	0.8	1.2	1.2	1.7	0.4	0.9	0.8	1.2	1.2	1.7
Resources												
Inferred reserves	0.2	1.0	0.5	1.0	0.9	1.0	0.0	1.0	0.0	1.0	0.0	1.0
Undiscovered	0.5	0.9	0.9	1.4	1.4	1.8	0.4	0.9	0.8	1.4	1.3	1.8
Finding rates	2.4	5.0	4.2	10.2	6.0	15.3	1.8	6.5	3.2	9.6	4.6	12.6
Success rates	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Technology Effects on Projected Oil Production Are Greater

Figure 87. Lower 48 oil production in alternative technology cases, 1996-2020 (million barrels per day)



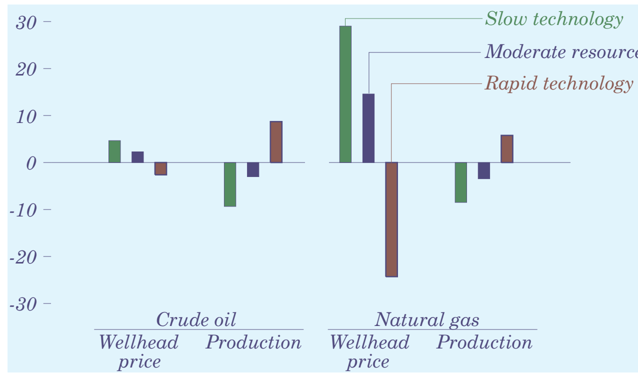
Domestic oil production is also sensitive to changes in the technological progress assumptions (Figure 87). In comparison with the projected 2020 lower 48 production level of 4.4 million barrels a day in the reference case, oil production increases to 4.7 million barrels a day in the rapid technology case and decreases to 4.1 million in the slow technology case. The changes, in relative terms, are greater than those seen for natural gas, primarily because of key differences between the oil and natural gas markets.

Domestic oil prices are determined largely by the international market. Thus, changes in U.S. oil production do not constitute a significant volume relative to the global market. Given the assumption that the changes in the levels of technology are isolated to U.S. oil producers, total oil supply largely adjusts to the changes in technological progress simply by adjusting imports of crude oil and other petroleum products. Net imports range from a low of 11.2 million barrels per day in the rapid technology case to a high of 12.1 million barrels per day in the slow technology case.

Unlike oil, natural gas is not easily transported between the United States and countries outside North America. Therefore, changes in gas production are determined more by the availability of supplies in North America than by the international market.

Expansion of the Resource Base Is a Key Factor for Prices and Production

Figure 88. Variation from reference case projections of prices and production in three alternative oil and gas cases, 2020 (percent change)



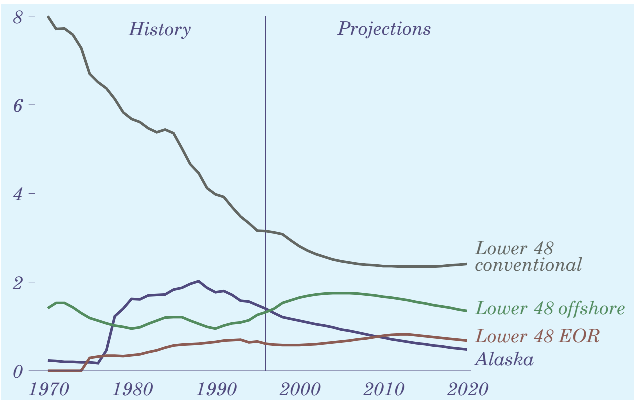
The rapid and slow technology cases show that the outlook for natural gas is highly dependent on the assumed size of the economically recoverable resource base. A moderate resource case shows the sensitivity of the *AEO98* projections to a change in the assumed rate of resource expansion. Assumptions in this case vary from the reference case in two ways: (1) the initial estimate of inferred reserves does not increase over the forecast period, and (2) undiscovered economically recoverable resources in the shallow waters of the Gulf of Mexico are assumed to expand to technologically recoverable levels, growing by roughly 0.1 percent a year. With these assumptions, the estimate of lower 48 unproved oil resources, given 2020 technology, is 3.0 percent lower than in the reference case, and the same estimate for natural gas is 6.2 percent lower.

Natural gas prices vary significantly from the reference case to the moderate resource case (Figure 88). Reduced gas supply in the moderate case results in a 3.5-percent decrease in gas production in 2020 relative to the reference case projection and a 14.6-percent increase in the lower 48 average wellhead price. The 10-percent relative drop in offshore production is partially offset by increased onshore production from unconventional sources in response to higher prices.

Crude oil production from offshore wells is also significantly lower in the moderate resource case than in the reference case. In 2020, there is a difference of 13.3 percent between the two cases.

Continued Decline Is Projected for U.S. Oil Production

Figure 89. Crude oil production by source, 1970--2020 (million barrels per day)



Projected domestic crude oil production continues its historic decline throughout the forecast (Figure 89), declining by 1.1 percent a year, from 6.5 million barrels per day in 1996 to 4.9 million barrels per day in 2020 [*43*]. Conventional onshore production in the lower 48 States, which accounted for 48.6 percent of total U.S. crude oil production in 1996, is also projected to decrease at an average annual rate of 1.1 percent over the forecast.

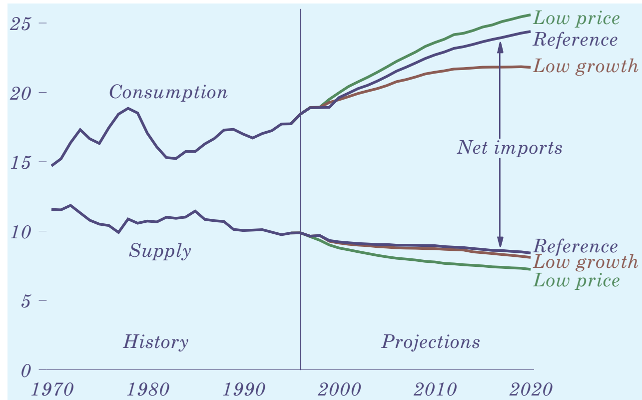
Crude oil production from Alaska is expected to decline at an average annual rate of 4.3 percent between 1996 and 2020. The overall decrease in Alaska's oil production is driven by the continued decline in production from Prudhoe Bay, the largest producing field, which historically has accounted for more than 60 percent of total Alaskan production.

Offshore production generally increases in the forecast through 2006 and then declines almost to current levels in 2020, resulting in an overall increase of 0.1 percent a year. Technological advances and lower costs associated with deep exploration and production in the Gulf of Mexico contribute to the increase in the early years of the forecast.

Increased production from enhanced oil recovery (EOR), which becomes more profitable as oil prices increase, slows the overall downward trend of oil production [*44*] through 2013, when EOR also begins to decline.

AEO98 Projects a Growing Gap Between Oil Supply, Consumption

Figure 90. Petroleum supply, consumption, and imports, 1970--2020 (million barrels per day)



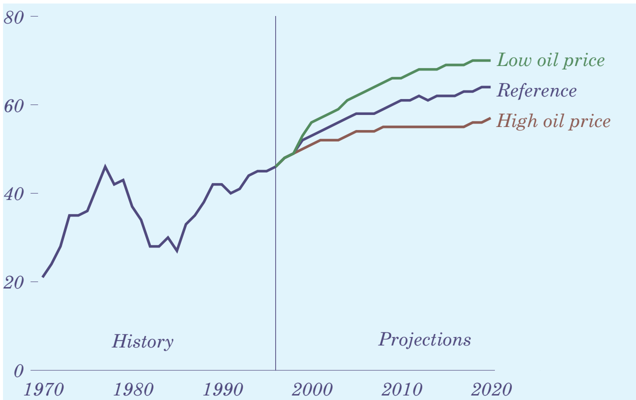
U.S. supply of petroleum declines in all *AEO98* cases (Figure 90), as domestic crude oil production falls off. In the low price case, domestic supply drops from its 1996 level of 9.9 million barrels per day to 7.2 million barrels per day in 2020. In the high price case, domestic supply declines only slightly, to 9.6 million barrels per day in 2020.

The greatest variation in petroleum consumption levels is seen in the economic growth cases, with an increase of 8.4 million barrels per day over the 1996 level in the high growth case, as compared with an increase of only 3.4 million barrels per day in the low growth case.

Additional petroleum imports will be needed to fill the widening gap between supply and consumption. The greatest gap between supply and consumption is seen in the low world oil price case and the smallest in the low economic growth 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—more than double the 1996 level of 8.5 million barrels per day—to a low of 13.7 million barrels per day in the low growth case. The value of petroleum imports in 2020 ranges from $102.1 billion in the low price case to $157.5 billion in the high growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $75.8 billion in 1980 [*45*], were $62.3 billion in 1996.

Imports Are Projected at Two-Thirds of U.S. Consumption in 2020

Figure 91. ***Share of U.S. petroleum consumption supplied by net imports, 1970--2020 (percent)***



In 1996, net imports of petroleum climbed to 46 percent of domestic petroleum consumption, matching the 1977 peak. Continued dependence on petroleum imports is projected, reaching 66 percent in 2020 in the reference case (Figure 91). The corresponding import shares of total consumption in 2020 are 58 percent in the high oil price case and 72 percent in the low price case.

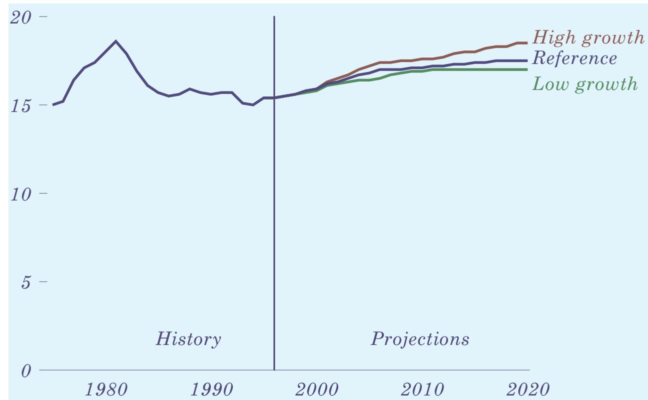
Although crude oil is expected to continue as the major component of petroleum imports, refined products represent a growing share. More imports will be needed as growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products make up 17 percent of net petroleum imports in 2020 in the low economic growth case and 30 percent in the high growth case, as compared with their 13-percent share in 1996 (Table 13).

Table 13. Petroleum consumption and net imports, 1996 and 2020 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
1996	18.4	8.5	7.4	1.1
2020				
Reference	24.4	16.0	11.7	4.3
Low oil price	25.6	18.4	12.9	5.5
High oil price	23.6	13.8	10.6	3.2
Low growth	21.8	13.7	11.4	2.3
High growth	26.8	17.8	12.4	5.4

Additions at Existing U.S. Refineries Are Expected To Increase Capacity

Figure 92. ***Domestic refining capacity, 1975--2020 (million barrels per day)***



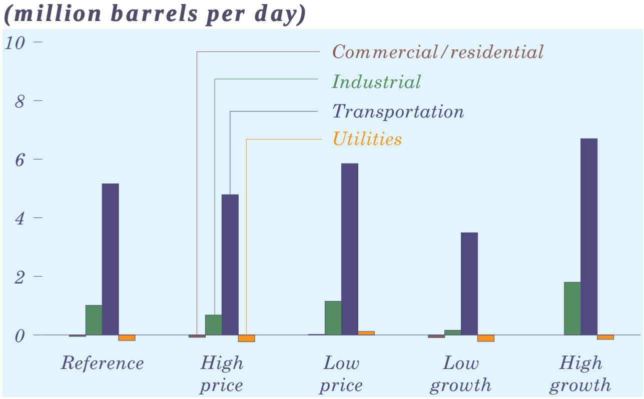
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity [*46*]. That trend was broken in 1995 by a capacity increase of 0.5 million barrels per day over a 2-year period. Financial and legal considerations make 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 *AEO98* cases (Figure 92).

Distillation capacity is projected to grow from the 1996 level of 15.4 million barrels per day to 17.0 million in 2020 in the low economic growth case and 18.5 million in the high growth case, as refining capacity almost meets the 1981 peak of 18.6 million barrels per day. Refining capacity is projected to expand on the East, West, and Gulf coasts. Existing refineries will continue to be utilized intensively throughout the forecast, in a range from 93 to 96 percent of design capacity. In comparison, the 1996 utilization rate was 94 percent, well above the rates of the 1980s and early 1990s.

Domestic refineries will produce a slightly higher yield of gasoline and jet fuel in 2020 in response to growing demand for those products. In 2020, gasoline is projected to represent 49 percent of production and jet fuel 13 percent, compared with 46 percent and 9 percent, respectively, in 1996.

Petroleum Use Varies by Sector in Different AEO98 Cases

Figure 93. **Change in petroleum consumption by sector in five cases, 1996 to 2020 (million barrels per day)**



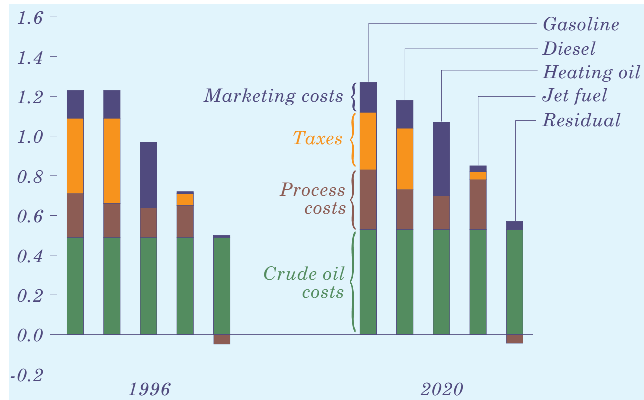
U.S. petroleum consumption is projected to increase by 6.0 million barrels per day between 1996 and 2020 in the reference case, compared with 3.4 million in the low economic growth case and 8.4 million in the high growth case (Figure 93). Industry will continue to account for about one-fourth of petroleum consumption, and two-thirds will be used for transportation.

All the cases show growth in petroleum consumption in the transportation and industrial sectors and, with the exception of the low world oil price case, show slight declines in consumption by residential, commercial, and electric utility users. In addition, a shift in consumption patterns is expected within the transportation sector. Gasoline, which in 1996 represented 65 percent of the petroleum consumed for transportation, shrinks to a 60-percent share in 2020, as alternative fuels penetrate transportation markets. The jet fuel share rises from 13 percent to 18 percent as air travel increases substantially. The share for diesel drops slightly, from 18 percent to 17 percent. Residual fuel used for vessel bunkering edges up from 3 percent to 4 percent, while other petroleum remains at 1 percent.

Gasoline, diesel, and jet fuel account for 74 percent of the growth in total petroleum consumption in the high economic growth case and 92 percent in the low economic growth case. All these fuels are "light products," which are more difficult to produce than are heavier products, such as asphalt and residual fuel oil.

Demand Growth Drives Up Costs for Gasoline, Jet Fuel, Heating Oil

Figure 94. **Components of refined product costs, 1996 and 2020 (1996 dollars per gallon)**



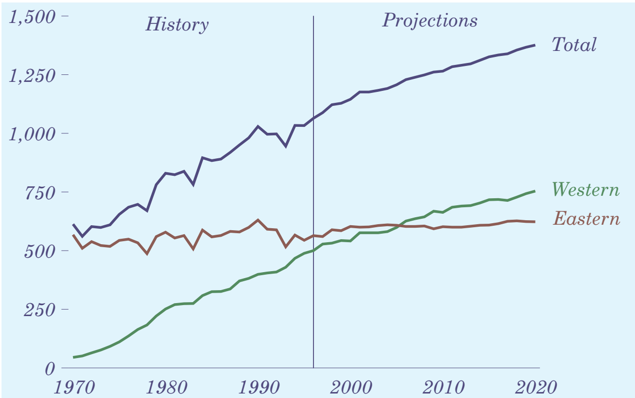
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 94). In the *AEO98* projections, crude oil costs continue to make the greatest contribution to product prices, and marketing costs remain stable, but the contributions of processing costs and taxes change considerably.

The processing costs for gasoline and jet fuel increase by 8 cents and 9 cents per gallon, respectively, between 1996 and 2010. For the most part, the increases can be attributed to the growth in demand for these products. A small portion of the increases can be attributed to investments related to compliance with refinery emissions, health, and safety regulations, which add 1 to 3 cents per gallon to the processing costs of light products (gasoline, distillate, jet fuel, kerosene, and liquefied petroleum gases).

Whereas processing costs tend to increase refined product prices, assumptions about Federal taxes tend to slow the growth of motor fuels prices. In keeping with the *AEO98* assumption of current laws and legislation, Federal motor fuels taxes are assumed to remain at nominal 1996 levels throughout the forecast. Federal taxes have actually been raised sporadically in the past. State motor fuels taxes are assumed to keep up with inflation, as they have in the past. The net impact of these assumptions is a decrease in total taxes between 1996 and 2020—9 cents per gallon for gasoline, 12 cents for diesel fuel, and 2 cents for jet fuel.

Western Coal Production Surpasses Eastern in the Projections

Figure 95. ***Coal production by region, 1970--2020 (million short tons)***



Major trends in the *AEO98* forecasts for coal can be contrasted with changes since 1970. For instance, eastern coal production, which declined slightly from 568 million tons in 1970 to 563 million tons in 1996, is projected to increase to 623 million tons in 2020, a change of 0.4 percent a year (Figure 95).

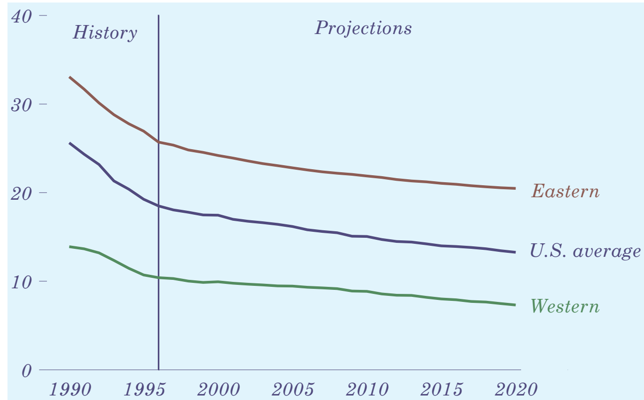
As coal-fired generation grows, labor productivity improvements make western low-sulfur coal the least-cost low-sulfur fuel in most regions. However, progressive tightening of the regulatory sulfur emissions cap and engineering limits on the use of western low-rank coal in older boilers mandate the use of scrubbers and other clean coal combustion technologies to meet emissions limits. The environmental efficiency of these technologies allows increasing use of eastern mid- and high-sulfur coals. Nevertheless, eastern mines are losing market share to less expensive, lower sulfur coal from western mines. The eastern share of national production, which fell from 93 percent in 1970 to 53 percent in 1996, is projected to be 45 percent in 2020.

Eastern consumers often limit western subbituminous coal to between 15 and 20 percent of the total burn in older boilers, to maintain good boiler performance. However, many older eastern boilers will operate efficiently on western bituminous coals, which, while they are more expensive than subbituminous coals, are lower in emissions potential and less expensive than eastern low-sulfur bituminous coals.

Minemouth coal prices declined by $4.32 per ton in 1996 dollars between 1970 and 1996, and they are projected to decline by 1.4 percent a year, or $5.23 per ton, between 1996 and 2020 (Figure 96). The price of coal delivered to electricity generators, which rose from $25.68 per ton in 1970 to $26.45 in 1996 as both the quantity and average distance of western coal shipments increased, falls to $19.52 per ton in 2020—a 1.3-percent annual decline.

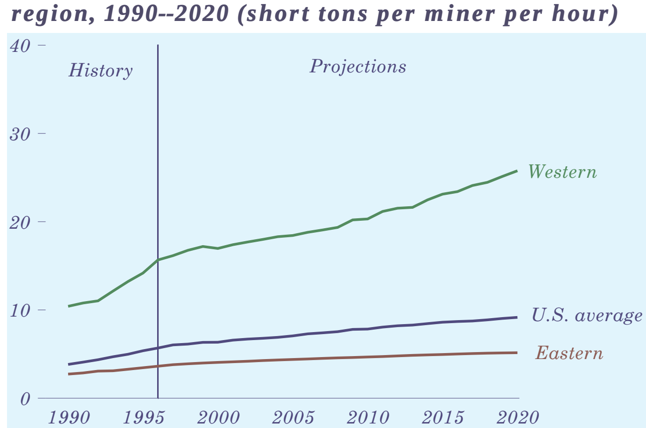
Average Minemouth Prices Are Projected To Continue Declining

Figure 96. ***Average minemouth price of coal by region, 1990--2020 (1996 dollars per ton)***



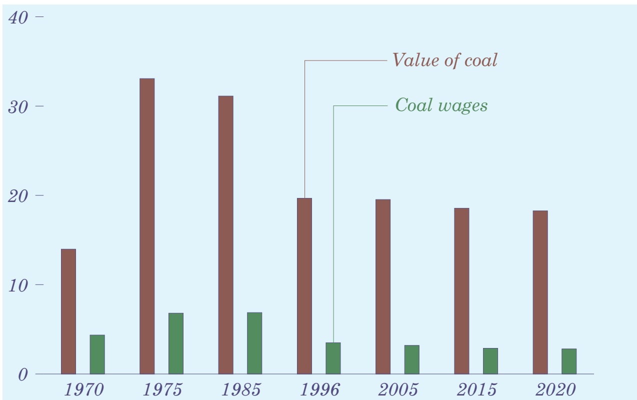
The mines of the Northern Great Plains have large reserves in very thick seams with low overburden ratios. Their labor productivity, higher than that of eastern mines in 1996, also increases more rapidly, in absolute terms, through 2020. Average U.S. labor productivity (Figure 97) follows the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 97. ***Coal mining labor productivity by region, 1990--2020 (short tons per miner per hour)***



Declining Labor Costs Contribute to the Projected Drop in Coal Prices

Figure 98. Labor cost component of minemouth coal prices, 1970--2020 (billion 1996 dollars)



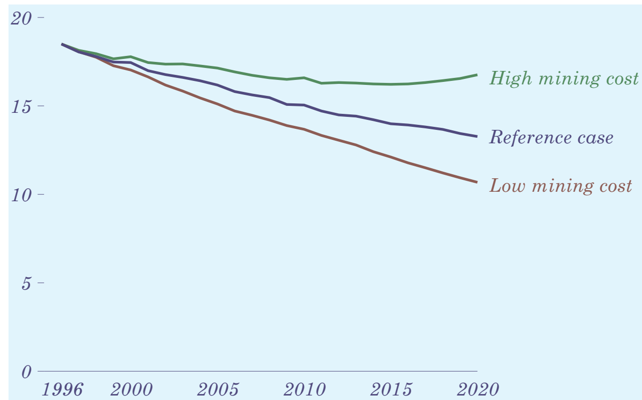
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will be influenced more by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. Western low-sulfur coal has been successfully tested in Ohio, South Carolina, and New England, and its penetration of eastern markets is projected to increase.

A market for inexpensive higher sulfur coals will persist, because the regulatory cap on sulfur oxides eventually will require emissions below the level produced by the lowest sulfur coal. Eastern coalfields contain extensive reserves of higher sulfur coal suited to inexpensive longwall mining. With natural gas prices projected to rise relative to coal prices after 2010, the projected construction of coal boilers with scrubbers will lead to expanded mining of Appalachian medium- and high-sulfur coals.

As labor productivity improved between 1970 and 1996, the number of miners fell by 2.1 percent a year. With improvements continuing through 2020, a further decline of 0.9 percent a year in the number of miners is projected. The contribution of wages to minemouth coal prices [*47*], which fell from 31 percent to 18 percent between 1970 and 1996, is projected to decline to 15 percent by 2020 (Figure 98).

Coal Price Projections Vary With Mining Cost Assumptions

Figure 99. Average minemouth coal prices in three cases, 1996--2020 (1996 dollars per ton)

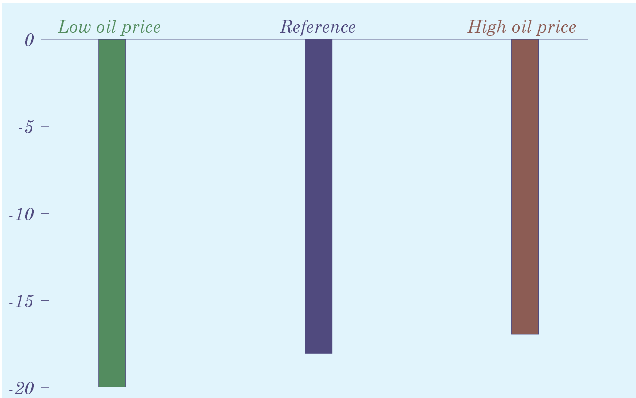


Alternative assumptions about future regional mining costs affect the market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, coal demand was held constant in Btu terms, although supply, in tons, varied as a result of regional differences in the coal's heat content. Also, delivered prices varied slightly more than minemouth prices as transportation costs changed with increasing or decreasing western market shares.

In the reference case projections, productivity increases by 2.0 percent a year through 2020, while wage rates are constant in 1996 dollars. The national minemouth coal price declines by 1.4 percent a year to $13.27 per ton in 2020 (Figure 99). In the low mining cost case, productivity increases by 3.3 percent a year, and real wages decline by 0.5 percent a year [*48*]. The average minemouth price falls by 2.3 percent a year to $10.68 per ton in 2020 (19.5 percent less than in the reference case). Eastern coal production is 34 million tons higher in the low 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 increases by only 0.8 percent a year, and real wages increase by 0.5 percent a year. The average minemouth price of coal falls by 0.4 percent a year to $16.76 per ton in 2020 (26.3 percent higher than in the reference case). Eastern production in 2020 is 29 million tons lower in the high labor cost case than in the reference case.

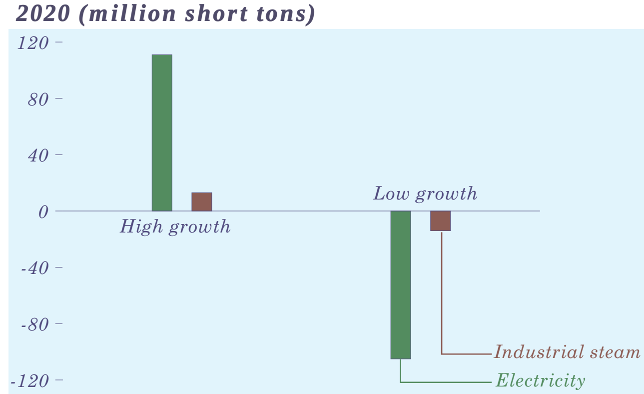
Coal Transportation Costs
Are Projected To Be Lower in 2020

Figure 100. Percent change in coal transportation costs in three cases, 1996--2020



High Economic Growth Assumptions
Lead to Higher Projected Coal Use

Figure 101. Variation from reference case projection of coal demand in two alternative cases, 2020 (million short tons)



The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 100), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates decline by 0.8 percent a year between 1996 and 2020. The most rapid declines have occurred on routes that originate in coalfields with 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.

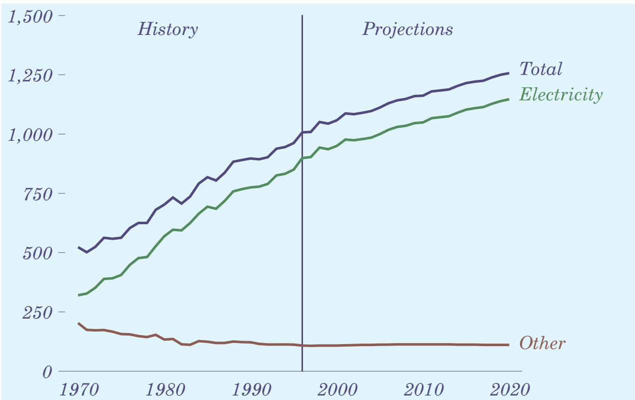
The economic value of steam coal is measured in dollars per million Btu. Thus, an increase in the heat content of a coal, other things being equal, tends to broaden its market potential. Powder River Basin coal, at 17 to 18 million Btu per ton, has a disadvantage relative to Appalachian coal at 24 to 26 million Btu per ton. Several processes have been developed to produce high-Btu, environmentally compliant solid fuels from Powder River Basin coal. If they prove to be physically stable and the economics are favorable, these products—with heat contents increased by up to 40 percenper ton [49]—will greatly enlarge the geographic market area for Powder River Basin coal.

A strong correlation between economic growth and electricity use accounts for the variation in coal demand across the economic growth cases (Figure 101), with domestic coal consumption ranging between 1,138 and 1,382 million tons. Of this difference, coal demand for electricity generation accounts for 216 million tons. The difference in total coal production between the two economic growth cases is 243 million tons, of which 151 million tons (62 percent) is projected to be western production. Demand for western coal increases more rapidly than total demand, because western coal contains less sulfur than eastern coal and sulfur emissions are subject to a regulatory cap, and because western coal is competitively priced in most regions where coal is an important utility fuel.

Changes in world oil prices affect the petroleum fuel costs for coal mining. In the high and low oil price cases, average minemouth coal prices are 0.1 percent higher and 0.8 percent lower, respectively, in 2020 than in the reference case. Low oil prices encourage electricity generation from oil, causing sulfur emissions to rise. Because emissions are legally capped, those from coal must decline—which is most economically achieved through the use of more eastern coal in units with scrubbers. In the absence of emissions limits, more western coal would be used and less eastern coal. Because western coal has lower heat content than eastern coal, more is consumed to generate the same amount of electricity. Thus, coal production is slightly higher in both the high and low oil price cases than in the reference case.

Electricity Generation Accounts for Nearly All Projected U.S. Coal Demand

Figure 102. ***Electricity and other coal consumption, 1970--2020 (million short tons per year)***



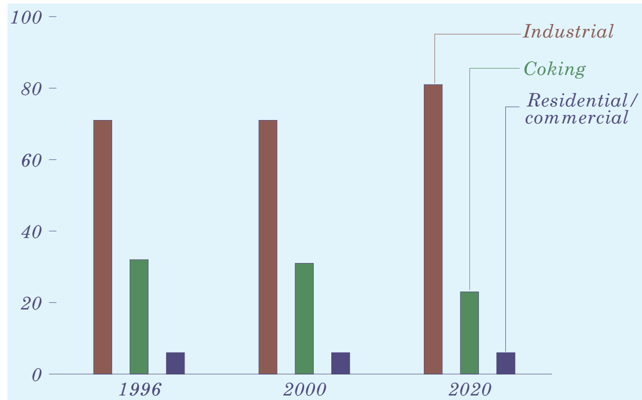
Domestic coal demand rises by 254 million tons in the forecast, from 1,003 million tons in 1996 to 1,257 million tons in 2020 (Figure 102), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors increases by 2 million tons, as reduced coking coal consumption is offset by coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration) rises from 896 million tons in 1996 to 1,147 million tons in 2020, due to increased utilization of existing generation capacity and, in later years, additions of new capacity. The average utilization rate for coal-fired power plants increases from 66 to 80 percent between 1996 and 2020. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per short ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for new power generation through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Small Increases in Industrial Coal Use Are Also Projected

Figure 103. ***Non-electricity coal consumption by sector, 1996, 2000, and 2020 (million short tons)***



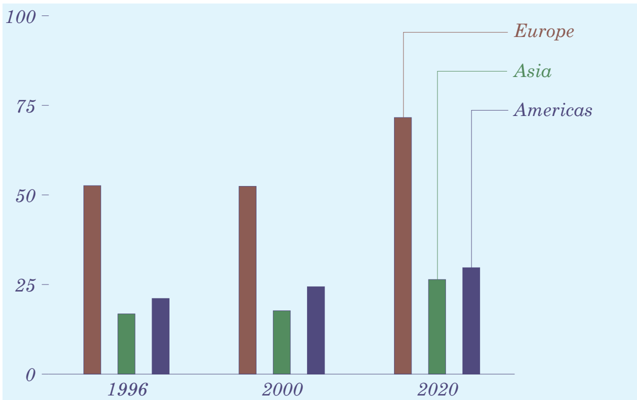
In the non-electricity sectors, an increase of 11 million tons in industrial steam coal consumption between 1996 and 2020 (0.6-percent annual growth) is offset by a decrease of 9 million tons in coking coal consumption (Figure 103). Increasing consumption of industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries and from increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes).

The projected decline in domestic consumption of coking coal results from the 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 1.4 percent a year through 2020. Domestic production of coking coal is stabilized by export demand, as consumption of imported coke and coking coal continues to increase.

While total energy consumption in the residential and commercial sectors grows by 0.8 percent and 0.6 percent a year, respectively, most of the growth is captured by electricity and natural gas. Coal consumption in these sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

Steam Coal Exports to Europe Are Projected To Double by 2020

Figure 104. U.S. coal exports by destination, 1996, 2000, and 2020 (million short tons)



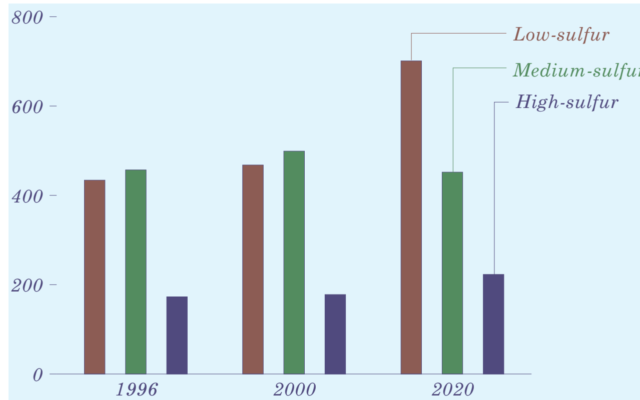
U.S. coal exports rise in the forecast from 90.5 million tons in 1996 to 127.7 million in 2020 (Figure 104), as a result of higher demand for steam coal imports in Europe. Exports of metallurgical coal in 2020 are 4.2 million tons lower than the 1996 level. Metallurgical exports to other regions do not increase significantly, because worldwide trade in metallurgical coal remains essentially unchanged.

U.S. steam coal exports to Europe increase from 21.5 million tons in 1996 to 47.4 million in 2020 (3.3-percent annual growth). Europe's steam coal imports rise from 113.1 million tons in 1996 to 174.5 million tons in 2020 (1.8 percent a year), as Germany, Spain, and France reduce subsidies for domestic coal. The *AEO98* forecast for European imports is lower than some that have been provided by the governments of the importing nations themselves, where environmental considerations, including emerging carbon emissions issues, limit fuel choices.

U.S. coal exports to Asia increase by 1.9 percent a year, from 16.8 million tons in 1996 to 26.4 million in 2020, as metallurgical exports fall by 1.4 percent and steam coal exports rise by 3.9 percent annually. Coal imports to Asia from all sources rise by 2.3 percent a year, from 257.2 million tons in 1996 to 441.6 million in 2020, as Pacific Rim nations without indigenous fossil fuel resources base electricity generation on imported coal. Most of the growth in Asian imports is projected to be supplied by Australia, South Africa, and Indonesia.

Low-Sulfur Coal Use Rises Throughout the Projections

Figure 105. Coal distribution by sulfur content, 1996, 2000, and 2020 (million short tons)



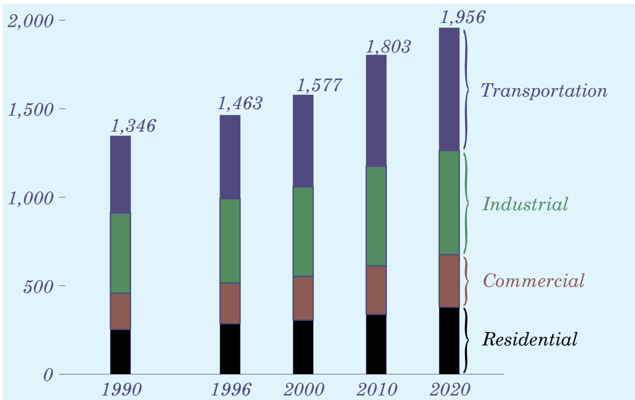
Phase 1 of the Clean Air Act Amendments of 1990 required 261 coal-fired generators to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Beginning on January 1, 2000, Phase 2 imposes a permanent cap of 8.95 million tons sulfur dioxide emissions per year (less than 1.2 pounds per million Btu of heat input for all units over 25 megawatts that were built before 1990) [*50*].

Relatively modest capital investments have allowed many generators to blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generates sulfur oxide allowances beyond those needed for Phase 1 compliance. Excess allowances are 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). Fuel switching for regulatory compliance and cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 105). National sulfur emissions from all fossil fuel generators have already decreased from 15.6 million tons in 1990 to 11.6 million tons in 1995 [*51*].

A decision to regulate air toxic emissions could require utilities to install equipment for removing them from combustion gases. On the supply side, such regulation might result in interregional switching to coals with lower levels of toxic trace elements. Either approach is likely to encourage more intensive coal preparation to reduce the content of several air toxic elements associated with sulfide minerals in coal ash.

AEO98 Projects Higher Carbon Emissions Than AEO97

Figure 106. Carbon emissions by sector, 1990--2020 (million metric tons per year)



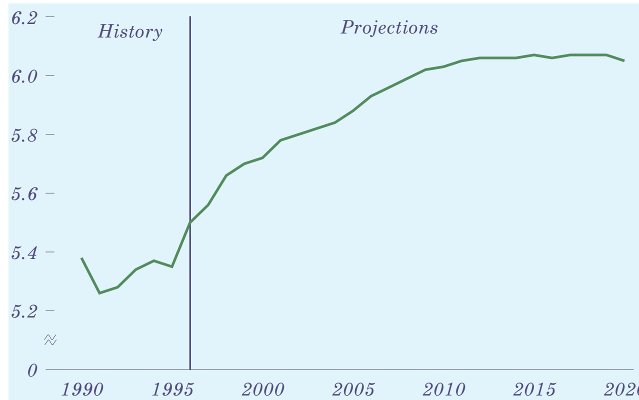
Carbon emissions from energy use are projected to increase by an average of 1.2 percent a year from 1996 to 2020, reaching 1,956 million metric tons (Figure 106). The 2015 projection of 1,888 million metric tons is higher than the *AEO97* projection of 1,799 million metric tons, due to higher energy consumption and a reduced share of renewable fuels.

Increasing concentrations of greenhouse gases— carbon dioxide, methane, nitrous oxide, and others— may increase the Earth's temperature and, in turn, affect the climate. The *AEO98* projections include analysis of the Climate Change Action Plan (CCAP), developed by the Clinton Administration in 1993 to stabilize U.S. greenhouse gas emissions by 2000 at 1990 levels. Carbon emissions from fuel combustion, the primary source of carbon emissions, were about 1,346 million metric tons in 1990. The analysis does not account for carbon-absorbing sinks, the 13 CCAP actions that are related to non-energy programs or gases other than carbon dioxide, nor any future mitigation actions that may be proposed.

Emissions in the 1990s have grown more rapidly than projected at the time the plan was formulated, partly due to moderate energy price increases and higher economic growth, which have led to higher energy demand. In addition, some CCAP programs have been curtailed. Additional carbon mitigation programs, technology improvements, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

U.S. Carbon Emissions per Capita Level Off Late in the Projections

Figure 107. Carbon emissions per capita, 1990--2020 (metric tons per person)



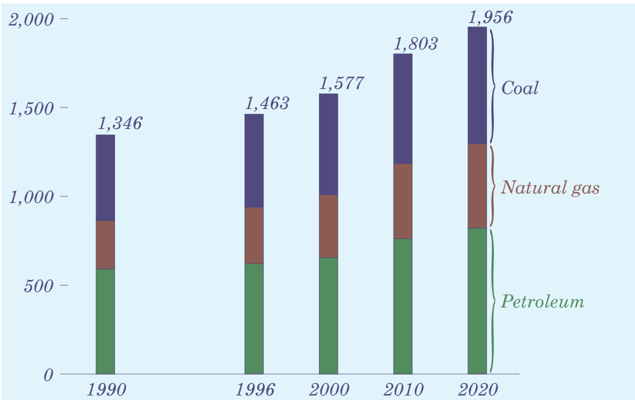
U.S. carbon emissions from energy use are projected to grow at an average annual rate of 1.2 percent; however, per capita emissions grow by only 0.4 percent a year (Figure 107). To achieve stabilization of total emissions, population growth would need to be offset by reductions in per capita emissions.

Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by 1.2 percent a year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in emissions, which increase by 1.1 percent a year—is likely to be moderated by slowing growth in floorspace, coupled with efficiency standards, voluntary efficiency programs, and technology improvements. Transportation emissions grow at an average annual rate of 1.6 percent as a result of increases in vehicle-miles traveled and freight and air travel, combined with slow growth in the average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate growth in energy use.

Further reductions in emissions could result from Climate Wise and Climate Challenge, voluntary programs for emissions reductions by industry and electricity generators, which are cosponsored by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy.

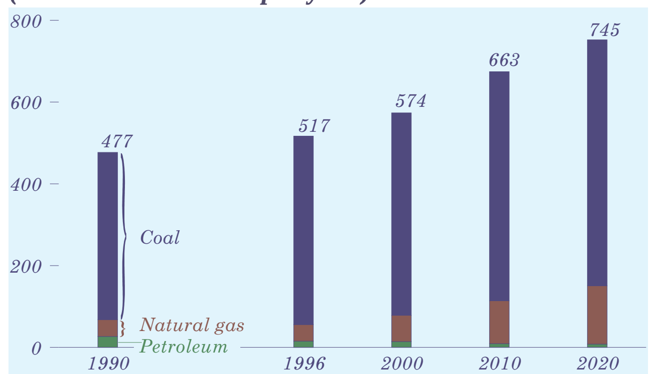
Petroleum Products Are the Leading
Energy Source of Carbon Emissions

Figure 108. Carbon emissions by fuel, 1990--2020 (million metric tons per year)



Coal Produces Most Carbon Emissions
from Electricity Generation

Figure 109. Carbon emissions from electricity generation by fuel, 1990--2020 (million metric tons per year)



Petroleum products are the leading source of carbon emissions from energy use. In 2020, petroleum is projected to contribute 822 million metric tons of carbon to the total 1,956 million tons, a 42-percent share (Figure 108). About 80 percent (659 million metric tons) of the petroleum emissions result from transportation use, which could be lower with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon emissions, projected to produce 658 million metric tons in 2020, or 34 percent of the total. The share declines from 36 percent in 1996 because coal consumption increases at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon emissions. Most of the increases in coal emissions result from electricity generation. A slight increase in emissions from industrial steam coal use is offset by a decline in emissions from coking coal.

In 2020, natural gas use is projected to produce 474 million metric tons of carbon emissions, a 24-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at average annual rates of 1.6 and 1.7 percent, respectively; however, natural gas produces only half the carbon emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 35 percent of total carbon emissions, and that share is expected to increase to 38 percent in 2020. Coal, which accounts for about 51 percent of electricity generation in 2020 (excluding cogeneration), produces 80 percent of electricity-related carbon emissions (Figure 109). In 2020, gas-fired generation accounts for 31 percent of total electricity but only 19 percent of electricity-related carbon emissions.

Between 1996 and 2020, 52 gigawatts of nuclear capacity are expected to be retired, resulting in a 43-percent decline in nuclear generation. To compensate for the loss of baseload capacity and meet rising demand, 389 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise electricity-related carbon emissions by 228 million metric tons, or 44 percent, from 1996 levels. Generation from renewable technologies remains level between 1996 and 2020, because of competition from fossil-fueled technologies.

The projections include activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, to the extent that such plans have been announced, but they do not include offset activities. Additional use of lower carbon fuels, reduced electricity demand growth, or improved technologies all could contribute to lower emissions than are projected here.

Electricity Sulfur Dioxide Emissions Are Projected To Decline

Figure 110. Sulfur dioxide emissions from electricity generation, 1990--2020 (million tons per year)

CAAA90 calls for emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to 12 million short tons in 1996 and to 8.95 million tons a year in 2000 and thereafter. More than 95 percent of the SO_2 produced by generators results from coal combustion, with the rest from residual oil.

In Phase 1, 261 generating units at 110 plants were issued tradeable 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 more than half of the generators. In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants will be tightened, and limits will be set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are expected to decline from 11.6 million tons in 1995 to 10.2 million in 2000 (Figure 110). Since allowance prices are projected to increase after 2000, it is expected that 11.4 gigawatts of capacity—about 38 300-megawatt plants—will be retrofitted with scrubbers to achieve the Phase 2 goal (Table 14).

Table 14. Scrubber retrofits, allowance costs, and banked allowances, 2000--2020

Forecast	2000	2005	2010	2015	2020
Cumulative retrofits from 1996 (gigawatts of capacity)	11.4	11.4	11.4	11.4	11.4
Allowance costs (1996 dollars per ton SO_2)	121	176	189	181	167
Cumulative banked allowances (million tons SO_2)	7.5	2.5	0.2	0.0	0.0

Nitrogen Oxide Emissions Rise in the Projections After 2000

Figure 111. Nitrogen oxide emissions from electricity generation, 1995--2020 (million tons per year)

CAAA90 also directed the EPA to study and issue standards for nitrogen oxide (NO_x) emissions, which are precursors to acid rain and ground-level ozone. In response, EPA promulgated regulations that impose NO_x emissions limits on electricity generators, based on specific boiler technologies. Combined with other NO_x reduction programs, such as those for mobile sources, the goal of the regulations is to reduce NO_x emissions in 2000 by about 2 million tons from what they would otherwise have been.

There are two phases to the program to reduce NO_x emissions from coal-fired plants, which produce most of the NO_x from electricity generation. In Phase 1, between 1996 and 1999, NO_x emission limits are applied to dry-bottom wall-fired and tangentially-fired boilers, designated as Group 1 boilers, by using available control technologies. In Phase 2, starting in 2000, emissions limits on the Group 1 boilers will be lowered slightly. In addition, in Phase 2, limits will be set for Group 2 boilers, which are coal-fired boilers that use other technologies. Under current regulations, NO_x emissions by electricity generators are projected to decline by 1.6 million tons between 1995 and 2000 but increase by nearly 0.7 million tons by 2020 with increasing coal use (Figure 111).

Other mitigation strategies could include voluntary programs or an allowance program similar to that for SO_2. Increased use of other fossil and renewable fuels for generation or technology advances that increase efficiency or produce less emissions could also reduce emissions from those projected here.

Forecast Comparisons

Three other organizations — DRI/McGraw-Hill (DRI), the WEFA Group (WEFA), and the Gas Research Institute (GRI) — also produce comprehensive energy projections with a time horizon similar to that of *AEO98*. The most recent projections from these organizations and others that concentrate on petroleum, natural gas, and international oil markets are compared to the *AEO98* projections in this section.

Economic Growth

Differences in long-run economic forecasts can be traced primarily to different views of the major supply-side determinants of growth: labor force and productivity change. Other forecasts are presented in Table 15. From an energy perspective, other forecasters also include different views of energy prices: typically, lower energy prices are assumed for the optimistic growth cases and higher energy prices for the pessimistic cases. For *AEO98*, reference case energy prices are used for both the high and low economic growth cases. The WEFA forecast shows the highest economic growth compared to the *AEO98* and DRI reference cases, including higher growth rates for the labor force. The *AEO98* long-run forecast of economic growth is higher than the *AEO97* forecast by 0.2 percent, when compared on a similar basis, with a projected annual growth rate for GDP of 2.1 percent from 1996 to 2015.

*Table 15. **Forecasts of economic growth, 1996--2020***

	Average annual percentage growth		
Forecast	**Real GDP**	**Labor force**	**Productivity**
AEO98			
Low growth	1.3	0.5	0.8
Reference	1.9	0.8	1.1
High growth	2.4	1.0	1.4
DRI			
Low	1.3	0.6	0.7
Reference	1.9	0.8	1.1
High	2.4	1.1	1.3
WEFA			
Reference	2.1	1.0	1.1

In the 1997 *Economic Report of the President*, real GDP growth of 2.2 percent a year between 1996 and 2003 was projected. *AEO98* projects annual growth of 2.3 percent over 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 NatWest Securities (NWS)— are shown in Table 16. With the exception of PEL in 2010 and IEA in 2005, the range between the *AEO98* low and high world oil price cases spans the range of other published forecasts. The *AEO98* reference case prices tend to be within $1.00 of the middle of the range for all the forecasts.

Table 16. Forecasts of world oil prices, 2000--2020

	1996 dollars per barrel				
Forecast	2000	2005	2010	2015	2020
AEO98 reference	19.11	20.19	20.81	21.48	22.32
AEO98 high price	21.86	24.50	26.87	28.59	28.71
AEO98 low price	14.47	14.58	14.44	14.42	14.43
DRI	17.29	19.27	21.07	23.43	26.16
IEA1	18.18	26.73	26.73	NA	NA
IEA2	18.18	18.18	18.18	NA	NA
PEL	18.01	15.52	13.14	NA	NA
PIRA	16.27	15.96	NA	NA	NA
WEFA	18.35	19.05	19.77	20.53	21.31
GRI	17.05	17.06	17.05	17.06	NA
NRCan	20.38	20.38	20.38	20.38	20.38
NWS	19.00	19.00	19.00	19.00	NA

NA = not available.

Total Energy Consumption

The *AEO98* 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.

Given potentially different assumptions about, for example, technological developments over the next 20 years, the forecasts from DRI, GRI, and WEFA have remarkable similarities to those in *AEO98*. Electricity is expected to remain the fastest growing source of delivered energy (Table 17), although its rate of growth is down sharply 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 consumption grows at the same rate as in recent history. Consumption growth for the remaining fuels slows as a result of moderating economic growth, fuel switching, and increased end-use efficiency.

Table 17. Forecasts of average annual growth rates for energy consumption (percent)

	History		Projections			
Energy use	1974-1984	1984-1995	AEO98 (1996-2020)	DRI (1996-2020)	GRI (1995-2015)	WEFA (1997-2020)
Petroleum*	-0.1	1.2	1.2	1.0	1.2	1.0
Natural gas*	-1.7	1.9	0.7	0.8	1.4	1.0
Coal*	-3.0	-1.4	0.2	0.3	-0.6	0.3
Electricity	3.0	2.5	1.4	1.5	2.0	1.7
Delivered energy	-0.4	2.0	1.1	1.0	1.3	1.1
Electricity losses	2.5	1.5	0.7	0.7	1.4	1.1
Primary energy	0.2	1.8	1.0	0.9	1.3	1.1

*Excludes consumption by electric utilities.

Residential and Commercial Sectors

Growth rates in energy demand for the residential and commercial sectors are expected to decrease by more than 50 percent from the rates between 1984 and 1995, largely because of projected lower growth in population, housing starts, and commercial floorspace additions. 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 in the residential sector and personal computers in the commercial sector, where they are already being used extensively.

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 18). Natural gas use also grows but at lower rates, and petroleum use continues to fall.

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

	History	Projections			
Forecast	1984-1995	AEO98 (1996-2020)	DRI (1996-2020)	GRI (1995-2015)	WEFA (1997-2020)
Residential					
Heating oil/LPG	0.2	-0.3	-0.9	-0.9	-0.1
Natural gas	0.6	0.4	0.6	1.0	0.7
Electricity	2.7	1.5	1.2	1.8	1.6
Delivered energy	1.7	0.7	0.6	1.0	1.0
Electricity losses	2.2	0.8	0.4	1.3	1.1
Primary energy	1.9	0.8	0.5	1.1	1.0
Commercial					
Petroleum	-3.6	-0.5	-1.6	-1.9	-0.6
Natural gas	1.7	0.7	0.5	1.4	0.7
Electricity	3.3	1.2	1.5	1.8	1.8
Delivered energy	1.5	0.8	0.8	1.3	1.1
Electricity losses	2.8	0.4	0.7	1.3	1.2
Primary energy	2.1	0.6	0.8	1.3	1.2

Industrial Sector

In all the forecasts, the industrial sector shows slower growth in primary energy consumption than it did between 1984 and 1995 (Table 19). The decline is attributable to lower growth for GDP and manufacturing output. In addition, there has been a continuing shift in the industrial output mix toward less energy-intensive products. The growth rates in the industrial sector for different fuels between 1984 and 1995 reflect a shift from petroleum products and coal to a greater reliance on natural gas and electricity. Natural gas use grows more slowly than in recent history across the forecasts, 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.

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

Forecast	History 1984-1995	Projections AEO98 (1996-2020)	DRI (1996-2020)	GRI (1995-2015)	WEFA (1997-2020)
Petroleum	0.7	0.8	0.7	1.3	0.8
Natural gas	2.7	0.6	0.9	1.3	0.9
Coal	-1.2	0.1	0.4	-0.6	0.3
Electricity	1.7	1.3	1.7	2.2	1.5
Delivered energy	2.3	0.8	0.9	1.3	0.9
Electricity losses	0.7	0.6	1.0	1.6	0.9
Primary energy	2.0	0.7	0.9	1.4	0.9

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow more slowly than in the recent past in each of the alternative forecasts (Table 20). All the forecasts anticipate continued rapid growth in air travel as well as significant increases in aircraft efficiency, while growth in light-duty vehicle travel slows considerably.

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

Forecast	History 1974-1984	History 1984-1995	Projections AEO98 (1996-2020)	DRI (1996-2020)	GRI (1995-2015)	WEFA (1997-2020)
Consumption						
Motor gasoline	0.1	1.4	1.1	1.0	0.7	0.8
Diesel fuel	4.5	2.8	1.4	1.1	1.9	1.4
Jet fuel	1.9	2.4	2.8	1.6	2.2	2.3
Residual fuel	1.4	0.7	2.3	2.4	2.5	2.2
All energy	0.9	1.8	1.6	1.3	1.4	1.3
Key indicators						
Car and light truck travel	2.8	2.8	1.5	2.1	1.5	NA
Air travel (revenue passenger-miles)	7.0	5.0	2.9	2.9	3.1	NA
Average new car fuel efficiency	4.5	0.5	0.4	0.6	0.8	NA
Gasoline prices	1.8	-3.1	0.1	0.5	0.0	0.3

NA = not available.

Electricity

Comparison across forecasts shows slight variation in projected electricity sales (Table 21). Sales projections for 2020 range from 1,422 billion kilowatthours (DRI) to 1,585 billion kilowatthours (WEFA) for the residential sector, as compared with the *AEO98* reference case value of 1,548 billion kilowatthours. The forecasts for total electricity sales in 2020 range from 4,308 billion kilowatthours (*AEO98*) to 4,581 billion kilowatthours (WEFA). All the projections for total electricity sales in 2020 fall within the range of the *AEO98* low and high economic growth cases (3,876 and 4,708 billion kilowatthours, respectively). Different assumptions governing expected economic activity, coupled with diversity in the estimation of penetration rates for energy-efficient technologies, are the primary reasons for variation among the forecasts.

All the forecasts compared here agree that stable fuel prices 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 and GRI forecasts assume that the electric power industry will be fully restructured, resulting in average electricity prices that approach long-run marginal costs. *AEO98* assumes that competitive pressures and FERC Orders 888 and 889 will push average costs and prices down somewhat, but not to the extent that would be achieved under a full restructuring of the industry. *AEO98* also assumes that increased competition in the electric power industry will lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient generating units, and other cost reductions. Further, in the DRI forecast, it is assumed that time-of-use electricity rates will cause some flattening of electricity demand (lower peak period sales relative to average sales), resulting in better utilization of capacity and capital cost savings.

The distribution of sales among sectors affects the mix of capacity types needed to satisfy sectoral demand. Although the *AEO98* mix of capacity among fuels is similar to those in the other forecasts, small differences in sectoral demands across the forecasts lead to significant changes in capacity mix. For example, growth in the residential sector, coupled with an oversupply of baseload capacity, results in a need for more peaking and intermediate capacity than baseload capacity. Consequently, generators are expected to plan for more combustion turbine and fuel cell technology than coal, oil, or gas steam capacity.

Natural Gas

The diversity among published forecasts of natural gas prices, production, consumption, and imports (Table 22) indicates 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. The forecasts for total natural gas consumption in 2015 vary from a high of 32.90 trillion cubic feet in the WEFA forecast to a low of 28.74 trillion cubic feet in the *AEO98* low economic growth case. The variation in the 2020 projections is even greater (a 20-percent difference between the high and low projections for 2020 and a 15-percent difference for 2015). The high projection for 2020 is 35.29 trillion cubic feet in the WEFA forecast, compared with a low of 29.40 trillion cubic feet in the *AEO98* low economic growth case. The main point of difference among the consumption forecasts for both years is the projected use of natural gas for electricity generation, with WEFA projecting high average annual growth rates for most of the country and considerably higher gas consumption by electricity generators than in any of the other forecasts.

The projections of wellhead prices for natural gas vary considerably more than the consumption forecasts: by 44 percent for 2015 and 56 percent for 2020. All the price projections fall within the range defined by the *AEO98* low and high economic growth cases. In the low economic growth case, the price path for natural gas between 2015 and 2020 is nearly flat, whereas the other forecasts show increases ranging from 7 cents (WEFA) to 29 cents (DRI) per thousand cubic feet. *AEO98* projects stronger growth of wellhead prices in the other cases. With the exception of the low economic growth case, the *AEO98* projections of wellhead prices for natural gas are higher in both 2015 and 2020 than those in any of the other forecasts.

Petroleum

Projected prices for crude oil in the *AEO98* low and high world oil price cases bound the 2010 and 2020 projections in five other petroleum forecasts (Table 23)—the *AEO98* reference case, WEFA, GRI, DRI, and the Independent Petroleum Association of America (IPAA). Comparisons with the GRI and IPAA forecasts, which do not extend to 2020, apply only to 2010. The *AEO98* reference case oil price projection for 2010 is similar to DRI's but more than $1 per barrel higher than WEFA's and almost $3 higher than GRI's; the projection for 2020 is less than $1 higher than WEFA's and nearly $4 less than DRI's.

The *AEO98* low and high oil price cases also bound the other projections for domestic production. Projected production in 2010 in the high price case is only slightly higher than the IPAA forecast, however. Production levels in the *AEO98* reference case are comparable with the WEFA, GRI, and DRI projections for 2010 and with the WEFA and DRI projections for 2020.

The most striking difference between the *AEO98* projections and the other forecasts is in petroleum consumption. All three *AEO98* cases project consumption levels higher than those in the four other forecasts.

Net petroleum imports in the *AEO98* reference and low price cases are well above the levels of the other forecasts. The projected percentage of petroleum consumption from imports, which is an indicator of the relative direction of production, net imports, and consumption, ranges between 55 percent (*AEO98* high oil price case) and 67 percent (*AEO98* low oil price case) in 2010. The range in 2010 falls between 58 percent in the *AEO98* high world oil price case and 72 percent in the low price case.

The *AEO98* high oil price case, which projects the lowest share of imports in both 2010 and 2020, also features the strongest production. In contrast, the low price case, with the highest imports share in both years, also features the lowest production and highest consumption. The *AEO98* reference case is distinguished from the DRI and WEFA projections by its relatively high levels of petroleum consumption, imports, and share of consumption from imports. IPAA also projects lower net imports and petroleum consumption than in the *AEO98* reference case but stronger production for 2010. GRI, which does not project imports, has production forecasts similar to those in the *AEO98* reference case, but with much lower levels of consumption.

Coal

In terms of projected coal production in 2015, the WEFA coal forecast is most comparable to, although somewhat higher than, the *AEO98* low economic growth case (Table 24). WEFA's sectoral demands for domestic coking coal and electricity generation are higher than those in the *AEO98* low economic growth case, but its industrial consumption and net exports are lower. By 2020, sectoral demands in the WEFA projection are similar to the *AEO98* reference case (consumption by the electricity generation sector is 9 million tons lower). Industrial demand is lower than in any *AEO98* case. In 2020, the WEFA projection of net exports is 2.0 percent higher than the *AEO98* level, while domestic coking coal consumption is 161 percent of the *AEO98* forecast. Overall, WEFA's projected coal consumption grows more slowly than that in *AEO98* before 2015 and more rapidly after that date, with the most significant difference being that WEFA shows growth in domestic coking coal consumption while all other forecasts show a steep decline. The WEFA projection foresees relatively high average mine prices ($0.70 per million Btu in 2015 and 2020, compared with the *AEO98* low growth case values of $0.66 in 2015 and $0.63 in 2020). Delivered prices to the electricity sector are also higher than in *AEO98*, with WEFA projecting $1.12 per million Btu in 2015 and $1.11 in 2020, compared with the *AEO98* low growth case values of $1.00 and $0.95.

The GRI coal forecast, which extends only to 2015, is most comparable to the *AEO98* high economic growth case in 2015—GRI has 1,427 million tons of production, whereas the *AEO98* high growth case has 1,415, a difference of 0.8 percent. Sectoral demand for domestic industrial coal in 2015 is lower than those in any of the *AEO98* cases included in this comparison. The demand for coal for electricity generation, at 1,262 million tons, is 6.7 percent higher than that in the *AEO98* high growth case. GRI projects net coal exports at 71 million tons in 2015, 63 percent of the forecast level in *AEO98*. GRI has a lower 2015 minemouth price ($0.64 per million Btu) and a higher delivered price ($1.15 per million Btu) for coal to electric utilities than the other projections. Clearly, the GRI forecast sees more robust growth in electricity sector coal demand than do the other forecasts.

The DRI forecast of coal production is lower than the GRI forecast in 2015 and most comparable to the *AEO98* reference case, although industrial steam coal, coking coal, and net export values are lower than those in the *AEO98* low economic growth case. However, coal consumption by the electricity sector reaches 1,188 million tons, compared with *AEO98* projections of 1,103 million tons in the reference case and 1,183 million tons in the high growth case. DRI shares GRI's pessimistic view of coal export markets, forecasting net exports at 79 million tons in 2015, compared to 112 million tons in *AEO98*. In 2020, DRI forecasts 1,424 million tons of production, a level between the *AEO98* reference case (1,376 million tons) and high growth case (1,501 million tons). Relatively high electricity demand is combined with pessimistic forecasts for exports, industrial steam coal, and domestic coking coal demand. DRI does not report mine prices, but it projects delivered prices to the electricity sector of $1.05 per million Btu in 2015 and $1.01 in 2020 (compared with the *AEO98* high growth case projections of $1.04 in 2015 and $0.99 in 2020).

In conclusion, the WEFA and DRI forecasts for 2015 and 2020 fall within the range of the three *AEO98* cases. While there are differences in projected levels for sectoral demands, they fall within a few percent of each other, with two exceptions—WEFA's optimistic forecast for domestic coking coal demand, and the pessimistic export forecast by GRI and DRI. Overall, GRI projects higher electricity coal demand and lower export demand than the other forecasts in 2015. All the forecasts predict falling minemouth and delivered coal prices, with the *AEO98* cases falling in the middle range in 2015, but providing the lowest minemouth and delivered prices in 2020.

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

Projection	AEO98			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI
2015						
Average end-use price (1996 cents per kilowatthour)	5.60	5.20	5.90	6.00	5.19	4.90
Residential	7.00	6.40	7.40	7.58	6.87	6.00
Commercial	6.10	5.50	6.70	6.36	5.97	5.10
Industrial	3.60	3.30	3.90	4.00	2.90	3.90
Net energy for load	4,412	4,082	4,721	4,507	4,789	4,722
Coal	2,190	2,003	2,369	2,074	2,761	2,544
Oil	33	27	39	62	43	125
Natural gas	1,171	1,041	1,283	1,398	899	1,153
Nuclear	480	480	480	391	441	426
Hydroelectric/other[a]	385	380	393	316	420	441
Nonutility sales to grid[b]	127	125	129	224	178	NA
Net imports	27	27	27	42	47	32
Electricity sales	4,115	3,807	4,405	4,211	4,442	4,159
Residential	1,449	1,384	1,516	1,455	1,503	1,361
Commercial/other[c]	1,323	1,262	1,387	1,398	1,369	1,350
Industrial	1,343	1,160	1,502	1,358	1,555	1,447
Capability (gigawatts)[d,e]	1,006.0	946.1	1,066.3	920.2	857.1	980.0
Coal	323.7	312.6	347.3	355.1	401.8	403.2
Oil and gas	496.0	448.7	531.5	385.3	268.0	388.9
Nuclear	63.9	63.9	63.9	55.8	63.6	71.1
Hydroelectric/other[a]	122.3	121.0	123.9	124.1	123.8	116.7
2020						
Average end-use price (1996 cents per kilowatthour)	5.50	5.00	5.80	5.84	NA	5.00
Residential	6.80	6.20	7.30	7.43	NA	6.10
Commercial	6.00	5.30	6.60	6.12	NA	5.20
Industrial	3.50	3.10	3.80	3.89	NA	3.90
Net energy for load	4,612	4,152	5,040	4,904	NA	4,939
Coal	2,265	2,042	2,530	2,272	NA	2,716
Oil	32	25	41	59	NA	145
Natural gas	1,389	1,169	1,517	1,657	NA	1,278
Nuclear	383	383	383	333	NA	332
Hydroelectric/other[a]	390	383	413	316	NA	439
Nonutility sales to grid[b]	126	123	129	224	NA	NA
Net imports	27	27	27	44	NA	30
Electricity sales	4,308	3,876	4,708	4,581	NA	4,353
Residential	1,548	1,467	1,634	1,585	NA	1,422
Commercial/other[c]	1,368	1,281	1,454	1,528	NA	1,399
Industrial	1,392	1,129	1,620	1,467	NA	1,532
Capability (gigawatts)[d,e]	1,041.1	959.5	1,120.0	991.2	NA	1,008.2
Coal	331.3	311.9	368.0	386.4	NA	420.6
Oil and gas	537.5	477.1	576.4	433.3	NA	414.7
Nuclear	49.2	49.2	49.2	47.4	NA	56.6
Hydroelectric/other[a]	123.1	121.3	126.8	124.1	NA	116.2

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

[b]For *AEO98*, includes only net sales from cogeneration; for the other forecasts, also includes nonutility sales to the grid.

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

[d]For DRI, "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 60 gigawatts.

Sources: **AEO98:** AEO98 National Energy Modeling System, runs AEO98B.D100197A (reference case), LMAC98.D100197A (low economic growth case), and HMAC98.D100197A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (Spring/Summer 1997). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1998 Edition. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring 1997* (April 1997).

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

Projection	AEO98			Other forecasts			
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI	AGA
2015							
Lower 48 wellhead price (1996 dollars per thousand cubic feet)	**2.38**	**1.89**	**2.74**	**2.24**	**2.02**	**2.19**	**2.14[a]**
Dry gas production[b]	**26.12**	**24.48**	**27.49**	**28.42**	**25.70**	**25.62**	**25.85**
Net imports	**4.64**	**4.41**	**5.02**	**4.49**	**4.17**	**4.96**	**3.75**
Consumption	**30.61**	**28.74**	**32.36**	**32.90**	**30.94**	**30.26**	**29.59**
Residential	5.66	5.50	5.83	5.62	5.82	5.80	6.09
Commercial	3.74	3.59	3.90	3.50	3.88[c]	3.60	4.04
Industrial[c]	9.75	9.11	10.35	8.98	11.05	9.05	10.55
Electricity generators	8.52	7.78	9.20	11.59	6.98	8.91	6.08
Other[d]	2.94	2.77	3.08	3.20	3.11	2.89	2.82
End-use prices (1996 dollars per thousand cubic feet)							
Residential	5.47	4.93	5.85	6.09	5.69	6.14	5.66[e]
Commercial	4.76	4.23	5.14	5.29	4.79[c]	5.22	4.01[e]
Industrial[c]	3.09	2.58	3.46	3.54	2.71	3.35[f]	2.39[e]
Electricity generators	3.04	2.51	3.42	2.60	2.40	2.61	2.35[e]
Transportation	7.26	6.73	7.60	NA	NA	NA	NA
2020							
Lower 48 wellhead price (1996 dollars per thousand cubic feet)	2.54	1.91	2.97	2.31	NA	2.48	NA
Dry gas production[b]	27.44	24.95	29.30	30.44	NA	26.04	NA
Net imports	4.91	4.60	5.36	4.87	NA	5.19	NA
Consumption	32.20	29.40	34.51	35.29	NA	30.90	NA
Residential	5.80	5.65	6.02	5.82	NA	6.01	NA
Commercial	3.75	3.55	3.96	3.62	NA	3.60	NA
Industrial[c]	9.70	8.82	10.58	9.21	NA	8.99	NA
Electricity generators	9.85	8.53	10.64	13.21	NA	9.36	NA
Other[d]	3.10	2.85	3.31	3.44	NA	2.95	NA
End-use prices (1996 dollars per thousand cubic feet)							
Residential	5.60	4.86	6.02	5.99	NA	6.37	NA
Commercial	4.91	4.21	5.34	5.22	NA	5.46	NA
Industrial[c]	3.26	2.59	3.71	3.61	NA	3.62[f]	NA
Electricity generators	3.22	2.54	3.67	2.67	NA	2.91	NA
Transportation	7.61	6.97	8.01	NA	NA	NA	NA

[a]Average acquisition price.
[b]Does not include supplemental fuels.
[c]includes gas consumed in cogeneration.
[d]Includes lease and plant fuels and pipeline fuel.
[e]Does not include certain State and local taxes.
[f]On-system sales.
NA = Not available.

Sources: **AEO98:** AEO98 National Energy Modeling System, runs AEO98B.D100197A (reference case), LMAC98.D100197A (low economic growth case), and HMAC98.D100197A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (Spring/Summer 1997). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1998 Edition. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring 1997* (April 1997). **AGA:** American Gas Association, *1997 AGA-TERA Base Case* (April 1997).

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

Projection	AEO98			Other forecasts			
	Reference	Low world oil price	High world oil price	WEFA	GRI	DRI	IPAA
2010							
World oil price (1996 dollars per barrel)	**20.81**	**14.44**	**26.87**	**19.77**	**17.04[a]**	**20.99**	**NA**
Crude oil and NGL production	**7.81**	**6.82**	**8.55**	**7.62**	**7.74**	**7.63**	**8.49**
Crude oil	5.57	4.63	6.28	5.34	5.37	5.34[b]	6.22
Natural gas liquids	2.24	2.19	2.27	2.28	2.37	2.29	2.27
Total net imports	**13.67**	**15.74**	**12.16**	**11.80**	**NA**	**12.68**	**12.33**
Crude oil	10.67	11.71	9.91	9.82	NA	9.74	NA
Petroleum products	3.00	4.03	2.25	1.99	NA	2.93	NA
Petroleum demand	**22.70**	**23.59**	**22.12**	**20.94**	**21.71**	**21.69**	**21.70**
Motor gasoline	9.75	10.14	9.56	8.79	8.78	9.54	9.02
Jet fuel	2.53	2.55	2.52	2.15	2.35	2.08	2.07
Distillate fuel	4.09	4.17	4.07	3.80	4.09	3.87	4.06
Residual fuel	0.88	1.11	0.82	1.10	1.02	0.92	1.09
Other	5.45	5.62	5.17	5.10	5.47	5.29	5.45
Import share of product supplied (percent)	**60.0**	**67.0**	**55.0**	**56.4**	**NA**	**58.4**	**56.8**
2020							
World oil price (1996 dollars per barrel)	**22.32**	**14.43**	**28.71**	**21.38**	**NA**	**26.08**	**NA**
Crude oil and NGL production	**7.39**	**6.31**	**8.50**	**7.85**	**NA**	**7.34**	**NA**
Crude oil	4.92	3.92	5.99	5.18	NA	4.92[b]	NA
Natural gas liquids	2.47	2.39	2.51	2.67	NA	2.42	NA
Total net imports	**15.98**	**18.42**	**13.75**	**13.89**	**NA**	**14.54**	**NA**
Crude oil	11.65	12.89	10.59	10.60	NA	10.09	NA
Petroleum products	4.33	5.53	3.16	3.21	NA	4.45	NA
Petroleum demand	**24.39**	**25.59**	**23.61**	**23.24**	**NA**	**23.33**	**NA**
Motor gasoline	10.39	10.99	10.06	9.56	NA	9.98	NA
Jet fuel	3.03	3.07	3.01	2.71	NA	2.34	NA
Distillate fuel	4.25	4.42	4.22	4.20	NA	4.28	NA
Residual fuel	0.99	1.23	0.93	1.23	NA	1.00	NA
Other	5.72	5.88	5.38	5.54	NA	5.73	NA
Import share of product supplied (percent)	**66.0**	**72.0**	**58.0**	**59.4**	**NA**	**62.3**	**NA**

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

Sources: **AEO98:** AEO98 National Energy Modeling System, runs AEO98B.D100197A (reference case), LWOP98.D100197C (low world oil price case), and HWOP98.D100197A (high world oil price case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (Spring/Summer 1997). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1998 Edition. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring 1997* (April 1997). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1997).

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

Projection	AEO98			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI
2015						
Production	**1,326**	**1,223**	**1,415**	**1,263**	**1,427**	**1,365**
Consumption by sector						
Electricity generation[a]	1,103	1,012	1,183	1,050	1,262	1,188
Coking plants	24	24	24	37	25	22
Industrial/other	88	77	97	66	70	75
Total	**1,215**	**1,113**	**1,305**	**1,153**	**1,357**	**1,284**
Net coal exports	**112**	**112**	**112**	**108**	**71**	**79**
Minemouth price						
(1996 dollars per short ton)	13.99	13.87	14.05	15.20	13.42	NA
(1996 dollars per million Btu)	0.67	0.66	0.67	0.70	0.64	NA
Average delivered price, electricity						
(1996 dollars per short ton)	20.72	20.26	20.99	NA	23.93	21.58
(1996 dollars per million Btu)	1.03	1.00	1.04	1.12	1.15	1.05
2020						
Production	**1,376**	**1,258**	**1,501**	**1,368**	**NA**	**1,424**
Consumption by sector						
Electricity generation[a]	1,147	1,042	1,258	1,138	NA	1,246
Coking plants	23	23	23	37	NA	20
Industrial/other	87	73	101	67	NA	76
Total	**1,257**	**1,138**	**1,382**	**1,242**	**NA**	**1,342**
Net coal exports	**120**	**120**	**120**	**122**	**NA**	**80**
Minemouth price						
(1996 dollars per short ton)	13.27	13.14	13.50	15.10	NA	NA
(1996 dollars per million Btu)	0.64	0.63	0.65	0.70	NA	NA
Average delivered price, electricity						
(1996 dollars per short ton)	19.52	18.91	20.01	NA	NA	20.86
(1996 dollars per million Btu)	0.97	0.95	0.99	1.11	NA	1.01

[a]The DRI and *AEO98* forecasts for electricity generation include nonutility generators. Consumption by industrial cogenerators is included in industrial consumption. The WEFA values for electricity consumption have been adjusted by including consumption by nonutility generators (11.2 million tons in 2015 and 2020).

NA = Not available.

Btu = British thermal unit.

Sources: **AEO98:** AEO98 National Energy Modeling System, runs AEO98B.D100197A (reference case), LMAC98.D100197A (low economic growth case), and HMAC98.D100197A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (Spring/Summer 1997). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1998 Edition, and *Coal Demand and Price Projections*, Vol. I, GRI-95/0493.1 (February 1996), Table 4-3. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring 1997* (April 1997).

AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AEO95	*Annual Energy Outlook 1995*
AEO97	*Annual Energy Outlook 1997*
AEO98	*Annual Energy Outlook 1998*
AFV	Alternative-fuel vehicle
AGA	American Gas Association
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CCAP	Climate Change Action Plan
CFC	Chlorofluorocarbon
CNG	Compressed natural gas
CPI	Consumer price index
CTC	Competitive transition charge
DRI	DRI/McGraw-Hill, Inc.
DSM	Demand-side management
E85	An 85-percent ethanol fuel
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
EU	European Union
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
GDP	Gross domestic product
GRI	Gas Research Institute
HCFC	Hydrochlorofluorocarbon
IEA	International Energy Agency
IGCC	Integrated coal gasification combined cycle
IPAA	Independent Petroleum Association of America
ISO	Independent system operator
LDC	Local distribution company
LEVP	Low Emissions Vehicle Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
M85	An 85-percent methanol fuel
MSW	Municipal solid waste
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act of 1987
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NOPR	Notice of Proposed Rulemaking
NPC	National Petroleum Council
NRCan	Natural Resources Canada
NWS	NatWest Securities, Ltd.
OASIS	Open Access Same-Time Information System
OTAG	Ozone Transport Assessment Group
PADD	Petroleum Administration for Defense District
PBF	Public benefits fund
PEL	Petroleum Economics, Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
PUHCA	Public Utility Holding Act of 1937
PURPA	Public Utility Regulatory Policies Act of 1978
RECS	Residential Energy Consumption Survey
RFG	Reformulated gasoline
RPS	Renewable portfolio standard
SCR	Selective catalytic reduction
SPR	Strategic Petroleum Reserve
STEO	Short-Term Energy Outlook
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WEFA	The WEFA Group (formerly the Wharton Econometric Forecasting Associates)

Text notes

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

[*2*] Energy Information Administration, *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, DOE/EIA-0608(96) (Washington, DC, October 1997).

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[*3*] "New Air Rules Signed, Lawmakers Attempt To Stall," *Washington Times* (July 17, 1997).

[*4*] Sharon Rinders, U.S. Environmental Protection Agency (personal communication, October 3, 1997).

[*5*] Energy and Environmental Analysis, Inc., *Impact of New Ozone and PM Standards on Industrial Gas Markets*, prepared for the Gas Research Institute (Arlington, VA, February 1997).

[*6*] *Ibid*.

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[*7*] U.S. Environmental Protection Agency, *Cost Estimates for Selected Applications of* NO_x *Control Technologies on Stationary Combustion Boilers* (Washington, DC, March 1996), Table 1-2.

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[*8*] Most of the bills are not far along in the legislative process, and they may undergo significant change. For a complete listing of Congressional bills and their current status, see web site www.thomas.loc.

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[*9*] Ancillary services are services provided to maintain the stable operation of the transmission system. For a discussion of the ancillary services identified by FERC, see Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997).

[*10*] Federal Energy Regulatory Commission, *Standards and Communications Protocols for Open Access Same-Time Information System Phase IA* (August 11, 1997).

[*11*] The North American Electric Reliability Council (NERC), the Electric Power Research Institute (EPRI), and other industry groups worked with FERC to develop standards for what they refer to as the "Transmission System Information Network" (TSIN). They jointly sponsor a web site, www.tsin.com, that provides links to each of the OASIS sites.

[*12*] Summarizing State plans is difficult, because they are constantly changing. Any review will be out of date before it can be printed. The value given here was derived by reviewing the information provided on the GDS Associates Electric Web (www.gdsassoc.com/ dereg/state.htm) on August 20, 1997. States were counted as aggressively moving toward retail competition if the summaries provided indicated a date for full retail choice and/or a retail pilot program either started or planned for the near future.

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[*13*] For a more detailed discussion of electricity prices in a competitive environment, see Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997).

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[*14*] Electricity prices are determined competitively in the reference case in the California, New York, and New Jersey regions, which have made sufficient progress to allow their transition to a more competitive structure to be represented.

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[*15*] The results described here are similar to those presented in *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*; however, the magnitudes of the price changes, especially in the Northwest, are smaller because this analysis used updated operations and maintenance costs and lower gas price expectations.

[*16*] State regulators and legislatures will determine how stranded costs are allocated among ratepayers (consumers), stockholders, and taxpayers.

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[*17*] Members of the Organization for Economic Cooperation and Development and countries of Eastern European and the former Soviet Union undergoing transition to market economies: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Czech Republic, Denmark, European Economic Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Spain, Sweden, Switzerland, Turkey, Ukraine, the United Kingdom of Great Britain and Northern Ireland, and the United States of America.

[*18*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997).

[*19*] Energy Information Administration, *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, DOE/EIA-0608(96) (Washington, DC, October 1997).

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[*20*] Energy Information Administration, *International Energy Outlook 1997*, DOE/EIA-0484(97) (Washington, DC, April 1997).

[*21*] Greenhouse gases differ in their impacts on global temperatures. For comparisons of emissions from the various gases, they are often weighted by their global warming potential (GWP), which is a measure of the relative impact of each gas on global warming relative to that of carbon dioxide, which is defined as having a GWP equal to 1.

[*21*] U.S. Department of State, Office of Global Change, *Climate Action Report*, Department of State Publication 10496 (Washington, DC, July 1997).

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[*23*] Energy Information Administration, *An Analysis of Carbon Mitigation Cases*, SR-OIAF-96-01 (Washington, DC, June 1996).

[*24*] Energy Information Administration, *Analysis of Carbon Stabilization Cases*, SR-OIAF-97-01 (Washington, DC, October 1997).

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[*25*] Only portions of the national economic statistics have been converted to 1992 chain-weighted dollars. Because the national input-output matrix for manufacturing industries, which underlies the projections in Figure 22, is still available only in 1987 fixed-weight dollars, the growth rates shown in the figure are based on 1987 fixed-weight dollars. The use of fixed-weight dollars is not expected to affect the picture of relative growth rates shown in the figure.

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[*26*] DRI/McGraw-Hill, *Review of the U.S. Economy, Long-Range Focus, Summer 1997* (Lexington, MA, 1997).

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[*27*] 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).

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[*28*] 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.

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

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[*30*] 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).

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[*31*] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence, assuming that flex-fuel vehicles use alternative fuels 50 percent of the time.

[*32*] 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. Over the past decade, horsepower increases for passenger vehicles have outpaced those for commercial light-duty vehicles. This trend is expected to continue.

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[*33*] Sales of alternative-fuel vehicles that are determined by market forces rather than by legislative mandates are defined here as market-driven AFV sales.

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[*34*] 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 Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 98* (June 17, 1997).

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[*35*] Values for incremental investments and energy expenditure savings are discounted back to 1997 at a 7-percent real discount rate.

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[*36*] 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 Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 98* (June 17, 1997).

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

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[*38*] For example, according to the latest USGS estimates, the size of the Nation's technically recoverable undiscovered conventional crude oil resources (in onshore areas and State waters) is most likely to be 30.3 billion barrels—with a 19 in 20 chance of being at least 23.5 billion barrels and a 1 in 20 chance of being at least 39.6 billion barrels. The corresponding USGS estimate for the Nation's natural gas resources is 258.7 trillion cubic feet—with a 19 in 20 chance of being at least 207.1 trillion cubic feet and a 1 in 20 chance of being at least 329.1 trillion cubic feet. *AEO98* does not examine the implications of geological resource uncertainty. The figures cited above are taken from U.S. Geological Survey, National Oil and Gas Resource Assessment Team, *1995 National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1118 (Washington, DC, 1995), p. 2. The cited numbers exclude natural gas liquids resources, for which the corresponding USGS estimates are 7.2, 5.8, and 8.9 billion barrels.

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[*39*] Substantial uncertainty surrounds the ultimate use of North Slope gas. However, projected low gas prices in the lower 48 markets justify the *AEO98* perspective that does not consider it a significant factor affecting domestic energy markets, especially natural gas markets.

[*40*] Eleven projects are currently proposed to expand pipeline capacity from Canada into the United States between 1998 and 2000. Three are slated to provide access to Sable Island supplies. It is assumed that not all proposed projects will be built, but that some combination of currently proposed projects will add approximately 2 billion cubic feet per day of pipeline capacity to access western Canadian supplies and 0.4 billion cubic feet per day to access Sable Island supplies. For information about specific projects, see Energy Information Administration, "Natural Gas Pipeline and System Expansions," *Natural Gas Monthly*, DOE/EIA-0130(97/04) (Washington, DC, April 1997).

[*41*] Two additional LNG import facilities located at Cove Point, MD, and Elba Island, GA, both of which are currently idle, are not projected to be reopened in the reference case. While LNG imports in the forecast all come from Algeria, new potential sources of supply include Australia, Abu Dhabi, Trinidad and Tobago, and Norway.

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[*42*] The two technology cases were run as fully integrated model runs. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about gas trade with Mexico.

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[*43*] Greater technological advances can markedly increase the quantity of economically recoverable resources by driving down costs, increasing success rates, and increasing recovery from producing wells. Expected production rate declines could be slowed or even reversed within the forecast period if faster implementation of advanced technologies is realized.

[44] Enhanced oil recovery (EOR) is the extraction of the oil that can be economically produced from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. EOR methods usually involve injecting heated fluids, pressurized gases, or special chemicals into an oil reservoir in order to produce additional oil.

[*45*] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(96/03) (Washington, DC, March 1996), Table 1.6.

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[*46*] In the 1980s, falling consumption led to surplus refining capacity, which reduced the need for product imports. See Energy Information Administration, *The U.S. Petroleum Industry: Past as Prologue 1970-1992*, DOE/EIA-0572 (Washington, DC, September 1993), p. 47.

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[*47*] Total labor costs are estimated by multiplying the average hourly earnings of coal mine production workers by total annual labor hours worked. Average hourly earnings do not represent total labor costs per hour for the employer, because they exclude retroactive payments and irregular bonuses, employee benefits, and the employer's share of payroll taxes.

[*48*]Variations in mining costs are not necessarily limited to changes in labor productivity and wage rates. Other factors that affect mining costs and, subsequently, the price of coal include such items as severance taxes, royalties, fuel costs, and the costs of parts and supplies.

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[*49*] The "Syncoal" and "Encoal" processes have been developed in partnership with the U.S. Department of Energy by coal producers located in the Montana and Wyoming portions of the Powder River Basin, respectively. The Syncoal process uses subbituminous coal with a moisture content of 25 to 40 percent, sulfur content of 0.5 to 1.5 percent, and heating value of 11 to 18 million Btu per ton. It yields a solid fuel with 1 percent moisture, 0.3 percent sulfur, and up to 24 million Btu per ton. The Encoal process uses mild gasification to produce "CDL"—a synthetic low-sulfur No. 6 fuel oil equivalent—and "PDF"—a low-sulfur solid fuel with a heat content of approximately 24 million Btu per ton. Encoal PDF solids have been successfully tested by American Electric Power as a steam fuel and by USX and Bethlehem Steel as a

blast furnace injectant. Encoal CDL has been used by industries in Maine, Michigan, and Louisiana. See U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Project Fact Sheets*, DOE/FE-0351 (Washington, DC, September 1996), pp. 72-75.

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[*50*] Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March 1994), p. 1.

[*51*] **1990:** Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0582(97) (Washington, DC, March 1997). **1995:** Energy Information Administration, *Electric Power Annual 1995*, Volume II, DOE/EIA-0348(95)/2 (Washington, DC, December 1996).

Table notes

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

Table 1. Summary of results for five cases (page 7): Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Table 2. Effective dates of appliance efficiency standards, 1988--1995 (page 11): U.S. Department of Energy, Office of Codes and Standards; and Electric Power Research Institute, "Energy Conservation Standards for Consumer Products."

Table 3. Product categories and priority levels for new standards (page 12): U.S. Department of Energy, Office of Codes and Standards.

Table 4. Natural gas prices to electricity producers in three competitive pricing cases, 2000--2020 (page 22): AEO98 National Energy Modeling System, runs HOGCOMP.D100697A, AEO98B.D100197A, and LOGCOMP.D100697A.

Table 5. Changes in efficiency, fuel consumption, and carbon emissions with changes in horsepower, 2000-2020 (page 45): AEO98 National Energy Modeling System, runs AEO98B.D100197A and DCDRUN. D110697D.

Table 6. Market shares of alternative-fuel light-duty vehicles by technology type, 2020 (page 46): U.S. Department of Energy, Office of Policy, *Technical Report Fourteen: Market Potential and Impacts of Alternative Fuel Use in Light-Duty Vehicles: A 2000/2010 Analysis* (Draft, 1995). California Air Resources Board, "Proposed Regulations for Low-Emission Vehicles and Clean Fuels, Staff Report" (Sacramento, CA, August 13, 1990). U.S. Department of Commerce, Bureau of the Census, *Truck Inventory and Use Survey, 1992*, TC92-T-52 (Washington, DC, May 1995). Energy Information Administration, *Describing Current and Potential Markets for Alternative Fuel Vehicles*, DOE/EIA-0604 (Washington, DC, March 1996). Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1994*, Vol. 1, DOE/EIA-0585(94)/1 (Washington, DC, February 1996). AEO98 National Energy Modeling System, run AEO98B. D100197A.

Table 7. Costs of producing electricity from new plants, 2005 and 2020 (page 53): AEO98 National Energy Modeling System, run AEO98B.D100197A.

Table 8. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions (page 59): Energy Information Administration, Office of Integrated Analysis and Forecasting.

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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 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Production								
Crude Oil and Lease Condensate	13.89	13.71	13.06	12.32	11.79	11.09	10.43	-1.1%
Natural Gas Plant Liquids	2.37	2.46	2.39	2.63	2.95	3.12	3.29	1.2%
Dry Natural Gas	19.12	19.55	20.84	22.88	25.39	26.85	28.21	1.5%
Coal	21.98	22.64	24.34	25.62	26.62	27.73	28.59	1.0%
Nuclear Power	7.19	7.20	7.36	6.87	6.36	5.12	4.09	-2.3%
Renewable Energy[1]	6.40	6.91	6.82	7.12	7.41	7.59	7.71	0.5%
Other[2]	1.36	1.33	0.56	0.55	0.48	0.47	0.47	-4.2%
Total	**72.31**	**73.80**	**75.37**	**77.98**	**81.00**	**81.97**	**82.77**	**0.5%**
Imports								
Crude Oil[3]	15.70	16.30	19.18	22.01	23.17	24.36	25.30	1.8%
Petroleum Products[4]	3.19	3.98	4.25	5.47	7.61	9.01	10.09	3.9%
Natural Gas	2.90	2.93	4.20	4.39	4.66	5.04	5.34	2.5%
Other Imports[5]	0.59	0.57	0.62	0.58	0.57	0.54	0.56	-0.1%
Total	**22.38**	**23.78**	**28.26**	**32.45**	**36.02**	**38.96**	**41.28**	**2.3%**
Exports								
Petroleum[6]	2.02	2.04	1.71	1.73	1.80	1.89	1.67	-0.8%
Natural Gas	0.16	0.16	0.28	0.28	0.29	0.30	0.32	3.0%
Coal	2.32	2.37	2.41	2.64	2.84	3.03	3.23	1.3%
Total	**4.50**	**4.57**	**4.39**	**4.65**	**4.93**	**5.21**	**5.23**	**0.6%**
Discrepancy[7]	**0.66**	**0.99**	**0.58**	**0.04**	**0.08**	**0.00**	**-0.25**	**N/A**
Consumption								
Petroleum Products[8]	34.74	36.01	38.35	41.32	44.33	46.20	47.64	1.2%
Natural Gas	22.18	22.60	24.74	26.93	29.63	31.44	33.06	1.6%
Coal	19.96	20.90	22.14	23.21	24.03	24.95	25.61	0.9%
Nuclear Power	7.19	7.20	7.36	6.87	6.36	5.12	4.09	-2.3%
Renewable Energy[1]	6.40	6.91	6.82	7.12	7.42	7.62	7.74	0.5%
Other[9]	0.39	0.39	0.41	0.37	0.40	0.40	0.43	0.4%
Total	**90.86**	**94.01**	**99.82**	**105.82**	**112.17**	**115.72**	**118.58**	**1.0%**
Net Imports - Petroleum	**16.87**	**18.25**	**21.72**	**25.75**	**28.99**	**31.48**	**33.71**	**2.6%**
Prices (1996 dollars per unit)								
World Oil Price (dollars per barrel)[10]	17.58	20.48	19.11	20.19	20.81	21.48	22.32	0.4%
Gas Wellhead Price (dollars per Mcf)[11]	1.61	2.24	2.11	2.15	2.31	2.38	2.54	0.5%
Coal Minemouth Price (dollars per ton)	19.25	18.50	17.45	16.18	15.05	13.99	13.27	-1.4%
Average Electric Price (cents per kilowatthour)	7.0	6.9	6.5	6.1	5.9	5.6	5.5	-1.0%

[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.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 and 1996 may differ from published data due to internal conversion factors.
Sources: 1995 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 coal minemouth prices: EIA, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1996 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). 1996 coal minemouth price: *Coal Industry Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

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

Sector and Source	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Energy Consumption								
Residential								
Distillate Fuel	0.89	0.89	0.85	0.79	0.77	0.74	0.72	-0.9%
Kerosene	0.07	0.08	0.08	0.07	0.07	0.07	0.07	-0.6%
Liquefied Petroleum Gas	0.40	0.42	0.45	0.47	0.49	0.50	0.51	0.8%
Petroleum Subtotal	1.36	1.40	1.38	1.34	1.33	1.32	1.30	-0.3%
Natural Gas	4.98	5.39	5.35	5.47	5.63	5.82	5.97	0.4%
Coal	0.05	0.05	0.06	0.05	0.05	0.05	0.05	-0.2%
Renewable Energy[1]	0.59	0.61	0.61	0.62	0.63	0.64	0.64	0.2%
Electricity	3.56	3.68	3.97	4.29	4.61	4.94	5.28	1.5%
Delivered Energy	**10.54**	**11.13**	**11.36**	**11.77**	**12.25**	**12.77**	**13.25**	**0.7%**
Electricity Related Losses	7.88	8.23	8.75	9.05	9.39	9.58	9.93	0.8%
Total	**18.42**	**19.36**	**20.11**	**20.81**	**21.64**	**22.35**	**23.17**	**0.8%**
Commercial								
Distillate Fuel	0.47	0.44	0.41	0.40	0.40	0.39	0.37	-0.7%
Residual Fuel	0.17	0.15	0.12	0.12	0.12	0.12	0.12	-0.9%
Kerosene	0.02	0.03	0.02	0.02	0.02	0.02	0.02	-0.2%
Liquefied Petroleum Gas	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.8%
Motor Gasoline[2]	0.07	0.03	0.03	0.03	0.03	0.02	0.02	-0.3%
Petroleum Subtotal	0.81	0.71	0.65	0.65	0.65	0.65	0.63	-0.5%
Natural Gas	3.11	3.30	3.47	3.62	3.75	3.85	3.85	0.7%
Coal	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.8%
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.1%
Electricity	3.26	3.37	3.59	3.84	4.09	4.33	4.45	1.2%
Delivered Energy	**7.26**	**7.47**	**7.80**	**8.21**	**8.60**	**8.92**	**9.04**	**0.8%**
Electricity Related Losses	7.21	7.54	7.91	8.09	8.35	8.39	8.37	0.4%
Total	**14.46**	**15.01**	**15.72**	**16.30**	**16.94**	**17.31**	**17.41**	**0.6%**
Industrial[4]								
Distillate Fuel	1.13	1.17	1.21	1.35	1.45	1.51	1.56	1.2%
Liquefied Petroleum Gas	2.00	2.12	2.14	2.25	2.40	2.45	2.47	0.6%
Petrochemical Feedstock	1.23	1.28	1.31	1.38	1.47	1.49	1.51	0.7%
Residual Fuel	0.37	0.34	0.35	0.35	0.35	0.34	0.35	0.1%
Motor Gasoline[2]	0.19	0.19	0.20	0.23	0.25	0.26	0.27	1.4%
Other Petroleum[5]	3.77	4.12	4.35	4.60	4.84	5.05	5.10	0.9%
Petroleum Subtotal	8.69	9.23	9.55	10.15	10.75	11.10	11.25	0.8%
Natural Gas[6]	9.91	10.14	10.94	11.16	11.67	11.77	11.80	0.6%
Metallurgical Coal	0.89	0.85	0.83	0.76	0.71	0.65	0.61	-1.4%
Steam Coal	1.60	1.55	1.56	1.70	1.77	1.78	1.79	0.6%
Net Coal Coke Imports	0.03	0.00	0.03	0.05	0.06	0.07	0.08	N/A
Coal Subtotal	2.51	2.40	2.42	2.51	2.54	2.51	2.48	0.1%
Renewable Energy[7]	1.74	1.82	1.96	2.11	2.25	2.31	2.34	1.0%
Electricity	3.46	3.46	3.69	4.05	4.37	4.58	4.75	1.3%
Delivered Energy	**26.30**	**27.05**	**28.57**	**29.97**	**31.58**	**32.27**	**32.62**	**0.8%**
Electricity Related Losses	7.65	7.74	8.14	8.53	8.92	8.88	8.93	0.6%
Total	**33.95**	**34.79**	**36.71**	**38.50**	**40.50**	**41.15**	**41.55**	**0.7%**

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

Sector and Source	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Transportation								
Distillate Fuel[8]	4.24	4.48	5.14	5.63	6.02	6.19	6.31	1.4%
Jet Fuel[9]	3.13	3.27	3.83	4.47	5.23	5.79	6.28	2.8%
Motor Gasoline[2]	14.65	14.94	15.96	17.17	18.22	18.84	19.38	1.1%
Residual Fuel	0.87	0.90	0.94	1.10	1.27	1.42	1.56	2.3%
Liquefied Petroleum Gas	0.03	0.03	0.04	0.10	0.16	0.20	0.24	8.7%
Other Petroleum[10]	0.28	0.29	0.31	0.33	0.35	0.37	0.37	1.1%
Petroleum Subtotal	23.21	23.91	26.22	28.81	31.25	32.80	34.14	1.5%
Pipeline Fuel Natural Gas	0.72	0.73	0.80	0.85	0.95	0.99	1.03	1.4%
Compressed Natural Gas	0.01	0.01	0.05	0.15	0.24	0.30	0.34	15.8%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.03	0.09	0.13	0.16	20.5%
Methanol[12]	0.00	0.00	0.00	0.03	0.08	0.13	0.15	20.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.7%
Electricity	0.06	0.06	0.06	0.11	0.16	0.19	0.22	5.6%
Delivered Energy	**24.00**	**24.72**	**27.14**	**29.97**	**32.77**	**34.54**	**36.04**	**1.6%**
Electricity Related Losses	0.13	0.13	0.14	0.23	0.32	0.37	0.41	4.9%
Total	**24.12**	**24.85**	**27.28**	**30.20**	**33.09**	**34.91**	**36.45**	**1.6%**
Delivered Energy Consumption for All Sectors								
Distillate Fuel	6.73	6.98	7.61	8.18	8.63	8.83	8.96	1.0%
Kerosene	0.11	0.13	0.12	0.11	0.11	0.11	0.11	-0.5%
Jet Fuel[9]	3.13	3.27	3.83	4.47	5.23	5.79	6.28	2.8%
Liquefied Petroleum Gas	2.50	2.65	2.71	2.90	3.13	3.24	3.31	0.9%
Motor Gasoline[2]	14.92	15.16	16.19	17.43	18.49	19.12	19.67	1.1%
Petrochemical Feedstock	1.23	1.28	1.31	1.38	1.47	1.49	1.51	0.7%
Residual Fuel	1.41	1.39	1.40	1.56	1.74	1.88	2.03	1.6%
Other Petroleum[13]	4.03	4.39	4.64	4.91	5.18	5.40	5.45	0.9%
Petroleum Subtotal	34.06	35.26	37.80	40.95	43.98	45.87	47.33	1.2%
Natural Gas[6]	18.73	19.56	20.61	21.24	22.25	22.72	22.99	0.7%
Metallurgical Coal	0.89	0.85	0.83	0.76	0.71	0.65	0.61	-1.4%
Steam Coal	1.73	1.68	1.70	1.84	1.92	1.93	1.94	0.6%
Net Coal Coke Imports	0.03	0.00	0.03	0.05	0.06	0.07	0.08	N/A
Coal Subtotal	2.64	2.53	2.56	2.65	2.69	2.66	2.63	0.2%
Renewable Energy[14]	2.33	2.44	2.58	2.76	2.96	3.08	3.15	1.1%
Methanol[12]	0.00	0.00	0.00	0.03	0.08	0.13	0.15	20.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.7%
Electricity	10.32	10.57	11.32	12.29	13.23	14.04	14.70	1.4%
Delivered Energy	**68.09**	**70.36**	**74.88**	**79.92**	**85.19**	**88.50**	**90.95**	**1.1%**
Electricity Related Losses	22.86	23.64	24.94	25.90	26.97	27.22	27.63	0.7%
Total	**90.95**	**94.01**	**99.82**	**105.82**	**112.17**	**115.72**	**118.58**	**1.0%**
Electric Generators[15]								
Distillate Fuel	0.13	0.09	0.08	0.07	0.07	0.07	0.07	-0.6%
Residual Fuel	0.55	0.66	0.47	0.30	0.28	0.25	0.24	-4.2%
Petroleum Subtotal	0.68	0.75	0.54	0.37	0.35	0.32	0.31	-3.6%
Natural Gas	3.44	3.04	4.14	5.69	7.38	8.71	10.07	5.1%
Steam Coal	17.31	18.36	19.57	20.55	21.34	22.29	22.99	0.9%
Nuclear Power	7.19	7.20	7.36	6.87	6.36	5.12	4.09	-2.3%
Renewable Energy[16]	4.08	4.47	4.24	4.37	4.46	4.53	4.59	0.1%
Electricity Imports[17]	0.39	0.39	0.41	0.34	0.31	0.28	0.28	-1.4%
Total	**33.09**	**34.21**	**36.26**	**38.19**	**40.20**	**41.26**	**42.33**	**0.9%**

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

Sector and Source	Reference Case 1995	1996	2000	2005	2010	2015	2020	Annual Growth 1996-2020 (percent)
Total Energy Consumption								
Distillate Fuel	6.86	7.07	7.68	8.25	8.70	8.90	9.04	1.0%
Kerosene	0.11	0.13	0.12	0.11	0.11	0.11	0.11	-0.5%
Jet Fuel[9]	3.13	3.27	3.83	4.47	5.23	5.79	6.28	2.8%
Liquefied Petroleum Gas	2.50	2.65	2.71	2.90	3.13	3.24	3.31	0.9%
Motor Gasoline[2]	14.92	15.16	16.19	17.43	18.49	19.12	19.67	1.1%
Petrochemical Feedstock	1.23	1.28	1.31	1.38	1.47	1.49	1.51	0.7%
Residual Fuel	1.96	2.05	1.87	1.86	2.02	2.14	2.27	0.4%
Other Petroleum[13]	4.03	4.39	4.64	4.91	5.18	5.40	5.45	0.9%
Petroleum Subtotal	34.74	36.01	38.35	41.32	44.33	46.20	47.64	1.2%
Natural Gas	22.18	22.60	24.74	26.93	29.63	31.44	33.06	1.6%
Metallurgical Coal	0.89	0.85	0.83	0.76	0.71	0.65	0.61	-1.4%
Steam Coal	19.05	20.05	21.28	22.40	23.26	24.22	24.92	0.9%
Net Coal Coke Imports	0.03	0.00	0.03	0.05	0.06	0.07	0.08	N/A
Coal Subtotal	19.96	20.90	22.14	23.21	24.03	24.95	25.61	0.9%
Nuclear Power	7.19	7.20	7.36	6.87	6.36	5.12	4.09	-2.3%
Renewable Energy[18]	6.40	6.91	6.82	7.12	7.42	7.62	7.74	0.5%
Methanol[12]	0.00	0.00	0.00	0.03	0.08	0.13	0.15	20.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.7%
Electricity Imports[17]	0.39	0.39	0.41	0.34	0.31	0.28	0.28	-1.4%
Total	**90.86**	**94.01**	**99.82**	**105.82**	**112.17**	**115.72**	**118.58**	**1.0%**
Energy Use and Related Statistics								
Delivered Energy Use	68.09	70.36	74.88	79.92	85.19	88.50	90.95	1.1%
Total Energy Use	90.86	94.01	99.82	105.82	112.16	115.71	118.55	1.0%
Population (millions)	263.58	266.07	275.62	287.12	298.92	311.19	323.47	0.8%
Gross Domestic Product (billion 1992 dollars)	6742.08	6928.40	7652.77	8503.48	9431.22	10210.71	10899.70	1.9%
Total Carbon Emissions (million metric tons)	1411.40	1462.90	1577.32	1688.76	1803.22	1888.33	1956.19	1.2%

[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.
[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.
[4]Fuel consumption includes consumption for cogeneration.
[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; including for cogeneration, both for sale to the grid and for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[12]Only M85 (85 percent methanol and 15 percent motor gasoline).
[13]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[17]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 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. Figures for 1995 and 1996 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1995 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1996 natural gas lease, plant, and pipeline fuel values: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). 1995 transportation sector compressed natural gas consumption: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A. 1995 and 1996 electric utility fuel consumption: EIA, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997). 1995 and 1996 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1995 values derived from: EIA, *State Energy Data Report 1994.* ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997), and Office of Coal, Nuclear, Electric,and Alternative Fuels estimates. Other 1996 values: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A3. Energy Prices by Sector and Source
(1996 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Residential	**13.02**	**12.94**	**12.45**	**12.31**	**12.21**	**11.91**	**11.97**	**-0.3%**
Primary Energy[1]	6.37	6.63	6.32	6.23	6.15	6.07	6.17	-0.3%
Petroleum Products[2]	7.63	8.51	8.67	9.20	9.42	9.54	9.70	0.5%
Distillate Fuel	6.39	7.09	7.15	7.47	7.55	7.64	7.71	0.3%
Liquefied Petroleum Gas	10.46	11.59	11.56	12.21	12.45	12.43	12.57	0.3%
Natural Gas	6.07	6.19	5.77	5.55	5.42	5.32	5.44	-0.5%
Electricity	25.00	24.65	22.93	22.04	21.43	20.40	20.01	-0.9%
Commercial	**12.77**	**12.92**	**12.33**	**11.84**	**11.63**	**11.19**	**11.15**	**-0.6%**
Primary Energy[1]	5.01	5.26	4.91	4.82	4.79	4.77	4.91	-0.3%
Petroleum Products[2]	5.11	5.56	5.54	5.87	6.02	6.12	6.25	0.5%
Distillate Fuel	4.49	5.27	5.23	5.53	5.65	5.75	5.86	0.4%
Residual Fuel	3.22	3.24	2.97	3.06	3.16	3.28	3.40	0.2%
Natural Gas[3]	5.07	5.28	4.88	4.71	4.66	4.62	4.77	-0.4%
Electricity	22.30	22.24	21.02	19.81	19.16	18.02	17.58	-1.0%
Industrial[4]	**4.97**	**5.40**	**4.92**	**5.04**	**5.15**	**5.10**	**5.21**	**-0.1%**
Primary Energy	3.41	4.03	3.59	3.79	3.97	4.04	4.20	0.2%
Petroleum Products[2]	4.97	5.68	4.96	5.32	5.53	5.55	5.70	0.0%
Distillate Fuel	4.72	5.50	5.24	5.56	5.74	5.88	6.07	0.4%
Liquefied Petroleum Gas	6.63	7.80	5.98	6.60	6.76	6.64	6.81	-0.6%
Residual Fuel	2.64	3.00	2.70	2.83	3.02	3.15	3.35	0.5%
Natural Gas[5]	2.37	2.96	2.73	2.77	2.93	3.00	3.17	0.3%
Metallurgical Coal	1.81	1.77	1.76	1.71	1.68	1.67	1.66	-0.3%
Steam Coal	1.50	1.46	1.41	1.36	1.33	1.31	1.30	-0.5%
Electricity	14.00	13.54	12.68	11.93	11.41	10.59	10.26	-1.1%
Transportation	**8.20**	**8.77**	**8.53**	**8.78**	**8.83**	**8.86**	**8.87**	**0.0%**
Primary Energy	8.18	8.76	8.52	8.76	8.81	8.84	8.85	0.0%
Petroleum Products[2]	8.18	8.76	8.52	8.77	8.80	8.82	8.82	0.0%
Distillate Fuel[6]	8.22	8.90	8.53	8.74	8.61	8.60	8.52	-0.2%
Jet Fuel[7]	4.18	5.52	5.12	5.58	5.85	6.05	6.27	0.5%
Motor Gasoline[8]	9.46	9.89	9.78	10.06	10.18	10.22	10.24	0.1%
Residual Fuel	2.33	2.55	2.61	2.85	3.07	3.14	3.32	1.1%
Liquid Petroleum Gas[9]	12.44	12.62	12.80	13.27	13.30	13.07	13.01	0.1%
Natural Gas[10]	5.41	5.41	5.46	5.72	6.60	7.06	7.39	1.3%
E85[11]	15.25	15.85	15.81	16.30	16.71	17.04	17.79	0.5%
Electricity	15.39	15.31	14.66	13.69	13.25	12.54	12.26	-0.9%
Average End-Use Energy	**8.29**	**8.68**	**8.26**	**8.33**	**8.35**	**8.28**	**8.35**	**-0.2%**
Primary Energy	7.91	8.35	7.94	8.05	8.09	8.04	8.11	-0.1%
Electricity	20.41	20.19	18.93	17.94	17.32	16.36	16.01	-1.0%
Electric Generators[12]								
Fossil Fuel Average	1.51	1.54	1.46	1.49	1.57	1.60	1.66	0.3%
Petroleum Products	2.94	3.28	3.21	3.57	3.84	4.00	4.21	1.1%
Distillate Fuel	4.01	4.90	4.84	5.16	5.33	5.47	5.64	0.6%
Residual Fuel	2.68	3.07	2.95	3.20	3.46	3.60	3.77	0.9%
Natural Gas	2.03	2.64	2.48	2.63	2.84	2.98	3.15	0.7%
Steam Coal	1.35	1.29	1.20	1.14	1.09	1.03	0.97	-1.2%

Table A3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case 1995	1996	2000	2005	2010	2015	2020	Annual Growth 1996-2020 (percent)
Average Price to All Users[13]								
Petroleum Products[2]	7.26	7.86	7.59	7.92	8.02	8.06	8.12	0.1%
Distillate Fuel	7.08	7.84	7.65	7.92	7.88	7.91	7.90	0.0%
Jet Fuel	4.18	5.52	5.12	5.58	5.85	6.05	6.27	0.5%
Liquefied Petroleum Gas	7.38	8.53	7.12	7.84	8.09	8.05	8.24	-0.1%
Motor Gasoline[8]	9.46	9.89	9.76	10.05	10.16	10.21	10.23	0.1%
Residual Fuel	2.56	2.84	2.73	2.92	3.12	3.21	3.38	0.7%
Natural Gas	3.63	4.13	3.74	3.66	3.70	3.72	3.86	-0.3%
Coal	1.38	1.32	1.22	1.16	1.11	1.05	1.00	-1.2%
E85[11]	15.25	15.85	15.81	16.30	16.71	17.04	17.79	0.5%
Electricity	20.41	20.19	18.93	17.94	17.32	16.36	16.01	-1.0%
Non-Renewable Energy Expenditures by Sector (Billion 1996 dollars)								
Residential	113.43	117.09	118.69	124.21	130.36	134.72	143.05	0.8%
Commercial	92.62	96.47	96.19	97.11	99.96	99.87	100.74	0.2%
Industrial	122.76	136.22	130.95	140.45	151.07	152.83	157.75	0.6%
Transportation	190.86	210.35	224.71	254.98	278.70	293.73	306.35	1.6%
Total Non-Renewable Expenditures	519.68	560.12	570.54	616.74	660.09	681.15	707.89	1.0%
Transportation Renewable Expenditures	0.02	0.03	0.05	0.45	1.47	2.25	2.79	21.1%
Total Expenditures	**519.70**	**560.15**	**570.59**	**617.19**	**661.57**	**683.40**	**710.68**	**1.0%**

[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 uses for lease and plant fuel.
[6] Low sulfur diesel fuel. 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 and State taxes and excludes county 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.
[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: 1995 and 1996 figures may differ from published data due to internal rounding.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1995.* Online. http://www.eia.doe.gov/oil-gas/pmal/pmaframe.html (May 30, 1997). 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/13-97/4) (Washington, DC, 1996-97). 1995 and 1996 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). 1995 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 electric generators natural gas delivered prices: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1995 and 1996 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1996 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). Other 1996 natural gas delivered prices: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A. Values for 1995 and 1996 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997) and the *Coal Industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997). 1995 residential electricity prices derived from EIA, *Short Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). 1995 and 1996 electricity prices for commercial, industrial, and transportation: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Key Indicators								
Households (millions)								
Single-Family	68.66	69.61	73.26	77.46	81.54	85.60	89.52	1.1%
Multifamily	24.56	24.76	25.54	26.54	27.92	29.44	30.84	0.9%
Mobile Homes	5.84	6.00	6.54	7.08	7.58	8.01	8.35	1.4%
Total	**99.06**	**100.37**	**105.34**	**111.08**	**117.04**	**123.05**	**128.71**	**1.0%**
Average House Square Footage	**1643**	**1649**	**1669**	**1689**	**1704**	**1716**	**1728**	**0.2%**
Energy Intensity								
(million Btu consumed per household)								
Delivered Energy Consumption	106.41	110.90	107.87	105.95	104.63	103.79	102.91	-0.3%
Electricity Related Losses	80.78	83.37	83.92	82.23	80.73	78.15	77.20	-0.3%
Total Energy Consumption	187.19	194.27	191.79	188.18	185.37	181.95	180.11	-0.3%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.44	0.47	0.46	0.48	0.50	0.51	0.53	0.5%
Space Cooling	0.49	0.46	0.48	0.51	0.54	0.58	0.60	1.1%
Water Heating	0.36	0.36	0.36	0.36	0.38	0.39	0.40	0.5%
Refrigeration	0.41	0.41	0.36	0.31	0.28	0.27	0.27	-1.6%
Cooking	0.13	0.13	0.13	0.14	0.15	0.16	0.17	1.0%
Clothes Dryers	0.19	0.19	0.20	0.21	0.22	0.24	0.25	1.1%
Freezers	0.13	0.13	0.11	0.09	0.08	0.07	0.07	-2.4%
Lighting	0.33	0.34	0.35	0.36	0.39	0.42	0.45	1.2%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.8%
Dishwashers[1]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.6%
Color Televisions	0.19	0.21	0.25	0.30	0.32	0.35	0.37	2.5%
Personal Computers	0.01	0.01	0.01	0.02	0.02	0.02	0.03	5.3%
Furnace Fans	0.11	0.12	0.13	0.14	0.15	0.16	0.18	1.7%
Other Uses[2]	0.71	0.78	1.06	1.29	1.49	1.68	1.86	3.7%
Delivered Energy	**3.56**	**3.68**	**3.97**	**4.29**	**4.61**	**4.94**	**5.28**	**1.5%**
Natural Gas								
Space Heating	3.45	3.76	3.72	3.78	3.87	3.97	4.04	0.3%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.1%
Water Heating	1.24	1.32	1.32	1.37	1.43	1.49	1.55	0.7%
Cooking	0.15	0.16	0.16	0.17	0.17	0.18	0.19	0.6%
Clothes Dryers	0.05	0.05	0.05	0.05	0.06	0.06	0.06	1.0%
Other Uses[3]	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.8%
Delivered Energy	**4.98**	**5.39**	**5.35**	**5.47**	**5.63**	**5.82**	**5.97**	**0.4%**
Distillate								
Space Heating	0.80	0.80	0.75	0.70	0.67	0.64	0.62	-1.0%
Water Heating	0.09	0.09	0.10	0.09	0.10	0.10	0.10	0.1%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.6%
Delivered Energy	**0.89**	**0.89**	**0.85**	**0.79**	**0.77**	**0.74**	**0.72**	**-0.9%**
Liquefied Petroleum Gas								
Space Heating	0.29	0.31	0.33	0.33	0.34	0.35	0.35	0.5%
Water Heating	0.07	0.07	0.08	0.09	0.10	0.10	0.11	1.8%
Cooking	0.03	0.03	0.04	0.04	0.04	0.04	0.04	1.1%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.5%
Delivered Energy	**0.40**	**0.42**	**0.45**	**0.47**	**0.49**	**0.50**	**0.51**	**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 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Delivered Energy Consumption by End-Use								
Space Heating	5.69	6.09	6.00	6.04	6.13	6.24	6.31	0.1%
Space Cooling	0.49	0.46	0.48	0.52	0.55	0.58	0.61	1.2%
Water Heating	1.76	1.84	1.86	1.91	1.99	2.08	2.17	0.7%
Refrigeration	0.41	0.41	0.36	0.31	0.28	0.27	0.27	-1.6%
Cooking	0.31	0.33	0.33	0.35	0.36	0.38	0.40	0.8%
Clothes Dryers	0.23	0.24	0.25	0.26	0.28	0.30	0.32	1.1%
Freezers	0.13	0.13	0.11	0.09	0.08	0.07	0.07	-2.4%
Lighting	0.33	0.34	0.35	0.36	0.39	0.42	0.45	1.2%
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.8%
Dishwashers	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.6%
Color Televisions	0.19	0.21	0.25	0.30	0.32	0.35	0.37	2.5%
Personal Computers	0.01	0.01	0.01	0.02	0.02	0.02	0.03	5.3%
Furnace Fans	0.11	0.12	0.13	0.14	0.15	0.16	0.18	1.7%
Other Uses[7]	0.80	0.89	1.17	1.40	1.61	1.80	1.99	3.4%
Delivered Energy	**10.54**	**11.13**	**11.36**	**11.77**	**12.25**	**12.77**	**13.25**	**0.7%**
Electricity Related Losses	**7.88**	**8.23**	**8.75**	**9.05**	**9.39**	**9.58**	**9.93**	**0.8%**
Total Energy Consumption by End-Use								
Space Heating	6.65	7.13	7.03	7.06	7.15	7.24	7.30	0.1%
Space Cooling	1.57	1.50	1.54	1.60	1.66	1.70	1.74	0.6%
Water Heating	2.55	2.66	2.64	2.68	2.76	2.84	2.93	0.4%
Refrigeration	1.32	1.32	1.15	0.97	0.86	0.80	0.79	-2.1%
Cooking	0.59	0.62	0.63	0.65	0.67	0.69	0.72	0.6%
Clothes Dryers	0.64	0.67	0.68	0.70	0.73	0.76	0.79	0.7%
Freezers	0.43	0.42	0.34	0.27	0.23	0.21	0.21	-2.9%
Lighting	1.05	1.09	1.12	1.12	1.20	1.24	1.30	0.7%
Clothes Washers	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.3%
Dishwashers	0.15	0.15	0.14	0.14	0.14	0.15	0.16	0.2%
Color Televisions	0.62	0.67	0.81	0.93	0.98	1.02	1.08	2.0%
Personal Computers	0.02	0.03	0.04	0.05	0.06	0.07	0.08	4.8%
Furnace Fans	0.36	0.38	0.41	0.43	0.46	0.48	0.51	1.2%
Other Uses[7]	2.37	2.64	3.50	4.13	4.64	5.06	5.48	3.1%
Total	**18.42**	**19.36**	**20.11**	**20.81**	**21.64**	**22.35**	**23.17**	**0.8%**
Non-Marketed Renewables								
Geothermal[8]	0.01	0.01	0.02	0.03	0.04	0.05	0.06	7.1%
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.3%
Total	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**0.07**	**5.0%**

[1]Does not include water heating 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 1993*.
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 and 1996: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Key Indicators								
Total Floor Space (billion square feet)								
Surviving	68.5	69.2	73.1	77.3	81.1	84.3	85.7	0.9%
New Additions	1.6	1.7	1.8	1.7	1.7	1.5	1.1	-1.7%
Total	**70.1**	**70.9**	**74.9**	**79.0**	**82.8**	**85.8**	**86.8**	**0.8%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	103.6	105.3	104.2	103.8	103.8	104.0	104.2	-0.0%
Electricity Related Losses	102.9	106.3	105.7	102.4	100.8	97.7	96.4	-0.4%
Total Energy Consumption	206.5	211.5	209.9	206.2	204.5	201.7	200.5	-0.2%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.12	0.12	0.12	0.13	0.14	0.15	0.15	0.9%
Space Cooling	0.57	0.51	0.53	0.54	0.55	0.56	0.56	0.4%
Water Heating	0.17	0.17	0.17	0.16	0.15	0.15	0.14	-0.8%
Ventilation	0.17	0.17	0.17	0.18	0.18	0.19	0.18	0.4%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-1.0%
Lighting	1.14	1.15	1.20	1.22	1.24	1.27	1.28	0.4%
Refrigeration	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.7%
Office Equipment (PC)	0.07	0.07	0.07	0.08	0.09	0.09	0.10	1.6%
Office Equipment (non-PC)	0.19	0.19	0.21	0.24	0.27	0.30	0.33	2.2%
Other Uses[1]	0.66	0.82	0.95	1.12	1.29	1.43	1.53	2.6%
Delivered Energy	**3.26**	**3.37**	**3.59**	**3.84**	**4.09**	**4.33**	**4.45**	**1.2%**
Natural Gas[2]								
Space Heating	1.29	1.34	1.33	1.37	1.40	1.42	1.40	0.2%
Space Cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.6%
Water Heating	0.46	0.45	0.47	0.50	0.52	0.54	0.55	0.8%
Cooking	0.18	0.18	0.20	0.21	0.22	0.23	0.23	1.1%
Other Uses[3]	1.17	1.31	1.44	1.52	1.59	1.64	1.65	1.0%
Delivered Energy	**3.11**	**3.30**	**3.47**	**3.62**	**3.75**	**3.85**	**3.85**	**0.7%**
Distillate								
Space Heating	0.20	0.20	0.19	0.18	0.18	0.17	0.15	-1.0%
Water Heating	0.05	0.05	0.05	0.05	0.05	0.04	0.04	-1.1%
Other Uses[4]	0.22	0.19	0.17	0.17	0.18	0.18	0.18	-0.3%
Delivered Energy	**0.47**	**0.44**	**0.41**	**0.40**	**0.40**	**0.39**	**0.37**	**-0.7%**
Other Fuels[5]	**0.42**	**0.36**	**0.33**	**0.34**	**0.35**	**0.36**	**0.36**	**0.0%**
Marketed Renewable Fuels								
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.1%
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.1%**
Delivered Energy Consumption by End-Use								
Space Heating	1.60	1.65	1.65	1.68	1.71	1.73	1.70	0.1%
Space Cooling	0.60	0.53	0.55	0.56	0.57	0.58	0.58	0.4%
Water Heating	0.68	0.68	0.69	0.70	0.72	0.73	0.73	0.3%
Ventilation	0.17	0.17	0.17	0.18	0.18	0.19	0.18	0.4%
Cooking	0.21	0.21	0.23	0.24	0.25	0.26	0.26	0.8%
Lighting	1.14	1.15	1.20	1.22	1.24	1.27	1.28	0.4%
Refrigeration	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.7%
Office Equipment (PC)	0.07	0.07	0.07	0.08	0.09	0.09	0.10	1.6%
Office Equipment (non-PC)	0.19	0.19	0.21	0.24	0.27	0.30	0.33	2.2%
Other Uses[6]	2.47	2.68	2.89	3.16	3.41	3.61	3.71	1.4%
Delivered Energy	**7.26**	**7.47**	**7.80**	**8.21**	**8.60**	**8.92**	**9.04**	**0.8%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Electricity Related Losses	**7.21**	**7.54**	**7.91**	**8.09**	**8.35**	**8.39**	**8.37**	**0.4%**
Total Energy Consumption by End-Use								
Space Heating	1.85	1.92	1.92	1.96	1.99	2.01	1.98	0.1%
Space Cooling	1.87	1.66	1.71	1.69	1.69	1.67	1.63	-0.1%
Water Heating	1.07	1.06	1.05	1.04	1.04	1.02	1.00	-0.2%
Ventilation	0.54	0.54	0.55	0.55	0.56	0.54	0.53	-0.1%
Cooking	0.28	0.28	0.29	0.30	0.31	0.31	0.31	0.3%
Lighting	3.67	3.73	3.83	3.78	3.77	3.74	3.67	-0.1%
Refrigeration	0.45	0.45	0.47	0.47	0.48	0.48	0.48	0.2%
Office Equipment (PC)	0.22	0.22	0.23	0.24	0.26	0.27	0.29	1.2%
Office Equipment (non-PC)	0.60	0.62	0.68	0.74	0.82	0.88	0.94	1.7%
Other Uses[6]	3.92	4.51	4.98	5.52	6.03	6.39	6.58	1.6%
Total	**14.46**	**15.01**	**15.72**	**16.30**	**16.94**	**17.31**	**17.41**	**0.6%**
Non-Marketed Renewable Fuels								
Solar[7]	0.01	0.01	0.02	0.03	0.03	0.04	0.04	4.2%
Total	**0.01**	**0.01**	**0.02**	**0.03**	**0.03**	**0.04**	**0.04**	**4.2%**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medcal equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1995 and 1996 Energy Information Administration (EIA), *Short-Term Energy Outlook , August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Key Indicators								
Value of Gross Output (billion 1987 dollars)								
Manufacturing	2950	3030	3324	3801	4318	4646	4957	2.1%
Nonmanufacturing	759	774	835	897	969	1019	1062	1.3%
Total	**3709**	**3805**	**4159**	**4698**	**5287**	**5665**	**6019**	**1.9%**
Energy Prices (1996 dollars per million Btu)								
Electricity	14.00	13.54	12.68	11.93	11.41	10.59	10.26	-1.1%
Natural Gas	2.37	2.96	2.73	2.77	2.93	3.00	3.17	0.3%
Steam Coal	1.50	1.46	1.41	1.36	1.33	1.31	1.30	-0.5%
Residual Oil	2.64	3.00	2.70	2.83	3.02	3.15	3.35	0.5%
Distillate Oil	4.72	5.50	5.24	5.56	5.74	5.88	6.07	0.4%
Liquefied Petroleum Gas	6.63	7.80	5.98	6.60	6.76	6.64	6.81	-0.6%
Motor Gasoline	9.40	9.86	8.46	8.91	9.17	9.40	9.56	-0.1%
Metallurgical Coal	1.81	1.77	1.76	1.71	1.68	1.67	1.66	-0.3%
Energy Consumption								
Consumption[1]								
Purchased Electricity	3.46	3.46	3.69	4.05	4.37	4.58	4.75	1.3%
Natural Gas[2]	9.91	10.14	10.94	11.16	11.67	11.77	11.80	0.6%
Steam Coal	1.60	1.55	1.56	1.70	1.77	1.78	1.79	0.6%
Metallurgical Coal and Coke[3]	0.91	0.85	0.86	0.81	0.77	0.73	0.69	-0.9%
Residual Fuel	0.37	0.34	0.35	0.35	0.35	0.34	0.35	0.1%
Distillate	1.13	1.17	1.21	1.35	1.45	1.51	1.56	1.2%
Liquefied Petroleum Gas	2.00	2.12	2.14	2.25	2.40	2.45	2.47	0.6%
Petrochemical Feedstocks	1.23	1.28	1.31	1.38	1.47	1.49	1.51	0.7%
Other Petroleum[4]	3.96	4.31	4.55	4.83	5.09	5.31	5.36	0.9%
Renewables[5]	1.74	1.82	1.96	2.11	2.25	2.31	2.34	1.0%
Delivered Energy	**26.30**	**27.05**	**28.57**	**29.97**	**31.58**	**32.27**	**32.62**	**0.8%**
Electricity Related Losses	7.65	7.74	8.14	8.53	8.92	8.88	8.93	0.6%
Total	**33.95**	**34.79**	**36.71**	**38.50**	**40.50**	**41.15**	**41.55**	**0.7%**
Consumption per Unit of Output[1] **(thousand Btu per 1987 dollars)**								
Purchased Electricity	0.93	0.91	0.89	0.86	0.83	0.81	0.79	-0.6%
Natural Gas[2]	2.67	2.66	2.63	2.37	2.21	2.08	1.96	-1.3%
Steam Coal	0.43	0.41	0.38	0.36	0.34	0.31	0.30	-1.3%
Metallurgical Coal and Coke[3]	0.25	0.22	0.21	0.17	0.15	0.13	0.11	-2.7%
Residual Fuel	0.10	0.09	0.08	0.07	0.07	0.06	0.06	-1.8%
Distillate	0.30	0.31	0.29	0.29	0.27	0.27	0.26	-0.7%
Liquefied Petroleum Gas	0.54	0.56	0.51	0.48	0.45	0.43	0.41	-1.3%
Petrochemical Feedstocks	0.33	0.34	0.31	0.29	0.28	0.26	0.25	-1.2%
Other Petroleum[4]	1.07	1.13	1.09	1.03	0.96	0.94	0.89	-1.0%
Renewables[5]	0.47	0.48	0.47	0.45	0.42	0.41	0.39	-0.9%
Delivered Energy	**7.09**	**7.11**	**6.87**	**6.38**	**5.97**	**5.70**	**5.42**	**-1.1%**
Electricity Related Losses	2.06	2.04	1.96	1.82	1.69	1.57	1.48	-1.3%
Total	**9.15**	**9.14**	**8.83**	**8.20**	**7.66**	**7.26**	**6.90**	**-1.2%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[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.

Sources: 1995 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1995*, DOE/EIA-0487(95) (Washington, DC, September 1996). 1996 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996 - 97). 1995 and 1996 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). 1995 and 1996 electricity prices: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A. Other 1995 values and 1996 prices derived from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). Other 1996 values: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Key Indicators								
Level of Travel (billions)								
Light-Duty Vehicles <8,500 lbs. (VMT)	2150	2275	2454	2665	2892	3077	3242	1.5%
Commercial Light Trucks (VMT)[1]	66	67	72	80	87	93	98	1.6%
Freight Trucks >10,000 lbs. (VMT)	152	161	188	212	232	243	250	1.8%
Air (seat miles available)	937	999	1230	1518	1855	2139	2416	3.7%
Rail (ton miles traveled)	1275	1204	1334	1432	1533	1584	1623	1.3%
Marine (ton miles traveled)	774	777	815	868	923	949	967	0.9%
Energy Efficiency Indicators								
New Car (miles per gallon)[2]	27.7	27.9	28.0	29.5	30.2	30.5	30.7	0.4%
New Light Truck (miles per gallon)[2]	20.4	20.7	19.3	19.8	20.1	20.5	21.1	0.1%
Light-Duty Fleet (miles per gallon)[3]	20.0	20.2	20.3	20.2	20.3	20.7	21.2	0.2%
New Commercial Light Truck (MPG)[1]	19.9	20.2	18.9	19.4	19.6	20.0	20.6	0.1%
Stock Commercial Light Truck (MPG)[1]	14.3	14.5	14.7	14.9	15.0	15.2	15.4	0.3%
Aircraft Efficiency (seat miles per gallon)	50.2	50.6	52.1	53.9	55.7	57.4	59.0	0.6%
Freight Truck Efficiency (miles per gallon)	5.6	5.6	5.7	5.9	6.0	6.0	6.1	0.4%
Rail Efficiency (ton miles per thousand Btu)	2.7	2.7	2.8	2.8	2.9	3.0	3.0	0.5%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.7	2.7	2.8	2.9	3.0	3.0	0.5%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	13.63	13.96	15.04	16.48	17.76	18.55	19.20	1.3%
Commercial Light Trucks[1]	0.58	0.58	0.62	0.67	0.73	0.76	0.79	1.3%
Freight Trucks [4]	3.84	4.02	4.54	4.99	5.32	5.47	5.58	1.4%
Air	3.18	3.32	3.87	4.52	5.27	5.84	6.35	2.7%
Rail	0.55	0.52	0.57	0.59	0.62	0.63	0.63	0.8%
Marine	1.39	1.43	1.51	1.71	1.91	2.09	2.25	1.9%
Pipeline Fuel	0.72	0.73	0.80	0.85	0.95	0.99	1.03	1.4%
Other[5]	0.24	0.25	0.27	0.29	0.31	0.32	0.33	1.3%
Total	**24.00**	**24.72**	**27.14**	**29.97**	**32.77**	**34.54**	**36.04**	**1.6%**

[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.
[5]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 values: Federal Highway Administration, *Highway Statistics 1995* (Washington, DC, 1995); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, 15, 16*, and 17 (Oak Ridge, TN, August 1997); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1994-2007*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 1996); EIA, *Residential Transportation Energy Consumption Survey 1991*, DOE/EIA-0464(91) (Washington, DC, December 1993); U.S. Dept. of Commerce, Bureau of the Census, "Truck Inventory and Use Survey", TC92-T-52, (Washington D.C., May 1995); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, D.C., March 1996); EIA, *Alternatives To Traditional Transportation Fuels 1994*, DOE/EIA-0585(94) (Washington, DC, February 1996); and EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). 1996: FAA, *FAA Aviation Forecasts Fiscal Years 1996-2007*, (Washington, DC, February 1995); EIA, *Short-Term Energy Outlook, August 1997*, Online. http://ww.eia.doe.gov/emeu/steo/pub/upd /aug97/index.html (August 21, 1997); EIA, *Fuel Oil and Kerosene Sales 1996*, DOE/EIA-0535(96) (Washington, DC, September 1997); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Generation by Fuel Type								
Electric Generators[1]								
Coal	1671	1758	1903	2007	2085	2190	2265	1.1%
Petroleum	64	80	54	37	35	33	32	-3.8%
Natural Gas	322	288	419	671	920	1171	1389	6.8%
Nuclear Power	673	675	689	643	596	480	383	-2.3%
Pumped Storage	-2	-2	-3	-3	-3	-3	-3	1.3%
Renewable Sources[2]	354	392	370	377	382	388	393	0.0%
Total	**3083**	**3191**	**3432**	**3732**	**4015**	**4258**	**4459**	**1.4%**
Non-Utility Generation for Own Use	26	26	26	26	26	26	26	0.0%
Cogenerators[3]								
Coal	37	39	37	38	39	39	39	-0.1%
Petroleum	5	6	6	6	6	6	6	0.2%
Natural Gas	170	174	184	192	201	200	194	0.5%
Other Gaseous Fuels[4]	7	7	7	7	7	7	7	0.0%
Renewable Sources[2]	37	41	42	43	43	43	42	0.1%
Other[5]	3	3	3	3	4	4	3	0.2%
Total	**259**	**270**	**278**	**289**	**299**	**299**	**291**	**0.3%**
Sales to Utilities	119	121	124	125	127	127	126	0.2%
Generation for Own Use	140	149	155	163	172	172	165	0.4%
Net Imports[6]	**38**	**38**	**39**	**33**	**30**	**27**	**27**	**-1.4%**
Electricity Sales by Sector								
Residential	1042	1079	1164	1258	1350	1449	1548	1.5%
Commercial	954	988	1053	1125	1200	1268	1304	1.2%
Industrial	1013	1014	1083	1186	1282	1343	1392	1.3%
Transportation	17	17	19	32	46	55	64	5.6%
Total	**3026**	**3098**	**3318**	**3601**	**3877**	**4115**	**4308**	**1.4%**
End-Use Prices (1996 cents per kilowatthour)[7]								
Residential	8.5	8.4	7.8	7.5	7.3	7.0	6.8	-0.9%
Commercial	7.6	7.6	7.2	6.8	6.5	6.1	6.0	-1.0%
Industrial	4.8	4.6	4.3	4.1	3.9	3.6	3.5	-1.1%
Transportation	5.2	5.2	5.0	4.7	4.5	4.3	4.2	-0.9%
All Sectors Average	**7.0**	**6.9**	**6.5**	**6.1**	**5.9**	**5.6**	**5.5**	**-1.0%**

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.

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

[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.

[4]Other gaseous fuels include refinery and still gas.

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

[6]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.

[7]Prices represent average revenue per kilowatthour.

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

Sources: 1995 and 1996 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 16* (July 1996) which indicates the transportation value should be higher. 1995 and 1996 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1995 and 1996 residential electricity prices derived from EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **1995 and 1996 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Electric Generators[2]								
Capability								
Coal Steam	305.5	305.3	296.8	302.1	304.6	316.0	323.6	0.2%
Other Fossil Steam[3]	139.3	138.1	121.3	103.6	101.0	97.1	96.0	-1.5%
Combined Cycle	14.7	15.3	27.7	71.3	106.5	154.9	186.5	11.0%
Combustion Turbine/Diesel	55.4	80.0	140.4	176.2	191.4	210.1	221.9	4.3%
Nuclear Power	99.6	100.8	95.6	86.8	80.4	63.9	49.2	-2.9%
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	88.5	88.6	91.3	92.9	93.6	94.7	95.7	0.3%
Total	**722.9**	**748.0**	**792.8**	**852.7**	**897.3**	**956.7**	**992.8**	**1.2%**
Cumulative Planned Additions[5]								
Coal Steam	1.2	2.4	3.2	3.2	4.7	4.7	4.7	3.0%
Other Fossil Steam[3]	0.0	0.0	0.1	0.1	0.1	0.1	0.1	2.2%
Combined Cycle	1.4	2.0	2.7	2.7	3.0	3.0	3.0	1.5%
Combustion Turbine/Diesel	2.8	3.8	5.2	5.2	5.2	5.2	5.2	1.3%
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	N/A
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.7	0.7	2.9	3.1	3.2	3.2	3.2	6.3%
Total	**7.4**	**11.3**	**16.3**	**16.6**	**18.5**	**18.5**	**18.5**	**2.1%**
Cumulative Unplanned Additions[5]								
Coal Steam	0.0	0.0	0.0	13.3	16.9	32.1	45.4	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	11.1	54.7	89.7	138.1	169.7	N/A
Combustion Turbine/Diesel	0.0	23.6	82.7	119.1	134.6	154.5	166.3	8.5%
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.4	0.5	0.7	2.0	2.8	4.2	5.4	10.8%
Total	**0.4**	**24.1**	**94.4**	**189.1**	**244.0**	**328.9**	**386.7**	**12.3%**
Cumulative Total Additions	**7.8**	**35.4**	**110.8**	**205.6**	**262.5**	**347.4**	**405.2**	**10.7%**
Cumulative Retirements[6]	**11.9**	**14.4**	**45.9**	**80.1**	**92.4**	**117.1**	**138.8**	**9.9%**

Table A9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Cogenerators[7]								
Capability								
Coal	7.1	7.1	7.3	7.5	7.7	7.7	7.7	0.3%
Petroleum	1.0	1.0	1.1	1.1	1.2	1.2	1.2	0.6%
Natural Gas	27.4	28.0	30.5	31.6	32.7	32.7	31.9	0.5%
Other Gaseous Fuels	1.1	1.2	1.1	1.1	1.1	1.1	1.1	-0.1%
Renewable Sources[4]	5.8	5.8	6.4	6.5	6.6	6.6	6.4	0.4%
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**42.4**	**43.0**	**46.4**	**47.9**	**49.3**	**49.3**	**48.3**	**0.5%**
Cumulative Additions[5]	**7.4**	**8.1**	**11.4**	**12.9**	**14.4**	**14.3**	**13.4**	**2.1%**

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.
[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]Cumulative additions after December 31, 1995. Non-zero utility planned additions in 1995 indicate units operational in 1995 but not supplying power to the grid.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
N/A = Not applicable.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 25, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1995 and 1996 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1995 and 1996 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Interregional Electricity Trade								
Gross Domestic Firm Power Sales	155.0	173.4	149.3	139.2	139.2	139.2	139.2	-0.9%
Gross Domestic Economy Sales	93.2	79.5	74.5	67.7	78.3	79.7	86.6	0.4%
Gross Domestic Trade	**248.2**	**252.9**	**223.9**	**207.0**	**217.5**	**218.9**	**225.8**	**-0.5%**
Gross Domestic Firm Power Sales (million 1996 dollars)	7194.8	8050.2	6932.3	6462.9	6462.9	6462.9	6462.9	-0.9%
Gross Domestic Economy Sales (million 1996 dollars)	2483.8	1812.7	1514.1	1446.9	1747.9	1712.8	1905.6	0.2%
Gross Domestic Sales (million 1996 dollars)	**9678.5**	**9862.9**	**8446.4**	**7909.8**	**8210.8**	**8175.6**	**8368.5**	**-0.7%**
International Electricity Trade								
Firm Power Imports From Canada and Mexico[1]	30.3	26.1	32.0	17.8	17.8	17.8	17.8	-1.6%
Economy Imports From Canada and Mexico[1]	18.0	20.7	22.2	35.7	33.6	30.1	30.1	1.6%
Gross Imports From Canada and Mexico[1]	**48.3**	**46.8**	**54.2**	**53.4**	**51.4**	**47.9**	**47.9**	**0.1%**
Firm Power Exports To Canada and Mexico	3.4	2.8	8.3	13.4	13.4	13.4	13.4	6.7%
Economy Exports To Canada and Mexico	7.2	6.4	6.4	7.0	7.7	7.7	7.7	0.7%
Gross Exports To Canada and Mexico	**10.7**	**9.3**	**14.7**	**20.3**	**21.0**	**21.0**	**21.0**	**3.5%**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier inaccordance with prior agreements or under specified conditions.

Sources: 1995 and 1996 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1995 and 1996 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993*. Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference 1995	1996	2000	2005	2010	2015	2020	Annual Growth 1996-2020 (percent)
Crude Oil								
Domestic Crude Production[1]	6.56	6.48	6.17	5.82	5.57	5.24	4.92	-1.1%
Alaska	1.48	1.40	1.13	0.93	0.75	0.60	0.48	-4.3%
Lower 48 States	5.08	5.08	5.04	4.89	4.82	4.64	4.44	-0.6%
Net Imports	7.14	7.40	8.75	10.14	10.67	11.22	11.65	1.9%
Other Crude Supply[2]	0.28	0.33	0.00	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**13.98**	**14.21**	**14.92**	**15.96**	**16.24**	**16.46**	**16.58**	**0.6%**
Natural Gas Plant Liquids	**1.76**	**1.83**	**1.87**	**2.02**	**2.24**	**2.35**	**2.47**	**1.3%**
Other Inputs[3]	**0.49**	**0.39**	**0.32**	**0.29**	**0.25**	**0.22**	**0.20**	**-2.7%**
Refinery Processing Gain[4]	**0.77**	**0.84**	**0.86**	**0.89**	**0.89**	**0.87**	**0.82**	**-0.1%**
Net Product Imports[5]	**0.75**	**1.10**	**1.42**	**1.96**	**3.00**	**3.70**	**4.33**	**5.9%**
Total Primary Supply[6]	**17.75**	**18.37**	**19.39**	**21.12**	**22.63**	**23.60**	**24.40**	**1.2%**
Refined Petroleum Products Supplied								
Motor Gasoline[7]	7.83	7.99	8.52	9.18	9.75	10.10	10.39	1.1%
Jet Fuel[8]	1.51	1.58	1.85	2.16	2.53	2.80	3.03	2.8%
Distillate Fuel[9]	3.23	3.32	3.61	3.88	4.09	4.19	4.25	1.0%
Residual Fuel	0.85	0.90	0.81	0.81	0.88	0.93	0.99	0.4%
Other[10]	4.34	4.66	4.82	5.11	5.45	5.64	5.72	0.9%
Total	**17.73**	**18.44**	**19.62**	**21.15**	**22.70**	**23.65**	**24.39**	**1.2%**
Refined Petroleum Products Supplied								
Residential and Commercial	1.15	1.13	1.11	1.09	1.09	1.09	1.08	-0.2%
Industrial[11]	4.58	4.87	5.02	5.33	5.65	5.82	5.89	0.8%
Transportation	11.79	12.11	13.26	14.57	15.81	16.60	17.27	1.5%
Electric Generators[12]	0.30	0.33	0.24	0.16	0.16	0.14	0.14	-3.5%
Total	**17.73**	**18.44**	**19.62**	**21.15**	**22.70**	**23.65**	**24.39**	**1.2%**
Discrepancy[13]	**-0.01**	**-0.08**	**-0.23**	**-0.03**	**-0.08**	**-0.05**	**0.01**	**N/A**
World Oil Price (1996 dollars per barrel)[14]	**17.58**	**20.48**	**19.11**	**20.19**	**20.81**	**21.48**	**22.32**	**0.4%**
Import Share of Product Supplied	**0.44**	**0.46**	**0.52**	**0.57**	**0.60**	**0.63**	**0.66**	**1.5%**
Net Expenditures for Imported Crude Oil and Products (billion 1996 dollars)	**50.34**	**62.27**	**71.35**	**90.49**	**106.39**	**120.20**	**133.54**	**3.2%**
Domestic Refinery Distillation Capacity	**15.4**	**15.4**	**15.9**	**16.8**	**17.1**	**17.4**	**17.5**	**0.5%**
Capacity Utilization Rate (percent)	**92.0**	**94.0**	**94.1**	**95.1**	**95.2**	**95.2**	**95.2**	**0.1%**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[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]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 and 1996 expenditures for imported crude oil and petroleum products based on internal calculations. 1995 and 1996 product supplied data from Table A2. Other 1995 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). Other 1996 data: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A12. Petroleum Product Prices
(1996 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference 1995	1996	2000	2005	2010	2015	2020	Annual Growth 1996-2020 (percent)
World Oil Price (1996 dollars per barrel)	**17.58**	**20.48**	**19.11**	**20.19**	**20.81**	**21.48**	**22.32**	**0.4%**
Delivered Sector Product Prices								
Residential								
Distillate Fuel	88.6	98.4	99.2	103.5	104.8	106.0	107.0	0.3%
Liquefied Petroleum Gas	90.3	100.0	99.8	105.4	107.5	107.3	108.5	0.3%
Commercial								
Distillate Fuel	62.3	73.1	72.5	76.8	78.3	79.7	81.3	0.4%
Residual Fuel	48.2	48.4	44.5	45.7	47.3	49.2	50.9	0.2%
Residual Fuel (1996 dollars per barrel)	20.26	20.35	18.68	19.21	19.85	20.65	21.36	0.2%
Industrial[1]								
Distillate Fuel	65.5	76.3	72.7	77.2	79.6	81.5	84.2	0.4%
Liquefied Petroleum Gas	57.3	67.3	51.6	57.0	58.4	57.3	58.8	-0.6%
Residual Fuel	39.6	45.0	40.4	42.3	45.2	47.2	50.1	0.5%
Residual Fuel (1996 dollars per barrel)	16.63	18.88	16.98	17.79	18.97	19.80	21.04	0.5%
Transportation								
Diesel Fuel (distillate)[2]	114.1	123.5	118.4	121.3	119.4	119.3	118.2	-0.2%
Jet Fuel[3]	56.5	74.6	69.1	75.3	79.0	81.7	84.6	0.5%
Motor Gasoline[4]	117.6	122.5	121.2	124.7	126.0	126.6	126.8	0.1%
Residual Fuel	34.8	38.2	39.1	42.7	46.0	47.0	49.7	1.1%
Residual Fuel (1996 dollars per barrel)	14.63	16.04	16.41	17.95	19.32	19.75	20.88	1.1%
Electric Generators[5]								
Distillate Fuel	55.6	68.0	67.1	71.6	73.9	75.9	78.2	0.6%
Residual Fuel	40.2	45.9	44.2	48.0	51.9	53.9	56.4	0.9%
Residual Fuel (1996 dollars per barrel)	16.87	19.27	18.55	20.15	21.78	22.64	23.70	0.9%
Refined Petroleum Product Prices[6]								
Distillate Fuel	98.1	108.7	106.1	109.8	109.2	109.7	109.6	0.0%
Jet Fuel[3]	56.5	74.6	69.1	75.3	79.0	81.7	84.6	0.5%
Liquefied Petroleum Gas	63.7	73.6	61.5	67.7	69.8	69.4	71.1	-0.1%
Motor Gasoline[4]	117.6	122.5	121.0	124.5	125.9	126.4	126.7	0.1%
Residual Fuel	38.4	42.5	40.9	43.7	46.7	48.0	50.5	0.7%
Residual Fuel (1996 dollars per barrel)	16.12	17.87	17.19	18.35	19.63	20.15	21.23	0.7%
Average	**95.0**	**102.8**	**99.8**	**103.8**	**104.9**	**105.4**	**106.0**	**0.1%**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. 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 and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1995.* Online. http://www.eia.doe.gov/oil-gas/pmal/pmaframe.html (May 30, 1997). 1996 prices for gasoline, distillate, and jet fuel are based on prices invarious issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). 1995 and 1996 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections**: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Production								
Dry Gas Production[1]	18.60	19.02	20.27	22.25	24.70	26.12	27.44	1.5%
Supplemental Natural Gas[2]	0.11	0.12	0.11	0.11	0.05	0.05	0.05	-3.6%
Net Imports	**2.69**	**2.72**	**3.84**	**4.02**	**4.28**	**4.64**	**4.91**	**2.5%**
Canada	2.79	2.76	3.86	3.89	4.13	4.50	4.80	2.3%
Mexico	-0.05	-0.02	-0.13	-0.14	-0.15	-0.15	-0.17	9.5%
Liquefied Natural Gas	-0.05	-0.03	0.12	0.27	0.29	0.29	0.29	N/A
Total Supply	**21.40**	**21.86**	**24.23**	**26.39**	**29.03**	**30.81**	**32.41**	**1.7%**
Consumption by Sector								
Residential	4.84	5.23	5.20	5.31	5.47	5.66	5.80	0.4%
Commercial	3.03	3.20	3.37	3.52	3.65	3.74	3.75	0.7%
Industrial[3]	8.41	8.60	9.29	9.39	9.75	9.75	9.70	0.5%
Electric Generators[4]	3.37	2.98	4.05	5.57	7.22	8.52	9.85	5.1%
Lease and Plant Fuel[5]	1.22	1.25	1.35	1.45	1.59	1.68	1.76	1.5%
Pipeline Fuel	0.70	0.71	0.78	0.82	0.93	0.96	1.00	1.4%
Transportation[6]	0.01	0.01	0.05	0.15	0.23	0.29	0.33	15.8%
Total	**21.58**	**21.99**	**24.08**	**26.22**	**28.84**	**30.61**	**32.20**	**1.6%**
Discrepancy[7]	**-0.18**	**-0.12**	**0.15**	**0.17**	**0.19**	**0.20**	**0.21**	**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.
[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, 1995 and 1996 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. Figures for 1995 and 1996 may differ from published data due to internal conversion factors.
Sources: 1995 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 consumption derived from: EIA, *State Energy Data Report 1994*, Online. ftp://ftp.eia.doe.gov/pub/state.data/021497.pdf (August 26, 1997). 1996 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). 1996 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, November 1997). 1996 transportation sector consumption: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A. Other 1996 consumption: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO98 National EnergyModeling System run AEO98B.D100197A. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A14. Natural Gas Prices, Margins, and Revenues
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Source Price								
Average Lower 48 Wellhead Price[1]	1.61	2.24	2.11	2.15	2.31	2.38	2.54	0.5%
Average Import Price	1.53	1.98	1.96	2.14	2.32	2.40	2.56	1.1%
Average[2]	**1.60**	**2.21**	**2.08**	**2.15**	**2.31**	**2.38**	**2.54**	**0.6%**
Delivered Prices								
Residential	6.25	6.37	5.93	5.71	5.58	5.47	5.60	-0.5%
Commercial	5.22	5.43	5.02	4.85	4.79	4.76	4.91	-0.4%
Industrial[3]	2.43	3.05	2.81	2.85	3.01	3.09	3.26	0.3%
Electric Generators[4]	2.08	2.70	2.54	2.69	2.91	3.04	3.22	0.7%
Transportation[5]	5.57	5.57	5.62	5.89	6.79	7.26	7.61	1.3%
Average[6]	**3.73**	**4.25**	**3.85**	**3.76**	**3.80**	**3.83**	**3.97**	**-0.3%**
Transmission and Distribution Margins[7]								
Residential	4.65	4.17	3.85	3.56	3.27	3.09	3.05	-1.3%
Commercial	3.62	3.23	2.93	2.70	2.48	2.38	2.37	-1.3%
Industrial[3]	0.83	0.84	0.73	0.70	0.71	0.70	0.71	-0.7%
Electric Generators[4]	0.48	0.49	0.45	0.54	0.60	0.66	0.68	1.3%
Transportation[5]	3.97	3.36	3.54	3.74	4.48	4.88	5.06	1.7%
Average[6]	**2.13**	**2.04**	**1.76**	**1.61**	**1.49**	**1.44**	**1.43**	**-1.5%**
Transmission and Distribution Revenue (billion 1996 dollars)								
Residential	22.51	21.81	20.00	18.93	17.91	17.48	17.70	-0.9%
Commercial	10.94	10.34	9.88	9.50	9.05	8.88	8.87	-0.6%
Industrial[3]	7.02	7.23	6.75	6.60	6.89	6.87	6.92	-0.2%
Electric Generators[4]	1.62	1.47	1.83	3.00	4.32	5.63	6.69	6.5%
Transportation[5]	0.04	0.03	0.16	0.56	1.04	1.43	1.68	17.8%
Total	**42.13**	**40.88**	**38.64**	**38.60**	**39.21**	**40.29**	**41.87**	**0.1%**

[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.
[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.

Sources: 1995 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants". 1995 and 1996 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1996 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). **Other 1995 values, other 1996 values, and projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A15. Oil and Gas Supply

Production and Supply	Reference 1995	1996	2000	2005	2010	2015	2020	Annual Growth 1996-2020 (percent)
Crude Oil								
Lower 48 Average Wellhead Price[1] (1996 dollars per barrel)	**15.96**	**19.41**	**19.12**	**20.52**	**21.08**	**21.01**	**21.58**	**0.4%**
Production (million barrels per day)[2]								
U.S. Total	**6.56**	**6.48**	**6.17**	**5.82**	**5.57**	**5.24**	**4.92**	**-1.1%**
Lower 48 Onshore	3.82	3.76	3.39	3.13	3.15	3.13	3.09	-0.8%
Conventional	3.16	3.15	2.81	2.47	2.36	2.35	2.41	-1.1%
Enhanced Oil Recovery	0.66	0.61	0.58	0.66	0.79	0.78	0.68	0.5%
Lower 48 Offshore	1.26	1.32	1.65	1.75	1.67	1.52	1.35	0.1%
Alaska	1.48	1.40	1.13	0.93	0.75	0.60	0.48	-4.3%
Lower 48 End of Year Reserves (billion barrels)	**17.03**	**16.82**	**15.25**	**14.69**	**14.87**	**14.67**	**14.33**	**-0.7%**
Natural Gas								
Lower 48 Average Wellhead Price[1] (1996 dollars per thousand cubic feet)	**1.61**	**2.24**	**2.11**	**2.15**	**2.31**	**2.38**	**2.54**	**0.5%**
Production (trillion cubic feet)[3]								
U.S. Total	**18.60**	**19.01**	**20.27**	**22.25**	**24.70**	**26.12**	**27.44**	**1.5%**
Lower 48 Onshore	12.82	13.07	13.90	15.30	17.33	18.72	18.99	1.6%
Associated-Dissolved[4]	1.80	1.84	1.69	1.39	1.27	1.21	1.19	-1.8%
Non-Associated	11.02	11.23	12.21	13.91	16.06	17.51	17.81	1.9%
Conventional	7.97	7.96	8.74	10.18	11.77	12.44	12.32	1.8%
Unconventional	3.05	3.27	3.47	3.73	4.30	5.08	5.49	2.2%
Lower 48 Offshore	5.35	5.50	5.88	6.43	6.81	6.81	7.83	1.5%
Associated-Dissolved[4]	0.77	0.80	0.89	0.93	0.92	0.89	0.85	0.3%
Non-Associated	4.58	4.70	4.99	5.49	5.89	5.92	6.98	1.7%
Alaska	0.43	0.43	0.49	0.53	0.56	0.59	0.62	1.5%
Lower 48 End of Year Reserves (trillion cubic feet)	**155.65**	**157.23**	**172.04**	**187.25**	**196.33**	**196.28**	**185.11**	**0.7%**
Supplemental Gas Supplies (trillion cubic ft.)[5]	**0.11**	**0.12**	**0.11**	**0.11**	**0.05**	**0.05**	**0.05**	**-3.6%**
Total Lower 48 Wells (thousands)	**18.51**	**21.75**	**22.18**	**25.30**	**28.19**	**29.39**	**32.04**	**1.6%**

Ft. = feet.
[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 and 1996 may differ from published data due to internal conversion factors.

Sources: 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95)/1 (Washington, DC, May 1996). 1995 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(95) (Washington, DC, November 1996). 1995 natural gas lower 48 average wellhead price. EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 and 1996 crude oil lower 48 average wellhead price: EIA, Office of Integrated Analysis and Forecasting. 1995 and 1996 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1996 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). 1996 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies. EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). Other 1995 and 1996 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Production[1]								
Appalachia	435	452	491	506	505	505	513	0.5%
Interior	169	173	183	176	177	167	166	-0.2%
West	430	439	471	525	583	654	697	1.9%
East of the Mississippi	544	564	603	608	602	609	623	0.4%
West of the Mississippi	488	500	541	599	663	717	754	1.7%
Total	**1033**	**1064**	**1145**	**1207**	**1265**	**1326**	**1376**	**1.1%**
Net Imports								
Imports	7	7	7	8	8	8	8	0.4%
Exports	88	90	94	104	112	119	128	1.4%
Total	**-81**	**-83**	**-87**	**-96**	**-104**	**-112**	**-120**	**1.5%**
Total Supply[2]	**952**	**981**	**1058**	**1111**	**1161**	**1215**	**1256**	**1.0%**
Consumption by Sector								
Residential and Commercial	6	6	6	6	6	7	6	0.4%
Industrial[3]	72	70	71	77	81	81	81	0.6%
Coke Plants	33	32	31	28	26	24	23	-1.4%
Electric Generators[4]	847	896	950	1000	1049	1103	1147	1.0%
Total	**958**	**1003**	**1058**	**1112**	**1162**	**1215**	**1257**	**0.9%**
Discrepancy and Stock Change[5].	**-6**	**-23**	**-1**	**-1**	**-1**	**-0**	**-1**	**N/A**
Average Minemouth Price								
(1996 dollars per short ton)	19.25	18.50	17.45	16.18	15.05	13.99	13.27	-1.4%
(1996 dollars per million Btu)	0.90	0.87	0.82	0.76	0.72	0.67	0.64	-1.3%
Delivered Prices (1996 dollars per short ton)[6]								
Industrial	33.14	32.28	31.03	29.92	29.29	28.90	28.57	-0.5%
Coke Plants	48.39	47.33	47.16	45.90	45.10	44.78	44.61	-0.2%
Electric Generators								
(1996 dollars per short ton)	27.61	26.45	24.71	23.37	22.09	20.72	19.52	-1.3%
(1996 dollars per million Btu)	1.35	1.29	1.20	1.14	1.09	1.03	0.97	-1.2%
Average	**28.75**	**27.52**	**25.80**	**24.40**	**23.12**	**21.76**	**20.56**	**-1.2%**
Exports[7]	41.17	40.77	38.37	36.40	35.02	33.75	32.47	-0.9%

[1]Includes anthracite, bituminous coal, and lignite.
[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.
[5]Balancing item: the sum of production, net imports, and net storage 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.
Sources: 1995: Energy Information Administration (EIA), *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996). 1996 data derived from: EIA, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A17. Renewable Energy Generating Capability and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Electric Generators[1] (excluding cogenerators)								
Net Summer Capability								
Conventional Hydropower	78.48	78.58	80.32	80.65	80.71	80.71	80.71	0.1%
Geothermal[2]	3.02	3.02	3.02	2.93	2.92	2.87	2.94	-0.1%
Municipal Solid Waste[3]	2.87	2.91	3.11	3.46	3.92	4.26	4.38	1.7%
Wood and Other Biomass[4]	1.91	1.91	1.91	2.02	2.07	2.28	2.50	1.1%
Solar Thermal	0.36	0.36	0.36	0.40	0.46	0.51	0.56	1.8%
Solar Photovoltaic	0.01	0.01	0.02	0.08	0.22	0.38	0.56	18.0%
Wind	1.84	1.85	2.55	3.31	3.33	3.68	4.06	3.3%
Total	**88.49**	**88.64**	**91.29**	**92.86**	**93.64**	**94.69**	**95.70**	**0.3%**
Generation (billion kilowatthours)								
Conventional Hydropower	309.82	346.28	316.00	318.16	318.67	318.76	318.82	-0.3%
Geothermal[2]	14.66	15.70	17.24	17.34	17.64	17.92	19.26	0.9%
Municipal Solid Waste[3]	18.69	18.85	20.76	23.14	26.32	28.68	29.52	1.9%
Wood and Other Biomass[4]	7.12	7.27	8.96	9.48	9.79	11.24	12.81	2.4%
Solar Thermal	0.82	0.82	0.92	1.04	1.24	1.39	1.56	2.7%
Solar Photovoltaic	0.00	0.00	0.05	0.20	0.60	1.00	1.45	29.4%
Wind	3.17	3.17	5.67	7.70	7.76	8.86	10.08	4.9%
Total	**354.28**	**392.09**	**369.60**	**377.06**	**382.03**	**387.84**	**393.50**	**0.0%**
Cogenerators[5]								
Net Summer Capability								
Municipal Solid Waste	0.41	0.41	0.43	0.45	0.46	0.47	0.48	0.7%
Biomass	5.35	5.41	5.93	6.06	6.14	6.08	5.95	0.4%
Total	**5.75**	**5.81**	**6.36**	**6.50**	**6.61**	**6.56**	**6.43**	**0.4%**
Generation (billion kilowatthours)								
Municipal Solid Waste	2.00	2.09	2.14	2.22	2.30	2.34	2.36	0.5%
Biomass	34.85	39.17	39.67	40.48	41.00	40.55	39.65	0.1%
Total	**36.85**	**41.25**	**41.81**	**42.70**	**43.29**	**42.89**	**42.01**	**0.1%**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of August 25, 1997. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1995 and 1996 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report," 1995 and 1996 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1995 and 1996 generation: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Marketed Renewable Energy[2]								
Residential	**0.59**	**0.61**	**0.61**	**0.62**	**0.63**	**0.64**	**0.64**	**0.2%**
Wood	0.59	0.61	0.61	0.62	0.63	0.64	0.64	0.2%
Commercial[3]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.1%**
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.1%
Industrial[4]	**1.73**	**1.82**	**1.96**	**2.10**	**2.24**	**2.31**	**2.34**	**1.0%**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	N/A
Municipal Solid Waste	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.8%
Biomass	1.70	1.78	1.92	2.07	2.20	2.27	2.30	1.1%
Transportation	**0.11**	**0.10**	**0.17**	**0.17**	**0.17**	**0.14**	**0.15**	**1.5%**
Ethanol used in E85[5]	0.00	0.00	0.00	0.02	0.07	0.11	0.13	20.5%
Ethanol used in Gasoline Blending	0.11	0.10	0.16	0.14	0.09	0.03	0.01	-8.3%
Electric Generators[6]	**3.97**	**4.40**	**4.21**	**4.31**	**4.40**	**4.48**	**4.56**	**0.2%**
Conventional Hydroelectric	3.18	3.56	3.25	3.27	3.28	3.28	3.28	-0.3%
Geothermal	0.39	0.43	0.48	0.50	0.52	0.53	0.58	1.2%
Municipal Solid Waste	0.30	0.30	0.33	0.37	0.42	0.46	0.47	1.9%
Biomass	0.06	0.06	0.08	0.08	0.09	0.10	0.11	2.4%
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.00	N/A
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.01	29.4%
Wind	0.03	0.03	0.06	0.08	0.08	0.09	0.10	4.9%
Total Marketed Renewable Energy	**6.41**	**6.93**	**6.95**	**7.21**	**7.44**	**7.58**	**7.69**	**0.4%**
Non-Marketed Renewable Energy[7] Selected Consumption								
Residential	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**0.07**	**5.0%**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.3%
Geothermal Heat Pumps	0.01	0.01	0.02	0.03	0.04	0.05	0.06	7.1%
Commercial	**0.01**	**0.01**	**0.02**	**0.03**	**0.03**	**0.04**	**0.04**	**4.2%**
Solar Thermal	0.01	0.01	0.02	0.03	0.03	0.04	0.04	4.2%

[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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.

[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.

[5]Excludes motor gasoline component of E85.

[6]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.

[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.

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

Sources: 1995 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1995 and 1996 electric generators: EIA, Form EIA-860, "Annual Electric Utility Report" and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Other 1995: EIA, Office of Integrated Analysis and Forecasting. 1996 ethanol: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96/1) (Washington, DC, June 1997). Other 1996: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Residential								
Petroleum	25.8	27.3	25.8	25.0	24.8	24.5	24.2	-0.5%
Natural Gas	71.7	77.4	77.0	78.7	81.1	83.8	85.9	0.4%
Coal	1.4	1.4	1.4	1.4	1.3	1.3	1.3	-0.3%
Electricity	170.1	179.9	201.3	215.9	230.9	248.8	267.5	1.7%
Total	**269.0**	**286.0**	**305.6**	**321.0**	**338.1**	**358.5**	**379.0**	**1.2%**
Commercial								
Petroleum	15.0	15.3	12.8	12.8	12.8	12.7	12.4	-0.9%
Natural Gas	44.8	47.4	49.9	52.1	54.0	55.4	55.5	0.7%
Coal	2.1	2.1	2.2	2.3	2.4	2.5	2.5	0.8%
Electricity	155.7	164.8	182.2	193.1	205.1	217.8	225.5	1.3%
Total	**217.6**	**229.6**	**247.1**	**260.4**	**274.4**	**288.4**	**296.0**	**1.1%**
Industrial[1]								
Petroleum	97.4	104.8	103.3	109.7	115.6	119.3	120.3	0.6%
Natural Gas[2]	139.5	142.8	155.5	158.5	165.8	167.1	167.5	0.7%
Coal	62.1	59.3	60.7	62.3	62.8	61.7	60.7	0.1%
Electricity	165.2	169.2	187.3	203.6	219.1	230.6	240.6	1.5%
Total	**464.2**	**476.1**	**506.7**	**534.1**	**563.3**	**578.7**	**589.2**	**0.9%**
Transportation								
Petroleum	447.5	457.9	502.4	552.8	601.0	632.3	658.6	1.5%
Natural Gas[3]	10.4	10.5	12.2	14.4	17.2	18.6	19.8	2.7%
Other[4]	0.0	0.0	0.1	0.5	1.5	2.2	2.7	N/A
Electricity	2.7	2.8	3.2	5.5	7.8	9.5	11.0	5.8%
Total	**460.6**	**471.2**	**517.9**	**573.3**	**627.5**	**662.7**	**692.1**	**1.6%**
Total Carbon Emissions[5]								
Petroleum	585.7	605.3	644.4	700.4	754.2	788.9	815.5	1.2%
Natural Gas	266.4	278.1	294.6	303.7	318.1	324.9	328.7	0.7%
Coal	65.6	62.8	64.3	66.0	66.6	65.6	64.5	0.1%
Other[4]	0.0	0.0	0.1	0.5	1.5	2.2	2.7	N/A
Electricity	493.7	516.7	574.0	618.1	662.9	706.8	744.7	1.5%
Total	**1411.4**	**1462.9**	**1577.3**	**1688.8**	**1803.2**	**1888.3**	**1956.2**	**1.2%**
Electric Generators[6]								
Petroleum	13.8	15.5	11.4	7.7	7.4	6.8	6.6	-3.5%
Natural Gas	47.2	40.3	59.6	82.0	106.3	125.4	145.0	5.5%
Coal	432.7	460.9	503.0	528.4	549.3	574.5	593.1	1.1%
Total	**493.7**	**516.7**	**574.0**	**618.1**	**662.9**	**706.8**	**744.7**	**1.5%**
Total Carbon Emissions[7]								
Petroleum	599.5	620.8	655.8	708.1	761.5	795.7	822.1	1.2%
Natural Gas	313.6	318.4	354.2	385.7	424.4	450.3	473.7	1.7%
Coal	498.3	523.7	567.3	594.4	615.9	640.1	657.7	1.0%
Other[4]	0.0	0.0	0.1	0.5	1.5	2.2	2.7	N/A
Total	**1411.4**	**1462.9**	**1577.3**	**1688.8**	**1803.2**	**1888.3**	**1956.2**	**1.2%**
Carbon Emissions (tons per person)	**5.4**	**5.5**	**5.7**	**5.9**	**6.0**	**6.1**	**6.0**	**0.4%**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]Includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). 1995 consumption estimates derived from EIA, *State Energy Data Report 1994*, Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). 1996 consumption estimates based on: EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997).
Projections: EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted, Dollars Unless Otherwise Noted)

Indicators	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
GDP Chain-Type Price Index (1992=1.000)	**1.078**	**1.102**	**1.208**	**1.379**	**1.600**	**1.891**	**2.262**	**3.0%**
Real Gross Domestic Product	**6742**	**6928**	**7653**	**8503**	**9431**	**10211**	**10900**	**1.9%**
Real Consumption	4595	4714	5220	5723	6349	6989	7626	2.0%
Real Investment	989	1067	1295	1500	1739	1934	2105	2.9%
Real Government Spending	1252	1258	1301	1383	1498	1583	1640	1.1%
Real Exports	791	857	1189	1746	2332	2849	3352	5.8%
Real Imports	890	971	1366	1847	2514	3283	4153	6.2%
Real Disposable Personal Income	**4964**	**5077**	**5595**	**6182**	**6884**	**7560**	**8217**	**2.0%**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.264**	**1.299**	**1.425**	**1.629**	**1.851**	**1.992**	**2.125**	**2.1%**
AA Utility Bond Rate (percent)	7.76	7.57	7.16	7.17	7.21	7.64	8.27	N/A
Real Yield on Government 10 Year Bonds (percent)	5.23	4.99	4.29	3.83	3.58	3.69	3.97	N/A
Real Utility Bond Rate (percent)	5.22	5.28	4.64	4.37	4.05	4.15	4.49	N/A
Delivered Energy Intensity (thousand Btu per 1992 dollar of GDP)								
Delivered Energy	10.13	10.16	9.79	9.41	9.04	8.68	8.35	-0.8%
Total Energy	13.52	13.57	13.05	12.45	11.90	11.34	10.89	-0.9%
Consumer Price Index (1982-84=1.00)	1.52	1.57	1.75	2.04	2.42	2.90	3.52	3.4%
Unemployment Rate (percent)	5.60	5.38	5.38	5.79	5.51	5.55	5.66	N/A
Unit Sales of Light-Duty Vehicles (million)	**14.77**	**15.10**	**15.24**	**15.58**	**16.65**	**17.15**	**17.49**	**0.6%**
Millions of People								
Population with Armed Forces Overseas	263.6	266.1	275.6	287.1	298.9	311.2	323.5	0.8%
Population (aged 16 and over)	202.1	204.2	212.8	223.8	235.4	245.8	255.6	0.9%
Employment, Non-Agriculture	117.2	119.5	128.1	135.5	143.9	149.2	153.4	1.0%
Employment, Manufacturing	18.5	18.5	18.1	17.9	17.5	16.4	15.2	-0.8%
Labor Force	132.3	133.9	142.1	149.6	156.5	160.2	162.4	0.8%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 1995 and 1996: Data Resources Incorporated (DRI), DRI Trend0897. **Projections:** Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table A21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
World Oil Price (1996 dollars per barrel)[1]	**17.58**	**20.48**	**19.11**	**20.19**	**20.81**	**21.48**	**22.32**	**0.4%**
Production[2]								
OECD								
U.S. (50 states)	9.31	9.37	9.11	8.96	8.94	8.73	8.48	-0.4%
Canada	2.43	2.51	2.55	2.46	2.59	2.62	2.66	0.2%
Mexico	3.19	3.28	3.20	3.24	3.34	3.43	3.53	0.3%
OECD Europe[3]	6.56	6.67	7.07	6.57	5.74	5.11	4.47	-1.7%
Other OECD	0.76	0.77	0.80	0.80	1.01	0.80	0.84	0.4%
Total OECD	**22.25**	**22.60**	**22.74**	**22.03**	**21.62**	**20.70**	**19.98**	**-0.5%**
Developing Countries								
Other South & Central America	3.07	3.29	4.29	4.75	5.23	6.03	6.68	3.0%
Pacific Rim	1.95	2.08	2.67	3.04	3.20	3.23	3.08	1.6%
OPEC	27.72	29.00	32.73	40.19	48.19	56.40	65.98	3.5%
Other Developing Countries	4.13	4.21	4.55	4.84	5.00	5.33	5.38	1.0%
Total Developing Countries	**36.88**	**38.59**	**44.25**	**52.82**	**61.63**	**70.98**	**81.11**	**3.1%**
Eurasia								
Former Soviet Union	6.99	7.14	7.70	9.13	9.83	10.59	11.41	2.0%
Eastern Europe	0.32	0.32	0.27	0.23	0.21	0.18	0.18	-2.3%
China	3.00	3.10	3.14	3.18	3.27	3.46	3.65	0.7%
Total Eurasia	**10.31**	**10.55**	**11.10**	**12.54**	**13.31**	**14.23**	**15.24**	**1.5%**
Total Production	**69.43**	**71.74**	**78.09**	**87.39**	**96.56**	**105.91**	**116.34**	**2.0%**
Consumption								
OECD								
U.S. (50 states)	17.73	18.31	19.62	21.15	22.70	23.66	24.39	1.2%
U.S. Territories	0.26	0.26	0.30	0.35	0.38	0.42	0.46	2.5%
Canada	1.77	1.77	1.87	2.01	2.15	2.28	2.43	1.3%
Mexico	1.96	1.98	2.25	2.39	2.74	3.00	3.27	2.1%
Japan	5.72	5.84	6.46	6.91	7.28	7.80	8.34	1.5%
Australia and New Zealand.	0.96	0.97	1.05	1.10	1.20	1.24	1.29	1.2%
OECD Europe[3]	13.85	13.93	14.36	14.78	15.11	15.40	15.69	0.5%
Total OECD	**42.24**	**43.05**	**45.91**	**48.68**	**51.56**	**53.80**	**55.88**	**1.1%**
Developing Countries								
Other South and Central America	3.59	3.79	4.70	5.56	6.51	7.49	8.61	3.5%
Pacific Rim	4.39	4.55	5.38	7.13	8.44	10.07	12.03	4.1%
OPEC	4.94	5.14	5.62	6.30	7.06	7.91	8.86	2.3%
Other Developing Countries	5.27	5.44	6.06	7.19	7.94	8.75	9.66	2.4%
Total Developing Countries	**18.19**	**18.91**	**21.76**	**26.19**	**29.95**	**34.22**	**39.16**	**3.1%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Eurasia								
Former Soviet Union	4.60	4.48	4.88	5.80	6.73	7.65	8.68	2.8%
Eastern Europe	1.40	1.43	1.45	1.51	1.73	1.96	2.24	1.9%
China	3.31	3.44	4.39	5.51	6.89	8.58	10.68	4.8%
Total Eurasia	**9.31**	**9.35**	**10.72**	**12.81**	**15.35**	**18.19**	**21.60**	**3.5%**
Total Consumption	**69.73**	**71.32**	**78.39**	**87.69**	**96.86**	**106.21**	**116.64**	**2.1%**
Non-OPEC Production	41.71	42.74	45.36	47.19	48.37	49.52	50.36	0.7%
Net Eurasia Exports	1.00	1.20	0.38	-0.28	-2.04	-3.96	-6.36	N/A
OPEC Market Share	0.40	0.40	0.42	0.46	0.50	0.53	0.57	1.4%

N/A =Not applicable.

[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 UnitedStates (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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.

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

Sources: 1995 and 1996 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	1996	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	13.71	11.62	11.79	12.01	10.90	11.09	11.37	10.15	10.43	10.76
Natural Gas Plant Liquids	2.46	2.79	2.95	3.07	2.91	3.12	3.29	2.97	3.29	3.52
Dry Natural Gas	19.55	24.21	25.39	26.45	25.16	26.85	28.26	25.65	28.21	30.12
Coal	22.64	25.32	26.62	27.57	25.59	27.73	29.59	26.10	28.59	31.28
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[1]	6.91	7.16	7.41	7.60	7.20	7.59	7.97	7.28	7.71	8.45
Other[2]	1.33	0.44	0.48	0.52	0.46	0.47	0.57	0.46	0.47	0.51
Total	**73.80**	**77.91**	**81.00**	**83.58**	**77.35**	**81.97**	**86.18**	**76.71**	**82.77**	**88.73**
Imports										
Crude Oil[3]	16.30	22.94	23.17	23.84	23.89	24.36	25.36	24.68	25.30	26.93
Petroleum Products[4]	3.98	5.95	7.61	8.43	6.25	9.01	10.38	6.26	10.09	12.13
Natural Gas	2.93	4.54	4.66	5.02	4.81	5.04	5.42	5.02	5.34	5.80
Other Imports[5]	0.57	0.55	0.57	0.59	0.52	0.54	0.57	0.52	0.56	0.59
Total	**23.78**	**33.98**	**36.02**	**37.88**	**35.47**	**38.96**	**41.73**	**36.49**	**41.28**	**45.45**
Exports										
Petroleum[6]	2.04	1.71	1.80	1.78	1.78	1.89	1.84	1.67	1.67	1.71
Natural Gas	0.16	0.29	0.29	0.29	0.30	0.30	0.30	0.32	0.32	0.32
Coal	2.37	2.84	2.84	2.84	3.03	3.03	3.03	3.23	3.23	3.23
Total	**4.57**	**4.84**	**4.93**	**4.91**	**5.11**	**5.21**	**5.17**	**5.22**	**5.23**	**5.26**
Discrepancy[7]	**0.99**	**-0.18**	**0.08**	**0.39**	**-0.01**	**0.00**	**0.43**	**-0.24**	**-0.25**	**0.18**
Consumption										
Petroleum Products[8]	36.01	41.90	44.33	46.55	42.63	46.20	49.56	42.65	47.64	52.31
Natural Gas	22.60	28.33	29.63	31.04	29.52	31.44	33.23	30.19	33.06	35.43
Coal	20.90	22.71	24.03	24.98	22.80	24.95	26.84	23.08	25.61	28.34
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[1]	6.91	7.18	7.42	7.62	7.22	7.62	8.00	7.31	7.74	8.48
Other[9]	0.39	0.39	0.40	0.40	0.39	0.40	0.41	0.42	0.43	0.45
Total	**94.01**	**106.87**	**112.17**	**116.94**	**107.69**	**115.72**	**123.17**	**107.74**	**118.58**	**129.10**
Net Imports - Petroleum	**18.25**	**27.19**	**28.99**	**30.50**	**28.36**	**31.48**	**33.89**	**29.28**	**33.71**	**37.35**
Prices (1996 dollars per unit)										
World Oil Price (dollars per barrel)[10]	20.48	20.29	20.81	21.55	20.65	21.48	22.38	21.24	22.32	23.44
Gas Wellhead Price (dollars per Mcf)[11]	2.24	1.91	2.31	2.69	1.89	2.38	2.73	1.91	2.54	2.97
Coal Minemouth Price (dollars per ton)	18.50	14.98	15.05	14.64	13.87	13.99	14.05	13.14	13.27	13.50
Average Electric Price (cents per kwh)	6.9	5.5	5.9	6.2	5.2	5.6	5.9	5.0	5.5	5.8

[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, 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.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures may differ from published data due to internal conversion factors.
Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). 1996 coal minemouth price: *Coal Industry Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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	0.89	0.76	0.77	0.77	0.74	0.74	0.75	0.72	0.72	0.73
Kerosene	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.42	0.47	0.49	0.51	0.48	0.50	0.53	0.49	0.51	0.54
Petroleum Subtotal	1.40	1.30	1.33	1.35	1.29	1.32	1.35	1.27	1.30	1.35
Natural Gas	5.39	5.52	5.63	5.74	5.66	5.82	6.00	5.81	5.97	6.20
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.61	0.61	0.63	0.64	0.62	0.64	0.66	0.62	0.64	0.67
Electricity	3.68	4.45	4.61	4.77	4.72	4.94	5.17	5.00	5.28	5.57
Delivered Energy	**11.13**	**11.95**	**12.25**	**12.55**	**12.34**	**12.77**	**13.23**	**12.76**	**13.25**	**13.84**
Electricity Related Losses	8.23	9.17	9.39	9.57	9.26	9.58	9.91	9.62	9.93	10.40
Total	**19.36**	**21.12**	**21.64**	**22.13**	**21.60**	**22.35**	**23.14**	**22.38**	**23.17**	**24.24**
Commercial										
Distillate Fuel	0.44	0.39	0.40	0.41	0.38	0.39	0.40	0.36	0.37	0.39
Residual Fuel	0.15	0.12	0.12	0.12	0.12	0.12	0.13	0.11	0.12	0.13
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.03
Liquefied Petroleum Gas	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Petroleum Subtotal	0.71	0.64	0.65	0.67	0.63	0.65	0.67	0.61	0.63	0.66
Natural Gas	3.30	3.65	3.75	3.85	3.69	3.85	4.01	3.65	3.85	4.07
Coal	0.08	0.09	0.09	0.10	0.09	0.10	0.10	0.09	0.10	0.10
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.37	3.96	4.09	4.23	4.13	4.33	4.53	4.17	4.45	4.73
Delivered Energy	**7.47**	**8.34**	**8.60**	**8.85**	**8.54**	**8.92**	**9.32**	**8.52**	**9.04**	**9.58**
Electricity Related Losses	7.54	8.16	8.35	8.49	8.09	8.39	8.68	8.01	8.37	8.83
Total	**15.01**	**16.51**	**16.94**	**17.33**	**16.63**	**17.31**	**18.00**	**16.53**	**17.41**	**18.41**
Industrial[4]										
Distillate Fuel	1.17	1.35	1.45	1.54	1.37	1.51	1.64	1.39	1.56	1.73
Liquefied Petroleum Gas	2.12	2.18	2.40	2.59	2.13	2.45	2.73	2.02	2.47	2.88
Petrochemical Feedstock	1.28	1.33	1.47	1.58	1.29	1.49	1.67	1.22	1.51	1.76
Residual Fuel	0.34	0.33	0.35	0.39	0.32	0.34	0.39	0.30	0.35	0.38
Motor Gasoline[2]	0.19	0.23	0.25	0.26	0.23	0.26	0.28	0.24	0.27	0.30
Other Petroleum[5]	4.12	4.43	4.84	5.17	4.59	5.05	5.48	4.54	5.10	5.66
Petroleum Subtotal	9.23	9.86	10.75	11.53	9.94	11.10	12.19	9.70	11.25	12.70
Natural Gas[6]	10.14	11.25	11.67	12.07	11.02	11.77	12.45	10.75	11.80	12.80
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	1.55	1.61	1.77	1.92	1.55	1.78	1.99	1.48	1.79	2.07
Net Coal Coke Imports	0.00	0.05	0.06	0.08	0.05	0.07	0.10	0.05	0.08	0.11
Coal Subtotal	2.40	2.36	2.54	2.71	2.25	2.51	2.74	2.14	2.48	2.79
Renewable Energy[7]	1.82	2.08	2.25	2.40	2.07	2.31	2.53	2.02	2.34	2.64
Electricity	3.46	3.96	4.37	4.76	3.96	4.58	5.13	3.85	4.75	5.53
Delivered Energy	**27.05**	**29.51**	**31.58**	**33.46**	**29.23**	**32.27**	**35.04**	**28.46**	**32.62**	**36.46**
Electricity Related Losses	7.74	8.16	8.92	9.56	7.76	8.88	9.82	7.41	8.93	10.31
Total	**34.79**	**37.68**	**40.50**	**43.02**	**36.99**	**41.15**	**44.86**	**35.87**	**41.55**	**46.77**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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 Fuel[8]	4.48	5.69	6.02	6.30	5.68	6.19	6.63	5.59	6.31	6.93
Jet Fuel[9]	3.27	4.89	5.23	5.54	5.24	5.79	6.30	5.48	6.28	7.01
Motor Gasoline[2]	14.94	17.52	18.22	18.87	17.72	18.84	19.92	17.74	19.38	20.92
Residual Fuel	0.90	1.23	1.27	1.31	1.35	1.42	1.48	1.46	1.56	1.65
Liquefied Petroleum Gas	0.03	0.15	0.16	0.17	0.19	0.20	0.22	0.21	0.24	0.26
Other Petroleum[10]	0.29	0.33	0.35	0.37	0.34	0.37	0.40	0.33	0.37	0.42
Petroleum Subtotal	23.91	29.81	31.25	32.55	30.51	32.80	34.95	30.82	34.14	37.19
Pipeline Fuel Natural Gas	0.73	0.91	0.95	0.99	0.92	0.99	1.04	0.96	1.03	1.11
Compressed Natural Gas	0.01	0.22	0.24	0.25	0.27	0.30	0.33	0.30	0.34	0.38
Renewable Energy (E85)[11]	0.00	0.08	0.09	0.09	0.12	0.13	0.14	0.14	0.16	0.17
Methanol[12]	0.00	0.08	0.08	0.09	0.12	0.13	0.14	0.14	0.15	0.17
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	0.15	0.16	0.16	0.18	0.19	0.20	0.20	0.22	0.23
Delivered Energy	**24.72**	**31.25**	**32.77**	**34.14**	**32.13**	**34.54**	**36.79**	**32.56**	**36.04**	**39.25**
Electricity Related Losses	0.13	0.31	0.32	0.33	0.35	0.37	0.38	0.39	0.41	0.43
Total	**24.85**	**31.56**	**33.09**	**34.46**	**32.48**	**34.91**	**37.17**	**32.95**	**36.45**	**39.68**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	6.98	8.19	8.63	9.01	8.16	8.83	9.43	8.05	8.96	9.79
Kerosene	0.13	0.11	0.11	0.12	0.11	0.11	0.12	0.11	0.11	0.12
Jet Fuel[9]	3.27	4.89	5.23	5.54	5.24	5.79	6.30	5.48	6.28	7.01
Liquefied Petroleum Gas	2.65	2.89	3.13	3.35	2.88	3.24	3.58	2.80	3.31	3.78
Motor Gasoline[2]	15.16	17.78	18.49	19.15	17.98	19.12	20.22	18.00	19.67	21.24
Petrochemical Feedstock	1.28	1.33	1.47	1.58	1.29	1.49	1.67	1.22	1.51	1.76
Residual Fuel	1.39	1.67	1.74	1.82	1.79	1.88	2.00	1.88	2.03	2.16
Other Petroleum[13]	4.39	4.75	5.18	5.52	4.91	5.40	5.86	4.86	5.45	6.05
Petroleum Subtotal	35.26	41.61	43.98	46.10	42.37	45.87	49.17	42.40	47.33	51.90
Natural Gas[6]	19.56	21.55	22.25	22.90	21.57	22.72	23.82	21.48	22.99	24.56
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	1.68	1.75	1.92	2.07	1.70	1.93	2.14	1.62	1.94	2.22
Net Coal Coke Imports	0.00	0.05	0.06	0.08	0.05	0.07	0.10	0.05	0.08	0.11
Coal Subtotal	2.53	2.51	2.69	2.86	2.40	2.66	2.89	2.28	2.63	2.95
Renewable Energy[14]	2.44	2.78	2.96	3.13	2.81	3.08	3.33	2.78	3.15	3.48
Methanol[12]	0.00	0.08	0.08	0.09	0.12	0.13	0.14	0.14	0.15	0.17
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.57	12.53	13.23	13.91	12.99	14.04	15.03	13.23	14.70	16.06
Delivered Energy	**70.36**	**81.06**	**85.19**	**89.00**	**82.24**	**88.50**	**94.39**	**82.30**	**90.95**	**99.12**
Electricity Related Losses	23.64	25.81	26.97	27.95	25.45	27.22	28.78	25.44	27.63	29.97
Total	**94.01**	**106.87**	**112.17**	**116.94**	**107.69**	**115.72**	**123.17**	**107.74**	**118.58**	**129.10**
Electric Generators[15]										
Distillate Fuel	0.09	0.07	0.07	0.08	0.07	0.07	0.08	0.07	0.07	0.08
Residual Fuel	0.66	0.23	0.28	0.37	0.20	0.25	0.32	0.18	0.24	0.32
Petroleum Subtotal	0.75	0.29	0.35	0.45	0.27	0.32	0.39	0.25	0.31	0.40
Natural Gas	3.04	6.78	7.38	8.13	7.95	8.71	9.40	8.72	10.07	10.87
Steam Coal	18.36	20.20	21.34	22.12	20.40	22.29	23.95	20.80	22.99	25.39
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[16]	4.47	4.40	4.46	4.48	4.42	4.53	4.67	4.53	4.59	5.00
Electricity Imports[17]	0.39	0.31	0.31	0.31	0.28	0.28	0.28	0.28	0.28	0.28
Total	**34.21**	**38.34**	**40.20**	**41.86**	**38.44**	**41.26**	**43.81**	**38.66**	**42.33**	**46.04**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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 Energy Consumption										
Distillate Fuel	7.07	8.26	8.70	9.09	8.23	8.90	9.50	8.12	9.04	9.87
Kerosene	0.13	0.11	0.11	0.12	0.11	0.11	0.12	0.11	0.11	0.12
Jet Fuel[9]	3.27	4.89	5.23	5.54	5.24	5.79	6.30	5.48	6.28	7.01
Liquefied Petroleum Gas	2.65	2.89	3.13	3.35	2.88	3.24	3.58	2.80	3.31	3.78
Motor Gasoline[2]	15.16	17.78	18.49	19.15	17.98	19.12	20.22	18.00	19.67	21.24
Petrochemical Feedstock	1.28	1.33	1.47	1.58	1.29	1.49	1.67	1.22	1.51	1.76
Residual Fuel	2.05	1.90	2.02	2.19	1.99	2.14	2.31	2.06	2.27	2.48
Other Petroleum[13]	4.39	4.75	5.18	5.52	4.91	5.40	5.86	4.86	5.45	6.05
Petroleum Subtotal	36.01	41.90	44.33	46.55	42.63	46.20	49.56	42.65	47.64	52.31
Natural Gas	22.60	28.33	29.63	31.04	29.52	31.44	33.23	30.19	33.06	35.43
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	20.05	21.95	23.26	24.19	22.10	24.22	26.09	22.42	24.92	27.62
Net Coal Coke Imports	0.00	0.05	0.06	0.08	0.05	0.07	0.10	0.05	0.08	0.11
Coal Subtotal	20.90	22.71	24.03	24.98	22.80	24.95	26.84	23.08	25.61	28.34
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[18]	6.91	7.18	7.42	7.62	7.22	7.62	8.00	7.31	7.74	8.48
Methanol[12]	0.00	0.08	0.08	0.09	0.12	0.13	0.14	0.14	0.15	0.17
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[17]	0.39	0.31	0.31	0.31	0.28	0.28	0.28	0.28	0.28	0.28
Total	**94.01**	**106.87**	**112.17**	**116.94**	**107.69**	**115.72**	**123.17**	**107.74**	**118.58**	**129.10**
Energy Use and Related Statistics										
Delivered Energy Use	70.36	81.06	85.19	89.00	82.24	88.50	94.39	82.30	90.95	99.12
Total Energy Use	94.01	106.86	112.16	116.94	107.68	115.71	123.15	107.71	118.55	129.07
Population (millions)	266.07	290.33	298.92	306.87	299.11	311.19	322.36	307.94	323.47	337.80
Gross Domestic Product (billion 1992 dollars)	6928.40	8756.37	9431.22	10065.82	9198.70	10210.71	11167.23	9533.35	10899.70	12190.94
Total Carbon Emissions (million metric tons)	1462.90	1713.00	1803.22	1882.98	1749.24	1888.33	2014.33	1770.02	1956.19	2133.90

[1]Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps & solar thermal hot water heating.
[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 B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[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; including for cogeneration, both for sale to the grid and for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[12]Only M85 (85 percent methanol and 15 percent motor gasoline).
[13]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, roadoil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[17]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 natural gas lease, plant, and pipeline fuel values: Energy Information Administration, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). 1996 electric utility fuel consumption: EIA, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997). 1996 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1996 values: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B3. Energy Prices by Sector and Source
(1996 Dollars per Million Btu)

Sector and Source	1996	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	**12.94**	**11.39**	**12.21**	**12.95**	**10.92**	**11.91**	**12.69**	**10.71**	**11.97**	**12.86**
Primary Energy[1]	6.63	5.78	6.15	6.52	5.56	6.07	6.43	5.48	6.17	6.57
Petroleum Products[2]	8.51	9.12	9.42	9.65	9.07	9.54	9.88	9.10	9.70	10.02
Distillate Fuel	7.09	7.39	7.55	7.72	7.31	7.64	7.83	7.23	7.71	7.94
Liquefied Petroleum Gas	11.59	11.97	12.45	12.69	11.85	12.43	12.92	11.95	12.57	12.92
Natural Gas	6.19	5.03	5.42	5.83	4.79	5.32	5.69	4.72	5.44	5.86
Electricity	24.65	20.06	21.43	22.60	18.86	20.40	21.65	18.17	20.01	21.42
Commercial	**12.92**	**10.74**	**11.63**	**12.50**	**10.07**	**11.19**	**12.11**	**9.74**	**11.15**	**12.25**
Primary Energy[1]	5.26	4.44	4.79	5.15	4.28	4.77	5.11	4.27	4.91	5.29
Petroleum Products[2]	5.56	5.82	6.02	6.18	5.74	6.12	6.36	5.77	6.25	6.50
Distillate Fuel	5.27	5.48	5.65	5.81	5.37	5.75	5.96	5.33	5.86	6.10
Residual Fuel	3.24	3.02	3.16	3.28	3.13	3.28	3.44	3.19	3.40	3.58
Natural Gas[3]	5.28	4.27	4.66	5.06	4.11	4.62	4.99	4.09	4.77	5.19
Electricity	22.24	17.69	19.16	20.53	16.25	18.02	19.50	15.44	17.58	19.36
Industrial[4]	**5.40**	**4.73**	**5.15**	**5.51**	**4.53**	**5.10**	**5.51**	**4.51**	**5.21**	**5.66**
Primary Energy	4.03	3.65	3.97	4.23	3.58	4.04	4.34	3.64	4.20	4.52
Petroleum Products[2]	5.68	5.26	5.53	5.70	5.08	5.55	5.84	5.17	5.70	5.96
Distillate Fuel	5.50	5.58	5.74	5.89	5.44	5.88	6.14	5.46	6.07	6.32
Liquefied Petroleum Gas	7.80	6.28	6.76	6.99	6.02	6.64	7.11	6.13	6.81	7.11
Residual Fuel	3.00	2.87	3.02	3.17	2.84	3.15	3.39	2.91	3.35	3.57
Natural Gas[5]	2.96	2.53	2.93	3.31	2.51	3.00	3.36	2.52	3.17	3.60
Metallurgical Coal	1.77	1.69	1.68	1.69	1.68	1.67	1.68	1.66	1.66	1.66
Steam Coal	1.46	1.33	1.33	1.33	1.31	1.31	1.31	1.29	1.30	1.30
Electricity	13.54	10.68	11.41	12.11	9.70	10.59	11.33	9.20	10.26	11.11
Transportation	**8.77**	**8.46**	**8.83**	**9.21**	**8.16**	**8.86**	**9.31**	**8.18**	**8.87**	**9.44**
Primary Energy	8.76	8.44	8.81	9.19	8.14	8.84	9.29	8.16	8.85	9.42
Petroleum Products[2]	8.76	8.44	8.80	9.18	8.12	8.82	9.28	8.13	8.82	9.39
Distillate Fuel[6]	8.90	8.27	8.61	8.97	7.93	8.60	9.01	7.74	8.52	9.00
Jet Fuel[7]	5.52	5.55	5.85	6.14	5.43	6.05	6.55	5.55	6.27	6.88
Motor Gasoline[8]	9.89	9.75	10.18	10.63	9.43	10.22	10.73	9.52	10.24	10.88
Residual Fuel	2.55	2.91	3.07	3.21	2.83	3.14	3.35	2.92	3.32	3.56
Liquid Petroleum Gas[9]	12.62	12.62	13.30	13.73	12.29	13.07	13.79	12.19	13.01	13.62
Natural Gas[10]	5.41	6.24	6.60	7.00	6.54	7.06	7.38	6.77	7.39	7.78
E85[11]	15.85	16.08	16.71	17.37	17.44	17.04	17.53	18.26	17.79	18.23
Electricity	15.31	12.57	13.25	13.82	11.79	12.54	13.15	11.42	12.26	12.93
Average End-Use Energy	**8.68**	**7.88**	**8.35**	**8.79**	**7.59**	**8.28**	**8.77**	**7.57**	**8.35**	**8.92**
Primary Energy	8.35	7.65	8.09	8.51	7.37	8.04	8.51	7.37	8.11	8.66
Electricity	20.19	16.26	17.32	18.28	15.14	16.36	17.37	14.60	16.01	17.14
Electric Generators[12]										
Fossil Fuel Average	1.54	1.44	1.57	1.71	1.43	1.60	1.72	1.42	1.66	1.80
Petroleum Products	3.28	3.78	3.84	3.86	3.83	4.00	4.09	3.96	4.21	4.31
Distillate Fuel	4.90	5.16	5.33	5.47	5.06	5.47	5.71	5.07	5.64	5.87
Residual Fuel	3.07	3.38	3.46	3.52	3.43	3.60	3.70	3.56	3.77	3.91
Natural Gas	2.64	2.43	2.84	3.24	2.46	2.98	3.35	2.49	3.15	3.59
Steam Coal	1.29	1.08	1.09	1.10	1.00	1.03	1.04	0.95	0.97	0.99

Table B3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu)

Sector and Source	1996	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]	7.86	7.71	8.02	8.31	7.45	8.06	8.44	7.50	8.12	8.57
Distillate Fuel	7.84	7.59	7.88	8.17	7.32	7.91	8.27	7.18	7.90	8.31
Jet Fuel	5.52	5.55	5.85	6.14	5.43	6.05	6.55	5.55	6.27	6.88
Liquefied Petroleum Gas	8.53	7.65	8.09	8.29	7.52	8.05	8.48	7.71	8.24	8.49
Motor Gasoline[8]	9.89	9.74	10.16	10.62	9.42	10.21	10.72	9.52	10.23	10.87
Residual Fuel	2.84	2.96	3.12	3.26	2.91	3.21	3.41	2.99	3.38	3.61
Natural Gas	4.13	3.31	3.70	4.07	3.23	3.72	4.08	3.23	3.86	4.28
Coal	1.32	1.10	1.11	1.12	1.03	1.05	1.06	0.97	1.00	1.02
E85[11]	15.85	16.08	16.71	17.37	17.44	17.04	17.53	18.26	17.79	18.23
Electricity	20.19	16.26	17.32	18.28	15.14	16.36	17.37	14.60	16.01	17.14
Non-Renewable Energy Expenditures by Sector (billion 1996 dollars)										
Residential	117.09	117.97	130.36	142.61	118.54	134.72	149.74	121.91	143.05	161.67
Commercial	96.47	89.54	99.96	110.54	85.96	99.87	112.82	82.88	100.74	117.21
Industrial	136.22	129.67	151.07	171.18	123.11	152.83	179.23	119.17	157.75	191.58
Transportation	210.35	254.82	278.70	302.88	251.65	293.73	329.22	254.92	306.35	355.25
Total Non-Renewable Expenditures	560.12	592.01	660.09	727.21	579.26	681.15	771.01	578.87	707.89	825.71
Transportation Renewable Expenditures	0.03	1.33	1.47	1.62	2.10	2.25	2.50	2.53	2.79	3.14
Total Expenditures	**560.15**	**593.33**	**661.57**	**728.83**	**581.35**	**683.40**	**773.50**	**581.40**	**710.68**	**828.84**

[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 uses for lease and plant fuel.
[6] Low sulfur diesel fuel. 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 and State taxes and excludes county 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.
[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: 1996 figures may differ from published data due to internal rounding.

Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EI 0380(96/13-97/4) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(9 (Washington, DC, June 1997). 1996 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1996 residential and commercial natural g delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). Other 1996 natural gas delivered prices: EIA, AEO98 National Energy Modeling Syste runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.. Values for 1996 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 199* DOE/EIA-0376(94) (Washington, DC, June 1997) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.go pub/state.data/021494.pdf (August 26, 1997) and the *Coal Industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997). 1996 electricity prices for commercial, industri and transportation: EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A. **Projections:** EIA, AEO98 National Ener Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	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	69.61	78.52	81.54	84.62	81.40	85.60	89.90	84.34	89.52	94.92
Multifamily	24.76	26.85	27.92	28.99	27.93	29.44	30.97	28.93	30.84	32.80
Mobile Homes	6.00	7.35	7.58	7.80	7.73	8.01	8.28	8.02	8.35	8.67
Total	**100.37**	**112.72**	**117.04**	**121.40**	**117.05**	**123.05**	**129.15**	**121.29**	**128.71**	**136.39**
Average House Square Footage	**1648**	**1696**	**1704**	**1712**	**1706**	**1716**	**1726**	**1717**	**1728**	**1738**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	110.90	105.99	104.63	103.42	105.44	103.79	102.47	105.21	102.91	101.45
Electricity Related Losses	83.37	81.98	80.73	79.45	79.60	78.15	77.01	79.61	77.20	76.21
Total Energy Consumption	194.27	187.97	185.37	182.86	185.04	181.95	179.48	184.82	180.11	177.66
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.47	0.49	0.50	0.51	0.50	0.51	0.53	0.51	0.53	0.55
Space Cooling	0.46	0.53	0.54	0.56	0.55	0.58	0.60	0.57	0.60	0.64
Water Heating	0.36	0.37	0.38	0.38	0.38	0.39	0.40	0.39	0.40	0.42
Refrigeration	0.41	0.27	0.28	0.29	0.26	0.27	0.29	0.26	0.27	0.29
Cooking	0.13	0.15	0.15	0.16	0.15	0.16	0.17	0.16	0.17	0.18
Clothes Dryers	0.19	0.21	0.22	0.23	0.22	0.24	0.25	0.24	0.25	0.27
Freezers	0.13	0.07	0.08	0.08	0.07	0.07	0.08	0.07	0.07	0.08
Lighting	0.34	0.38	0.39	0.41	0.40	0.42	0.44	0.43	0.45	0.48
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]	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06
Color Televisions	0.21	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.37	0.39
Personal Computers	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Furnace Fans	0.12	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.18	0.19
Other Uses[2]	0.78	1.43	1.49	1.54	1.60	1.68	1.77	1.75	1.86	1.97
Delivered Energy	**3.68**	**4.45**	**4.61**	**4.77**	**4.72**	**4.94**	**5.17**	**5.00**	**5.28**	**5.57**
Natural Gas										
Space Heating	3.76	3.80	3.87	3.94	3.87	3.97	4.09	3.96	4.04	4.19
Space Cooling	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Water Heating	1.32	1.39	1.43	1.46	1.45	1.49	1.54	1.50	1.55	1.62
Cooking	0.16	0.17	0.17	0.18	0.17	0.18	0.19	0.18	0.19	0.19
Clothes Dryers	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07
Other Uses[3]	0.09	0.10	0.10	0.11	0.10	0.11	0.11	0.11	0.11	0.12
Delivered Energy	**5.39**	**5.52**	**5.63**	**5.74**	**5.66**	**5.82**	**6.00**	**5.81**	**5.97**	**6.20**
Distillate										
Space Heating	0.80	0.67	0.67	0.68	0.64	0.64	0.65	0.62	0.62	0.63
Water Heating	0.09	0.09	0.10	0.10	0.09	0.10	0.10	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	**0.89**	**0.76**	**0.77**	**0.77**	**0.74**	**0.74**	**0.75**	**0.72**	**0.72**	**0.73**
Liquefied Petroleum Gas										
Space Heating	0.31	0.33	0.34	0.36	0.33	0.35	0.36	0.33	0.35	0.37
Water Heating	0.07	0.09	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.12
Cooking	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
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	**0.42**	**0.47**	**0.49**	**0.51**	**0.48**	**0.50**	**0.53**	**0.49**	**0.51**	**0.54**
Marketed Renewables (wood)[5]	0.61	0.61	0.63	0.64	0.62	0.64	0.66	0.62	0.64	0.67
Other Fuels[6]	0.13	0.12	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1996	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	6.09	6.02	6.13	6.24	6.08	6.24	6.42	6.16	6.31	6.53
Space Cooling	0.46	0.53	0.55	0.57	0.56	0.58	0.61	0.58	0.61	0.65
Water Heating	1.84	1.95	1.99	2.04	2.02	2.08	2.15	2.10	2.17	2.25
Refrigeration	0.41	0.27	0.28	0.29	0.26	0.27	0.29	0.26	0.27	0.29
Cooking	0.33	0.35	0.36	0.38	0.36	0.38	0.40	0.38	0.40	0.42
Clothes Dryers	0.24	0.27	0.28	0.29	0.28	0.30	0.31	0.30	0.32	0.33
Freezers	0.13	0.07	0.08	0.08	0.07	0.07	0.08	0.07	0.07	0.08
Lighting	0.34	0.38	0.39	0.41	0.40	0.42	0.44	0.43	0.45	0.48
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06
Color Televisions	0.21	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.37	0.39
Personal Computers	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Furnace Fans	0.12	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.18	0.19
Other Uses[7]	0.89	1.55	1.61	1.66	1.72	1.80	1.89	1.87	1.99	2.10
Delivered Energy	**11.13**	**11.95**	**12.25**	**12.55**	**12.34**	**12.77**	**13.23**	**12.76**	**13.25**	**13.84**
Electricity Related Losses	**8.23**	**9.17**	**9.39**	**9.57**	**9.26**	**9.58**	**9.91**	**9.62**	**9.93**	**10.40**
Total Energy Consumption by End-Use										
Space Heating	7.13	7.02	7.15	7.27	7.06	7.24	7.44	7.13	7.30	7.56
Space Cooling	1.50	1.61	1.66	1.70	1.63	1.70	1.77	1.68	1.74	1.83
Water Heating	2.66	2.71	2.76	2.81	2.76	2.84	2.92	2.85	2.93	3.04
Refrigeration	1.32	0.84	0.86	0.89	0.76	0.80	0.83	0.75	0.79	0.83
Cooking	0.62	0.65	0.67	0.69	0.66	0.69	0.72	0.68	0.72	0.76
Clothes Dryers	0.67	0.71	0.73	0.76	0.72	0.76	0.79	0.75	0.79	0.83
Freezers	0.42	0.23	0.23	0.24	0.20	0.21	0.22	0.20	0.21	0.22
Lighting	1.09	1.17	1.20	1.23	1.20	1.24	1.29	1.26	1.30	1.37
Clothes Washers	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Dishwashers	0.15	0.14	0.14	0.15	0.14	0.15	0.16	0.15	0.16	0.17
Color Televisions	0.67	0.96	0.98	1.00	0.99	1.02	1.06	1.04	1.08	1.12
Personal Computers	0.03	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Furnace Fans	0.38	0.44	0.46	0.47	0.46	0.48	0.51	0.49	0.51	0.54
Other Uses[7]	2.64	4.50	4.64	4.77	4.85	5.06	5.27	5.24	5.48	5.78
Total	**19.36**	**21.12**	**21.64**	**22.13**	**21.60**	**22.35**	**23.14**	**22.38**	**23.17**	**24.24**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.03	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.08**

[1]Does not include water heating 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 1993*.
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996: Energy Information Administration (EIA) *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

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

Key Indicators and Consumption	1996	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 Floor Space (billion square feet)										
Surviving	69.2	78.7	81.1	83.5	80.7	84.3	87.9	80.8	85.7	90.5
New Additions	1.7	1.5	1.7	1.9	1.2	1.5	1.7	0.9	1.1	1.4
Total	**70.9**	**80.2**	**82.8**	**85.5**	**82.0**	**85.8**	**89.7**	**81.7**	**86.8**	**91.9**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	105.3	104.0	103.8	103.5	104.2	104.0	103.9	104.2	104.2	104.2
Electricity Related Losses	106.3	101.8	100.8	99.3	98.6	97.7	96.8	98.1	96.4	96.1
Total Energy Consumption	211.5	205.8	204.5	202.9	202.8	201.7	200.8	202.3	200.5	200.3
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.12	0.13	0.14	0.14	0.14	0.15	0.15	0.14	0.15	0.16
Space Cooling	0.51	0.53	0.55	0.56	0.53	0.56	0.59	0.52	0.56	0.60
Water Heating	0.17	0.15	0.15	0.16	0.14	0.15	0.15	0.14	0.14	0.15
Ventilation	0.17	0.18	0.18	0.19	0.18	0.19	0.19	0.17	0.18	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.03
Lighting	1.15	1.22	1.24	1.27	1.24	1.27	1.31	1.22	1.28	1.33
Refrigeration	0.14	0.15	0.16	0.16	0.15	0.16	0.17	0.15	0.17	0.18
Office Equipment (PC)	0.07	0.08	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.11
Office Equipment (non-PC)	0.19	0.26	0.27	0.28	0.28	0.30	0.32	0.30	0.33	0.35
Other Uses[1]	0.82	1.24	1.29	1.34	1.35	1.43	1.52	1.41	1.53	1.64
Delivered Energy	**3.37**	**3.96**	**4.09**	**4.23**	**4.13**	**4.33**	**4.53**	**4.17**	**4.45**	**4.73**
Natural Gas[2]										
Space Heating	1.34	1.37	1.40	1.42	1.38	1.42	1.46	1.35	1.40	1.46
Space Cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.45	0.50	0.52	0.54	0.51	0.54	0.57	0.51	0.55	0.59
Cooking	0.18	0.22	0.22	0.23	0.22	0.23	0.24	0.22	0.23	0.25
Other Uses[3]	1.31	1.53	1.59	1.64	1.56	1.64	1.72	1.54	1.65	1.75
Delivered Energy	**3.30**	**3.65**	**3.75**	**3.85**	**3.69**	**3.85**	**4.01**	**3.65**	**3.85**	**4.07**
Distillate										
Space Heating	0.20	0.17	0.18	0.18	0.16	0.17	0.17	0.15	0.15	0.16
Water Heating	0.05	0.05	0.05	0.05	0.04	0.04	0.05	0.04	0.04	0.04
Other Uses[4]	0.19	0.17	0.18	0.18	0.17	0.18	0.18	0.17	0.18	0.19
Delivered Energy	**0.44**	**0.39**	**0.40**	**0.41**	**0.38**	**0.39**	**0.40**	**0.36**	**0.37**	**0.39**
Other Fuels[5]	**0.36**	**0.34**	**0.35**	**0.36**	**0.34**	**0.36**	**0.37**	**0.34**	**0.36**	**0.38**
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Delivered Energy Consumption by End-Use										
Space Heating	1.65	1.68	1.71	1.74	1.68	1.73	1.78	1.64	1.70	1.78
Space Cooling	0.53	0.55	0.57	0.59	0.55	0.58	0.61	0.54	0.58	0.62
Water Heating	0.68	0.70	0.72	0.74	0.70	0.73	0.76	0.69	0.73	0.78
Ventilation	0.17	0.18	0.18	0.19	0.18	0.19	0.19	0.17	0.18	0.20
Cooking	0.21	0.24	0.25	0.26	0.25	0.26	0.27	0.24	0.26	0.28
Lighting	1.15	1.22	1.24	1.27	1.24	1.27	1.31	1.22	1.28	1.33
Refrigeration	0.14	0.15	0.16	0.16	0.15	0.16	0.17	0.15	0.17	0.18
Office Equipment (PC)	0.07	0.08	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.11
Office Equipment (non-PC)	0.19	0.26	0.27	0.28	0.28	0.30	0.32	0.30	0.33	0.35
Other Uses[6]	2.68	3.28	3.41	3.53	3.43	3.61	3.79	3.47	3.71	3.96
Delivered Energy	**7.47**	**8.34**	**8.60**	**8.85**	**8.54**	**8.92**	**9.32**	**8.52**	**9.04**	**9.58**

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

Key Indicators and Consumption	1996	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	**7.54**	**8.16**	**8.35**	**8.49**	**8.09**	**8.39**	**8.68**	**8.01**	**8.37**	**8.83**
Total Energy Consumption by End-Use										
Space Heating	1.92	1.95	1.99	2.03	1.95	2.01	2.07	1.91	1.98	2.07
Space Cooling	1.66	1.64	1.69	1.72	1.60	1.67	1.73	1.54	1.63	1.73
Water Heating	1.06	1.01	1.04	1.06	0.98	1.02	1.06	0.95	1.00	1.05
Ventilation	0.54	0.54	0.56	0.57	0.52	0.54	0.57	0.50	0.53	0.56
Cooking	0.28	0.30	0.31	0.31	0.30	0.31	0.32	0.29	0.31	0.33
Lighting	3.73	3.73	3.77	3.82	3.66	3.74	3.83	3.57	3.67	3.80
Refrigeration	0.45	0.46	0.48	0.50	0.45	0.48	0.51	0.44	0.48	0.51
Office Equipment (PC)	0.22	0.25	0.26	0.27	0.26	0.27	0.29	0.27	0.29	0.31
Office Equipment (non-PC)	0.62	0.79	0.82	0.85	0.83	0.88	0.93	0.86	0.94	1.02
Other Uses[6]	4.51	5.83	6.03	6.22	6.07	6.39	6.70	6.18	6.58	7.02
Total	**15.01**	**16.51**	**16.94**	**17.33**	**16.63**	**17.31**	**18.00**	**16.53**	**17.41**	**18.41**
Non-Marketed Renewable Fuels										
Solar[7]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.01**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lightir emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas,coal, motor gasoline, and keroser
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.000 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 Energy Information Administration, *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/ pub/upd/aug97/index.html (August 21, 199
Projections: EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

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

Key Indicators and Consumption	1996	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 1987 dollars)										
Manufacturing	3030	3967	4318	4625	4088	4646	5129	4108	4957	5701
Nonmanufacturing	774	899	969	1036	921	1019	1115	941	1062	1181
Total	**3805**	**4866**	**5287**	**5660**	**5009**	**5665**	**6244**	**5049**	**6019**	**6882**
Energy Prices (1996 dollars per million Btu)										
Electricity	13.54	10.68	11.41	12.11	9.70	10.59	11.33	9.20	10.26	11.11
Natural Gas	2.96	2.53	2.93	3.31	2.51	3.00	3.36	2.52	3.17	3.60
Steam Coal	1.46	1.33	1.33	1.33	1.31	1.31	1.31	1.29	1.30	1.30
Residual Oil	3.00	2.87	3.02	3.17	2.84	3.15	3.39	2.91	3.35	3.57
Distillate Oil	5.50	5.58	5.74	5.89	5.44	5.88	6.14	5.46	6.07	6.32
Liquefied Petroleum Gas	7.80	6.28	6.76	6.99	6.02	6.64	7.11	6.13	6.81	7.11
Motor Gasoline	9.86	8.95	9.17	9.45	8.79	9.40	9.67	9.03	9.56	9.98
Metallurgical Coal	1.77	1.69	1.68	1.69	1.68	1.67	1.68	1.66	1.66	1.66
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.46	3.96	4.37	4.76	3.96	4.58	5.13	3.85	4.75	5.53
Natural Gas[2]	10.14	11.25	11.67	12.07	11.02	11.77	12.45	10.75	11.80	12.80
Steam Coal	1.55	1.61	1.77	1.92	1.55	1.78	1.99	1.48	1.79	2.07
Metallurgical Coal and Coke[3]	0.85	0.75	0.77	0.79	0.70	0.73	0.75	0.66	0.69	0.72
Residual Fuel	0.34	0.33	0.35	0.39	0.32	0.34	0.39	0.30	0.35	0.38
Distillate	1.17	1.35	1.45	1.54	1.37	1.51	1.64	1.39	1.56	1.73
Liquefied Petroleum Gas	2.12	2.18	2.40	2.59	2.13	2.45	2.73	2.02	2.47	2.88
Petrochemical Feedstocks	1.28	1.33	1.47	1.58	1.29	1.49	1.67	1.22	1.51	1.76
Other Petroleum[4]	4.31	4.66	5.09	5.43	4.83	5.31	5.76	4.78	5.36	5.95
Renewables[5]	1.82	2.08	2.25	2.40	2.07	2.31	2.53	2.02	2.34	2.64
Delivered Energy	**27.05**	**29.51**	**31.58**	**33.46**	**29.23**	**32.27**	**35.04**	**28.46**	**32.62**	**36.46**
Electricity Related Losses	7.74	8.16	8.92	9.56	7.76	8.88	9.82	7.41	8.93	10.31
Total	**34.79**	**37.68**	**40.50**	**43.02**	**36.99**	**41.15**	**44.86**	**35.87**	**41.55**	**46.77**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.91	0.81	0.83	0.84	0.79	0.81	0.82	0.76	0.79	0.80
Natural Gas[2]	2.66	2.31	2.21	2.13	2.20	2.08	1.99	2.13	1.96	1.86
Steam Coal	0.41	0.33	0.34	0.34	0.31	0.31	0.32	0.29	0.30	0.30
Metallurgical Coal and Coke[3]	0.22	0.15	0.15	0.14	0.14	0.13	0.12	0.13	0.11	0.10
Residual Fuel	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.05
Distillate	0.31	0.28	0.27	0.27	0.27	0.27	0.26	0.27	0.26	0.25
Liquefied Petroleum Gas	0.56	0.45	0.45	0.46	0.42	0.43	0.44	0.40	0.41	0.42
Petrochemical Feedstocks	0.34	0.27	0.28	0.28	0.26	0.26	0.27	0.24	0.25	0.26
Other Petroleum[4]	1.13	0.96	0.96	0.96	0.96	0.94	0.92	0.95	0.89	0.86
Renewables[5]	0.48	0.43	0.42	0.42	0.41	0.41	0.41	0.40	0.39	0.38
Delivered Energy	**7.11**	**6.07**	**5.97**	**5.91**	**5.84**	**5.70**	**5.61**	**5.64**	**5.42**	**5.30**
Electricity Related Losses	2.04	1.68	1.69	1.69	1.55	1.57	1.57	1.47	1.48	1.50
Total	**9.14**	**7.74**	**7.66**	**7.60**	**7.38**	**7.26**	**7.18**	**7.10**	**6.90**	**6.80**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[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.
Sources: 1996 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996 - 97). 1996 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). 1996 electricity prices: EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A. Other 1996 prices derived from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). Other 1996 values: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1996	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										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 lbs. (VMT)	2275	2785	2892	2994	2912	3077	3233	3005	3242	3455
Commercial Light Trucks (VMT)[1]	67	83	87	91	86	93	99	88	98	107
Freight Trucks >10,000 lbs. (VMT)	161	217	232	245	220	243	263	218	250	279
Air (seat miles available)	999	1722	1855	1979	1916	2139	2346	2082	2416	2720
Rail (ton miles traveled)	1204	1448	1533	1601	1452	1584	1696	1434	1623	1786
Marine (ton miles traveled)	777	873	923	964	874	949	1015	865	967	1059
Energy Efficiency Indicators										
New Car (miles per gallon)[2]	27.9	30.6	30.2	30.0	31.0	30.5	29.9	31.7	30.7	30.0
New Light Truck (miles per gallon)[2]	20.7	20.3	20.1	19.9	20.9	20.5	20.1	21.8	21.1	20.5
Light-Duty Fleet (miles per gallon)[3]	20.2	20.5	20.3	20.2	21.0	20.7	20.5	21.5	21.2	20.8
New Commercial Light Truck (MPG)[1]	20.2	19.8	19.6	19.4	20.4	20.0	19.6	21.3	20.6	20.0
Stock Commercial Light Truck (MPG)[1]	14.5	15.1	15.0	14.9	15.3	15.2	15.0	15.7	15.4	15.2
Aircraft Efficiency (seat miles per gallon)	50.6	55.5	55.7	55.9	57.1	57.4	57.6	58.7	59.0	59.2
Freight Truck Efficiency (miles per gallon)	5.6	5.9	6.0	6.0	6.0	6.0	6.1	6.0	6.1	6.1
Rail Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0
Domestic Shipping Efficiency										
(ton miles per thousand Btu)	2.7	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	13.96	17.07	17.76	18.39	17.44	18.55	19.62	17.57	19.20	20.74
Commercial Light Trucks[1]	0.58	0.69	0.73	0.76	0.70	0.76	0.83	0.70	0.79	0.88
Freight Trucks[4]	4.02	5.00	5.32	5.60	4.98	5.47	5.89	4.90	5.58	6.16
Air	3.32	4.94	5.27	5.59	5.29	5.84	6.36	5.54	6.35	7.07
Rail	0.52	0.59	0.62	0.65	0.58	0.63	0.67	0.57	0.63	0.69
Marine	1.43	1.85	1.91	1.97	1.99	2.09	2.18	2.11	2.25	2.38
Pipeline Fuel	0.73	0.91	0.95	0.99	0.92	0.99	1.04	0.96	1.03	1.11
Other[5]	0.25	0.29	0.31	0.33	0.29	0.32	0.35	0.29	0.33	0.37
Total	**24.72**	**31.25**	**32.77**	**34.14**	**32.13**	**34.54**	**36.79**	**32.56**	**36.04**	**39.25**

[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.
[5]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1996: Federal Administration Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1996-2007*, (Washington, DC, February 1995); Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://ww.eia.doe.gov/emeu/steo/pub/upd /aug97/index.html (August 21, 1997); EIA, *Fuel Oil and Kerosene Sales 1996*, DOE/EIA-0535(96) (Washington, DC, September 1997); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

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

Supply, Disposition, and Prices	1996	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
Generation by Fuel Type										
Electric Generators[1]										
Coal	1758	1974	2085	2166	2003	2190	2369	2042	2265	2530
Petroleum	80	29	35	45	27	33	39	25	32	41
Natural Gas	288	822	920	1040	1041	1171	1283	1169	1389	1517
Nuclear Power	675	596	596	596	480	480	480	383	383	383
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	392	379	382	385	383	388	396	386	393	416
Total	**3191**	**3797**	**4015**	**4228**	**3930**	**4258**	**4565**	**4002**	**4459**	**4884**
Non-Utility Generation for Own Use	26	26	26	26	26	26	26	26	26	26
Cogenerators[3]										
Coal	39	37	39	40	37	39	41	35	39	42
Petroleum	6	6	6	6	6	6	6	5	6	6
Natural Gas	174	195	201	206	192	200	208	182	194	204
Other Gaseous Fuels[4]	7	7	7	7	7	7	7	7	7	7
Renewable Sources[2]	41	41	43	45	40	43	46	38	42	46
Other[5]	3	3	4	4	3	4	4	3	3	4
Total	**270**	**289**	**299**	**308**	**284**	**299**	**312**	**271**	**291**	**308**
Sales to Utilities	121	126	127	128	125	127	129	123	126	129
Generation for Own Use	149	163	172	180	159	172	183	148	165	180
Net Imports[6]	**38**	**30**	**30**	**30**	**27**	**27**	**27**	**27**	**27**	**27**
Electricity Sales by Sector										
Residential	1079	1305	1350	1397	1384	1449	1516	1467	1548	1634
Commercial	988	1162	1200	1238	1209	1268	1329	1221	1304	1387
Industrial	1014	1161	1282	1395	1160	1343	1502	1129	1392	1620
Transportation	17	44	46	47	53	55	58	60	64	67
Total	**3098**	**3673**	**3877**	**4077**	**3807**	**4115**	**4405**	**3876**	**4308**	**4708**
End-Use Prices (1996 cents per kilowatthour)[7]										
Residential	8.4	6.8	7.3	7.7	6.4	7.0	7.4	6.2	6.8	7.3
Commercial	7.6	6.0	6.5	7.0	5.5	6.1	6.7	5.3	6.0	6.6
Industrial	4.6	3.6	3.9	4.1	3.3	3.6	3.9	3.1	3.5	3.8
Transportation	5.2	4.3	4.5	4.7	4.0	4.3	4.5	3.9	4.2	4.4
All Sectors Average	**6.9**	**5.5**	**5.9**	**6.2**	**5.2**	**5.6**	**5.9**	**5.0**	**5.5**	**5.8**

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[4]Other gaseous fuels include refinery and still gas.
[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[6]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[7]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 16* (July 1996) which indicates the transportation value should be higher. 1996 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996 residential electricity prices derived from EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/teo/pub/upd/aug97/index.html (August 21, 1997). **1996 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1996	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	305.3	300.4	304.6	312.0	305.3	316.0	339.2	304.8	323.6	359.8
Other Fossil Steam[3]	138.1	101.0	101.0	101.0	97.1	97.1	97.1	96.0	96.0	96.0
Combined Cycle	15.3	86.5	106.5	126.9	123.6	154.9	175.4	145.4	186.5	208.2
Combustion Turbine/Diesel	80.0	175.8	191.4	202.6	195.5	210.1	223.8	204.5	221.9	237.5
Nuclear Power	100.8	80.4	80.4	80.4	63.9	63.9	63.9	49.2	49.2	49.2
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
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]	88.6	93.2	93.6	94.1	93.9	94.7	95.9	94.5	95.7	98.8
Total	**748.0**	**857.0**	**897.3**	**936.8**	**899.1**	**956.7**	**1015.2**	**914.3**	**992.8**	**1069.4**
Cumulative Planned Additions[5]										
Coal Steam	2.4	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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]	0.7	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Total	**11.3**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	12.6	16.9	24.3	21.3	32.1	55.3	26.6	45.4	81.6
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	69.7	89.7	110.1	106.7	138.1	158.6	128.5	169.7	191.3
Combustion Turbine/Diesel	23.6	119.0	134.6	145.8	139.9	154.5	168.2	148.9	166.3	181.9
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]	0.5	2.3	2.8	3.2	3.3	4.2	5.3	4.1	5.4	8.4
Total	**24.1**	**203.7**	**244.0**	**283.4**	**271.3**	**328.9**	**387.4**	**308.1**	**386.7**	**463.3**
Cumulative Total Additions	**35.4**	**222.2**	**262.5**	**301.9**	**289.8**	**347.4**	**405.9**	**326.6**	**405.2**	**481.8**
Cumulative Retirements[6]	**14.4**	**92.4**	**92.4**	**92.4**	**117.1**	**117.1**	**117.1**	**138.8**	**138.8**	**138.8**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1996	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[7]										
Capability										
Coal	7.1	7.4	7.7	7.9	7.3	7.7	8.1	7.1	7.7	8.2
Petroleum	1.0	1.1	1.2	1.2	1.1	1.2	1.3	1.1	1.2	1.3
Natural Gas	28.0	31.8	32.7	33.5	31.4	32.7	33.9	30.1	31.9	33.4
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewable Sources[4]	5.8	6.3	6.6	6.9	6.1	6.6	7.0	5.8	6.4	7.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**47.7**	**49.3**	**50.7**	**47.0**	**49.3**	**51.3**	**45.2**	**48.3**	**51.0**
Cumulative Additions[5]	**8.1**	**12.8**	**14.4**	**15.8**	**12.1**	**14.3**	**16.4**	**10.3**	**13.4**	**16.1**

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.
[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]Cumulative additions after December 31, 1995. Non-zero utility planned additions in 1995 indicate units operational in 1995 but not supplying power to the grid.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 25, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1996 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1996 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1996	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 Sales	173.4	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	79.5	70.7	78.3	82.8	76.6	79.7	84.2	77.7	86.6	85.6
Gross Domestic Trade	**252.9**	**209.9**	**217.5**	**222.0**	**215.8**	**218.9**	**223.4**	**216.9**	**225.8**	**224.8**
Gross Domestic Firm Power Sales (million 1996 dollars)	8050.2	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9
Gross Domestic Economy Sales (million 1996 dollars)	1812.7	1495.4	1747.9	2055.2	1514.5	1712.8	1985.1	1462.8	1905.6	2079.9
Gross Domestic Sales (million 1996 dollars)	**9862.9**	**7958.3**	**8210.8**	**8518.1**	**7977.4**	**8175.6**	**8448.0**	**7925.6**	**8368.5**	**8542.7**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	26.1	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Economy Imports From Canada and Mexico[1]	20.7	33.4	33.6	33.6	30.1	30.1	30.1	30.1	30.1	30.1
Gross Imports From Canada and Mexico[1]	**46.8**	**51.2**	**51.4**	**51.3**	**47.9**	**47.9**	**47.9**	**47.9**	**47.9**	**47.9**
Firm Power Exports To Canada and Mexico	2.8	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
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	**9.3**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier inaccordance with prior agreements or under specified conditions.

Sources: 1996 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1996 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993.* Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

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

Supply and Disposition	1996	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]	6.48	5.49	5.57	5.67	5.15	5.24	5.37	4.79	4.92	5.08
Alaska	1.40	0.75	0.75	0.75	0.60	0.60	0.60	0.48	0.48	0.48
Lower 48 States	5.08	4.75	4.82	4.93	4.55	4.64	4.77	4.32	4.44	4.60
Net Imports	7.40	10.57	10.67	10.98	11.00	11.22	11.68	11.37	11.65	12.40
Other Crude Supply[2]	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.21**	**16.06**	**16.24**	**16.66**	**16.16**	**16.46**	**17.05**	**16.16**	**16.58**	**17.48**
Natural Gas Plant Liquids	**1.83**	**2.13**	**2.24**	**2.32**	**2.20**	**2.35**	**2.47**	**2.25**	**2.47**	**2.64**
Other Inputs[3]	**0.39**	**0.22**	**0.25**	**0.28**	**0.22**	**0.22**	**0.28**	**0.21**	**0.20**	**0.22**
Refinery Processing Gain[4]	**0.84**	**0.89**	**0.89**	**0.91**	**0.87**	**0.87**	**0.91**	**0.84**	**0.82**	**0.87**
Net Product Imports[5]	**1.10**	**2.18**	**3.00**	**3.44**	**2.32**	**3.70**	**4.43**	**2.31**	**4.33**	**5.38**
Total Primary Supply[6]	**18.37**	**21.47**	**22.63**	**23.61**	**21.77**	**23.60**	**25.15**	**21.78**	**24.40**	**26.59**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.99	9.37	9.75	10.10	9.49	10.10	10.68	9.51	10.39	11.22
Jet Fuel[8]	1.58	2.36	2.53	2.68	2.53	2.80	3.04	2.65	3.03	3.39
Distillate Fuel[9]	3.32	3.88	4.09	4.28	3.87	4.19	4.47	3.82	4.25	4.64
Residual Fuel	0.90	0.83	0.88	0.96	0.87	0.93	1.01	0.90	0.99	1.08
Other[10]	4.66	5.01	5.45	5.83	5.05	5.64	6.19	4.93	5.72	6.47
Total	**18.44**	**21.45**	**22.70**	**23.84**	**21.81**	**23.65**	**25.39**	**21.80**	**24.39**	**26.79**
Refined Petroleum Products Supplied										
Residential and Commercial	1.13	1.07	1.09	1.12	1.06	1.09	1.13	1.04	1.08	1.13
Industrial[11]	4.87	5.17	5.65	6.06	5.19	5.82	6.40	5.04	5.89	6.68
Transportation	12.11	15.08	15.81	16.46	15.44	16.60	17.68	15.60	17.27	18.81
Electric Generators[12]	0.33	0.13	0.16	0.20	0.12	0.14	0.17	0.11	0.14	0.18
Total	**18.44**	**21.45**	**22.70**	**23.84**	**21.81**	**23.65**	**25.39**	**21.80**	**24.39**	**26.79**
Discrepancy[13]	**-0.08**	**0.02**	**-0.08**	**-0.23**	**-0.04**	**-0.05**	**-0.24**	**-0.02**	**0.01**	**-0.20**
World Oil Price (1996 dollars per barrel)[14]	**20.48**	**20.29**	**20.81**	**21.55**	**20.65**	**21.48**	**22.38**	**21.24**	**22.32**	**23.44**
Import Share of Product Supplied	**0.46**	**0.59**	**0.60**	**0.61**	**0.61**	**0.63**	**0.63**	**0.63**	**0.66**	**0.66**
Net Expenditures for Imported Crude Oil and Products (billion 1996 dollars)	**62.27**	**95.94**	**106.39**	**116.59**	**101.94**	**120.20**	**135.96**	**106.95**	**133.54**	**157.55**
Domestic Refinery Distillation Capacity	**15.4**	**16.9**	**17.1**	**17.6**	**17.0**	**17.4**	**18.0**	**17.0**	**17.5**	**18.5**
Capacity Utilization Rate (percent)	**94.0**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.1**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[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]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 expenditures for imported crude oil and petroleum products based on internal calculations. 1996 product supplied data from Table B2. Other 1996 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B12. Petroleum Product Prices
(1996 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1996	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 (1996 dollars per barrel)	**20.48**	**20.29**	**20.81**	**21.55**	**20.65**	**21.48**	**22.38**	**21.24**	**22.32**	**23.44**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	98.4	102.5	104.8	107.1	101.3	106.0	108.6	100.3	107.0	110.1
Liquefied Petroleum Gas	100.0	103.3	107.5	109.5	102.3	107.3	111.5	103.1	108.5	111.5
Commercial										
Distillate Fuel	73.1	76.0	78.3	80.5	74.5	79.7	82.7	73.9	81.3	84.6
Residual Fuel	48.4	45.2	47.3	49.1	46.8	49.2	51.5	47.7	50.9	53.6
Residual Fuel (1996 dollars per barrel)	20.35	18.99	19.85	20.63	19.67	20.65	21.63	20.05	21.36	22.53
Industrial[1]										
Distillate Fuel	76.3	77.3	79.6	81.7	75.5	81.5	85.1	75.7	84.2	87.7
Liquefied Petroleum Gas	67.3	54.2	58.4	60.3	52.0	57.3	61.3	52.9	58.8	61.4
Residual Fuel	45.0	43.0	45.2	47.4	42.5	47.2	50.7	43.5	50.1	53.4
Residual Fuel (1996 dollars per barrel)	18.88	18.07	18.97	19.90	17.84	19.80	21.28	18.27	21.04	22.44
Transportation										
Diesel Fuel (distillate)[2]	123.5	114.7	119.4	124.3	109.9	119.3	124.9	107.4	118.2	124.9
Jet Fuel[3]	74.6	74.9	79.0	83.0	73.4	81.7	88.4	74.9	84.6	92.9
Motor Gasoline[4]	122.5	120.8	126.0	131.7	116.7	126.6	132.9	117.9	126.8	134.8
Residual Fuel	38.2	43.5	46.0	48.0	42.4	47.0	50.2	43.6	49.7	53.3
Residual Fuel (1996 dollars per barrel)	16.04	18.27	19.32	20.18	17.81	19.75	21.09	18.33	20.88	22.40
Electric Generators[5]										
Distillate Fuel	68.0	71.6	73.9	75.9	70.2	75.9	79.1	70.3	78.2	81.3
Residual Fuel	45.9	50.5	51.9	52.7	51.4	53.9	55.4	53.3	56.4	58.5
Residual Fuel (1996 dollars per barrel)	19.27	21.23	21.78	22.14	21.57	22.64	23.26	22.38	23.70	24.56
Refined Petroleum Product Prices[6]										
Distillate Fuel	108.7	105.3	109.2	113.3	101.5	109.7	114.6	99.6	109.6	115.3
Jet Fuel[3]	74.6	74.9	79.0	83.0	73.4	81.7	88.4	74.9	84.6	92.9
Liquefied Petroleum Gas	73.6	66.0	69.8	71.5	64.9	69.4	73.2	66.5	71.1	73.3
Motor Gasoline[4]	122.5	120.6	125.9	131.5	116.6	126.4	132.7	117.8	126.7	134.6
Residual Fuel	42.5	44.4	46.7	48.8	43.6	48.0	51.1	44.7	50.5	54.0
Residual Fuel (1996 dollars per barrel)	17.87	18.63	19.63	20.48	18.31	20.15	21.45	18.77	21.23	22.69
Average	**102.8**	**100.8**	**104.9**	**108.9**	**97.5**	**105.4**	**110.5**	**98.1**	**106.0**	**112.1**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. 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 and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections**: EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B13. Natural Gas Supply and Disposition, and Prices
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1996	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										
Dry Gas Production[1]	19.02	23.55	24.70	25.73	24.48	26.12	27.49	24.95	27.44	29.30
Supplemental Natural Gas[2]	0.12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Net Imports	**2.72**	**4.16**	**4.28**	**4.63**	**4.41**	**4.64**	**5.02**	**4.60**	**4.91**	**5.36**
Canada	2.76	4.01	4.13	4.44	4.27	4.50	4.84	4.48	4.80	5.21
Mexico	-0.02	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.17	-0.17	-0.17
Liquefied Natural Gas	-0.03	0.29	0.29	0.33	0.29	0.29	0.33	0.29	0.29	0.33
Total Supply	**21.86**	**27.76**	**29.03**	**30.41**	**28.94**	**30.81**	**32.56**	**29.60**	**32.41**	**34.72**
Consumption by Sector										
Residential	5.23	5.37	5.47	5.58	5.50	5.66	5.83	5.65	5.80	6.02
Commercial	3.20	3.54	3.65	3.74	3.59	3.74	3.90	3.55	3.75	3.96
Industrial[3]	8.60	9.41	9.75	10.09	9.11	9.75	10.35	8.82	9.70	10.58
Electric Generators[4]	2.98	6.63	7.22	7.96	7.78	8.52	9.20	8.53	9.85	10.64
Lease and Plant Fuel[5]	1.25	1.53	1.59	1.64	1.60	1.68	1.75	1.63	1.76	1.86
Pipeline Fuel	0.71	0.88	0.93	0.96	0.90	0.96	1.01	0.93	1.00	1.08
Transportation[6]	0.01	0.22	0.23	0.24	0.27	0.29	0.32	0.29	0.33	0.37
Total	**21.99**	**27.58**	**28.84**	**30.22**	**28.74**	**30.61**	**32.36**	**29.40**	**32.20**	**34.51**
Discrepancy[7]	**-0.12**	**0.18**	**0.19**	**0.19**	**0.20**	**0.20**	**0.21**	**0.20**	**0.21**	**0.21**

[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.
[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, 1996 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. Figures for 1996 may differ from published data due to internal conversion factors.
Sources: 1996 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). 1996 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, November 1997). 1996 transportation sector consumption: EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A. Other 1996 consumption: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A. **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B14. Natural Gas Prices, Margins, and Revenue
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1996	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]	2.24	1.91	2.31	2.69	1.89	2.38	2.73	1.91	2.54	2.97
Average Import Price	1.98	1.97	2.32	2.72	1.90	2.40	2.80	1.90	2.56	3.00
Average[2]	**2.21**	**1.92**	**2.31**	**2.70**	**1.89**	**2.38**	**2.74**	**1.91**	**2.54**	**2.97**
Delivered Prices										
Residential	6.37	5.17	5.58	6.00	4.93	5.47	5.85	4.86	5.60	6.02
Commercial	5.43	4.39	4.79	5.21	4.23	4.76	5.14	4.21	4.91	5.34
Industrial[3]	3.05	2.60	3.01	3.41	2.58	3.09	3.46	2.59	3.26	3.71
Electric Generators[4]	2.70	2.48	2.91	3.32	2.51	3.04	3.42	2.54	3.22	3.67
Transportation[5]	5.57	6.42	6.79	7.20	6.73	7.26	7.60	6.97	7.61	8.01
Average[6]	**4.25**	**3.41**	**3.80**	**4.19**	**3.32**	**3.83**	**4.19**	**3.32**	**3.97**	**4.40**
Transmission and Distribution Margins[7]										
Residential	4.17	3.25	3.27	3.30	3.04	3.09	3.11	2.95	3.05	3.05
Commercial	3.23	2.47	2.48	2.51	2.34	2.38	2.39	2.30	2.37	2.37
Industrial[3]	0.84	0.68	0.71	0.72	0.69	0.70	0.72	0.68	0.71	0.74
Electric Generators[4]	0.49	0.56	0.60	0.62	0.62	0.66	0.68	0.63	0.68	0.69
Transportation[5]	3.36	4.50	4.48	4.51	4.84	4.88	4.86	5.06	5.06	5.03
Average[6]	**2.04**	**1.49**	**1.49**	**1.49**	**1.43**	**1.44**	**1.45**	**1.41**	**1.43**	**1.42**
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	21.81	17.47	17.91	18.43	16.74	17.48	18.12	16.68	17.70	18.37
Commercial	10.34	8.76	9.05	9.40	8.38	8.88	9.32	8.15	8.87	9.36
Industrial[3]	7.23	6.42	6.89	7.21	6.29	6.87	7.45	6.01	6.92	7.78
Electric Generators[4]	1.47	3.71	4.32	4.93	4.85	5.63	6.25	5.41	6.69	7.40
Transportation[5]	0.03	0.98	1.04	1.10	1.29	1.43	1.54	1.49	1.68	1.88
Total	**40.88**	**37.33**	**39.21**	**41.08**	**37.55**	**40.29**	**42.69**	**37.74**	**41.87**	**44.79**

[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.
[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.

Sources: 1996 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991*. 1996 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). **Other 1996 values, and projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B15. Oil and Gas Supply

Production and Supply	1996	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										
Lower 48 Average Wellhead Price[1]										
(1996 dollars per barrel)	**19.41**	**20.53**	**21.08**	**21.80**	**20.19**	**21.01**	**21.83**	**20.67**	**21.58**	**23.03**
Production (million barrels per day)[2]										
U.S. Total	**6.48**	**5.49**	**5.57**	**5.67**	**5.15**	**5.24**	**5.37**	**4.79**	**4.92**	**5.08**
Lower 48 Onshore	3.76	3.09	3.15	3.22	3.06	3.13	3.22	2.99	3.09	3.21
Conventional	3.15	2.33	2.36	2.41	2.30	2.35	2.40	2.34	2.41	2.49
Enhanced Oil Recovery	0.61	0.76	0.79	0.81	0.76	0.78	0.82	0.65	0.68	0.73
Lower 48 Offshore	1.32	1.65	1.67	1.70	1.49	1.52	1.55	1.33	1.35	1.38
Alaska	1.40	0.75	0.75	0.75	0.60	0.60	0.60	0.48	0.48	0.48
Lower 48 End of Year Reserves (billion barrels)	**16.82**	**14.64**	**14.87**	**15.19**	**14.42**	**14.67**	**15.10**	**13.93**	**14.33**	**14.84**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1996 dollars per thousand cubic feet)	**2.24**	**1.91**	**2.31**	**2.69**	**1.89**	**2.38**	**2.73**	**1.91**	**2.54**	**2.97**
Production (trillion cubic feet)[3]										
U.S. Total	**19.01**	**23.55**	**24.70**	**25.73**	**24.48**	**26.12**	**27.49**	**24.95**	**27.44**	**29.30**
Lower 48 Onshore	13.07	16.33	17.33	18.25	17.29	18.72	19.75	17.14	18.99	20.22
Associated-Dissolved[4]	1.84	1.25	1.27	1.28	1.19	1.21	1.22	1.17	1.19	1.21
Non-Associated	11.23	15.08	16.06	16.97	16.10	17.51	18.53	15.97	17.81	19.01
Conventional	7.96	10.96	11.77	12.37	11.46	12.44	13.07	11.15	12.32	13.07
Unconventional	3.27	4.12	4.30	4.60	4.64	5.08	5.45	4.82	5.49	5.94
Lower 48 Offshore	5.50	6.66	6.81	6.91	6.60	6.81	7.15	7.21	7.83	8.46
Associated-Dissolved[4]	0.80	0.92	0.92	0.93	0.89	0.89	0.90	0.85	0.85	0.86
Non-Associated	4.70	5.74	5.89	5.98	5.72	5.92	6.25	6.37	6.98	7.60
Alaska	0.43	0.56	0.56	0.57	0.58	0.59	0.60	0.60	0.62	0.63
Lower 48 End of Year Reserves										
(trillion cubic feet)	**157.23**	**192.24**	**196.33**	**203.56**	**187.35**	**196.28**	**205.88**	**175.69**	**185.11**	**191.48**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.12**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Total Lower 48 Wells (thousands)	**21.75**	**25.87**	**28.19**	**30.36**	**26.53**	**29.39**	**31.91**	**28.09**	**32.04**	**35.14**

Ft. = feet.
[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.

Sources: 1996 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1996 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1996 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). 1996 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies. EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). Other 1996 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	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	452	477	505	504	473	505	531	479	513	566
Interior	173	168	177	174	149	167	176	154	166	180
West	439	560	583	648	601	654	708	626	697	755
East of the Mississippi	564	569	602	589	567	609	635	584	623	676
West of the Mississippi	500	635	663	738	656	717	781	674	754	825
Total	**1064**	**1204**	**1265**	**1326**	**1223**	**1326**	**1415**	**1258**	**1376**	**1501**
Net Imports										
Imports	7	8	8	8	8	8	8	8	8	8
Exports	90	112	112	112	119	119	119	128	128	128
Total	**-83**	**-104**	**-104**	**-104**	**-112**	**-112**	**-112**	**-120**	**-120**	**-120**
Total Supply[2]	**981**	**1100**	**1161**	**1222**	**1111**	**1215**	**1304**	**1138**	**1256**	**1381**
Consumption by Sector										
Residential and Commercial	6	6	6	7	6	7	7	6	6	7
Industrial[3]	70	73	81	87	71	81	90	67	81	94
Coke Plants	32	26	26	26	24	24	24	23	23	23
Electric Generators[4]	896	995	1049	1102	1012	1103	1183	1042	1147	1258
Total	**1003**	**1101**	**1162**	**1223**	**1113**	**1215**	**1305**	**1138**	**1257**	**1382**
Discrepancy and Stock Change[5]	**-23**	**-1**	**-1**	**-0**	**-2**	**-0**	**-1**	**0**	**-1**	**-1**
Average Minemouth Price										
(1996 dollars per short ton)	18.50	14.98	15.05	14.64	13.87	13.99	14.05	13.14	13.27	13.50
(1996 dollars per million Btu)	0.87	0.71	0.72	0.70	0.66	0.67	0.67	0.63	0.64	0.65
Delivered Prices (1996 dollars per short ton)[6]										
Industrial	32.28	29.22	29.29	29.25	28.76	28.90	28.85	28.43	28.57	28.58
Coke Plants	47.33	45.21	45.10	45.20	44.90	44.78	44.89	44.60	44.61	44.61
Electric Generators										
(1996 dollars per short ton)	26.45	21.91	22.09	22.15	20.26	20.72	20.99	18.91	19.52	20.01
(1996 dollars per million Btu)	1.29	1.08	1.09	1.10	1.00	1.03	1.04	0.95	0.97	0.99
Average	**27.52**	**22.96**	**23.12**	**23.16**	**21.34**	**21.76**	**21.98**	**19.99**	**20.56**	**21.00**
Exports[7]	**40.77**	**34.98**	**35.02**	**35.02**	**33.47**	**33.75**	**33.89**	**31.88**	**32.47**	**32.75**

[1]Includes anthracite, bituminous coal, and lignite.
[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.
[5]Balancing item: the sum of production, net imports, and net storage 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.
Sources: 1996 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B17. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1996	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	78.58	80.71	80.71	80.71	80.71	80.71	80.71	80.71	80.71	80.71
Geothermal[2]	3.02	2.71	2.92	3.07	2.59	2.87	3.52	2.55	2.94	3.87
Municipal Solid Waste[3]	2.91	3.77	3.92	4.07	4.02	4.26	4.49	4.09	4.38	4.68
Wood and Other Biomass[4]	1.91	2.02	2.07	2.08	2.27	2.28	2.64	2.31	2.50	4.58
Solar Thermal	0.36	0.46	0.46	0.46	0.51	0.51	0.51	0.56	0.56	0.56
Solar Photovoltaic	0.01	0.22	0.22	0.22	0.38	0.38	0.38	0.56	0.56	0.56
Wind	1.85	3.28	3.33	3.46	3.39	3.68	3.63	3.71	4.06	3.83
Total	**88.64**	**93.17**	**93.64**	**94.07**	**93.87**	**94.69**	**95.88**	**94.49**	**95.70**	**98.79**
Generation (billion kilowatthours)										
Conventional Hydropower	346.28	318.61	318.67	318.74	318.65	318.76	318.86	318.68	318.82	318.96
Geothermal[2]	15.70	16.12	17.64	18.66	15.95	17.92	22.49	16.50	19.26	25.79
Municipal Solid Waste[3]	18.85	25.25	26.32	27.36	27.02	28.68	30.24	27.46	29.52	31.57
Wood and Other Biomass[4]	7.27	9.48	9.79	9.87	11.21	11.24	13.81	11.51	12.81	27.37
Solar Thermal	0.82	1.25	1.24	1.24	1.39	1.39	1.39	1.57	1.56	1.56
Solar Photovoltaic	0.00	0.60	0.60	0.60	1.00	1.00	1.00	1.45	1.45	1.45
Wind	3.17	7.60	7.76	8.13	7.95	8.86	8.66	9.01	10.08	9.31
Total	**392.09**	**378.89**	**382.03**	**384.60**	**383.17**	**387.84**	**396.44**	**386.17**	**393.50**	**416.01**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.41	0.45	0.46	0.47	0.46	0.47	0.49	0.45	0.48	0.50
Biomass	5.41	5.81	6.14	6.42	5.62	6.08	6.49	5.35	5.95	6.50
Total	**5.81**	**6.27**	**6.61**	**6.89**	**6.07**	**6.56**	**6.98**	**5.81**	**6.43**	**6.99**
Generation (billion kilowatthours)										
Municipal Solid Waste	2.09	2.24	2.30	2.34	2.26	2.34	2.40	2.26	2.36	2.45
Biomass	39.17	38.85	41.00	42.77	37.52	40.55	43.18	35.71	39.65	43.18
Total	**41.25**	**41.09**	**43.29**	**45.11**	**39.79**	**42.89**	**45.59**	**37.97**	**42.01**	**45.63**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of August 25, 1997. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1996 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report," 1996 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1996 generation: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1996	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	**0.61**	**0.61**	**0.63**	**0.64**	**0.62**	**0.64**	**0.66**	**0.62**	**0.64**	**0.67**
Wood	0.61	0.61	0.63	0.64	0.62	0.64	0.66	0.62	0.64	0.67
Commercial[3]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	**1.82**	**2.08**	**2.24**	**2.39**	**2.06**	**2.31**	**2.53**	**2.01**	**2.34**	**2.64**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.78	2.04	2.20	2.35	2.03	2.27	2.49	1.98	2.30	2.60
Transportation	**0.10**	**0.11**	**0.17**	**0.22**	**0.11**	**0.14**	**0.26**	**0.12**	**0.15**	**0.21**
Ethanol used in E85[5]	0.00	0.07	0.07	0.08	0.10	0.11	0.12	0.12	0.13	0.15
Ethanol used in Gasoline Blending	0.10	0.04	0.09	0.14	0.01	0.03	0.13	0.00	0.01	0.07
Electric Generators[6]	**4.40**	**4.33**	**4.40**	**4.45**	**4.39**	**4.48**	**4.67**	**4.42**	**4.56**	**4.92**
Conventional Hydroelectric	3.56	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
Geothermal	0.43	0.47	0.52	0.55	0.47	0.53	0.68	0.49	0.58	0.78
Municipal Solid Waste	0.30	0.40	0.42	0.44	0.43	0.46	0.48	0.44	0.47	0.51
Biomass	0.06	0.08	0.09	0.09	0.10	0.10	0.12	0.10	0.11	0.24
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wind	0.03	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10
Total Marketed Renewable Energy	**6.93**	**7.14**	**7.44**	**7.70**	**7.19**	**7.58**	**8.11**	**7.17**	**7.69**	**8.43**
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	**0.02**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.08**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.03	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
Commercial	**0.01**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
Solar Thermal	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, andwind 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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]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.
[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.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1996 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Utility Report" and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1996 ethanol: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96/1) (Washington, DC, June 1997). Other 1996: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1996	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	27.3	24.3	24.8	25.2	24.0	24.5	25.2	23.7	24.2	25.0
Natural Gas	77.4	79.5	81.1	82.7	81.5	83.8	86.4	83.7	85.9	89.2
Coal	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	179.9	221.7	230.9	238.6	235.0	248.8	261.8	252.6	267.5	284.5
Total	**286.0**	**326.9**	**338.1**	**347.9**	**341.9**	**358.5**	**374.7**	**361.3**	**379.0**	**400.0**
Commercial										
Petroleum	15.3	12.5	12.8	13.1	12.3	12.7	13.2	11.9	12.4	13.0
Natural Gas	47.4	52.5	54.0	55.5	53.1	55.4	57.7	52.5	55.5	58.6
Coal	2.1	2.4	2.4	2.5	2.4	2.5	2.6	2.4	2.5	2.7
Electricity	164.8	197.3	205.1	211.6	205.3	217.8	229.4	210.3	225.5	241.5
Total	**229.6**	**264.7**	**274.4**	**282.7**	**273.1**	**288.4**	**302.9**	**277.1**	**296.0**	**315.8**
Industrial[1]										
Petroleum	104.8	106.1	115.6	123.4	107.9	119.3	129.8	105.6	120.3	134.0
Natural Gas[2]	142.8	160.0	165.8	171.4	156.6	167.1	176.7	152.8	167.5	181.7
Coal	59.3	58.7	62.8	66.6	56.0	61.7	67.0	52.9	60.7	67.9
Electricity	169.2	197.2	219.1	238.3	196.9	230.6	259.4	194.5	240.6	282.1
Total	**476.1**	**522.0**	**563.3**	**599.6**	**517.4**	**578.7**	**633.0**	**505.9**	**589.2**	**665.6**
Transportation										
Petroleum	457.9	574.3	601.0	625.3	588.6	632.3	671.7	594.9	658.6	716.3
Natural Gas[3]	10.5	16.3	17.2	17.8	17.3	18.6	19.6	18.2	19.8	21.4
Other[4]	0.0	1.4	1.5	1.5	2.0	2.2	2.4	2.4	2.7	3.0
Electricity	2.8	7.5	7.8	8.1	9.0	9.5	10.0	10.3	11.0	11.7
Total	**471.2**	**599.4**	**627.5**	**652.8**	**616.8**	**662.7**	**703.8**	**625.8**	**692.1**	**752.5**
Total Carbon Emissions[5]										
Petroleum	605.3	717.2	754.2	787.0	732.8	788.9	839.9	736.0	815.5	888.4
Natural Gas	278.1	308.3	318.1	327.4	308.5	324.9	340.5	307.3	328.7	350.9
Coal	62.8	62.4	66.6	70.5	59.7	65.6	70.9	56.6	64.5	71.9
Other[4]	0.0	1.4	1.5	1.5	2.0	2.2	2.4	2.4	2.7	3.0
Electricity	516.7	623.7	662.9	696.6	646.2	706.8	760.6	667.7	744.7	819.7
Total	**1462.9**	**1713.0**	**1803.2**	**1883.0**	**1749.2**	**1888.3**	**2014.3**	**1770.0**	**1956.2**	**2133.9**
Electric Generators[6]										
Petroleum	15.5	6.1	7.4	9.4	5.6	6.8	8.2	5.2	6.6	8.5
Natural Gas	40.3	97.6	106.3	117.1	114.5	125.4	135.4	125.5	145.0	156.6
Coal	460.9	520.0	549.3	570.1	526.1	574.5	617.0	537.0	593.1	654.7
Total	**516.7**	**623.7**	**662.9**	**696.6**	**646.2**	**706.8**	**760.6**	**667.7**	**744.7**	**819.7**
Total Carbon Emissions[7]										
Petroleum	620.8	723.4	761.5	796.4	738.4	795.7	848.1	741.1	822.1	896.9
Natural Gas	318.4	405.8	424.4	444.5	423.0	450.3	475.9	432.8	473.7	507.5
Coal	523.7	582.4	615.9	640.5	585.8	640.1	687.9	593.6	657.7	726.5
Other[4]	0.0	1.4	1.5	1.5	2.0	2.2	2.4	2.4	2.7	3.0
Total	**1462.9**	**1713.0**	**1803.2**	**1883.0**	**1749.2**	**1888.3**	**2014.3**	**1770.0**	**1956.2**	**2133.9**
Carbon Emissions (tons per person)	**5.5**	**5.9**	**6.0**	**6.1**	**5.8**	**6.1**	**6.2**	**5.7**	**6.0**	**6.3**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]Includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). 1996 consumption estimates based on: EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1996	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 (1992=1.000)	**1.102**	**1.984**	**1.600**	**1.355**	**2.518**	**1.891**	**1.501**	**3.202**	**2.262**	**1.694**
Real Gross Domestic Product	**6928**	**8756**	**9431**	**10066**	**9199**	**10211**	**11167**	**9533**	**10900**	**12191**
Real Consumption	4714	6036	6349	6656	6507	6989	7453	6949	7626	8275
Real Investment	1067	1534	1739	1937	1634	1934	2230	1738	2105	2467
Real Government Spending	1258	1428	1498	1568	1476	1583	1688	1493	1640	1783
Real Exports	857	2107	2332	2552	2465	2849	3224	2771	3352	3920
Real Imports	971	2423	2514	2641	3101	3283	3509	3843	4153	4508
Real Disposable Personal Income	**5077**	**6511**	**6884**	**7242**	**6955**	**7560**	**8128**	**7336**	**8217**	**9006**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.299**	**1.700**	**1.851**	**1.982**	**1.752**	**1.992**	**2.198**	**1.761**	**2.125**	**2.444**
AA Utility Bond Rate (percent)	7.57	9.04	7.21	5.65	8.98	7.64	6.22	8.75	8.27	7.09
Real Yield on Government 10 Year Bonds (percent)	4.99	3.21	3.58	3.70	3.08	3.69	4.01	2.72	3.97	4.42
Real Utility Bond Rate (percent)	5.28	4.19	4.05	3.85	4.07	4.15	4.04	3.88	4.49	4.50
Delivered Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	10.16	9.27	9.04	8.85	8.95	8.68	8.46	8.64	8.35	8.14
Total Energy	13.57	12.21	11.90	11.63	11.72	11.34	11.04	11.31	10.89	10.60
Consumer Price Index (1982-84=1.00)	1.57	3.01	2.42	2.04	3.88	2.90	2.30	5.00	3.52	2.64
Unemployment Rate (percent)	5.38	5.92	5.51	5.32	6.04	5.55	5.33	6.18	5.66	5.43
Unit Sales of Light-Duty Vehicles (million)	**15.10**	**15.60**	**16.65**	**17.79**	**15.64**	**17.15**	**18.82**	**15.60**	**17.49**	**19.82**
Millions of People										
Population with Armed Forces Overseas	266.1	290.3	298.9	306.9	299.1	311.2	322.4	307.9	323.5	337.8
Population (aged 16 and over)	204.2	229.3	235.4	241.2	237.1	245.8	254.0	244.1	255.6	266.2
Employment, Non-Agriculture	119.5	138.0	143.9	149.3	140.8	149.2	157.1	142.2	153.4	163.9
Employment, Manufacturing	18.5	16.6	17.5	18.4	15.1	16.4	17.5	13.5	15.2	16.6
Labor Force	133.9	151.1	156.5	161.5	152.5	160.2	167.2	152.4	162.4	171.4

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1996: Data Resources Incorporated (DRI), DRI Trend0897. **Projections:** Energy Information Administration, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	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 (1996 dollars per barrel)[1]	**20.48**	**20.29**	**20.81**	**21.55**	**20.65**	**21.48**	**22.38**	**21.24**	**22.32**	**23.44**
Production[2]										
OECD										
U.S. (50 states)	9.37	8.72	8.94	9.19	8.47	8.73	9.11	8.14	8.48	8.90
Canada	2.51	2.60	2.59	2.60	2.63	2.62	2.63	2.66	2.66	2.66
Mexico	3.28	3.34	3.34	3.34	3.44	3.43	3.44	3.53	3.53	3.53
OECD Europe[3]	6.67	5.74	5.74	5.74	5.11	5.11	5.11	4.47	4.47	4.47
Other OECD	0.77	1.01	1.01	1.01	0.80	0.80	0.80	0.84	0.84	0.84
Total OECD	**22.60**	**21.40**	**21.62**	**21.88**	**20.44**	**20.70**	**21.09**	**19.64**	**19.98**	**20.40**
Developing Countries										
Other South & Central America	3.29	5.23	5.23	5.23	6.03	6.03	6.03	6.68	6.68	6.68
Pacific Rim	2.08	3.20	3.20	3.20	3.23	3.23	3.23	3.08	3.08	3.08
OPEC	29.00	47.10	48.19	49.01	54.75	56.40	57.68	63.70	65.98	67.94
Other Developing Countries	4.21	5.01	5.00	5.01	5.33	5.33	5.33	5.38	5.38	5.38
Total Developing Countries	**38.59**	**60.54**	**61.63**	**62.46**	**69.34**	**70.98**	**72.27**	**78.84**	**81.11**	**83.07**
Eurasia										
Former Soviet Union	7.14	9.83	9.83	9.83	10.59	10.59	10.59	11.41	11.41	11.41
Eastern Europe	0.32	0.21	0.21	0.21	0.18	0.18	0.18	0.18	0.18	0.18
China	3.10	3.27	3.27	3.27	3.46	3.46	3.46	3.65	3.65	3.65
Total Eurasia	**10.55**	**13.31**	**13.31**	**13.31**	**14.24**	**14.23**	**14.24**	**15.24**	**15.24**	**15.24**
Total Production	**71.74**	**95.26**	**96.56**	**97.65**	**104.02**	**105.91**	**107.59**	**113.72**	**116.34**	**118.71**
Consumption										
OECD										
U.S. (50 states)	18.31	21.45	22.70	23.84	21.81	23.66	25.39	21.80	24.39	26.80
U.S. Territories	0.26	0.38	0.38	0.38	0.42	0.42	0.42	0.46	0.46	0.46
Canada	1.77	2.14	2.15	2.14	2.28	2.28	2.28	2.43	2.43	2.43
Mexico	1.98	2.74	2.74	2.74	3.00	3.00	3.00	3.27	3.27	3.27
Japan	5.84	7.27	7.28	7.27	7.78	7.80	7.78	8.33	8.34	8.33
Australia and New Zealand.	0.97	1.20	1.20	1.20	1.24	1.24	1.24	1.29	1.29	1.29
OECD Europe[3]	13.93	15.10	15.11	15.10	15.39	15.40	15.39	15.69	15.69	15.69
Total OECD	**43.05**	**50.28**	**51.56**	**52.67**	**51.93**	**53.80**	**55.50**	**53.27**	**55.88**	**58.27**
Developing Countries										
Other South and Central America	3.79	6.51	6.51	6.51	7.48	7.49	7.48	8.60	8.61	8.60
Pacific Rim	4.55	8.43	8.44	8.43	10.07	10.07	10.07	12.03	12.03	12.03
OPEC	5.14	7.06	7.06	7.06	7.91	7.91	7.91	8.86	8.86	8.86
Other Developing Countries	5.44	7.94	7.94	7.94	8.75	8.75	8.75	9.66	9.66	9.66
Total Developing Countries	**18.91**	**29.94**	**29.95**	**29.94**	**34.21**	**34.22**	**34.21**	**39.15**	**39.16**	**39.15**

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	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
Eurasia										
Former Soviet Union	4.48	6.73	6.73	6.73	7.64	7.65	7.64	8.68	8.68	8.68
Eastern Europe	1.43	1.72	1.73	1.72	1.96	1.96	1.96	2.24	2.24	2.24
China	3.44	6.89	6.89	6.89	8.58	8.58	8.58	10.68	10.68	10.68
Total Eurasia	**9.35**	**15.34**	**15.35**	**15.34**	**18.18**	**18.19**	**18.18**	**21.60**	**21.60**	**21.60**
Total Consumption	**71.32**	**95.56**	**96.86**	**97.95**	**104.32**	**106.21**	**107.89**	**114.02**	**116.64**	**119.01**
Non-OPEC Production	42.74	48.16	48.37	48.63	49.27	49.52	49.91	50.01	50.36	50.78
Net Eurasia Exports	1.20	-2.03	-2.04	-2.03	-3.95	-3.96	-3.95	-6.35	-6.36	-6.35
OPEC Market Share	0.40	0.49	0.50	0.50	0.53	0.53	0.54	0.56	0.57	0.57

[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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LMAC98.D100197A, AEO98B.D100197A, and HMAC98.D100197A.

Oil Price Case Comparisons

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

Supply, Disposition, and Prices	1996	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	13.71	9.80	11.79	13.30	8.96	11.09	13.47	8.30	10.43	12.69
Natural Gas Plant Liquids	2.46	2.88	2.95	2.99	3.06	3.12	3.17	3.17	3.29	3.34
Dry Natural Gas	19.55	24.91	25.39	25.78	26.44	26.85	27.30	27.28	28.21	28.62
Coal	22.64	26.30	26.62	26.67	27.32	27.73	27.83	28.68	28.59	28.64
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[1]	6.91	7.41	7.41	7.37	7.58	7.59	7.54	7.68	7.71	7.74
Other[2]	1.33	0.41	0.48	0.49	0.43	0.47	0.50	0.46	0.47	0.48
Total	**73.80**	**78.08**	**81.00**	**82.97**	**78.91**	**81.97**	**84.93**	**79.66**	**82.77**	**85.60**
Imports										
Crude Oil[3]	16.30	25.43	23.17	21.51	26.98	24.36	21.88	27.99	25.30	22.99
Petroleum Products[4]	3.98	9.40	7.61	6.20	10.83	9.01	6.98	12.34	10.09	7.73
Natural Gas	2.93	4.61	4.66	4.86	4.95	5.04	5.24	5.23	5.34	5.55
Other Imports[5]	0.57	0.57	0.57	0.57	0.54	0.54	0.54	0.56	0.56	0.56
Total	**23.78**	**40.01**	**36.02**	**33.14**	**43.31**	**38.96**	**34.65**	**46.11**	**41.28**	**36.82**
Exports										
Petroleum[6]	2.04	1.82	1.80	1.73	1.95	1.89	1.77	1.75	1.67	1.48
Natural Gas	0.16	0.29	0.29	0.29	0.30	0.30	0.30	0.32	0.32	0.32
Coal	2.37	2.84	2.84	2.84	3.03	3.03	3.03	3.23	3.23	3.23
Total	**4.57**	**4.96**	**4.93**	**4.87**	**5.27**	**5.21**	**5.10**	**5.31**	**5.23**	**5.03**
Discrepancy[7]	**0.99**	**-0.06**	**0.08**	**0.37**	**-0.07**	**0.00**	**0.39**	**-0.48**	**-0.25**	**0.36**
Consumption										
Petroleum Products[8]	36.01	46.11	44.33	43.18	48.29	46.20	44.66	50.02	47.64	46.12
Natural Gas	22.60	29.09	29.63	30.22	30.90	31.44	32.08	32.00	33.06	33.69
Coal	20.90	23.68	24.03	24.06	24.54	24.95	25.06	25.71	25.61	25.67
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[1]	6.91	7.43	7.42	7.39	7.60	7.62	7.56	7.72	7.74	7.77
Other[9]	0.39	0.40	0.40	0.39	0.41	0.40	0.40	0.44	0.43	0.42
Total	**94.01**	**113.07**	**112.17**	**111.60**	**116.87**	**115.72**	**114.87**	**119.98**	**118.58**	**117.75**
Net Imports - Petroleum	**18.25**	**33.01**	**28.99**	**25.97**	**35.87**	**31.48**	**27.09**	**38.57**	**33.71**	**29.24**
Prices (1996 dollars per unit)										
World Oil Price (dollars per barrel)[10]	20.48	14.44	20.81	26.87	14.42	21.48	28.59	14.43	22.32	28.71
Gas Wellhead Price (dollars per Mcf)[11]	2.24	2.25	2.31	2.38	2.35	2.38	2.42	2.45	2.54	2.58
Coal Minemouth Price (dollars per ton)	18.50	14.83	15.05	14.85	13.96	13.99	13.92	13.16	13.27	13.28
Average Electric Price (cents per kwh)	6.9	5.9	5.9	6.0	5.6	5.6	5.6	5.4	5.5	5.5

[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, 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.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures may differ from published data due to internal conversion factors.
Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). 1996 coal minemouth price: *Coal Industry Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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
Energy Consumption										
Residential										
Distillate Fuel	0.89	0.80	0.77	0.74	0.78	0.74	0.71	0.76	0.72	0.69
Kerosene	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.42	0.51	0.49	0.47	0.53	0.50	0.48	0.54	0.51	0.49
Petroleum Subtotal	1.40	1.38	1.33	1.28	1.38	1.32	1.26	1.38	1.30	1.25
Natural Gas	5.39	5.63	5.63	5.60	5.82	5.82	5.78	5.99	5.97	5.95
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.61	0.63	0.63	0.63	0.64	0.64	0.63	0.64	0.64	0.64
Electricity	3.68	4.61	4.61	4.60	4.95	4.94	4.94	5.29	5.28	5.27
Delivered Energy	**11.13**	**12.31**	**12.25**	**12.16**	**12.84**	**12.77**	**12.66**	**13.35**	**13.25**	**13.16**
Electricity Related Losses	8.23	9.49	9.39	9.35	9.69	9.58	9.55	10.06	9.93	9.92
Total	**19.36**	**21.80**	**21.64**	**21.51**	**22.53**	**22.35**	**22.21**	**23.41**	**23.17**	**23.08**
Commercial										
Distillate Fuel	0.44	0.44	0.40	0.39	0.44	0.39	0.38	0.44	0.37	0.37
Residual Fuel	0.15	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Petroleum Subtotal	0.71	0.70	0.65	0.65	0.70	0.65	0.64	0.70	0.63	0.63
Natural Gas	3.30	3.72	3.75	3.74	3.80	3.85	3.84	3.81	3.85	3.85
Coal	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.37	4.10	4.09	4.09	4.33	4.33	4.32	4.46	4.45	4.44
Delivered Energy	**7.47**	**8.61**	**8.60**	**8.57**	**8.94**	**8.92**	**8.90**	**9.07**	**9.04**	**9.02**
Electricity Related Losses	7.54	8.43	8.35	8.31	8.48	8.39	8.36	8.48	8.37	8.35
Total	**15.01**	**17.04**	**16.94**	**16.88**	**17.42**	**17.31**	**17.26**	**17.55**	**17.41**	**17.37**
Industrial[4]										
Distillate Fuel	1.17	1.45	1.45	1.44	1.51	1.51	1.51	1.56	1.56	1.56
Liquefied Petroleum Gas	2.12	2.45	2.40	2.32	2.51	2.45	2.36	2.53	2.47	2.39
Petrochemical Feedstock	1.28	1.48	1.47	1.42	1.51	1.49	1.45	1.52	1.51	1.46
Residual Fuel	0.34	0.40	0.35	0.33	0.40	0.34	0.31	0.39	0.35	0.32
Motor Gasoline[2]	0.19	0.25	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.27
Other Petroleum[5]	4.12	5.06	4.84	4.43	5.24	5.05	4.52	5.24	5.10	4.59
Petroleum Subtotal	9.23	11.09	10.75	10.20	11.43	11.10	10.40	11.52	11.25	10.58
Natural Gas[6]	10.14	11.28	11.67	12.14	11.39	11.77	12.37	11.47	11.80	12.35
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	1.55	1.75	1.77	1.78	1.77	1.78	1.79	1.77	1.79	1.79
Net Coal Coke Imports	0.00	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Coal Subtotal	2.40	2.53	2.54	2.55	2.50	2.51	2.51	2.46	2.48	2.48
Renewable Energy[7]	1.82	2.25	2.25	2.24	2.32	2.31	2.30	2.35	2.34	2.34
Electricity	3.46	4.31	4.37	4.43	4.51	4.58	4.64	4.64	4.75	4.80
Delivered Energy	**27.05**	**31.46**	**31.58**	**31.55**	**32.15**	**32.27**	**32.22**	**32.44**	**32.62**	**32.54**
Electricity Related Losses	7.74	8.87	8.92	9.01	8.83	8.88	8.97	8.83	8.93	9.02
Total	**34.79**	**40.33**	**40.50**	**40.56**	**40.98**	**41.15**	**41.19**	**41.27**	**41.55**	**41.56**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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
Transportation										
Distillate Fuel[8]	4.48	6.04	6.02	6.01	6.22	6.19	6.18	6.35	6.31	6.29
Jet Fuel[9]	3.27	5.28	5.23	5.21	5.85	5.79	5.74	6.36	6.28	6.24
Motor Gasoline[2]	14.94	18.94	18.22	17.85	19.74	18.84	18.27	20.50	19.38	18.77
Residual Fuel	0.90	1.28	1.27	1.27	1.43	1.42	1.41	1.57	1.56	1.55
Liquefied Petroleum Gas	0.03	0.17	0.16	0.15	0.22	0.20	0.19	0.26	0.24	0.22
Other Petroleum[10]	0.29	0.36	0.35	0.35	0.37	0.37	0.36	0.38	0.37	0.37
Petroleum Subtotal	23.91	32.06	31.25	30.83	33.84	32.80	32.15	35.42	34.14	33.45
Pipeline Fuel Natural Gas	0.73	0.92	0.95	0.96	0.96	0.99	0.99	0.99	1.03	1.04
Compressed Natural Gas	0.01	0.25	0.24	0.23	0.31	0.30	0.29	0.36	0.34	0.33
Renewable Energy (E85)[11]	0.00	0.10	0.09	0.08	0.14	0.13	0.12	0.17	0.16	0.15
Methanol[12]	0.00	0.09	0.08	0.08	0.13	0.13	0.12	0.16	0.15	0.15
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	0.16	0.16	0.16	0.19	0.19	0.19	0.22	0.22	0.22
Delivered Energy	**24.72**	**33.57**	**32.77**	**32.34**	**35.57**	**34.54**	**33.86**	**37.33**	**36.04**	**35.33**
Electricity Related Losses	0.13	0.33	0.32	0.32	0.37	0.37	0.36	0.42	0.41	0.40
Total	**24.85**	**33.89**	**33.09**	**32.65**	**35.95**	**34.91**	**34.22**	**37.75**	**36.45**	**35.74**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	6.98	8.73	8.63	8.58	8.96	8.83	8.76	9.11	8.96	8.91
Kerosene	0.13	0.12	0.11	0.11	0.12	0.11	0.11	0.12	0.11	0.11
Jet Fuel[9]	3.27	5.28	5.23	5.21	5.85	5.79	5.74	6.36	6.28	6.24
Liquefied Petroleum Gas	2.65	3.22	3.13	3.03	3.34	3.24	3.13	3.42	3.31	3.19
Motor Gasoline[2]	15.16	19.21	18.49	18.12	20.03	19.12	18.55	20.80	19.67	19.06
Petrochemical Feedstock	1.28	1.48	1.47	1.42	1.51	1.49	1.45	1.52	1.51	1.46
Residual Fuel	1.39	1.80	1.74	1.72	1.95	1.88	1.85	2.09	2.03	1.99
Other Petroleum[13]	4.39	5.39	5.18	4.76	5.59	5.40	4.86	5.60	5.45	4.94
Petroleum Subtotal	35.26	45.22	43.98	42.95	47.35	45.87	44.45	49.02	47.33	45.90
Natural Gas[6]	19.56	21.80	22.25	22.67	22.29	22.72	23.26	22.62	22.99	23.52
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	1.68	1.90	1.92	1.92	1.92	1.93	1.93	1.92	1.94	1.94
Net Coal Coke Imports	0.00	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Coal Subtotal	2.53	2.67	2.69	2.69	2.65	2.66	2.66	2.61	2.63	2.63
Renewable Energy[14]	2.44	2.98	2.96	2.95	3.10	3.08	3.06	3.17	3.15	3.13
Methanol[12]	0.00	0.09	0.08	0.08	0.13	0.13	0.12	0.16	0.15	0.15
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.57	13.18	13.23	13.27	13.98	14.04	14.08	14.61	14.70	14.73
Delivered Energy	**70.36**	**85.94**	**85.19**	**84.62**	**89.50**	**88.50**	**87.64**	**92.19**	**90.95**	**90.06**
Electricity Related Losses	23.64	27.13	26.97	26.98	27.37	27.22	27.24	27.79	27.63	27.70
Total	**94.01**	**113.07**	**112.17**	**111.60**	**116.87**	**115.72**	**114.87**	**119.98**	**118.58**	**117.75**
Electric Generators[15]										
Distillate Fuel	0.09	0.13	0.07	0.07	0.20	0.07	0.07	0.27	0.07	0.07
Residual Fuel	0.66	0.76	0.28	0.16	0.74	0.25	0.14	0.73	0.24	0.15
Petroleum Subtotal	0.75	0.89	0.35	0.23	0.94	0.32	0.21	1.00	0.31	0.22
Natural Gas	3.04	7.29	7.38	7.55	8.61	8.71	8.82	9.38	10.07	10.16
Steam Coal	18.36	21.00	21.34	21.37	21.90	22.29	22.39	23.10	22.99	23.04
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[16]	4.47	4.45	4.46	4.44	4.50	4.53	4.50	4.55	4.59	4.64
Electricity Imports[17]	0.39	0.31	0.31	0.31	0.28	0.28	0.28	0.28	0.28	0.28
Total	**34.21**	**40.30**	**40.20**	**40.26**	**41.35**	**41.26**	**41.32**	**42.40**	**42.33**	**42.42**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1996	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	7.07	8.86	8.70	8.65	9.16	8.90	8.83	9.39	9.04	8.97
Kerosene	0.13	0.12	0.11	0.11	0.12	0.11	0.11	0.12	0.11	0.11
Jet Fuel[9]	3.27	5.28	5.23	5.21	5.85	5.79	5.74	6.36	6.28	6.24
Liquefied Petroleum Gas	2.65	3.22	3.13	3.03	3.34	3.24	3.13	3.42	3.31	3.19
Motor Gasoline[2]	15.16	19.21	18.49	18.12	20.03	19.12	18.55	20.80	19.67	19.06
Petrochemical Feedstock	1.28	1.48	1.47	1.42	1.51	1.49	1.45	1.52	1.51	1.46
Residual Fuel	2.05	2.56	2.02	1.87	2.69	2.14	1.99	2.82	2.27	2.14
Other Petroleum[13]	4.39	5.39	5.18	4.76	5.59	5.40	4.86	5.60	5.45	4.94
Petroleum Subtotal	36.01	46.11	44.33	43.18	48.29	46.20	44.66	50.02	47.64	46.12
Natural Gas	22.60	29.09	29.63	30.22	30.90	31.44	32.08	32.00	33.06	33.69
Metallurgical Coal	0.85	0.71	0.71	0.71	0.65	0.65	0.65	0.61	0.61	0.61
Steam Coal	20.05	22.90	23.26	23.29	23.82	24.22	24.33	25.02	24.92	24.98
Net Coal Coke Imports	0.00	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Coal Subtotal	20.90	23.68	24.03	24.06	24.54	24.95	25.06	25.71	25.61	25.67
Nuclear Power	7.20	6.36	6.36	6.36	5.12	5.12	5.12	4.09	4.09	4.09
Renewable Energy[18]	6.91	7.43	7.42	7.39	7.60	7.62	7.56	7.72	7.74	7.77
Methanol[12]	0.00	0.09	0.08	0.08	0.13	0.13	0.12	0.16	0.15	0.15
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[17]	0.39	0.31	0.31	0.31	0.28	0.28	0.28	0.28	0.28	0.28
Total	**94.01**	**113.07**	**112.17**	**111.60**	**116.87**	**115.72**	**114.87**	**119.98**	**118.58**	**117.75**
Energy Use and Related Statistics										
Delivered Energy Use	70.36	85.94	85.19	84.62	89.50	88.50	87.64	92.19	90.95	90.06
Total Energy Use	94.01	113.06	112.16	111.60	116.86	115.71	114.86	119.95	118.55	117.72
Population (millions)	266.07	298.92	298.92	298.92	311.19	311.19	311.19	323.47	323.47	323.47
Gross Domestic Product (billion 1992 dollars)	6928.40	9464.46	9431.22	9398.11	10250.80	10210.71	10167.86	10952.92	10899.70	10873.21
Total Carbon Emissions (million metric tons)	1462.90	1821.67	1803.22	1793.22	1910.76	1888.33	1872.24	1989.51	1956.19	1939.82

[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.
[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.
[4]Fuel consumption includes consumption for cogeneration.
[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; including for cogeneration, both for sale to the grid and for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline(nonrenewable).
[12]Only M85 (85 percent methanol and 15 percent motor gasoline).
[13]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[17]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 natural gas lease, plant, and pipeline fuel values: Energy Information Administration, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo /pub/upd/aug97/index.html (August 21, 1997). 1996 electric utility fuel consumption: EIA, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997). 1996 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1996 values: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C3. Energy Prices by Sector and Source
(1996 Dollars per Million Btu)

Sector and Source	1996	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	**12.94**	**12.02**	**12.21**	**12.49**	**11.71**	**11.91**	**12.22**	**11.62**	**11.97**	**12.21**
Primary Energy[1]	6.63	5.92	6.15	6.44	5.80	6.07	6.37	5.80	6.17	6.40
Petroleum Products[2]	8.51	8.15	9.42	10.47	8.05	9.54	10.97	8.05	9.70	10.83
Distillate Fuel	7.09	6.51	7.55	8.50	6.44	7.64	8.86	6.38	7.71	8.70
Liquefied Petroleum Gas	11.59	10.80	12.45	13.65	10.49	12.43	14.16	10.44	12.57	13.89
Natural Gas	6.19	5.41	5.42	5.56	5.30	5.32	5.41	5.32	5.44	5.51
Electricity	24.65	21.37	21.43	21.61	20.38	20.40	20.63	19.79	20.01	20.20
Commercial	**12.92**	**11.51**	**11.63**	**11.90**	**11.08**	**11.19**	**11.44**	**10.89**	**11.15**	**11.35**
Primary Energy[1]	5.26	4.62	4.79	5.03	4.58	4.77	5.01	4.62	4.91	5.10
Petroleum Products[2]	5.56	4.88	6.02	6.97	4.81	6.12	7.36	4.79	6.25	7.29
Distillate Fuel	5.27	4.59	5.65	6.58	4.55	5.75	6.95	4.53	5.86	6.86
Residual Fuel	3.24	2.27	3.16	3.99	2.24	3.28	4.34	2.22	3.40	4.34
Natural Gas[3]	5.28	4.65	4.66	4.78	4.61	4.62	4.71	4.67	4.77	4.84
Electricity	22.24	19.08	19.16	19.44	18.00	18.02	18.26	17.36	17.58	17.78
Industrial[4]	**5.40**	**4.65**	**5.15**	**5.51**	**4.54**	**5.10**	**5.56**	**4.52**	**5.21**	**5.57**
Primary Energy	4.03	3.41	3.97	4.36	3.39	4.04	4.54	3.42	4.20	4.59
Petroleum Products[2]	5.68	4.28	5.53	6.45	4.14	5.55	6.80	4.11	5.70	6.70
Distillate Fuel	5.50	4.66	5.74	6.69	4.68	5.88	7.07	4.72	6.07	7.10
Liquefied Petroleum Gas	7.80	5.16	6.76	7.82	4.75	6.64	8.22	4.68	6.81	8.04
Residual Fuel	3.00	2.06	3.02	3.86	2.08	3.15	4.22	2.15	3.35	4.27
Natural Gas[5]	2.96	2.90	2.93	3.01	3.00	3.00	3.05	3.09	3.17	3.21
Metallurgical Coal	1.77	1.69	1.68	1.69	1.67	1.67	1.67	1.66	1.66	1.66
Steam Coal	1.46	1.33	1.33	1.33	1.31	1.31	1.31	1.30	1.30	1.30
Electricity	13.54	11.37	11.41	11.55	10.56	10.59	10.71	10.13	10.26	10.35
Transportation	**8.77**	**7.62**	**8.83**	**9.83**	**7.49**	**8.86**	**10.20**	**7.31**	**8.87**	**9.96**
Primary Energy	8.76	7.59	8.81	9.81	7.46	8.84	10.18	7.28	8.85	9.95
Petroleum Products[2]	8.76	7.58	8.80	9.81	7.43	8.82	10.18	7.24	8.82	9.93
Distillate Fuel[6]	8.90	7.60	8.61	9.57	7.41	8.60	9.77	7.13	8.52	9.55
Jet Fuel[7]	5.52	4.66	5.85	6.78	4.62	6.05	7.71	4.53	6.27	7.62
Motor Gasoline[8]	9.89	8.82	10.18	11.27	8.72	10.22	11.62	8.54	10.24	11.36
Residual Fuel	2.55	2.07	3.07	3.89	2.04	3.14	4.24	2.17	3.32	4.29
Liquid Petroleum Gas[9]	12.62	11.67	13.30	14.50	11.15	13.07	14.81	10.91	13.01	14.33
Natural Gas[10]	5.41	6.41	6.60	6.82	6.79	7.06	7.24	7.02	7.39	7.56
E85[11]	15.85	14.89	16.71	18.40	16.16	17.04	19.05	16.68	17.79	19.12
Electricity	15.31	13.23	13.25	13.33	12.56	12.54	12.64	12.20	12.26	12.34
Average End-Use Energy	**8.68**	**7.66**	**8.35**	**8.93**	**7.50**	**8.28**	**9.04**	**7.41**	**8.35**	**8.97**
Primary Energy	8.35	7.32	8.09	8.73	7.17	8.04	8.89	7.07	8.11	8.80
Electricity	20.19	17.29	17.32	17.49	16.37	16.36	16.53	15.86	16.01	16.15
Electric Generators[12]										
Fossil Fuel Average	1.54	1.56	1.57	1.62	1.60	1.60	1.64	1.60	1.66	1.70
Petroleum Products	3.28	2.51	3.84	5.09	2.63	4.00	5.60	2.78	4.21	5.59
Distillate Fuel	4.90	4.17	5.33	6.27	4.16	5.47	6.66	4.14	5.64	6.66
Residual Fuel	3.07	2.23	3.46	4.59	2.23	3.60	5.09	2.27	3.77	5.10
Natural Gas	2.64	2.83	2.84	2.96	2.98	2.98	3.07	3.06	3.15	3.23
Steam Coal	1.29	1.08	1.09	1.10	1.01	1.03	1.04	0.96	0.97	0.99

Table C3. Energy Prices by Sector and Source (Continued)
(1996 Dollars per Million Btu)

Sector and Source	1996	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]	7.86	6.74	8.02	9.03	6.61	8.06	9.41	6.48	8.12	9.22
Distillate Fuel	7.84	6.82	7.88	8.84	6.67	7.91	9.09	6.46	7.90	8.92
Jet Fuel	5.52	4.66	5.85	6.78	4.62	6.05	7.71	4.53	6.27	7.62
Liquefied Petroleum Gas	8.53	6.49	8.09	9.18	6.17	8.05	9.65	6.15	8.24	9.49
Motor Gasoline[8]	9.89	8.80	10.16	11.25	8.71	10.21	11.60	8.54	10.23	11.35
Residual Fuel	2.84	2.13	3.12	3.95	2.11	3.21	4.30	2.19	3.38	4.35
Natural Gas	4.13	3.69	3.70	3.79	3.73	3.72	3.78	3.79	3.86	3.91
Coal	1.32	1.10	1.11	1.12	1.04	1.05	1.06	0.99	1.00	1.01
E85[11]	15.85	14.89	16.71	18.40	16.16	17.04	19.05	16.68	17.79	19.12
Electricity	20.19	17.29	17.32	17.49	16.37	16.36	16.53	15.86	16.01	16.15
Non-Renewable Energy Expenditures by Sector (Billion 1996 dollars)										
Residential	117.09	129.07	130.36	132.55	133.32	134.72	137.32	139.93	143.05	145.10
Commercial	96.47	99.01	99.96	101.99	99.02	99.87	101.79	98.66	100.74	102.32
Industrial	136.22	135.88	151.07	161.56	135.46	152.83	166.36	135.97	157.75	168.29
Transportation	210.35	246.60	278.70	305.93	255.93	293.73	331.56	261.53	306.35	337.35
Total Non-Renewable Expenditures	560.12	610.57	660.09	702.04	623.73	681.15	737.03	636.09	707.89	753.07
Transportation Renewable Expenditures	0.03	1.42	1.47	1.53	2.29	2.25	2.36	2.81	2.79	2.81
Total Expenditures	**560.15**	**611.98**	**661.57**	**703.57**	**626.02**	**683.40**	**739.39**	**638.90**	**710.68**	**755.88**

[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 uses for lease and plant fuel.
[6]Low sulfur diesel fuel. 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 and State taxes and excludes county 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.
[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: 1996 figures may differ from published data due to internal rounding.

Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EI 0380(96/13-97/4) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1994*, DOE/EIA-0376(9 (Washington, DC, June 1997). 1996 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1996 residential and commercial natural g delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). Other 1996 natural gas delivered prices: EIA, AEO98 National Energy Modeling Syste runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A. Values for 1996 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 19* DOE/EIA-0376(94) (Washington, DC, June 1997) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gc pub/state.data/021494.pdf (August 26, 1997) and the *Coal Industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997). 1996 electricity prices for commercial, industri and transportation: EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A. **Projections:** EIA, AEO98 National Ener Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

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

Key Indicators and Consumption	1996	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	69.61	81.61	81.54	81.49	85.66	85.60	85.54	89.58	89.52	89.49
Multifamily	24.76	27.96	27.92	27.87	29.48	29.44	29.38	30.89	30.84	30.80
Mobile Homes	6.00	7.57	7.58	7.59	7.99	8.01	8.02	8.32	8.35	8.37
Total	**100.37**	**117.14**	**117.04**	**116.95**	**123.13**	**123.05**	**122.95**	**128.79**	**128.71**	**128.66**
Average House Square Footage	**1649**	**1704**	**1704**	**1704**	**1716**	**1716**	**1716**	**1728**	**1728**	**1728**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	110.90	105.05	104.63	103.95	104.28	103.79	102.99	103.68	102.91	102.32
Electricity Related Losses	83.37	81.53	80.73	80.38	78.92	78.15	77.87	78.20	77.20	77.11
Total Energy Consumption	194.27	186.58	185.37	184.33	183.20	181.95	180.86	181.88	180.11	179.44
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.47	0.50	0.50	0.50	0.51	0.51	0.51	0.53	0.53	0.53
Space Cooling	0.46	0.54	0.54	0.54	0.58	0.58	0.57	0.61	0.60	0.60
Water Heating	0.36	0.38	0.38	0.37	0.39	0.39	0.39	0.41	0.40	0.40
Refrigeration	0.41	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27
Cooking	0.13	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Clothes Dryers	0.19	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Freezers	0.13	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Lighting	0.34	0.40	0.39	0.39	0.42	0.42	0.42	0.45	0.45	0.45
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]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Color Televisions	0.21	0.32	0.32	0.32	0.35	0.35	0.35	0.37	0.37	0.37
Personal Computers	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Furnace Fans	0.12	0.15	0.15	0.15	0.16	0.16	0.16	0.18	0.18	0.18
Other Uses[2]	0.78	1.49	1.49	1.49	1.68	1.68	1.68	1.86	1.86	1.86
Delivered Energy	**3.68**	**4.61**	**4.61**	**4.60**	**4.95**	**4.94**	**4.94**	**5.29**	**5.28**	**5.27**
Natural Gas										
Space Heating	3.76	3.87	3.87	3.84	3.98	3.97	3.94	4.06	4.04	4.02
Space Cooling	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Water Heating	1.32	1.43	1.43	1.42	1.49	1.49	1.49	1.56	1.55	1.55
Cooking	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Clothes Dryers	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Other Uses[3]	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**5.39**	**5.63**	**5.63**	**5.60**	**5.82**	**5.82**	**5.78**	**5.99**	**5.97**	**5.95**
Distillate										
Space Heating	0.80	0.70	0.67	0.64	0.68	0.64	0.61	0.66	0.62	0.59
Water Heating	0.09	0.10	0.10	0.09	0.10	0.10	0.09	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	**0.89**	**0.80**	**0.77**	**0.74**	**0.78**	**0.74**	**0.71**	**0.76**	**0.72**	**0.69**
Liquefied Petroleum Gas										
Space Heating	0.31	0.36	0.34	0.33	0.37	0.35	0.33	0.37	0.35	0.34
Water Heating	0.07	0.10	0.10	0.09	0.11	0.10	0.10	0.11	0.11	0.11
Cooking	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
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	**0.42**	**0.51**	**0.49**	**0.47**	**0.53**	**0.50**	**0.48**	**0.54**	**0.51**	**0.49**
Marketed Renewables (wood)[5]	0.61	0.63	0.63	0.63	0.64	0.64	0.63	0.64	0.64	0.64
Other Fuels[6]	0.13	0.13	0.13	0.12	0.13	0.12	0.12	0.13	0.12	0.12

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

Key Indicators and Consumption	1996	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	6.09	6.18	6.13	6.06	6.30	6.24	6.15	6.39	6.31	6.24
Space Cooling	0.46	0.55	0.55	0.55	0.58	0.58	0.58	0.61	0.61	0.61
Water Heating	1.84	2.00	1.99	1.98	2.09	2.08	2.07	2.18	2.17	2.16
Refrigeration	0.41	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27
Cooking	0.33	0.36	0.36	0.36	0.38	0.38	0.38	0.40	0.40	0.40
Clothes Dryers	0.24	0.28	0.28	0.28	0.30	0.30	0.30	0.32	0.32	0.32
Freezers	0.13	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Lighting	0.34	0.40	0.39	0.39	0.42	0.42	0.42	0.45	0.45	0.45
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Color Televisions	0.21	0.32	0.32	0.32	0.35	0.35	0.35	0.37	0.37	0.37
Personal Computers	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Furnace Fans	0.12	0.15	0.15	0.15	0.16	0.16	0.16	0.18	0.18	0.18
Other Uses[7]	0.89	1.61	1.61	1.60	1.80	1.80	1.80	1.99	1.99	1.99
Delivered Energy	**11.13**	**12.31**	**12.25**	**12.16**	**12.84**	**12.77**	**12.66**	**13.35**	**13.25**	**13.16**
Electricity Related Losses	**8.23**	**9.49**	**9.39**	**9.35**	**9.69**	**9.58**	**9.55**	**10.06**	**9.93**	**9.92**
Total Energy Consumption by End-Use										
Space Heating	7.13	7.21	7.15	7.07	7.31	7.24	7.14	7.40	7.30	7.23
Space Cooling	1.50	1.67	1.66	1.65	1.71	1.70	1.69	1.76	1.74	1.74
Water Heating	2.66	2.77	2.76	2.74	2.85	2.84	2.82	2.95	2.93	2.92
Refrigeration	1.32	0.87	0.86	0.86	0.80	0.80	0.80	0.79	0.79	0.79
Cooking	0.62	0.68	0.67	0.67	0.69	0.69	0.69	0.72	0.72	0.72
Clothes Dryers	0.67	0.74	0.73	0.73	0.76	0.76	0.76	0.79	0.79	0.79
Freezers	0.42	0.23	0.23	0.23	0.22	0.21	0.21	0.21	0.21	0.21
Lighting	1.09	1.21	1.20	1.19	1.25	1.24	1.24	1.31	1.30	1.30
Clothes Washers	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Dishwashers	0.15	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16
Color Televisions	0.67	0.99	0.98	0.98	1.03	1.02	1.02	1.09	1.08	1.07
Personal Computers	0.03	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Furnace Fans	0.38	0.46	0.46	0.46	0.49	0.48	0.48	0.52	0.51	0.51
Other Uses[7]	2.64	4.67	4.64	4.63	5.10	5.06	5.05	5.53	5.48	5.48
Total	**19.36**	**21.80**	**21.64**	**21.51**	**22.53**	**22.35**	**22.21**	**23.41**	**23.17**	**23.08**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**

[1]Does not include water heating 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 1993*.
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996: Energy Information Administration (EIA) *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

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

Key Indicators and Consumption	1996	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 Floor Space (billion square feet)										
Surviving	69.2	81.2	81.1	81.1	84.4	84.3	84.3	85.7	85.7	85.6
New Additions	1.7	1.7	1.7	1.7	1.5	1.5	1.5	1.1	1.1	1.1
Total	**70.9**	**82.9**	**82.8**	**82.8**	**85.9**	**85.8**	**85.8**	**86.9**	**86.8**	**86.8**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	105.3	103.9	103.8	103.5	104.1	104.0	103.8	104.4	104.2	103.9
Electricity Related Losses	106.3	101.8	100.8	100.3	98.8	97.7	97.4	97.7	96.4	96.3
Total Energy Consumption	211.5	205.7	204.5	203.9	202.9	201.7	201.2	202.0	200.5	200.2
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.12	0.14	0.14	0.14	0.15	0.15	0.14	0.15	0.15	0.15
Space Cooling	0.51	0.55	0.55	0.55	0.56	0.56	0.56	0.56	0.56	0.56
Water Heating	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.18	0.18	0.18	0.18
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.15	1.24	1.24	1.24	1.28	1.27	1.27	1.28	1.28	1.27
Refrigeration	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Office Equipment (non-PC)	0.19	0.27	0.27	0.27	0.30	0.30	0.30	0.33	0.33	0.33
Other Uses[1]	0.82	1.29	1.29	1.29	1.43	1.43	1.43	1.53	1.53	1.53
Delivered Energy	**3.37**	**4.10**	**4.09**	**4.09**	**4.33**	**4.33**	**4.32**	**4.46**	**4.45**	**4.44**
Natural Gas[2]										
Space Heating	1.34	1.37	1.40	1.40	1.37	1.42	1.42	1.35	1.40	1.40
Space Cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.45	0.52	0.52	0.52	0.54	0.54	0.54	0.55	0.55	0.55
Cooking	0.18	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.23
Other Uses[3]	1.31	1.59	1.59	1.58	1.64	1.64	1.63	1.65	1.65	1.64
Delivered Energy	**3.30**	**3.72**	**3.75**	**3.74**	**3.80**	**3.85**	**3.84**	**3.81**	**3.85**	**3.85**
Distillate										
Space Heating	0.20	0.22	0.18	0.16	0.22	0.17	0.15	0.22	0.15	0.14
Water Heating	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.05	0.04	0.04
Other Uses[4]	0.19	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Delivered Energy	**0.44**	**0.44**	**0.40**	**0.39**	**0.44**	**0.39**	**0.38**	**0.44**	**0.37**	**0.37**
Other Fuels[5]	**0.36**	**0.35**	**0.35**	**0.35**	**0.36**	**0.36**	**0.36**	**0.36**	**0.36**	**0.36**
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Delivered Energy Consumption by End-Use										
Space Heating	1.65	1.72	1.71	1.70	1.74	1.73	1.72	1.72	1.70	1.69
Space Cooling	0.53	0.57	0.57	0.57	0.58	0.58	0.58	0.58	0.58	0.58
Water Heating	0.68	0.72	0.72	0.72	0.73	0.73	0.73	0.74	0.73	0.73
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.18	0.18	0.18	0.18
Cooking	0.21	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26	0.26
Lighting	1.15	1.24	1.24	1.24	1.28	1.27	1.27	1.28	1.28	1.27
Refrigeration	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Office Equipment (non-PC)	0.19	0.27	0.27	0.27	0.30	0.30	0.30	0.33	0.33	0.33
Other Uses[6]	2.68	3.41	3.41	3.41	3.61	3.61	3.61	3.72	3.71	3.71
Delivered Energy	**7.47**	**8.61**	**8.60**	**8.57**	**8.94**	**8.92**	**8.90**	**9.07**	**9.04**	**9.02**

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

Key Indicators and Consumption	1996	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	**7.54**	**8.43**	**8.35**	**8.31**	**8.48**	**8.39**	**8.36**	**8.48**	**8.37**	**8.35**
Total Energy Consumption by End-Use										
Space Heating	1.92	2.01	1.99	1.98	2.02	2.01	2.00	2.00	1.98	1.97
Space Cooling	1.66	1.70	1.69	1.68	1.68	1.67	1.66	1.65	1.63	1.63
Water Heating	1.06	1.04	1.04	1.03	1.03	1.02	1.01	1.01	1.00	1.00
Ventilation	0.54	0.56	0.56	0.55	0.55	0.54	0.54	0.53	0.53	0.53
Cooking	0.28	0.31	0.31	0.30	0.31	0.31	0.31	0.31	0.31	0.30
Lighting	3.73	3.80	3.77	3.75	3.77	3.74	3.73	3.71	3.67	3.66
Refrigeration	0.45	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Office Equipment (PC)	0.22	0.26	0.26	0.26	0.27	0.27	0.27	0.29	0.29	0.29
Office Equipment (non-PC)	0.62	0.82	0.82	0.82	0.89	0.88	0.88	0.94	0.94	0.94
Other Uses[6]	4.51	6.06	6.03	6.02	6.42	6.39	6.38	6.62	6.58	6.58
Total	**15.01**	**17.04**	**16.94**	**16.88**	**17.42**	**17.31**	**17.26**	**17.55**	**17.41**	**17.37**
Non-Marketed Renewable Fuels										
Solar[7]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.01**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lightir emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas,coal, motor gasoline, and keroser
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.000 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 Energy Information Administration, *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 199
Projections: EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

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

Key Indicators and Consumption	1996	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 1987 dollars)										
Manufacturing	3030	4328	4318	4309	4656	4646	4636	4955	4957	4948
Nonmanufacturing	774	964	969	971	1014	1019	1022	1057	1062	1066
Total	**3805**	**5292**	**5287**	**5280**	**5670**	**5665**	**5658**	**6011**	**6019**	**6014**
Energy Prices (1996 dollars per million Btu)										
Electricity	13.54	11.37	11.41	11.55	10.56	10.59	10.71	10.13	10.26	10.35
Natural Gas	2.96	2.90	2.93	3.01	3.00	3.00	3.05	3.09	3.17	3.21
Steam Coal	1.46	1.33	1.33	1.33	1.31	1.31	1.31	1.30	1.30	1.30
Residual Oil	3.00	2.06	3.02	3.86	2.08	3.15	4.22	2.15	3.35	4.27
Distillate Oil	5.50	4.66	5.74	6.69	4.68	5.88	7.07	4.72	6.07	7.10
Liquefied Petroleum Gas	7.80	5.16	6.76	7.82	4.75	6.64	8.22	4.68	6.81	8.04
Motor Gasoline	9.86	7.84	9.17	10.26	7.89	9.40	10.75	7.84	9.56	10.67
Metallurgical Coal	1.77	1.69	1.68	1.69	1.67	1.67	1.67	1.66	1.66	1.66
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.46	4.31	4.37	4.43	4.51	4.58	4.64	4.64	4.75	4.80
Natural Gas[2]	10.14	11.28	11.67	12.14	11.39	11.77	12.37	11.47	11.80	12.35
Steam Coal	1.55	1.75	1.77	1.78	1.77	1.78	1.79	1.77	1.79	1.79
Metallurgical Coal and Coke[3]	0.85	0.77	0.77	0.77	0.73	0.73	0.73	0.69	0.69	0.69
Residual Fuel	0.34	0.40	0.35	0.33	0.40	0.34	0.31	0.39	0.35	0.32
Distillate	1.17	1.45	1.45	1.44	1.51	1.51	1.51	1.56	1.56	1.56
Liquefied Petroleum Gas	2.12	2.45	2.40	2.32	2.51	2.45	2.36	2.53	2.47	2.39
Petrochemical Feedstocks	1.28	1.48	1.47	1.42	1.51	1.49	1.45	1.52	1.51	1.46
Other Petroleum[4]	4.31	5.30	5.09	4.68	5.50	5.31	4.78	5.51	5.36	4.86
Renewables[5]	1.82	2.25	2.25	2.24	2.32	2.31	2.30	2.35	2.34	2.34
Delivered Energy	**27.05**	**31.46**	**31.58**	**31.55**	**32.15**	**32.27**	**32.22**	**32.44**	**32.62**	**32.54**
Electricity Related Losses	7.74	8.87	8.92	9.01	8.83	8.88	8.97	8.83	8.93	9.02
Total	**34.79**	**40.33**	**40.50**	**40.56**	**40.98**	**41.15**	**41.19**	**41.27**	**41.55**	**41.56**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.91	0.81	0.83	0.84	0.80	0.81	0.82	0.77	0.79	0.80
Natural Gas[2]	2.66	2.13	2.21	2.30	2.01	2.08	2.19	1.91	1.96	2.05
Steam Coal	0.41	0.33	0.34	0.34	0.31	0.31	0.32	0.29	0.30	0.30
Metallurgical Coal and Coke[3]	0.22	0.15	0.15	0.15	0.13	0.13	0.13	0.11	0.11	0.11
Residual Fuel	0.09	0.08	0.07	0.06	0.07	0.06	0.06	0.07	0.06	0.05
Distillate	0.31	0.27	0.27	0.27	0.27	0.27	0.27	0.26	0.26	0.26
Liquefied Petroleum Gas	0.56	0.46	0.45	0.44	0.44	0.43	0.42	0.42	0.41	0.40
Petrochemical Feedstocks	0.34	0.28	0.28	0.27	0.27	0.26	0.26	0.25	0.25	0.24
Other Petroleum[4]	1.13	1.00	0.96	0.89	0.97	0.94	0.84	0.92	0.89	0.81
Renewables[5]	0.48	0.43	0.42	0.42	0.41	0.41	0.41	0.39	0.39	0.39
Delivered Energy	**7.11**	**5.95**	**5.97**	**5.98**	**5.67**	**5.70**	**5.69**	**5.40**	**5.42**	**5.41**
Electricity Related Losses	2.04	1.68	1.69	1.71	1.56	1.57	1.59	1.47	1.48	1.50
Total	**9.14**	**7.62**	**7.66**	**7.68**	**7.23**	**7.26**	**7.28**	**6.87**	**6.90**	**6.91**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[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.
Sources: 1996 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996 - 97). 1996 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). 1996 electricity prices: EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A. Other 1996 prices derived from EIA, *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997). Other 1996 values: EIA, *Short-Term Energy Outlook, August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1996	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	
Key Indicators											
Level of Travel (billions)											
Light-Duty Vehicles <8,500 lbs. (VMT)	2275	2917	2892	2872	3105	3077	3050	3275	3242	3222	
Commercial Light Trucks (VMT)[1]	67	87	87	88	93	93	93	98	98	98	
Freight Trucks >10,000 lbs. (VMT)	161	233	232	232	243	243	243	251	250	251	
Air (seat miles available)	999	1876	1855	1845	2167	2139	2117	2453	2416	2401	
Rail (ton miles traveled)	1204	1507	1533	1551	1557	1584	1610	1593	1623	1648	
Marine (ton miles traveled)	777	899		923	938	925	949	971	941	967	989
Energy Efficiency Indicators											
New Car (miles per gallon)[2]	27.9	28.7	30.2	31.5	28.7	30.5	32.1	28.7	30.7	32.1	
New Light Truck (miles per gallon)[2]	20.7	19.1	20.1	20.8	19.4	20.5	21.5	19.8	21.1	21.9	
Light-Duty Fleet (miles per gallon)[3]	20.2	19.7	20.3	20.8	19.9	20.7	21.4	20.2	21.2	22.0	
New Commercial Light Truck (MPG)[1]	20.2	18.7	19.6	20.3	19.0	20.0	21.0	19.3	20.6	21.4	
Stock Commercial Light Truck (MPG)[1]	14.5	14.6	15.0	15.3	14.7	15.2	15.6	14.8	15.4	15.9	
Aircraft Efficiency (seat miles per gallon)	50.6	55.7	55.7	55.7	57.4	57.4	57.3	59.0	59.0	59.1	
Freight Truck Efficiency (miles per gallon)	5.6	5.9		6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1
Rail Efficiency (ton miles per thousand Btu)	2.7	2.9		2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.9		2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu)											
Light-Duty Vehicles	13.96	18.50	17.76	17.36	19.48	18.55	17.95	20.35	19.20	18.56	
Commercial Light Trucks[1]	0.58	0.75	0.73	0.72	0.79	0.76	0.75	0.83	0.79	0.77	
Freight Trucks[4]	4.02	5.36	5.32	5.31	5.51	5.47	5.44	5.63	5.58	5.55	
Air	3.32	5.33	5.27	5.26	5.91	5.84	5.80	6.43	6.35	6.30	
Rail	0.52	0.61	0.62	0.63	0.62	0.63	0.64	0.62	0.63	0.64	
Marine	1.43	1.91	1.91	1.91	2.09	2.09	2.09	2.26	2.25	2.25	
Pipeline Fuel	0.73	0.92	0.95	0.96	0.96	0.99	0.99	0.99	1.03	1.04	
Other[5]	0.25	0.31	0.31	0.31	0.33	0.32	0.32	0.34	0.33	0.33	
Total	**24.72**	**33.57**	**32.77**	**32.34**	**35.57**	**34.54**	**33.86**	**37.33**	**36.04**	**35.33**	

[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.
[5]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.

Sources: 1996: Federal Administration Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1996-2007*, (Washington, DC, February 1995); Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://ww.eia.doe.gov/emeu/steo/pub/upd /aug97/index.html (August 21, 1997); EIA, *Fuel Oil and Kerosene Sales 1996*, DOE/EIA-0535(96) (Washington, DC, September 1997); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

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

Supply, Disposition, and Prices	1996	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	1758	2044	2085	2088	2141	2190	2203	2275	2265	2274
Petroleum	80	90	35	23	98	33	21	107	32	22
Natural Gas	288	891	920	942	1139	1171	1183	1277	1389	1401
Nuclear Power	675	596	596	596	480	480	480	383	383	383
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	392	382	382	382	386	388	386	395	393	392
Total	**3191**	**4000**	**4015**	**4028**	**4241**	**4258**	**4269**	**4433**	**4459**	**4468**
Non-Utility Generation for Own Use	26	26	26	26	26	26	26	26	26	26
Cogenerators[3]										
Coal	39	39	39	39	39	39	39	39	39	39
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	174	188	201	207	190	200	207	190	194	199
Other Gaseous Fuels[4]	7	7	7	7	7	7	7	7	7	7
Renewable Sources[2]	41	44	43	43	43	43	42	42	42	42
Other[5]	3	4	4	4	4	4	4	4	3	3
Total	**270**	**287**	**299**	**305**	**289**	**299**	**304**	**288**	**291**	**295**
Sales to Utilities	121	126	127	128	126	127	128	126	126	127
Generation for Own Use	149	162	172	177	163	172	176	162	165	168
Net Imports[6]	**38**	**30**	**30**	**30**	**27**	**27**	**27**	**27**	**27**	**27**
Electricity Sales by Sector										
Residential	1079	1351	1350	1348	1450	1449	1447	1550	1548	1545
Commercial	988	1201	1200	1198	1269	1268	1266	1306	1304	1302
Industrial	1014	1263	1282	1299	1321	1343	1359	1360	1392	1406
Transportation	17	46	46	46	56	55	55	64	64	63
Total	**3098**	**3862**	**3877**	**3890**	**4097**	**4115**	**4126**	**4281**	**4308**	**4316**
End-Use Prices (1996 cents per kilowatthour)[7]										
Residential	8.4	7.3	7.3	7.4	7.0	7.0	7.0	6.8	6.8	6.9
Commercial	7.6	6.5	6.5	6.6	6.1	6.1	6.2	5.9	6.0	6.1
Industrial	4.6	3.9	3.9	3.9	3.6	3.6	3.7	3.5	3.5	3.5
Transportation	5.2	4.5	4.5	4.5	4.3	4.3	4.3	4.2	4.2	4.2
All Sectors Average	**6.9**	**5.9**	**5.9**	**6.0**	**5.6**	**5.6**	**5.6**	**5.4**	**5.5**	**5.5**

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[4]Other gaseous fuels include refinery and still gas.
[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[6]In 1996 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[7]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1994.* Online. ftp://ftp.eia.doe.gov/pub/state.data/021494.pdf (August 26, 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 16* (July 1996) which indicates the transportation value should be higher. 1996 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996 residential electricity prices derived from EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/teo/pub/upd/aug97/index.html (August 21, 1997). **1996 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1996	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
		Projections								
Electric Generators[2]										
Capability										
Coal Steam	305.3	296.8	304.6	303.9	306.1	316.0	317.0	323.3	323.6	324.6
Other Fossil Steam[3]	138.1	101.0	101.0	101.0	97.1	97.1	97.1	96.0	96.0	96.0
Combined Cycle	15.3	96.2	106.5	111.5	140.2	154.9	157.8	165.9	186.5	189.2
Combustion Turbine/Diesel	80.0	205.8	191.4	188.8	230.3	210.1	209.9	239.9	221.9	220.8
Nuclear Power	100.8	80.4	80.4	80.4	63.9	63.9	63.9	49.2	49.2	49.2
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
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]	88.6	93.8	93.6	93.7	94.6	94.7	94.4	96.3	95.7	95.6
Total	**748.0**	**893.7**	**897.3**	**899.0**	**952.0**	**956.7**	**960.1**	**990.5**	**992.8**	**995.3**
Cumulative Planned Additions[5]										
Coal Steam	2.4	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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]	0.7	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Total	**11.3**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	9.0	16.9	16.1	22.2	32.1	33.1	43.2	45.4	46.4
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	79.3	89.7	94.7	123.4	138.1	141.0	149.0	169.7	172.4
Combustion Turbine/Diesel	23.6	149.1	134.6	132.0	174.7	154.5	154.3	184.3	166.3	165.2
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]	0.5	3.0	2.8	2.9	4.0	4.2	3.9	6.0	5.4	5.2
Total	**24.1**	**240.4**	**244.0**	**245.6**	**324.2**	**328.9**	**332.3**	**382.5**	**386.7**	**389.2**
Cumulative Total Additions	**35.4**	**258.9**	**262.5**	**264.1**	**342.7**	**347.4**	**350.9**	**401.0**	**405.2**	**407.7**
Cumulative Retirements[6]	**14.4**	**92.4**	**92.4**	**92.4**	**117.1**	**117.1**	**117.1**	**136.9**	**138.8**	**138.8**

Table C9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1996	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
Cogenerators[7]										
Capability										
Coal	7.1	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Petroleum	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Natural Gas	28.0	31.2	32.7	33.5	31.5	32.7	33.5	31.4	31.9	32.5
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewable Sources[4]	5.8	6.6	6.6	6.6	6.6	6.6	6.5	6.5	6.4	6.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**47.9**	**49.3**	**50.0**	**48.1**	**49.3**	**50.0**	**48.0**	**48.3**	**48.8**
Cumulative Additions[5]	**8.1**	**12.9**	**14.4**	**15.0**	**13.2**	**14.3**	**15.0**	**13.0**	**13.4**	**13.9**

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.
[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]Cumulative additions after December 31, 1995. Non-zero utility planned additions in 1995 indicate units operational in 1995 but not supplying power to the grid.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 25, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1996 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1996 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1996	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
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	173.4	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	79.5	78.5	78.3	86.4	91.9	79.7	89.6	94.5	86.6	86.5
Gross Domestic Trade	**252.9**	**217.7**	**217.5**	**225.6**	**231.1**	**218.9**	**228.9**	**233.7**	**225.8**	**225.7**
Gross Domestic Firm Power Sales (million 1996 dollars)	8050.2	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9	6462.9
Gross Domestic Economy Sales (million 1996 dollars)	1812.7	1723.2	1747.9	2115.7	1980.0	1712.8	2121.2	2047.1	1905.6	1974.9
Gross Domestic Sales (million 1996 dollars)	**9862.9**	**8186.1**	**8210.8**	**8578.6**	**8442.9**	**8175.6**	**8584.1**	**8509.9**	**8368.5**	**8437.8**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	26.1	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Economy Imports From Canada and Mexico[1]	20.7	33.6	33.6	33.7	30.1	30.1	30.1	30.1	30.1	30.1
Gross Imports From Canada and Mexico[1]	**46.8**	**51.4**	**51.4**	**51.4**	**47.9**	**47.9**	**47.9**	**47.9**	**47.9**	**47.9**
Firm Power Exports To Canada and Mexico	2.8	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
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	**9.3**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier inaccordance with prior agreements or under specified conditions.

Sources: 1996 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1996 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993*. Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	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]	6.48	4.63	5.57	6.28	4.23	5.24	6.36	3.92	4.92	5.99
Alaska	1.40	0.72	0.75	0.77	0.57	0.60	0.82	0.45	0.48	0.63
Lower 48 States	5.08	3.91	4.82	5.51	3.67	4.64	5.54	3.47	4.44	5.36
Net Imports	7.40	11.71	10.67	9.91	12.43	11.22	10.08	12.89	11.65	10.59
Other Crude Supply[2]	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.21**	**16.34**	**16.24**	**16.19**	**16.66**	**16.46**	**16.44**	**16.81**	**16.58**	**16.58**
Natural Gas Plant Liquids	**1.83**	**2.19**	**2.24**	**2.27**	**2.31**	**2.35**	**2.39**	**2.39**	**2.47**	**2.51**
Other Inputs[3]	**0.39**	**0.20**	**0.25**	**0.26**	**0.19**	**0.22**	**0.24**	**0.20**	**0.20**	**0.21**
Refinery Processing Gain[4]	**0.84**	**0.75**	**0.89**	**0.93**	**0.75**	**0.87**	**0.94**	**0.73**	**0.82**	**0.89**
Net Product Imports[5]	**1.10**	**4.03**	**3.00**	**2.25**	**4.71**	**3.70**	**2.66**	**5.53**	**4.33**	**3.16**
Total Primary Supply[6]	**18.37**	**23.50**	**22.63**	**21.91**	**24.62**	**23.60**	**22.67**	**25.66**	**24.40**	**23.35**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.99	10.14	9.75	9.56	10.58	10.10	9.79	10.99	10.39	10.06
Jet Fuel[8]	1.58	2.55	2.53	2.52	2.83	2.80	2.77	3.07	3.03	3.01
Distillate Fuel[9]	3.32	4.17	4.09	4.07	4.31	4.19	4.15	4.42	4.25	4.22
Residual Fuel	0.90	1.11	0.88	0.82	1.17	0.93	0.87	1.23	0.99	0.93
Other[10]	4.66	5.62	5.45	5.17	5.82	5.64	5.29	5.88	5.72	5.38
Total	**18.44**	**23.59**	**22.70**	**22.12**	**24.71**	**23.65**	**22.87**	**25.59**	**24.39**	**23.61**
Refined Petroleum Products Supplied										
Residential and Commercial	1.13	1.15	1.09	1.07	1.16	1.09	1.06	1.15	1.08	1.05
Industrial[11]	4.87	5.81	5.65	5.37	5.98	5.82	5.47	6.03	5.89	5.56
Transportation	12.11	16.24	15.81	15.59	17.15	16.60	16.25	17.96	17.27	16.90
Electric Generators[12]	0.33	0.39	0.16	0.10	0.42	0.14	0.09	0.45	0.14	0.10
Total	**18.44**	**23.59**	**22.70**	**22.12**	**24.71**	**23.65**	**22.87**	**25.59**	**24.39**	**23.61**
Discrepancy[13]	**-0.08**	**-0.09**	**-0.08**	**-0.22**	**-0.08**	**-0.05**	**-0.20**	**0.07**	**0.01**	**-0.26**
World Oil Price (1996 dollars per barrel)[14]	**20.48**	**14.44**	**20.81**	**26.87**	**14.42**	**21.48**	**28.59**	**14.43**	**22.32**	**28.71**
Import Share of Product Supplied	**0.46**	**0.67**	**0.60**	**0.55**	**0.69**	**0.63**	**0.56**	**0.72**	**0.66**	**0.58**
Net Expenditures for Imported Crude Oil and Products (billion 1996 dollars)	**62.27**	**86.05**	**106.39**	**120.84**	**94.25**	**120.20**	**135.01**	**102.10**	**133.54**	**146.89**
Domestic Refinery Distillation Capacity	**15.4**	**17.2**	**17.1**	**17.1**	**17.6**	**17.4**	**17.4**	**17.8**	**17.5**	**17.5**
Capacity Utilization Rate (percent)	**94.0**	**95.3**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**	**95.2**

[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, and other hydrocarbons.
[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]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 expenditures for imported crude oil and petroleum products based on internal calculations. 1996 product supplied data from Table C2. Other 1996 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C12. Petroleum Product Prices
(1996 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1996	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 (1996 dollars per barrel)	**20.48**	**14.44**	**20.81**	**26.87**	**14.42**	**21.48**	**28.59**	**14.43**	**22.32**	**28.71**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	98.4	90.2	104.8	117.8	89.3	106.0	122.9	88.4	107.0	120.7
Liquefied Petroleum Gas	100.0	93.2	107.5	117.8	90.5	107.3	122.3	90.1	108.5	119.9
Commercial										
Distillate Fuel	73.1	63.6	78.3	91.3	63.2	79.7	96.4	62.8	81.3	95.2
Residual Fuel	48.4	34.0	47.3	59.8	33.6	49.2	65.0	33.3	50.9	65.0
Residual Fuel (1996 dollars per barrel)	20.35	14.26	19.85	25.12	14.09	20.65	27.31	13.99	21.36	27.29
Industrial[1]										
Distillate Fuel	76.3	64.6	79.6	92.7	65.0	81.5	98.1	65.5	84.2	98.4
Liquefied Petroleum Gas	67.3	44.6	58.4	67.5	41.0	57.3	70.9	40.4	58.8	69.4
Residual Fuel	45.0	30.9	45.2	57.8	31.2	47.2	63.2	32.1	50.1	63.9
Residual Fuel (1996 dollars per barrel)	18.88	12.96	18.97	24.30	13.10	19.80	26.54	13.50	21.04	26.85
Transportation										
Diesel Fuel (distillate)[2]	123.5	105.4	119.4	132.8	102.7	119.3	135.5	98.9	118.2	132.4
Jet Fuel[3]	74.6	62.9	79.0	91.6	62.3	81.7	104.1	61.2	84.6	102.9
Motor Gasoline[4]	122.5	109.1	126.0	139.5	107.9	126.6	143.9	105.7	126.8	140.7
Residual Fuel	38.2	30.9	46.0	58.2	30.5	47.0	63.4	32.4	49.7	64.2
Residual Fuel (1996 dollars per barrel)	16.04	13.00	19.32	24.44	12.82	19.75	26.63	13.62	20.88	26.97
Electric Generators[5]										
Distillate Fuel	68.0	57.9	73.9	86.9	57.6	75.9	92.4	57.5	78.2	92.3
Residual Fuel	45.9	33.5	51.9	68.7	33.3	53.9	76.1	34.0	56.4	76.4
Residual Fuel (1996 dollars per barrel)	19.27	14.05	21.78	28.86	13.99	22.64	31.97	14.28	23.70	32.08
Refined Petroleum Product Prices[6]										
Distillate Fuel	108.7	94.6	109.2	122.6	92.4	109.7	126.1	89.6	109.6	123.8
Jet Fuel[3]	74.6	62.9	79.0	91.6	62.3	81.7	104.1	61.2	84.6	102.9
Liquefied Petroleum Gas	73.6	56.0	69.8	79.2	53.3	69.4	83.3	53.1	71.1	81.9
Motor Gasoline[4]	122.5	108.9	125.9	139.3	107.7	126.4	143.7	105.6	126.7	140.6
Residual Fuel	42.5	31.8	46.7	59.1	31.5	48.0	64.4	32.8	50.5	65.1
Residual Fuel (1996 dollars per barrel)	17.87	13.36	19.63	24.84	13.24	20.15	27.03	13.79	21.23	27.32
Average	**102.8**	**88.6**	**104.9**	**117.9**	**87.0**	**105.4**	**122.8**	**85.2**	**106.0**	**120.2**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. 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 and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). 1996 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1994*, DOE/EIA-0376(94) (Washington, DC, June 1997). **Projections**: EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

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

Supply, Disposition, and Prices	1996	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										
Dry Gas Production[1]	19.02	24.23	24.70	25.08	25.72	26.12	26.56	26.54	27.44	27.84
Supplemental Natural Gas[2]	0.12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Net Imports	**2.72**	**4.23**	**4.28**	**4.47**	**4.55**	**4.64**	**4.84**	**4.80**	**4.91**	**5.12**
Canada	2.76	4.08	4.13	4.29	4.41	4.50	4.66	4.69	4.80	4.96
Mexico	-0.02	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.17	-0.17	-0.17
Liquefied Natural Gas	-0.03	0.29	0.29	0.33	0.29	0.29	0.33	0.29	0.29	0.33
Total Supply	**21.86**	**28.51**	**29.03**	**29.61**	**30.32**	**30.81**	**31.45**	**31.39**	**32.41**	**33.01**
Consumption by Sector										
Residential	5.23	5.48	5.47	5.44	5.66	5.66	5.62	5.82	5.80	5.78
Commercial	3.20	3.61	3.65	3.64	3.70	3.74	3.73	3.70	3.75	3.74
Industrial[3]	8.60	9.39	9.75	10.18	9.41	9.75	10.31	9.42	9.70	10.22
Electric Generators[4]	2.98	7.13	7.22	7.38	8.42	8.52	8.63	9.18	9.85	9.94
Lease and Plant Fuel[5]	1.25	1.57	1.59	1.61	1.67	1.68	1.71	1.72	1.76	1.79
Pipeline Fuel	0.71	0.89	0.93	0.94	0.93	0.96	0.96	0.97	1.00	1.02
Transportation[6]	0.01	0.24	0.23	0.22	0.31	0.29	0.28	0.35	0.33	0.32
Total	**21.99**	**28.32**	**28.84**	**29.42**	**30.09**	**30.61**	**31.24**	**31.16**	**32.20**	**32.81**
Discrepancy[7]	**-0.12**	**0.19**	**0.19**	**0.19**	**0.23**	**0.20**	**0.21**	**0.23**	**0.21**	**0.21**

[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.
[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, 1996 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.
Sources: 1996 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(97/6) (Washington, DC, June 1997). 1996 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, November 1997). 1996 transportation sector consumption: EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A. Other 1996 consumption: EIA, *Short-Term Energy Outlook August 1997.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A. **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C14. Natural Gas Prices, Margins, and Revenue
(1996 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1996	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]	2.24	2.25	2.31	2.38	2.35	2.38	2.42	2.45	2.54	2.58
Average Import Price	1.98	2.29	2.32	2.44	2.37	2.40	2.48	2.44	2.56	2.61
Average[2]	**2.21**	**2.26**	**2.31**	**2.39**	**2.35**	**2.38**	**2.43**	**2.45**	**2.54**	**2.59**
Delivered Prices										
Residential	6.37	5.57	5.58	5.72	5.45	5.47	5.56	5.48	5.60	5.67
Commercial	5.43	4.79	4.79	4.92	4.74	4.76	4.84	4.80	4.91	4.98
Industrial[3]	3.05	2.99	3.01	3.10	3.09	3.09	3.14	3.18	3.26	3.30
Electric Generators[4]	2.70	2.89	2.91	3.03	3.05	3.04	3.14	3.13	3.22	3.30
Transportation[5]	5.57	6.60	6.79	7.01	6.99	7.26	7.45	7.22	7.61	7.78
Average[6]	**4.25**	**3.80**	**3.80**	**3.89**	**3.83**	**3.83**	**3.89**	**3.90**	**3.97**	**4.02**
Transmission and Distribution Margins[7]										
Residential	4.17	3.31	3.27	3.33	3.10	3.09	3.13	3.03	3.05	3.08
Commercial	3.23	2.53	2.48	2.53	2.39	2.38	2.41	2.36	2.37	2.39
Industrial[3]	0.84	0.73	0.71	0.71	0.74	0.70	0.71	0.74	0.71	0.71
Electric Generators[4]	0.49	0.63	0.60	0.64	0.70	0.66	0.71	0.68	0.68	0.71
Transportation[5]	3.36	4.34	4.48	4.62	4.64	4.88	5.02	4.78	5.06	5.19
Average[6]	**2.04**	**1.54**	**1.49**	**1.50**	**1.48**	**1.44**	**1.46**	**1.45**	**1.43**	**1.43**
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	21.81	18.15	17.91	18.11	17.56	17.48	17.60	17.66	17.70	17.79
Commercial	10.34	9.13	9.05	9.21	8.84	8.88	9.00	8.73	8.87	8.95
Industrial[3]	7.23	6.87	6.89	7.22	6.94	6.87	7.31	6.93	6.92	7.30
Electric Generators[4]	1.47	4.51	4.32	4.72	5.86	5.63	6.14	6.25	6.69	7.10
Transportation[5]	0.03	1.05	1.04	1.03	1.42	1.43	1.41	1.67	1.68	1.67
Total	**40.88**	**39.71**	**39.21**	**40.28**	**40.62**	**40.29**	**41.47**	**41.24**	**41.87**	**42.81**

[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.
[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.
Sources: 1996 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991.* 1996 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). **Other 1996 values, and projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C15. Oil and Gas Supply

Production and Supply	1996	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										
Lower 48 Average Wellhead Price[1] (1996 dollars per barrel)	**19.41**	**14.77**	**21.08**	**26.44**	**14.04**	**21.01**	**27.94**	**14.03**	**21.58**	**27.99**
Production (million barrels per day)[2]										
U.S. Total	**6.48**	**4.63**	**5.57**	**6.28**	**4.23**	**5.24**	**6.36**	**3.92**	**4.92**	**5.99**
Lower 48 Onshore	3.76	2.44	3.15	3.70	2.33	3.13	3.90	2.27	3.09	3.94
Conventional	3.15	1.97	2.36	2.70	1.86	2.35	2.83	1.83	2.41	2.93
Enhanced Oil Recovery	0.61	0.47	0.79	1.00	0.47	0.78	1.07	0.44	0.68	1.01
Lower 48 Offshore	1.32	1.47	1.67	1.82	1.33	1.52	1.64	1.20	1.35	1.43
Alaska	1.40	0.72	0.75	0.77	0.57	0.60	0.82	0.45	0.48	0.63
Lower 48 End of Year Reserves (billion barrels)	**16.82**	**12.14**	**14.87**	**17.01**	**11.59**	**14.67**	**17.65**	**11.17**	**14.33**	**17.46**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1996 dollars per thousand cubic feet)	**2.24**	**2.25**	**2.31**	**2.38**	**2.35**	**2.38**	**2.42**	**2.45**	**2.54**	**2.58**
Production (trillion cubic feet)[3]										
U.S. Total	**19.01**	**24.23**	**24.70**	**25.08**	**25.72**	**26.12**	**26.56**	**26.54**	**27.44**	**27.84**
Lower 48 Onshore	13.07	17.08	17.33	17.57	18.52	18.72	19.09	18.41	18.99	19.37
Associated-Dissolved[4]	1.84	1.19	1.27	1.33	1.13	1.21	1.30	1.10	1.19	1.29
Non-Associated	11.23	15.90	16.06	16.24	17.40	17.51	17.79	17.32	17.81	18.07
Conventional	7.96	11.57	11.77	12.08	12.27	12.44	12.61	12.07	12.32	12.49
Unconventional	3.27	4.32	4.30	4.16	5.13	5.08	5.17	5.25	5.49	5.58
Lower 48 Offshore	5.50	6.58	6.81	6.94	6.60	6.81	6.88	7.51	7.83	7.86
Associated-Dissolved[4]	0.80	0.88	0.92	0.95	0.85	0.89	0.92	0.81	0.85	0.87
Non-Associated	4.70	5.71	5.89	5.99	5.76	5.92	5.96	6.70	6.98	6.99
Alaska	0.43	0.56	0.56	0.56	0.59	0.59	0.59	0.62	0.62	0.62
Lower 48 End of Year Reserves (trillion cubic feet)	**157.23**	**192.57**	**196.33**	**201.09**	**192.18**	**196.28**	**200.81**	**182.39**	**185.11**	**187.42**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.12**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Total Lower 48 Wells (thousands)	**21.75**	**24.00**	**28.19**	**32.36**	**24.58**	**29.39**	**35.03**	**26.19**	**32.04**	**37.30**

Ft. = feet.
[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.

Sources: 1996 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1996 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1996 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96) (Washington, DC, June 1997). 1996 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies. EIA, *Natural Gas Monthly*, DOE/EIA-0130(97/06) (Washington, DC, June 1997). Other 1996 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	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	452	502	505	487	510	505	492	524	513	506
Interior	173	163	177	170	159	167	166	161	166	162
West	439	588	583	618	637	654	676	696	697	713
East of the Mississippi	564	591	602	575	611	609	593	634	623	610
West of the Mississippi	500	662	663	700	694	717	741	748	754	771
Total	**1064**	**1253**	**1265**	**1275**	**1305**	**1326**	**1334**	**1382**	**1376**	**1381**
Net Imports										
Imports	7	8	8	8	8	8	8	8	8	8
Exports	90	112	112	112	119	119	119	128	128	128
Total	**-83**	**-104**	**-104**	**-104**	**-112**	**-112**	**-112**	**-120**	**-120**	**-120**
Total Supply[2]	**981**	**1149**	**1161**	**1171**	**1193**	**1215**	**1222**	**1262**	**1256**	**1261**
Consumption by Sector										
Residential and Commercial	6	6	6	6	7	7	6	7	6	6
Industrial[3]	70	80	81	81	81	81	81	81	81	82
Coke Plants	32	26	26	26	24	24	24	23	23	23
Electric Generators[4]	896	1036	1049	1058	1083	1103	1111	1152	1147	1151
Total	**1003**	**1149**	**1162**	**1172**	**1194**	**1215**	**1223**	**1262**	**1257**	**1262**
Discrepancy and Stock Change[5]	**-23**	**1**	**-1**	**-0**	**-1**	**-0**	**-1**	**-1**	**-1**	**-1**
Average Minemouth Price										
(1996 dollars per short ton)	18.50	14.83	15.05	14.85	13.96	13.99	13.92	13.16	13.27	13.28
(1996 dollars per million Btu)	0.87	0.71	0.72	0.71	0.67	0.67	0.67	0.63	0.64	0.64
Delivered Prices (1996 dollars per short ton)[6]										
Industrial	32.28	29.23	29.29	29.30	28.79	28.90	28.86	28.50	28.57	28.62
Coke Plants	47.33	45.20	45.10	45.22	44.88	44.78	44.77	44.60	44.61	44.62
Electric Generators										
(1996 dollars per short ton)	26.45	21.79	22.09	22.26	20.48	20.72	20.94	19.23	19.52	19.79
(1996 dollars per million Btu)	1.29	1.08	1.09	1.10	1.01	1.03	1.04	0.96	0.97	0.99
Average	**27.52**	**22.85**	**23.12**	**23.26**	**21.55**	**21.76**	**21.95**	**20.29**	**20.56**	**20.81**
Exports[7]	40.77	34.86	35.02	35.18	33.52	33.75	33.84	32.12	32.47	32.66

[1]Includes anthracite, bituminous coal, and lignite.
[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.
[5]Balancing item: the sum of production, net imports, and net storage 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.
Sources: 1996 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C17. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1996	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
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.58	80.71	80.71	80.71	80.71	80.71	80.71	80.71	80.71	80.71
Geothermal[2]	3.02	2.92	2.92	2.88	2.70	2.87	2.76	2.74	2.94	2.95
Municipal Solid Waste[3]	2.91	3.93	3.92	3.91	4.27	4.26	4.25	4.39	4.38	4.38
Wood and Other Biomass[4]	1.91	2.06	2.07	2.08	2.19	2.28	2.18	2.41	2.50	2.20
Solar Thermal	0.36	0.53	0.46	0.46	0.58	0.51	0.51	0.63	0.56	0.56
Solar Photovoltaic	0.01	0.22	0.22	0.22	0.38	0.38	0.38	0.56	0.56	0.56
Wind	1.85	3.42	3.33	3.41	3.73	3.68	3.64	4.90	4.06	4.22
Total	**88.64**	**93.78**	**93.64**	**93.69**	**94.56**	**94.69**	**94.43**	**96.35**	**95.70**	**95.57**
Generation (billion kilowatthours)										
Conventional Hydropower	346.28	318.67	318.67	318.67	318.75	318.76	318.76	318.81	318.82	318.82
Geothermal[2]	15.70	17.60	17.64	17.35	16.74	17.92	17.13	17.91	19.26	19.33
Municipal Solid Waste[3]	18.85	26.38	26.32	26.27	28.73	28.68	28.61	29.60	29.52	29.48
Wood and Other Biomass[4]	7.27	9.70	9.79	9.90	10.63	11.24	10.56	12.20	12.81	10.74
Solar Thermal	0.82	1.49	1.24	1.24	1.64	1.39	1.38	1.81	1.56	1.56
Solar Photovoltaic	0.00	0.60	0.60	0.60	1.00	1.00	1.00	1.45	1.45	1.45
Wind	3.17	8.00	7.76	8.00	8.98	8.86	8.70	12.75	10.08	10.58
Total	**392.09**	**382.44**	**382.03**	**382.03**	**386.47**	**387.84**	**386.15**	**394.52**	**393.50**	**391.96**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.41	0.46	0.46	0.46	0.47	0.47	0.47	0.48	0.48	0.48
Biomass	5.41	6.17	6.14	6.10	6.13	6.08	6.03	6.02	5.95	5.91
Total	**5.81**	**6.64**	**6.61**	**6.56**	**6.61**	**6.56**	**6.50**	**6.50**	**6.43**	**6.38**
Generation (billion kilowatthours)										
Municipal Solid Waste	2.09	2.30	2.30	2.29	2.34	2.34	2.33	2.37	2.36	2.35
Biomass	39.17	41.20	41.00	40.66	40.88	40.55	40.15	40.13	39.65	39.33
Total	**41.25**	**43.50**	**43.29**	**42.95**	**43.23**	**42.89**	**42.48**	**42.50**	**42.01**	**41.68**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of August 25, 1997. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1996 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report," 1996 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1996 generation: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C18. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1996	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
Marketed Renewable Energy[2]										
Residential	**0.61**	**0.63**	**0.63**	**0.63**	**0.64**	**0.64**	**0.63**	**0.64**	**0.64**	**0.64**
Wood	0.61	0.63	0.63	0.63	0.64	0.64	0.63	0.64	0.64	0.64
Commercial[3]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	**1.82**	**2.25**	**2.24**	**2.23**	**2.32**	**2.31**	**2.30**	**2.35**	**2.34**	**2.33**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.78	2.21	2.20	2.20	2.28	2.27	2.26	2.31	2.30	2.29
Transportation	**0.10**	**0.11**	**0.17**	**0.17**	**0.12**	**0.14**	**0.22**	**0.14**	**0.15**	**0.17**
Ethanol used in E85[5]	0.00	0.08	0.07	0.07	0.12	0.11	0.11	0.14	0.13	0.12
Ethanol used in Gasoline Blending	0.10	0.03	0.09	0.10	0.00	0.03	0.11	0.00	0.01	0.04
Electric Generators[6]	**4.40**	**4.40**	**4.40**	**4.39**	**4.45**	**4.48**	**4.45**	**4.54**	**4.56**	**4.55**
Conventional Hydroelectric	3.56	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
Geothermal	0.43	0.52	0.52	0.51	0.50	0.53	0.51	0.53	0.58	0.58
Municipal Solid Waste	0.30	0.42	0.42	0.42	0.46	0.46	0.46	0.47	0.47	0.47
Biomass	0.06	0.09	0.09	0.09	0.09	0.10	0.09	0.11	0.11	0.10
Solar Thermal	0.01	0.02	0.01	0.01	0.02	0.01	0.01	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wind	0.03	0.08	0.08	0.08	0.09	0.09	0.09	0.13	0.10	0.11
Total Marketed Renewable Energy	**6.93**	**7.40**	**7.44**	**7.42**	**7.53**	**7.58**	**7.60**	**7.68**	**7.69**	**7.69**
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	**0.02**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.07**	**0.07**	**0.07**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
Commercial	**0.01**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
Solar Thermal	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, andwind 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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.

[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.

[5]Excludes motor gasoline component of E85.

[6]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.

[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.

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

Sources: 1996 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Utility Report" and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1996 ethanol: EIA, *Petroleum Supply Annual 1996*, DOE/EIA-0340(96/1) (Washington, DC, June 1997). Other 1996: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1996	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										
Petroleum	27.3	25.7	24.8	23.9	25.7	24.5	23.5	25.6	24.2	23.3
Natural Gas	77.4	81.1	81.1	80.6	83.9	83.8	83.2	86.3	85.9	85.6
Coal	1.4	1.4	1.3	1.3	1.4	1.3	1.3	1.3	1.3	1.3
Electricity	179.9	232.5	230.9	230.0	250.6	248.8	248.4	272.3	267.5	266.9
Total	**286.0**	**340.8**	**338.1**	**335.8**	**361.5**	**358.5**	**356.4**	**385.5**	**379.0**	**377.1**
Commercial										
Petroleum	15.3	13.7	12.8	12.6	13.8	12.7	12.5	13.7	12.4	12.3
Natural Gas	47.4	53.5	54.0	53.9	54.8	55.4	55.3	54.8	55.5	55.4
Coal	2.1	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Electricity	164.8	206.6	205.1	204.3	219.4	217.8	217.4	229.6	225.5	224.8
Total	**229.6**	**276.2**	**274.4**	**273.3**	**290.5**	**288.4**	**287.7**	**300.6**	**296.0**	**295.0**
Industrial[1]										
Petroleum	104.8	120.6	115.6	107.8	124.1	119.3	109.2	124.1	120.3	110.7
Natural Gas[2]	142.8	160.2	165.8	172.4	161.8	167.1	175.6	162.8	167.5	175.3
Coal	59.3	62.4	62.8	63.0	61.4	61.7	61.9	60.3	60.7	60.8
Electricity	169.2	217.4	219.1	221.6	228.4	230.6	233.3	239.0	240.6	242.8
Total	**476.1**	**560.6**	**563.3**	**564.8**	**575.7**	**578.7**	**579.9**	**586.2**	**589.2**	**589.7**
Transportation										
Petroleum	457.9	617.7	601.0	593.0	652.8	632.3	618.3	683.5	658.6	644.8
Natural Gas[3]	10.5	16.8	17.2	17.2	18.3	18.6	18.4	19.5	19.8	19.8
Other[4]	0.0	1.5	1.5	1.4	2.3	2.2	2.1	2.8	2.7	2.5
Electricity	2.8	8.0	7.8	7.8	9.7	9.5	9.4	11.3	11.0	10.9
Total	**471.2**	**644.0**	**627.5**	**619.3**	**683.0**	**662.7**	**648.2**	**717.1**	**692.1**	**678.0**
Total Carbon Emissions[5]										
Petroleum	605.3	777.8	754.2	737.4	816.4	788.9	763.4	846.9	815.5	791.1
Natural Gas	278.1	311.7	318.1	324.0	318.7	324.9	332.5	323.4	328.7	336.2
Coal	62.8	66.2	66.6	66.8	65.3	65.6	65.7	64.2	64.5	64.6
Other[4]	0.0	1.5	1.5	1.4	2.3	2.2	2.1	2.8	2.7	2.5
Electricity	516.7	664.5	662.9	663.7	708.1	706.8	708.5	752.2	744.7	745.4
Total	**1462.9**	**1821.7**	**1803.2**	**1793.2**	**1910.8**	**1888.3**	**1872.2**	**1989.5**	**1956.2**	**1939.8**
Electric Generators[6]										
Petroleum	15.5	18.7	7.4	4.7	19.7	6.8	4.3	21.0	6.6	4.5
Natural Gas	40.3	104.9	106.3	108.7	124.0	125.4	127.0	135.1	145.0	146.3
Coal	460.9	540.9	549.3	550.3	564.4	574.5	577.3	596.2	593.1	594.5
Total	**516.7**	**664.5**	**662.9**	**663.7**	**708.1**	**706.8**	**708.5**	**752.2**	**744.7**	**745.4**
Total Carbon Emissions[7]										
Petroleum	620.8	796.5	761.5	742.1	836.1	795.7	767.7	867.9	822.1	795.6
Natural Gas	318.4	416.6	424.4	432.7	442.7	450.3	459.5	458.5	473.7	482.5
Coal	523.7	607.1	615.9	617.0	629.7	640.1	643.0	660.3	657.7	659.2
Other[4]	0.0	1.5	1.5	1.4	2.3	2.2	2.1	2.8	2.7	2.5
Total	**1462.9**	**1821.7**	**1803.2**	**1793.2**	**1910.8**	**1888.3**	**1872.2**	**1989.5**	**1956.2**	**1939.8**
Carbon Emissions										
(tons per person)	**5.5**	**6.1**	**6.0**	**6.0**	**6.1**	**6.1**	**6.0**	**6.2**	**6.0**	**6.0**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]Includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573(96) (Washington, DC, October 1997). 1996 consumption estimates based on: EIA, *Short Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System run LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1996	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 (1992=1.000)	**1.102**	**1.599**	**1.600**	**1.602**	**1.894**	**1.891**	**1.889**	**2.275**	**2.262**	**2.250**
Real Gross Domestic Product	**6928**	**9464**	**9431**	**9398**	**10251**	**10211**	**10168**	**10953**	**10900**	**10873**
Real Consumption	4714	6381	6349	6319	7026	6989	6950	7676	7626	7599
Real Investment	1067	1748	1739	1730	1944	1934	1923	2120	2105	2101
Real Government Spending	1258	1504	1498	1493	1590	1583	1576	1648	1640	1634
Real Exports	857	2348	2332	2318	2872	2849	2827	3382	3352	3329
Real Imports	971	2566	2514	2469	3355	3283	3214	4262	4153	4071
Real Disposable Personal Income	**5077**	**6930**	**6884**	**6842**	**7616**	**7560**	**7504**	**8289**	**8217**	**8171**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.299**	**1.855**	**1.851**	**1.847**	**1.996**	**1.992**	**1.987**	**2.124**	**2.125**	**2.121**
AA Utility Bond Rate (percent)	7.57	7.15	7.21	7.29	7.56	7.64	7.74	8.16	8.27	8.27
Real Yield on Government 10 Year Bonds (percent)	4.99	3.54	3.58	3.61	3.64	3.69	3.73	3.92	3.97	4.02
Real Utility Bond Rate (percent)	5.28	3.95	4.05	4.17	4.02	4.15	4.31	4.29	4.49	4.59
Delivered Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	10.16	9.09	9.04	9.01	8.74	8.68	8.63	8.43	8.35	8.29
Total Energy	13.57	11.95	11.90	11.88	11.41	11.34	11.31	10.96	10.89	10.84
Consumer Price Index (1982-84=1.00)	1.57	2.41	2.42	2.43	2.89	2.90	2.92	3.50	3.52	3.53
Unemployment Rate (percent)	5.38	5.46	5.51	5.58	5.51	5.55	5.62	5.58	5.66	5.63
Unit Sales of Light-Duty Vehicles (million)	**15.10**	**17.01**	**16.65**	**16.31**	**17.54**	**17.15**	**16.73**	**17.98**	**17.49**	**17.27**
Millions of People										
Population with Armed Forces Overseas	266.1	298.9	298.9	298.9	311.2	311.2	311.2	323.5	323.5	323.5
Population (aged 16 and over)	204.2	235.4	235.4	235.4	245.8	245.8	245.8	255.6	255.6	255.6
Employment, Non-Agriculture	119.5	144.4	143.9	143.4	149.8	149.2	148.6	154.1	153.4	152.9
Employment, Manufacturing	18.5	17.6	17.5	17.5	16.5	16.4	16.3	15.2	15.2	15.1
Labor Force	133.9	156.6	156.5	156.4	160.3	160.2	160.0	162.5	162.4	162.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1996: Data Resources Incorporated (DRI), DRI Trend0897. **Projections:** Energy Information Administration, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	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 (1996 dollars per barrel)[1]	**20.48**	**14.44**	**20.81**	**26.87**	**14.42**	**21.48**	**28.59**	**14.43**	**22.32**	**28.71**
Production[2]										
OECD										
U.S. (50 states)	9.37	7.78	8.94	9.78	7.54	8.73	10.03	7.32	8.48	9.67
Canada	2.51	2.55	2.59	2.63	2.57	2.62	2.67	2.59	2.66	2.70
Mexico	3.28	3.23	3.34	3.41	3.31	3.43	3.52	3.39	3.53	3.63
OECD Europe[3]	6.67	5.65	5.74	5.80	5.02	5.11	5.18	4.38	4.47	4.53
Other OECD	0.77	0.97	1.01	1.04	0.76	0.80	0.83	0.80	0.84	0.88
Total OECD	**22.60**	**20.18**	**21.62**	**22.65**	**19.21**	**20.70**	**22.23**	**18.48**	**19.98**	**21.40**
Developing Countries										
Other South & Central America	3.29	5.07	5.23	5.34	5.81	6.03	6.18	6.41	6.68	6.85
Pacific Rim	2.08	3.10	3.20	3.27	3.11	3.23	3.31	2.96	3.08	3.16
OPEC	29.00	56.29	48.19	42.96	66.60	56.40	49.12	78.32	65.98	58.08
Other Developing Countries	4.21	4.85	5.00	5.11	5.14	5.33	5.47	5.16	5.38	5.52
Total Developing Countries	**38.59**	**69.31**	**61.63**	**56.69**	**80.66**	**70.98**	**64.08**	**92.85**	**81.11**	**73.62**
Eurasia										
Former Soviet Union	7.14	9.53	9.83	10.04	10.21	10.59	10.87	10.96	11.41	11.71
Eastern Europe	0.32	0.20	0.21	0.22	0.18	0.18	0.19	0.17	0.18	0.19
China	3.10	3.17	3.27	3.34	3.34	3.46	3.55	3.51	3.65	3.75
Total Eurasia	**10.55**	**12.90**	**13.31**	**13.59**	**13.72**	**14.23**	**14.60**	**14.64**	**15.24**	**15.64**
Total Production	**71.74**	**102.39**	**96.56**	**92.93**	**113.59**	**105.91**	**100.92**	**125.97**	**116.34**	**110.66**
Consumption										
OECD										
U.S. (50 states)	18.31	23.59	22.70	22.12	24.71	23.66	22.89	25.58	24.39	23.61
U.S. Territories	0.26	0.44	0.38	0.35	0.48	0.42	0.37	0.55	0.46	0.42
Canada	1.77	2.42	2.15	1.98	2.62	2.28	2.07	2.83	2.43	2.20
Mexico	1.98	3.00	2.74	2.58	3.35	3.00	2.78	3.71	3.27	3.01
Japan	5.84	8.53	7.28	6.56	9.55	7.80	6.77	10.62	8.34	7.11
Australia and New Zealand.	0.97	1.25	1.20	1.16	1.31	1.24	1.20	1.37	1.29	1.24
OECD Europe[3]	13.93	15.97	15.11	14.56	16.40	15.40	14.73	16.80	15.69	15.02
Total OECD	**43.05**	**55.21**	**51.56**	**49.31**	**58.43**	**53.80**	**50.81**	**61.46**	**55.88**	**52.61**
Developing Countries										
Other South and Central America	3.79	6.72	6.51	6.37	7.76	7.49	7.29	8.95	8.61	8.40
Pacific Rim	4.55	8.76	8.44	8.23	10.51	10.07	9.77	12.61	12.03	11.67
OPEC	5.14	7.06	7.06	7.06	7.91	7.91	7.91	8.86	8.86	8.86
Other Developing Countries	5.44	8.69	7.94	7.48	9.87	8.75	8.06	11.18	9.66	8.77
Total Developing Countries	**18.91**	**31.24**	**29.95**	**29.14**	**36.05**	**34.22**	**33.03**	**41.61**	**39.16**	**37.70**

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1996	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
Eurasia										
Former Soviet Union	4.48	7.04	6.73	6.54	8.03	7.65	7.38	9.16	8.68	8.39
Eastern Europe	1.43	1.77	1.73	1.69	2.03	1.96	1.92	2.31	2.24	2.19
China	3.44	7.44	6.89	6.55	9.35	8.58	8.08	11.72	10.68	10.07
Total Eurasia	9.35	16.25	15.35	14.78	19.40	18.19	17.38	23.20	21.60	20.65
Total Consumption	71.32	102.69	96.86	93.23	113.89	106.21	101.22	126.27	116.64	110.96
Non-OPEC Production	42.74	46.10	48.37	49.97	46.99	49.52	51.80	47.65	50.36	52.58
Net Eurasia Exports	1.20	-3.35	-2.04	-1.19	-5.68	-3.96	-2.77	-8.57	-6.36	-5.01
OPEC Market Share	0.40	0.55	0.50	0.46	0.59	0.53	0.49	0.62	0.57	0.52

[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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, August 1997*, Online. http://www.eia.doe.gov/emeu/steo/pub/upd/aug97/index.html (August 21, 1997). **Projections:** EIA, AEO98 National Energy Modeling System runs LWOP98.D100197C, AEO98B.D100197A, and HWOP98.D100197A.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Crude Oil Equivalency Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Production								
Crude Oil and Lease Condensate	6.56	6.48	6.17	5.82	5.57	5.24	4.92	-1.1%
Natural Gas Plant Liquids	1.12	1.16	1.13	1.24	1.39	1.47	1.55	1.2%
Dry Natural Gas	9.03	9.21	9.82	10.81	11.99	12.68	13.29	1.5%
Coal	10.38	10.67	11.47	12.10	12.57	13.10	13.47	1.0%
Nuclear Power	3.40	3.39	3.47	3.24	3.00	2.42	1.93	-2.3%
Renewable Energy[1]	3.02	3.25	3.21	3.36	3.50	3.58	3.63	0.5%
Other[2]	0.64	0.63	0.26	0.26	0.23	0.22	0.22	-4.2%
Total	**34.16**	**34.79**	**35.53**	**36.84**	**38.26**	**38.72**	**39.01**	**0.5%**
Imports								
Crude Oil [3]	7.23	7.51	8.84	10.14	10.67	11.22	11.65	1.8%
Petroleum Products[4]	1.51	1.88	2.01	2.58	3.60	4.26	4.76	3.9%
Natural Gas	1.37	1.38	1.98	2.07	2.20	2.38	2.52	2.5%
Other Imports[5]	0.28	0.27	0.29	0.27	0.27	0.26	0.26	-0.1%
Total	**10.39**	**11.04**	**13.12**	**15.07**	**16.74**	**18.12**	**19.20**	**2.3%**
Exports								
Petroleum[6]	0.95	0.96	0.81	0.82	0.85	0.89	0.79	-0.8%
Natural Gas	0.07	0.07	0.13	0.13	0.14	0.14	0.15	3.0%
Coal	1.10	1.12	1.13	1.25	1.34	1.43	1.52	1.3%
Total	**2.13**	**2.15**	**2.07**	**2.20**	**2.33**	**2.46**	**2.46**	**0.6%**
Discrepancy[7]	**0.50**	**0.61**	**0.44**	**0.25**	**0.28**	**0.25**	**0.08**	**-8.3%**
Consumption								
Petroleum Products[8]	16.41	16.96	18.06	19.52	20.94	21.82	22.44	1.2%
Natural Gas	10.48	10.65	11.66	12.72	13.99	14.85	15.57	1.6%
Coal	9.41	9.84	10.41	10.94	11.32	11.75	12.03	0.8%
Nuclear Power	3.40	3.39	3.47	3.24	3.00	2.42	1.93	-2.3%
Renewable Energy[1]	3.02	3.25	3.21	3.36	3.51	3.60	3.64	0.5%
Other[9]	0.18	0.18	0.19	0.18	0.19	0.19	0.20	0.4%
Total	**42.92**	**44.28**	**47.01**	**49.96**	**52.95**	**54.63**	**55.82**	**1.0%**
Net Imports - Petroleum	**7.78**	**8.43**	**10.04**	**11.90**	**13.42**	**14.59**	**15.63**	**2.6%**
Prices (1996 dollars per unit)								
World Oil Price (dollars per barrel)[10]	17.58	20.48	19.11	20.19	20.81	21.48	22.32	0.4%
Gas Wellhead Price (dollars per Mcf)[11]	1.61	2.24	2.11	2.15	2.31	2.38	2.54	0.5%
Coal Minemouth Price (dollars per ton)	19.25	18.50	17.45	16.18	15.05	13.99	13.27	-1.4%
Average Electric Price (cents per kilowatthour)	7.0	6.9	6.5	6.1	5.9	5.6	5.5	-1.0%

[1]Includes grid connected electricity from hydroelectric; wood and wood waste; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes 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 withdraws.

[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.

Mcf = Thousand cubic feet.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 and 1996 may differ from published data due to internal conversion factors.

Sources: 1995 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 coal minemouth prices: EIA, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1996 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/7) (Washington, DC, June 1997). 1996 coal minemouth price: *Coal Industy Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table D2. Total Energy Supply and Disposition Crude Oil Equivalency Summary
(Million Tons Oil Equivalent per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1996-2020 (percent)
	1995	1996	2000	2005	2010	2015	2020	
Production								
Crude Oil and Lease Condensate	326.51	322.31	307.03	289.71	277.19	260.84	245.12	-1.1%
Natural Gas Plant Liquids	55.81	57.89	56.09	61.88	69.29	73.30	77.32	1.2%
Dry Natural Gas	449.52	459.75	490.02	537.86	597.00	631.24	663.25	1.5%
Coal	516.77	532.29	572.35	602.26	625.87	651.94	672.08	1.0%
Nuclear Power	169.06	169.39	173.03	161.40	149.53	120.43	96.10	-2.3%
Renewable Energy[1]	150.53	162.37	160.31	167.35	174.11	178.43	181.16	0.5%
Other[2]	31.99	31.21	13.18	12.99	11.38	11.07	11.04	-4.2%
Total	**1700.18**	**1735.20**	**1772.01**	**1833.45**	**1904.36**	**1927.23**	**1946.07**	**0.5%**
Imports								
Crude Oil[3]	369.04	383.28	450.99	517.38	544.84	572.68	594.81	1.8%
Petroleum Products[4]	75.00	93.65	99.95	128.56	179.00	211.89	237.16	3.9%
Natural Gas	68.26	68.90	98.80	103.26	109.61	118.56	125.56	2.5%
Other Imports[5]	13.98	13.31	14.66	13.66	13.37	12.80	13.08	-0.1%
Total	**526.28**	**559.13**	**664.40**	**762.87**	**846.81**	**915.93**	**970.62**	**2.3%**
Exports								
Petroleum[6]	47.52	47.97	40.22	40.63	42.28	44.35	39.33	-0.8%
Natural Gas	3.71	3.66	6.48	6.62	6.84	6.96	7.51	3.0%
Coal	54.55	55.72	56.62	62.11	66.83	71.22	76.06	1.3%
Total	**105.77**	**107.35**	**103.32**	**109.35**	**115.95**	**122.52**	**122.90**	**0.6%**
Discrepancy[7]	**15.52**	**23.19**	**13.72**	**0.86**	**1.92**	**0.08**	**-5.98**	**N/A**
Consumption								
Petroleum Products[8]	816.87	846.58	901.55	971.39	1042.31	1086.11	1120.14	1.2%
Natural Gas	521.47	531.36	581.76	633.24	696.55	739.08	777.33	1.6%
Coal	469.20	491.26	520.48	545.58	564.90	586.55	602.18	0.9%
Nuclear Power	169.06	169.39	173.03	161.40	149.53	120.43	96.10	-2.3%
Renewable Energy[1]	150.56	162.41	160.33	167.48	174.52	179.05	181.90	0.5%
Other[9]	9.17	9.16	9.68	8.73	9.33	9.51	10.15	0.4%
Total	**2136.20**	**2210.16**	**2346.82**	**2487.83**	**2637.14**	**2720.72**	**2787.81**	**1.0%**
Net Imports - Petroleum	**396.52**	**428.96**	**510.71**	**605.32**	**681.55**	**740.22**	**792.63**	**2.6%**
Prices (1996 dollars per unit)								
World Oil Price (dollars per barrel)[10]	17.58	20.48	19.11	20.19	20.81	21.48	22.32	0.4%
Gas Wellhead Price (dollars per Mcf)[11]	1.61	2.24	2.11	2.15	2.31	2.38	2.54	0.5%
Coal Minemouth Price (dollars per ton)	19.25	18.50	17.45	16.18	15.05	13.99	13.27	-1.4%
Average Electric Price (cents per kilowatt hour)	7.0	6.9	6.5	6.1	5.9	5.6	5.5	-1.0%

[1]Includes grid connected electricity from hydroelectric; wood and wood waste; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes 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 withdraws.
[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.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1994 and 1995 may differ from published data due to internal conversion factors.
Sources: 1995 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 coal minemouth prices: EIA, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1996 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/7) (Washington, DC, June 1997). 1996 coal minemouth price*: Coal Industy Annual 1996* DOE/EIA-0584(96) (Washington, DC, November 1997). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(97/08) (Washington, DC, August 1997). Other 1996 values: EIA, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, AEO98 National Energy Modeling System run AEO98B.d100197A.

Household Expenditures

Table E1. 1996 Average Household Expenditures for Energy by Household Characteristic (1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2172.61**	**1115.45**	**702.23**	**341.89**	**71.32**	**1057.17**
Households by Income Quintile						
1st	1363.02	863.41	519.96	293.78	49.67	499.61
2nd	1792.24	988.62	603.76	325.47	59.39	803.62
3rd	2299.18	1106.29	726.61	304.91	74.78	1192.89
4th	2452.73	1203.44	776.74	345.84	80.85	1249.30
5th	2985.52	1418.02	891.19	433.90	92.92	1567.51
Households by Census Division						
New England	2493.19	1383.55	657.76	337.62	388.17	1109.64
Middle Atlantic	2279.33	1427.41	654.11	544.06	229.24	851.92
South Atlantic	2222.69	1117.06	568.24	520.92	27.90	1105.63
East North Central	2173.83	1049.84	630.63	366.92	52.28	1123.99
East South Central	2002.11	1061.02	850.12	174.14	36.76	941.09
West North Central	2470.76	1220.00	991.02	221.81	7.17	1250.76
West South Central	2300.26	1169.36	878.53	290.82	0.00	1130.91
Mountain	2007.98	830.39	554.41	270.31	5.67	1177.59
Pacific	1959.49	844.34	577.31	254.39	12.64	1115.14

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table E2. 2000 Average Household Expenditures for Energy by Household Characteristics (1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2088.77**	**1025.77**	**661.24**	**299.54**	**64.98**	**1063.01**
Households by Income Quintile						
1st	1293.10	787.76	488.39	253.97	45.40	505.35
2nd	1715.66	908.44	570.71	283.94	53.78	807.22
3rd	2217.35	1018.21	683.83	266.59	67.79	1199.15
4th	2363.79	1107.62	731.77	302.54	73.31	1256.17
5th	2883.07	1309.26	838.24	385.60	85.41	1573.82
Households by Census Division						
New England	2471.60	1288.11	587.47	322.56	378.09	1183.49
Middle Atlantic	2220.30	1334.54	642.55	475.94	216.04	885.76
South Atlantic	2128.69	1027.99	559.67	445.19	23.13	1100.70
East North Central	2099.66	947.72	587.17	320.42	40.13	1151.94
East South Central	1939.69	993.59	797.77	162.66	33.17	946.09
West North Central	2369.05	1090.27	875.97	208.38	5.91	1278.79
West South Central	2206.56	1025.60	820.40	205.20	0.00	1180.96
Mountain	1891.44	818.57	543.08	269.75	5.73	1072.88
Pacific	1850.08	777.24	518.37	245.72	13.15	1072.85

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table E3. 2005 Average Household Expenditures for Energy by Household Characteristic
(1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2102.36**	**986.66**	**646.06**	**280.28**	**60.32**	**1115.70**
Households by Income Quintile						
1st	1287.16	754.76	476.50	236.10	42.16	532.40
2nd	1721.62	875.06	559.49	265.69	49.88	846.56
3rd	2237.57	980.38	667.53	249.98	62.87	1257.19
4th	2385.32	1066.68	715.19	283.36	68.12	1318.64
5th	2910.25	1259.14	818.21	361.63	79.30	1651.11
Households by Census Division						
New England	2508.08	1239.01	565.44	307.65	365.92	1269.07
Middle Atlantic	2233.59	1284.98	634.03	443.11	207.83	948.61
South Atlantic	2153.06	994.11	551.01	421.25	21.84	1158.95
East North Central	2127.33	917.12	578.26	302.15	36.70	1210.21
East South Central	1915.25	940.87	759.01	152.76	29.11	974.37
West North Central	2351.95	1027.93	826.04	196.11	5.77	1324.02
West South Central	2230.61	1001.69	805.33	196.36	0.00	1228.92
Mountain	1925.57	813.56	549.10	259.08	5.38	1112.01
Pacific	1899.47	760.39	516.80	230.97	12.62	1139.07

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table E4. 2010 Average Household Expenditures for Energy by Household Characteristic
(1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2096.67**	**961.06**	**637.31**	**267.84**	**55.91**	**1135.61**
Households by Income Quintile						
1st	1274.80	732.89	469.38	224.58	38.93	541.92
2nd	1711.28	852.33	552.58	253.59	46.16	858.95
3rd	2233.42	955.23	657.56	239.37	58.30	1278.19
4th	2385.04	1040.72	706.24	271.26	63.23	1344.32
5th	2913.22	1228.20	808.12	346.38	73.70	1685.02
Households by Census Division						
New England	2529.19	1211.51	567.61	292.37	351.52	1317.68
Middle Atlantic	2243.65	1259.57	641.07	419.91	198.59	984.08
South Atlantic	2138.88	961.98	540.82	400.38	20.78	1176.90
East North Central	2128.40	903.95	575.87	294.58	33.49	1224.45
East South Central	1878.77	906.90	732.27	148.53	26.10	971.87
West North Central	2308.36	986.35	788.93	191.83	5.58	1322.02
West South Central	2217.35	979.99	788.11	191.88	0.00	1237.36
Mountain	1918.10	805.04	542.59	257.33	5.13	1113.05
Pacific	1957.95	760.16	524.44	223.61	12.11	1197.79

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table E5. 2015 Average Household Expenditures for Energy by Household Characteristic
(1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2048.72**	**927.04**	**616.72**	**258.28**	**52.04**	**1121.68**
Households by Income Quintile						
1st	1241.79	705.75	453.71	215.97	36.07	536.04
2nd	1670.10	821.47	534.47	244.12	42.88	848.63
3rd	2183.58	920.95	635.41	231.20	54.34	1262.63
4th	2334.18	1005.29	684.43	261.95	58.91	1328.89
5th	2852.44	1187.08	783.61	334.66	68.80	1665.36
Households by Census Division						
New England	2521.78	1204.52	580.87	286.86	336.79	1317.26
Middle Atlantic	2221.02	1239.10	640.16	408.27	190.67	981.92
South Atlantic	2096.85	925.90	518.78	387.44	19.68	1170.95
East North Central	2081.30	869.51	553.20	285.47	30.84	1211.79
East South Central	1830.47	874.83	704.96	146.39	23.48	955.64
West North Central	2247.45	944.97	750.72	188.83	5.42	1302.48
West South Central	2157.21	934.85	748.38	186.47	0.00	1222.37
Mountain	1863.27	771.50	519.28	247.30	4.92	1091.77
Pacific	1903.40	731.95	507.51	212.62	11.82	1171.45

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table E6. 2020 Average Household Expenditures for Energy by Household Characteristic
(1996 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2025.38**	**920.78**	**614.12**	**258.16**	**48.50**	**1104.60**
Households by Income Quintile						
1st	1228.62	700.18	451.48	215.18	33.52	528.44
2nd	1650.33	815.13	531.44	243.72	39.96	835.19
3rd	2157.18	913.93	631.90	231.39	50.64	1243.25
4th	2309.35	999.67	682.47	262.22	54.98	1309.68
5th	2821.99	1181.09	781.87	335.02	64.20	1640.90
Households by Census Division						
New England	2527.71	1212.28	594.80	294.11	323.37	1315.43
Middle Atlantic	2236.04	1255.92	663.72	410.04	182.16	980.12
South Atlantic	2070.01	915.23	506.04	390.51	18.68	1154.79
East North Central	2051.36	863.27	542.95	291.81	28.51	1188.09
East South Central	1803.10	866.48	698.42	146.71	21.36	936.61
West North Central	2214.57	938.99	743.88	189.73	5.38	1275.58
West South Central	2129.88	927.05	740.35	186.71	0.00	1202.82
Mountain	1823.27	759.18	507.49	246.99	4.71	1064.09
Pacific	1882.40	727.30	506.32	209.79	11.18	1155.11

Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

Table F1. Key Results for Residential Sector Technology Cases

Energy Consumption	1996	2005 1998 Tech.	2005 Reference Case	2005 Advanced Tech. Cost Reduction	2005 Best Available Tech.	2010 1998 Tech.	2010 Reference Case	2010 Advanced Tech. Cost Reduction	2010 Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.89	0.83	0.79	0.78	0.77	0.82	0.77	0.75	0.73
Kerosene	0.08	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07
Liquefied Petroleum Gas	0.42	0.48	0.47	0.46	0.44	0.51	0.49	0.47	0.44
Petroleum Subtotal	1.40	1.38	1.34	1.32	1.28	1.40	1.33	1.29	1.24
Natural Gas	5.39	5.56	5.47	5.42	5.25	5.83	5.63	5.53	5.13
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy	0.61	0.62	0.62	0.62	0.62	0.64	0.63	0.62	0.62
Electricity	3.68	4.36	4.29	4.13	3.80	4.74	4.61	4.30	3.79
Delivered Energy	**11.13**	**11.99**	**11.77**	**11.53**	**11.00**	**12.67**	**12.25**	**11.79**	**10.84**
Electricity Related Losses	8.23	9.19	9.05	8.71	8.02	9.66	9.39	8.76	7.73
Total	**19.36**	**21.18**	**20.81**	**20.24**	**19.02**	**22.33**	**21.64**	**20.56**	**18.57**
Delivered Energy Consumption per Household (million Btu per Year)	**110.90**	**107.90**	**105.95**	**103.83**	**99.06**	**108.23**	**104.63**	**100.77**	**92.59**

Table F2. Key Results for Commercial Sector Technology Cases

Energy Consumption	1996	2005 1998 Tech.	2005 Reference Case	2005 Advanced Tech. Cost Reduction	2005 Best Available Tech.	2010 1998 Tech.	2010 Reference Case	2010 Advanced Tech. Cost Reduction	2010 Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.44	0.41	0.40	0.40	0.40	0.40	0.40	0.39	0.39
Residual Fuel	0.15	0.13	0.12	0.13	0.13	0.13	0.12	0.13	0.13
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquid 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	0.71	0.67	0.65	0.66	0.66	0.67	0.65	0.66	0.66
Natural Gas	3.30	3.64	3.62	3.55	3.49	3.79	3.75	3.63	3.55
Coal	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.37	3.88	3.84	3.78	3.52	4.17	4.09	3.94	3.61
Delivered Energy	**7.47**	**8.28**	**8.21**	**8.08**	**7.76**	**8.72**	**8.60**	**8.34**	**7.91**
Electricity Related Losses	7.54	8.18	8.09	7.96	7.42	8.50	8.35	8.04	7.35
Total	**15.01**	**16.46**	**16.30**	**16.04**	**15.18**	**17.23**	**16.94**	**16.38**	**15.26**
Delivered Energy Consumption per Square Foot (thousand Btu per year)	**105.27**	**104.75**	**103.85**	**102.32**	**98.25**	**105.33**	**103.79**	**100.64**	**95.48**

Table F1. Key Results for Residential Sector Technology Cases (Continued)

2015				2020				Annual Growth 1996-2020			
1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.	1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.	1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.
0.81	0.74	0.72	0.69	0.81	0.72	0.69	0.66	-0.4%	-0.9%	-1.1%	-1.3%
0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.06	-0.3%	-0.6%	-0.7%	-1.0%
0.54	0.50	0.48	0.44	0.56	0.51	0.49	0.43	1.2%	0.8%	0.6%	0.1%
1.43	1.32	1.27	1.19	1.45	1.30	1.24	1.15	0.1%	-0.3%	-0.5%	-0.8%
6.14	5.82	5.66	5.05	6.45	5.97	5.74	5.00	0.8%	0.4%	0.3%	-0.3%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-0.2%	-0.2%	-0.2%	-0.2%
0.65	0.64	0.63	0.63	0.66	0.64	0.63	0.64	0.3%	0.2%	0.1%	0.2%
5.14	4.94	4.54	3.96	5.54	5.28	4.80	4.16	1.7%	1.5%	1.1%	0.5%
13.42	**12.77**	**12.15**	**10.89**	**14.15**	**13.25**	**12.47**	**11.01**	**1.0%**	**0.7%**	**0.5%**	**-0.0%**
9.97	9.58	8.81	7.68	10.42	9.93	9.02	7.83	1.0%	0.8%	0.4%	-0.2%
23.39	**22.35**	**20.96**	**18.57**	**24.56**	**23.17**	**21.49**	**18.83**	**1.0%**	**0.8%**	**0.4%**	**-0.1%**
109.06	**103.79**	**98.76**	**88.50**	**109.91**	**102.91**	**96.88**	**85.51**	**-0.0%**	**-0.3%**	**-0.6%**	**-1.1%**

Tech. = Technology.
Btu = British thermal units.
Note: 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: AEO98 National Energy Modeling System, runs RSFRZN.D100297A, AEO98B.D100197A, RSATCR.D100297A, and RSBEST.D100297A.

Table F2. Key Results for Commercial Sector Technology Cases (Continued)

2015				2020				Annual Growth 1996-2020			
1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.	1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.	1998 Tech.	Reference Case	Advanced Tech. Cost Reduction	Best Available Tech.
0.39	0.39	0.38	0.38	0.38	0.37	0.37	0.37	-0.6%	-0.7%	-0.7%	-0.8%
0.13	0.12	0.13	0.13	0.13	0.12	0.13	0.13	-0.6%	-0.9%	-0.6%	-0.6%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.0%	-0.2%	-0.0%	-0.0%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.8%	0.8%	0.8%	0.8%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%	-0.3%	-0.3%	-0.3%
0.66	0.65	0.65	0.65	0.65	0.63	0.64	0.64	-0.4%	-0.5%	-0.5%	-0.5%
3.90	3.85	3.67	3.59	3.92	3.85	3.63	3.56	0.7%	0.7%	0.4%	0.3%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.8%	0.8%	0.8%	0.8%
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.1%	1.1%	1.1%	1.1%
4.44	4.33	4.11	3.71	4.59	4.45	4.18	3.73	1.3%	1.2%	0.9%	0.4%
9.10	**8.92**	**8.54**	**8.05**	**9.26**	**9.04**	**8.55**	**8.03**	**0.9%**	**0.8%**	**0.6%**	**0.3%**
8.60	8.39	7.97	7.18	8.62	8.37	7.86	7.02	0.6%	0.4%	0.2%	-0.3%
17.70	**17.31**	**16.51**	**15.23**	**17.88**	**17.41**	**16.40**	**15.05**	**0.7%**	**0.6%**	**0.4%**	**0.0%**
106.05	**103.99**	**99.50**	**93.77**	**106.64**	**104.16**	**98.46**	**92.52**	**0.1%**	**-0.0%**	**-0.3%**	**-0.5%**

Tech. = Technology.
Btu = British thermal units.
Note: 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: AEO98 National Energy Modeling System, runs COMTK98.D100397A, AEO98B.D100197A,COMATCR.D100397A, and COMBEST.D100397A.

Table F3. Key Results for Industrial Technology Cases

	1996	2000			2010			2020		
		1998 Technology	Reference Case	High Technology	1998 Technology	Reference Case	High Technology	1998 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.17	1.21	1.21	1.20	1.45	1.45	1.40	1.57	1.56	1.46
Liquefied Petroleum Gas	2.12	2.15	2.14	2.13	2.43	2.40	2.12	2.53	2.47	2.14
Petrochemical Feedstocks	1.28	1.31	1.31	1.30	1.49	1.47	1.30	1.55	1.51	1.31
Residual Fuel	0.34	0.35	0.35	0.34	0.38	0.35	0.32	0.39	0.35	0.30
Motor Gasoline	0.19	0.20	0.20	0.20	0.25	0.25	0.24	0.27	0.27	0.25
Other Petroleum	4.12	4.35	4.35	4.34	4.95	4.84	4.56	5.25	5.10	4.68
Petroleum Subtotal	9.23	9.57	9.55	9.51	10.96	10.75	9.93	11.55	11.25	10.14
Natural Gas	10.14	11.03	10.94	10.89	12.03	11.67	11.19	12.37	11.80	11.09
Metallurgical Coal	0.85	0.84	0.83	0.82	0.72	0.71	0.65	0.62	0.61	0.53
Steam Coal	1.55	1.58	1.56	1.54	1.88	1.77	1.67	1.95	1.79	1.64
Net Coal Coke Imports	0.00	0.03	0.03	0.03	0.07	0.06	0.07	0.09	0.08	0.09
Coal Subtotal	2.40	2.45	2.42	2.39	2.67	2.54	2.39	2.66	2.48	2.26
Renewable Energy	1.82	1.97	1.96	1.95	2.28	2.25	2.21	2.40	2.34	2.30
Electricity	3.46	3.73	3.69	3.68	4.48	4.37	4.25	4.92	4.75	4.51
Delivered Energy	**27.05**	**28.75**	**28.57**	**28.42**	**32.42**	**31.58**	**29.97**	**33.91**	**32.62**	**30.30**
Electricity Related Losses	7.74	8.21	8.14	8.10	9.14	8.92	8.66	9.26	8.93	8.48
Total	**34.79**	**36.96**	**36.71**	**36.52**	**41.56**	**40.50**	**38.62**	**43.16**	**41.55**	**38.78**
Energy Use per Dollar of Output (thousand Btu per 1987 dollar)										
Delivered Energy	**7.11**	**6.91**	**6.87**	**6.83**	**6.13**	**5.97**	**5.67**	**5.63**	**5.42**	**5.03**
Total Energy	**9.14**	**8.89**	**8.83**	**8.78**	**7.86**	**7.66**	**7.31**	**7.17**	**6.90**	**6.44**

Btu = British thermal units.
Note: 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: AEO98 Forecasting System runs INDLO98.D100397C, AEO98B.D100197A, and INDHI98.D100397C.

Table F4. Key Results for Transportation Technology Cases

	1996	2000			2010			2020		
		1998 Tech.	Reference Case	Advanced Tech.	1998 Tech.	Reference Case	Advanced Tech.	1998 Tech.	Reference Case	Advanced Tech.
Energy Consumption (quadrillion Btu)										
Distillate Fuel	4.48	5.15	5.14	5.09	6.21	6.02	6.40	6.67	6.31	7.31
Jet Fuel	3.27	3.84	3.83	3.79	5.32	5.23	4.88	6.56	6.28	5.64
Motor Gasoline	14.94	15.83	15.96	15.96	18.23	18.22	15.72	19.92	19.38	14.20
Residual Fuel	0.90	0.94	0.94	0.93	1.27	1.27	1.26	1.57	1.56	1.54
Liquid Petroleum Gas	0.03	0.04	0.04	0.04	0.16	0.16	0.24	0.23	0.24	0.43
Other Petroleum	0.29	0.34	0.31	0.34	0.38	0.35	0.38	0.40	0.37	0.40
Petroleum Subtotal	23.91	26.14	26.22	26.17	31.57	31.25	28.88	35.36	34.14	29.52
Pipeline Fuel Natural Gas	0.73	0.80	0.80	0.80	0.95	0.95	0.95	1.03	1.03	1.03
Compressed Natural Gas	0.01	0.05	0.05	0.05	0.22	0.24	0.30	0.30	0.34	0.47
Renewables (E85)	0.00	0.00	0.00	0.00	0.09	0.09	0.60	0.16	0.16	1.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.08	0.08	0.56	0.16	0.15	1.05
Methanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.06	0.06	0.06	0.18	0.16	0.16	0.28	0.22	0.24
Delivered Energy	**24.72**	**27.06**	**27.14**	**27.09**	**33.09**	**32.77**	**31.46**	**37.29**	**36.04**	**33.37**
Electricity Related Losses	0.13	0.14	0.14	0.14	0.37	0.32	0.32	0.52	0.41	0.45
Total	**24.85**	**27.20**	**27.28**	**27.23**	**33.46**	**33.09**	**31.78**	**37.82**	**36.45**	**33.82**
Light-Duty Fleet Efficiency (miles per gallon)	**20.2**	**20.6**	**20.3**	**20.3**	**20.4**	**20.3**	**21.0**	**20.6**	**21.2**	**22.6**

Tech = Technology.
Btu = British thermal units.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: AEO98 Forecasting System runs DCDRUN.D100797B, AEO98B.D100197A, and DCDRUN.D100797C.

Table F5. Key Results for Integrated End-Use Technology Cases

	1996	2000			2010			2020		
		1998 Tech.	Reference Case	High Tech.	1998 Tech.	Reference Case	High Tech.	1998 Tech.	Reference Case	High Tech.
Consumption by Sector (quadrillion Btu)										
Residential	19.36	20.10	20.11	20.00	21.75	21.64	20.96	23.54	23.17	22.19
Commercial	15.01	15.74	15.72	15.66	17.12	16.94	16.50	17.79	17.41	16.56
Industrial	34.79	36.95	36.71	36.48	41.61	40.50	38.11	43.29	41.55	37.94
Transportation	24.85	27.19	27.28	27.22	33.46	33.09	32.07	37.78	36.45	34.63
Total	**94.01**	**99.98**	**99.82**	**99.36**	**113.94**	**112.17**	**107.64**	**122.40**	**118.58**	**111.32**
Energy Intensity (thousand Btu per 1992 dollar of GDP)	**13.57**	**13.07**	**13.05**	**12.99**	**12.10**	**11.90**	**11.38**	**11.24**	**10.89**	**10.20**
Carbon Emissions by Sector (million metric tons)										
Residential	286	306	306	304	341	338	325	388	379	359
Commercial	230	248	247	246	278	274	266	305	296	279
Industrial	476	510	507	503	581	563	532	618	589	537
Transportation	471	517	518	517	634	628	601	717	692	641
Total	**1463**	**1580**	**1577**	**1569**	**1834**	**1803**	**1724**	**2029**	**1956**	**1816**
Carbon Emissions by End-Use Fuel (million metric tons)										
Petroleum	605	643	644	643	761	754	712	841	816	731
Natural Gas	278	296	295	293	323	318	310	338	329	317
Coal	63	65	64	63	70	67	62	69	64	58
Other	0	0	0	0	2	2	10	3	3	20
Electricity	517	576	574	570	679	663	630	778	745	690
Total	**1463**	**1580**	**1577**	**1569**	**1834**	**1803**	**1724**	**2029**	**1956**	**1816**
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	16	12	11	11	9	7	7	7	7	7
Natural Gas	40	60	60	59	112	106	94	147	145	134
Coal	461	504	503	501	558	549	529	624	593	549
Total	**517**	**576**	**574**	**570**	**679**	**663**	**630**	**778**	**745**	**690**
Carbon Emissions by Primary Fuel (million metric tons)										
Petroleum	621	655	656	654	770	762	719	848	822	738
Natural Gas	318	356	354	352	434	424	405	485	474	451
Coal	524	569	567	564	628	616	590	694	658	607
Other	0	0	0	0	2	2	10	3	3	20
Total	**1463**	**1580**	**1577**	**1569**	**1834**	**1803**	**1724**	**2029**	**1956**	**1816**

Btu = British thermal units.
GDP = Gross domestic product.
Tech. = Technology
Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Adminnistration, AEO98 National Energy Modeling System runs LDEMTEK.D100297A, AEO98B.D100197A, and HDEMTEK.D102297A.

Table F6. Key Results for Nuclear Retirement Cases

(Thousand Megawatts)

Net Summer Capability	1996	Projections								
		2000			2010			2020		
		Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear
Electric Generators										
Capability										
Coal Steam	305.3	296.8	296.8	296.8	310.8	304.6	301.5	361.3	323.6	307.3
Other Fossil Steam	138.1	121.3	121.3	121.3	101.0	101.0	101.0	96.0	96.0	96.0
Combined Cycle	15.3	27.7	27.7	27.2	124.9	106.5	99.0	198.0	186.5	172.7
Combustion Turbine/Diesel	80.0	142.1	140.4	140.1	196.3	191.4	188.7	223.0	221.9	221.1
Nuclear Power	100.8	92.6	95.6	97.6	49.2	80.4	93.5	2.3	49.2	80.4
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	88.6	91.3	91.3	91.3	93.9	93.6	93.6	97.0	95.7	96.0
Total	**748.0**	**791.6**	**792.8**	**794.1**	**896.0**	**897.3**	**897.1**	**997.5**	**992.8**	**993.5**
Cumulative Planned Additions										
Coal Steam	2.4	3.2	3.2	3.2	4.7	4.7	4.7	4.7	4.7	4.7
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	2.7	2.7	2.7	3.0	3.0	3.0	3.0	3.0	3.0
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.7	2.9	2.9	2.9	3.2	3.2	3.2	3.2	3.2	3.2
Total	**11.3**	**16.3**	**16.3**	**16.3**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions										
Coal Steam	0.0	0.0	0.0	0.0	23.0	16.9	13.7	83.1	45.4	29.1
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	11.1	11.1	10.6	108.1	89.7	82.1	181.1	169.7	155.8
Combustion Turbine/Diesel	23.6	84.4	82.7	82.4	139.5	134.6	132.0	167.4	166.3	165.5
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	0.5	0.7	0.7	0.7	3.1	2.8	2.8	6.7	5.4	5.7
Total	**24.1**	**96.2**	**94.4**	**93.7**	**273.8**	**244.0**	**230.6**	**438.3**	**386.7**	**356.2**
Cumulative Total Additions	**35.4**	**112.5**	**110.8**	**110.0**	**292.3**	**262.5**	**249.2**	**456.8**	**405.2**	**374.7**
Cumulative Retirements	**14.4**	**48.9**	**45.9**	**43.9**	**122.7**	**92.4**	**79.2**	**184.7**	**138.8**	**108.4**
Cogenerators										
Capacity										
Coal	7.1	7.3	7.3	7.3	7.7	7.7	7.7	7.7	7.7	7.7
Petroleum	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Natural Gas	28.0	30.5	30.5	30.5	32.7	32.7	32.7	31.9	31.9	31.9
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewable Sources	5.8	6.4	6.4	6.4	6.6	6.6	6.6	6.4	6.4	6.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**46.4**	**46.4**	**46.4**	**49.3**	**49.3**	**49.3**	**48.3**	**48.3**	**48.3**
Cumulative Additions	**8.1**	**11.4**	**11.4**	**11.4**	**14.4**	**14.4**	**14.4**	**13.4**	**13.4**	**13.4**

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 25, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Source: Energy Information Administration, AEO98 National Energy Modeling System runs LNUC98.D100297B, AEO98B.D100197A, and HNUC98.D100297B.

Table F7. Key Results for Electricity Demand Cases

	1996	2000		2010		2020		Annual Growth 1996-2020	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	3,098	3,318	3,330	3,877	4,034	4,308	4,927	1.4%	2.0%
Net Imports (billion kilowatthours)	38	39	39	30	30	27	27	-1.4%	-1.4%
Electricity Prices (1996 cents per kilowatthour)	6.9	6.5	6.5	5.9	6.1	5.5	6.2	-1.0%	-0.4%
Generation by Fuel (billion kilowatthours)									
Coal	1,797	1,940	1,943	2,124	2,169	2,304	2,605	1.0%	1.6%
Natural Gas	469	609	617	1,128	1,239	1,590	1,905	5.2%	6.0%
Renewables	433	411	411	425	424	436	437	0.0%	0.0%
Other	762	749	751	637	649	421	460	-2.4%	-2.1%
Total	**3,461**	**3,710**	**3,723**	**4,314**	**4,481**	**4,750**	**5,407**	**1.3%**	1.9%
Generating Capacity (gigawatts)									
Coal	305.3	296.8	296.8	304.6	306.7	323.6	361.0	0.2%	0.7%
Combined-Cycle/Combustion Turbine	95.3	168.0	174.2	297.9	317.0	408.4	476.8	6.2%	6.9%
Renewables	88.6	91.3	91.3	93.6	93.5	95.7	95.8	0.3%	0.3%
Nuclear Power	100.8	95.6	95.6	80.4	80.4	49.2	49.2	-2.9%	-2.9%
Cogenerators	43.0	46.4	46.4	49.3	49.3	48.3	48.3	0.5%	0.5%
Other	158.0	141.1	141.1	120.8	120.8	115.9	115.9	-1.3%	-1.3%
Total	**791.1**	**839.2**	**845.3**	**946.7**	**967.7**	**1,041.1**	**1,147.1**	**1.2%**	**1.6%**
Energy Production									
Coal (million short tons)	980	1,058	1,062	1,161	1,193	1,256	1,396	1.0%	1.5%
Natural Gas (trillion cubic feet)	21.86	24.23	24.24	29.03	29.95	32.41	34.91	1.7%	2.0%
Carbon Emissions (million metric tons)	1,463	1,577	1,579	1,803	1,832	1,956	2,073	1.2%	1.5%
Prices to Electric Generators (1996 dollars per million Btu)									
Coal	1.29	1.20	1.20	1.09	1.09	0.97	0.97	-1.2%	-1.2%
Natural Gas	2.64	2.48	2.52	2.84	3.06	3.15	3.90	0.7%	1.6%

Btu = British thermal units.

Notes: Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas.

Source: Energy Information Administration, AEO98 Forecasting System runs HDEMD.D100297B and AEO98B.D100197A.

Table F8. Key Results for Electricity Generation Sector Technology Cases
(Thousand Megawatts)

Net Summer Cability	1996	2000			2010			2020		
		Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil
Electric Generators										
Capability										
Pulverized Coal	304.8	296.2	296.2	296.2	298.4	304.1	301.3	350.7	323.0	306.9
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	0.5	0.5	1.2	0.5	0.5	18.4
Conventional Natural Gas Combined-Cycle	15.3	25.3	20.9	17.2	105.1	22.7	24.4	152.0	22.7	27.8
Advanced Natural Gas Combined-Cycle	0.0	0.0	6.7	12.3	0.0	83.8	85.1	0.0	163.8	161.4
Conventional Combustion Turbine	80.0	141.6	137.5	136.9	192.6	156.5	177.5	220.4	163.8	202.1
Advanced Combustion Turbine	0.0	0.0	2.9	3.1	0.0	34.9	10.0	0.0	58.1	12.3
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3
Nuclear	100.8	95.6	95.6	95.6	80.4	80.4	80.4	49.2	49.2	49.2
Oil and Gas Steam	138.1	121.3	121.3	121.3	101.0	101.0	101.0	96.0	96.0	96.0
Renewable Sources	108.5	111.1	111.1	111.1	114.2	113.5	113.8	119.7	115.6	116.7
Total	**748.0**	**791.6**	**792.8**	**794.3**	**892.3**	**897.3**	**894.7**	**988.6**	**992.8**	**991.1**
Cumulative Planned Additions										
Pulverized Coal	2.4	3.2	3.2	3.2	4.7	4.7	4.7	4.7	4.7	4.7
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conventional Natural Gas Combined-Cycle	2.0	2.7	2.7	2.7	3.0	3.0	3.0	3.0	3.0	3.0
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conventional Cmbustion Turbine	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Advanced Combustion Turbine	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
Nuclear	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Oil and Gas Steam	0.0	0.0	0.07	0.0	0.0	0.07	0.0	0.0	0.07	0.0
Renewable Sources	1.9	4.0	4.0	4.0	4.3	4.3	4.3	4.3	4.3	4.3
Total	**11.3**	**16.3**	**16.3**	**16.3**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions										
Pulerized Coal	0.0	0.0	0.0	0.0	11.2	16.9	14.1	73.0	45.4	29.2
Coal Gasification Comined-Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	17.9
Conventional Natural Gas Combined-Cycle	0.0	8.7	4.4	0.6	88.3	5.9	7.6	135.2	5.9	10.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	6.7	12.3	0.0	83.8	85.1	0.0	163.8	161.4
Conventional Combustion Turbine	23.6	83.9	79.8	79.3	135.9	99.7	120.8	164.8	108.2	146.4
Advanced Combustion Turbine	0.0	0.0	2.9	3.1	0.0	34.9	10.0	0.0	58.1	12.3
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	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	0.5	0.7	0.7	0.7	3.5	2.8	3.1	9.5	5.4	6.5
Total	**24.1**	**93.2**	**94.4**	**95.9**	**238.9**	**244.0**	**241.3**	**382.4**	**386.7**	**385.0**
Cumulative Total Additions	**35.4**	**109.6**	**110.8**	**112.2**	**257.4**	**262.5**	**259.8**	**400.9**	**405.2**	**403.5**
Cumulative Retirements	**14.4**	**45.9**	**45.9**	**45.9**	**92.4**	**92.4**	**92.4**	**138.8**	**138.8**	**138.8**
Cogenerators										
Capability										
Coal	7.1	7.3	7.3	7.3	7.7	7.7	7.7	7.7	7.7	7.7
Petroleum	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Natural Gas	28.0	30.5	30.5	30.5	32.7	32.7	32.7	31.9	31.9	31.9
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewables	5.8	6.4	6.4	6.4	6.6	6.6	6.6	6.4	6.4	6.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**46.4**	**46.4**	**46.4**	**49.3**	**49.3**	**49.4**	**48.4**	**48.3**	**48.4**
Cumulative Additions	**8.1**	**11.4**	**11.4**	**11.4**	**14.4**	**14.4**	**14.4**	**13.4**	**13.4**	**13.4**

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 31, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Source: Energy Information Administration, AEO98 National Energy Modeling System runs LTECEL.D100297A, AEO98B.D1000197A, and HTECEL.D100297A.

Table F9. Key Results for Competitive Price Cases

	1996	2000			2010			2020		
		Low Gas Comp.	Reference Comp.	High Gas Comp.	Low Gas Comp.	Reference Comp.	High Gas Comp.	Low Gas Comp.	Reference Comp.	High Gas Comp.
Electricity Sales										
(billion kilowatthours)	**3,098**	**3,331**	**3,330**	**3,331**	**3,908**	**3,908**	**3,903**	**4,278**	**4,276**	**4,285**
Electricity Prices										
(1996 cents per kilowatthour)	**6.9**	**6.3**	**6.3**	**6.3**	**5.4**	**5.6**	**5.9**	**5.1**	**5.6**	**6.0**
Generation by Fuel										
(billion kilowatthours)										
Coal	1,758	1,912	1,912	1,911	2,051	2,087	2,123	2,100	2,222	2,437
Natural Gas	288	422	421	423	985	951	900	1,507	1,388	1,175
Oil	80	55	55	55	27	32	43	22	30	39
Conventional Hydropower	346	316	316	316	319	319	319	319	319	319
Geothermal	16	17	17	17	19	19	19	24	24	24
Municipal Solid Waste	19	21	21	21	26	26	26	30	30	30
Wood and Other Biomass	7	9	9	9	13	10	11	28	18	18
Solar Thermal	1	1	1	1	1	1	1	2	2	2
Solar Photovoltaic	0	0	0	0	1	1	1	1	1	1
Wind	3	6	6	6	13	10	10	15	12	13
Other	673	686	686	686	593	593	593	380	380	380
Total	**3,191**	**3,445**	**3,444**	**3,445**	**4,048**	**4,049**	**4,044**	**4,427**	**4,426**	**4,436**
Generating Capacity										
(gigawatts)										
Coal	305	297	297	297	304	304	306	309	316	345
Natural Gas and Oil	233	295	295	295	422	423	421	511	513	499
Conventional Hydropower	79	80	80	80	81	81	81	81	81	81
Geothermal	3	3	3	3	3	3	3	4	4	4
Municipal Solid Waste	3	3	3	3	4	4	4	4	4	4
Wood and Other Biomass	2	2	2	2	3	2	2	5	3	3
Solar Thermal	0	0	0	0	0	0	0	1	1	1
Solar Photovoltaic	0	0	0	0	0	0	0	1	1	1
Wind	2	3	3	3	5	4	4	6	5	5
Other	121	116	116	116	100	100	100	69	69	69
Total	**748**	**799**	**799**	**798**	**922**	**923**	**922**	**990**	**997**	**1,011**
Energy Production										
Coal (million short tons)	1,064	1,150	1,151	1,150	1,247	1,269	1,298	1,288	1,361	1,455
Natural Gas										
(trilliion cubic feet)	21.86	24.26	24.23	24.26	29.43	28.95	28.21	33.89	32.33	30.06
Carbon Emissions										
(million metric tons)	**517**	**577**	**577**	**577**	**657**	**664**	**670**	**714**	**734**	**764**
Prices to Electric Generators										
(1996 dollars per million Btu)										
Coal	1.29	1.20	1.20	1.20	1.08	1.09	1.10	0.97	0.98	0.98
Natural Gas	2.64	2.48	2.50	2.49	2.72	2.92	3.27	2.65	3.25	3.83

Btu = British thermal units.

Comp. = Competitive

Source: Energy Information Administration, AEO98 National Energy Modeling System runs LOGCOMP.D101697A, BASECOMP.D10177A, and HOGCOMP.D101697A,

Table F10. Key Results for Renewable Portfolio Standard Cases

	1996	2000			2010			2020		
		Reference	5% RPS	10% RPS	Reference	5% RPS	10% RPS	Reference	5% RPS	10% RPS
Electricity Sales										
(billion kilowatthours)	**3,098**	**3,318**	**3,314**	**3,314**	**3,877**	**3,863**	**3,845**	**4,308**	**4,286**	**4,246**
Electricity Prices										
(1996 cents per kilowatthour)	**6.9**	**6.5**	**6.5**	**6.5**	**5.9**	**6.0**	**6.1**	**5.5**	**5.6**	**5.7**
Generation by Fuel										
(billion kilowatthours)										
Coal	1,758	1,903	1,898	1,897	2,085	2,050	2,017	2,265	2,189	2,101
Natural Gas	288	419	410	412	920	877	810	1,389	1,320	1,185
Oil	80	54	53	51	35	32	28	32	28	22
Conventional Hydropower	346	316	316	316	319	319	319	319	319	319
Geothermal	16	17	18	18	18	21	23	19	31	34
Municipal Solid Waste	19	21	21	21	26	26	26	30	30	30
Wood and Other Biomass	7	9	9	9	10	48	100	13	104	258
Solar Thermal	1	1	1	1	1	1	1	2	1	1
Solar Photovoltaic	0	0	0	0	1	1	1	1	2	2
Wind	3	6	15	15	8	31	63	10	33	63
Other	673	686	686	686	593	593	593	380	380	380
Total	**3,191**	**3,432**	**3,427**	**3,427**	**4,015**	**4,000**	**3,982**	**4,459**	**4,437**	**4,394**
Generating Capacity										
(gigawatts)										
Coal	305	297	297	297	304	303	301	324	313	303
Natural Gas and Oil	233	289	288	288	399	393	382	504	497	477
Conventional Hydropower	79	80	80	80	81	81	81	81	81	81
Geothermal	3	3	3	3	3	3	4	3	5	5
Municipal Solid Waste	3	3	3	3	4	4	4	4	4	4
Wood and Other Biomass	2	2	2	2	2	8	15	3	16	38
Solar Thermal	0	0	0	0	0	0	0	1	1	1
Solar Photovoltaic	0	0	0	0	0	0	0	1	1	1
Wind	2	3	6	6	3	11	26	4	13	26
Other	120	116	116	116	100	100	100	69	69	69
Total	**748**	**793**	**795**	**795**	**897**	**905**	**913**	**993**	**999**	**1,004**
Energy Production										
Coal (million short tons)	980	1,058	1,058	1,058	1,161	1,150	1,131	1,256	1,225	1,182
Natural Gas										
(trilliion cubic feet)	21.9	24.2	24.2	24.2	29	28.8	28.3	32.4	32	31.2
Carbon Emissions										
(million metric tons)	**517**	**574**	**571**	**571**	**663**	**648**	**631**	**745**	**718**	**682**
Prices to generators										
(1996 dollars per million btu)										
Coal	1.29	1.20	1.20	1.20	1.14	1.14	1.14	0.97	0.97	0.98
Natural Gas	2.64	2.48	2.48	2.47	2.63	2.59	2.55	3.15	3.08	2.92

Source: Energy Information Administration, AEO98 National Energy Modeling System runs AEO98B.D100197A,RPS05.D100297A, and RPS10.D100297A.

Table F11. Key Results for High Renewable Energy Case

Capacity and Generation	1996	2010		2020	
		Reference	High Renewables	Reference	High Renewables
Capacity (Gigawatts)					
Net Summer Capability					
Electric Generators					
Conventional Hydropower	78.58	80.71	80.71	80.71	80.71
Geothermal	3.02	2.92	3.48	2.94	5.11
Municipal Solid Waste	2.91	3.92	4.15	4.38	4.69
Wood and Other Biomass	1.91	2.07	4.09	2.50	11.61
Solar Thermal	0.36	0.46	0.44	0.56	0.68
Solar Photovoltaic	0.01	0.22	0.22	0.56	0.56
Wind	1.85	3.33	10.82	4.06	25.46
Total	**88.64**	**93.64**	**103.9**	**95.7**	**128.8**
Cogenerators					
Municipal Solid Waste	0.41	0.46	0.46	0.48	0.48
Wood and Other Biomass	5.41	6.14	6.15	5.95	5.96
Total	**5.81**	**6.61**	**6.61**	**6.43**	**6.44**
Generation					
(billion kilowatthours)					
Electric Generators					
Coal	1758	2085	2056	2265	2188
Petroleum	80	35	31	32	25
Natural Gas	288	920	901	1389	1301
Total Fossil[1]	**2126**	**3040**	**2988**	**3686**	**3514**
Conventional Hydropower	346.28	318.67	318.70	318.82	318.80
Geothermal	15.70	17.64	21.52	19.26	34.91
Municipal Solid Waste	18.85	26.32	27.86	29.52	31.64
Wood and Other Biomass	7.27	9.79	23.97	12.81	76.59
Solar Thermal	0.82	1.24	1.15	1.56	2.34
Solar Photovoltaic	0	0.60	0.60	1.45	1.45
Wind	3.17	7.76	34.53	10.08	86.44
Total Renewable	**392.09**	**382.03**	**428.30**	**393.50**	**552.20**
Cogenerators					
Coal	39	39	39	39	39
Petroleum	6	6	6	6	6
Natural Gas	174	201	201	194	194
Total Fossil[1]	**219**	**246**	**246**	**239**	**239**
Municipal Solid Waste	2.09	2.30	2.30	2.36	2.36
Wood and Other Biomass	39.17	41.00	41.03	39.65	39.71
Total Renewables	**41.25**	**43.29**	**43.33**	**42.01**	**42.07**

[1]Total of items presented.
Source: Energy Information Administration, AEO98 Forecasting System runs AEO98B.D100197A and HIRENEW.D100297A.

Table F12. Key Results for Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	Projections								
		2005			2010			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Total Energy Supply and Disposition Summary										
Production										
Crude Oil and Lease Condensate	13.71	12.08	12.32	12.54	11.25	11.79	12.23	9.45	10.43	11.33
Natural Gas Plant Liquids	2.46	2.62	2.63	2.64	2.86	2.95	3.02	2.99	3.29	3.49
Dry Natural Gas	19.55	22.78	22.88	22.95	24.74	25.39	25.95	25.82	28.21	29.84
Coal	22.64	25.66	25.62	25.55	26.95	26.62	26.17	30.59	28.59	26.97
Nuclear Power	7.20	6.87	6.87	6.87	6.36	6.36	6.36	4.09	4.09	4.09
Renewable Energy	6.91	7.12	7.12	7.12	7.41	7.41	7.39	7.78	7.71	7.64
Other	1.33	0.55	0.55	0.55	0.48	0.48	0.44	0.48	0.47	0.47
Total	**73.80**	**77.67**	**77.98**	**78.22**	**80.05**	**81.00**	**81.55**	**81.21**	**82.77**	**83.83**
Imports										
Crude Oil[1]	16.30	22.23	22.01	21.82	23.73	23.17	22.72	26.29	25.30	24.37
Petroleum Products	3.98	5.43	5.47	5.51	7.61	7.61	7.71	10.13	10.09	9.95
Natural Gas	2.93	4.39	4.39	4.39	4.70	4.66	4.66	5.38	5.34	5.34
Other Imports	0.58	0.58	0.58	0.58	0.57	0.57	0.57	0.56	0.56	0.56
Total	**23.78**	**32.63**	**32.45**	**32.30**	**36.61**	**36.02**	**35.66**	**42.36**	**41.28**	**40.22**
Exports										
Petroleum	2.04	1.71	1.73	1.73	1.76	1.80	1.80	1.64	1.67	1.62
Natural Gas	0.16	0.28	0.28	0.28	0.29	0.29	0.29	0.32	0.32	0.32
Coal	2.37	2.64	2.64	2.64	2.84	2.84	2.84	3.23	3.23	3.23
Total	**4.57**	**4.63**	**4.65**	**4.66**	**4.89**	**4.93**	**4.93**	**5.20**	**5.23**	**5.17**
Discrepancy	**0.99**	**0.14**	**0.04**	**0.02**	**0.18**	**0.08**	**-0.00**	**-0.04**	**-0.25**	**-0.26**
Consumption										
Petroleum Products	36.01	41.34	41.32	41.35	44.39	44.33	44.37	47.64	47.64	47.74
Natural Gas	22.60	26.83	26.93	27.01	29.01	29.63	30.18	30.72	33.06	34.68
Coal	20.98	23.27	23.21	23.16	24.36	24.03	23.57	27.63	25.61	23.99
Nuclear Power	7.20	6.87	6.87	6.87	6.36	6.36	6.36	4.09	4.09	4.09
Renewable Energy	6.91	7.12	7.12	7.13	7.42	7.42	7.41	7.81	7.74	7.67
Other	0.39	0.37	0.37	0.37	0.40	0.40	0.40	0.43	0.43	0.44
Total	**94.01**	**105.81**	**105.82**	**105.88**	**111.95**	**112.17**	**112.29**	**118.33**	**118.58**	**118.62**
Net Imports - Petroleum	**18.25**	**25.95**	**25.75**	**25.59**	**29.58**	**28.99**	**28.64**	**34.78**	**33.71**	**32.70**
Prices (1996 dollars per unit)										
World Oil Price (dollars per barrel)	20.48	20.39	20.19	20.08	21.28	20.81	20.52	23.03	22.32	21.77
Gas Wellhead Price (dollars per Mcf)	2.24	2.22	2.15	2.09	2.67	2.31	2.05	3.28	2.54	1.92
Coal Minemouth Price (dollars per ton)	18.50	15.98	16.18	16.19	14.62	15.05	15.01	13.29	13.27	13.52
Avg. Electricity Price (cents per Kwh)	6.9	6.1	6.1	6.1	6.0	5.9	5.9	5.6	5.5	5.2
Natural Gas Supply, Disposition,and Delivered Prices										
Production (trillion cubic feet)										
Dry Gas Production	19.02	22.16	22.25	22.33	24.07	24.70	25.24	25.11	27.44	29.02
Supplemental Natural Gas	0.12	0.11	0.11	0.11	0.05	0.05	0.05	0.06	0.05	0.05
Net Imports (trillion cubic feet)	**2.72**	**4.02**	**4.02**	**4.02**	**4.32**	**4.28**	**4.28**	**4.95**	**4.91**	**4.91**
Total Supply (trillion cubic feet)	**21.86**	**26.29**	**26.39**	**26.46**	**28.44**	**29.03**	**29.57**	**30.12**	**32.41**	**33.99**
Consumption by Sector (trillion cubic feet)										
Residential	5.23	5.30	5.31	5.32	5.38	5.47	5.53	5.63	5.80	5.96
Commercial	3.20	3.51	3.52	3.52	3.62	3.65	3.66	3.69	3.75	3.79
Industrial	8.60	9.36	9.39	9.41	9.54	9.75	9.85	9.28	9.70	9.96
Electric Generators	2.98	5.53	5.57	5.60	7.03	7.22	7.54	8.42	9.85	10.84
Lease and Plant Fuel	1.25	1.45	1.45	1.46	1.56	1.59	1.62	1.65	1.76	1.84
Pipeline Fuel	0.71	0.82	0.82	0.84	0.88	0.93	0.96	0.92	1.00	1.06
Transportation	0.01	0.15	0.15	0.15	0.23	0.23	0.23	0.33	0.33	0.34
Total	21.99	26.12	26.22	26.29	28.25	28.84	29.39	29.92	32.20	33.78
Discrepancy (trillion cubic feet)	**-0.12**	**0.17**	**0.17**	**0.17**	**0.19**	**0.19**	**0.18**	**0.21**	**0.21**	**0.21**

Table F12. Key Results for Oil and Gas Technological Progress Cases (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1996	Projections								
		2005			2010			2020		
		Slow Tech. Progress	Reference	Rapid Tech. Progress	Slow Tech. Progress	Reference	Rapid Tech. Progress	Slow Tech. Progress	Reference	Rapid Tech. Progress
Natural Gas Supply. Disposition, and Delivered Prices (Continued)										
Delivered Prices (1996 dollars per Mcf)										
Residential	6.37	5.79	5.71	5.68	6.01	5.58	5.34	6.35	5.60	4.99
Commercial	5.43	4.92	4.85	4.82	5.20	4.79	4.56	5.64	4.91	4.33
Industrial	3.05	2.92	2.85	2.81	3.39	3.01	2.76	4.00	3.26	2.65
Electric Generators	2.70	2.76	2.69	2.65	3.28	2.91	2.66	3.92	3.22	2.71
Transportation	5.57	5.96	5.89	5.86	7.15	6.79	6.59	8.22	7.61	7.12
Average	**4.25**	**3.83**	**3.76**	**3.73**	**4.20**	**3.80**	**3.55**	**4.73**	**3.97**	**3.38**
Crude Oil Supply										
Lower 48 Average Wellhead Price (1996 dollars per barrel)	**19.41**	**20.78**	**20.52**	**20.37**	**21.62**	**21.08**	**20.75**	**22.58**	**21.58**	**21.01**
Production (million barrels per day)										
U.S. Total	**6.48**	**5.70**	**5.82**	**5.92**	**5.31**	**5.57**	**5.78**	**4.47**	**4.92**	**5.35**
Lower 48 Onshore	3.76	3.10	3.13	3.15	3.04	3.15	3.21	2.83	3.09	3.33
Conventional	3.15	2.47	2.47	2.48	2.32	2.36	2.41	2.23	2.41	2.63
Enhanced Oil Recovery	0.61	0.63	0.66	0.67	0.72	0.79	0.80	0.60	0.68	0.70
Lower 48 Offshore	1.32	1.74	1.75	1.77	1.63	1.67	1.70	1.27	1.35	1.39
Alaska	1.40	0.87	0.93	1.01	0.64	0.75	0.87	0.37	0.48	0.63
Lower 48 End of Year Reserves (billion barrels)	**16.82**	**14.49**	**14.69**	**14.82**	**14.30**	**14.87**	**15.25**	**13.05**	**14.33**	**15.43**
Natural Gas Supply										
Lower 48 Average Wellhead Price (1996 dollars per Mcf)	**2.24**	**2.22**	**2.15**	**2.09**	**2.67**	**2.31**	**2.05**	**3.28**	**2.54**	**1.92**
Production (trillion cubic feet)										
U.S. Total	**19.01**	**22.16**	**22.25**	**22.33**	**24.07**	**24.70**	**25.24**	**25.11**	**27.44**	**29.02**
Lower 48 Onshore	13.07	15.30	15.30	15.32	17.11	17.33	17.58	17.64	18.99	20.34
Associated-Dissolved	1.84	1.39	1.39	1.39	1.26	1.27	1.27	1.16	1.19	1.22
Non-Associated	11.23	13.91	13.91	13.93	15.86	16.06	16.30	16.48	17.81	19.11
Conventional	7.96	10.22	10.18	10.20	11.58	11.77	12.00	11.41	12.32	13.21
Unconventional	3.27	3.69	3.73	3.73	4.28	4.30	4.30	5.08	5.49	5.91
Lower 48 Offshore	5.50	6.33	6.43	6.48	6.39	6.81	7.10	6.86	7.83	8.07
Associated-Dissolved	0.80	0.93	0.93	0.94	0.92	0.92	0.93	0.83	0.85	0.86
Non-Associated	4.70	5.39	5.49	5.55	5.47	5.89	6.17	6.03	6.98	7.21
Alaska	0.43	0.53	0.53	0.53	0.56	0.56	0.56	0.62	0.62	0.62
U.S. End of Year Reserves (trillion cubic feet)	**157.23**	**181.42**	**187.25**	**194.70**	**184.77**	**196.33**	**210.10**	**165.97**	**185.11**	**202.09**
Supplemental Gas Supplies (trillion cubic feet)	**0.12**	**0.11**	**0.11**	**0.11**	**0.05**	**0.05**	**0.05**	**0.06**	**0.05**	**0.05**
Total Lower 48 Wells Completed (thousands)	**21.91**	**26.34**	**25.30**	**24.49**	**30.56**	**28.19**	**26.44**	**36.10**	**32.04**	**28.75**

Tech = Technology.
Kwh = Kilowatthour.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.
Sources: Energy Information Administration, AEO98 National Energy Modeling System runs LTECOG.D100497C, AEO98B.D100197A, and HTECOG.D100497D.

Table F13. Key Results for Oil and Gas Moderate Resource Case

	1996	2005		2010		2020		Annual Growth 1996-2020	
		Reference Case	Moderate Resource	Reference Case	Moderate Resource	Reference Case	Moderate Resource	Reference Case	Moderate Resource
Crude Oil									
Lower 48 Average Wellhead Price (1996 dollars per barrel)	**19.41**	**20.52**	**20.57**	**21.08**	**21.19**	**21.58**	**22.07**	**0.4%**	**0.5%**
Production (million barrels per day)									
U.S. Total	**6.48**	**5.82**	**5.80**	**5.57**	**5.52**	**4.92**	**4.78**	**-1.1%**	**-1.3%**
Lower 48 Onshore	3.76	3.13	3.14	3.15	3.15	3.09	3.12	-0.8%	-0.8%
Conventional	3.15	2.47	2.48	2.36	2.37	2.41	2.43	-1.1%	-1.1%
Enhanced Oil Recovery	0.61	0.66	0.66	0.79	0.79	0.68	0.69	0.5%	0.6%
Lower 48 Offshore	1.32	1.75	1.73	1.67	1.62	1.35	1.17	0.1%	-0.5%
Alaska	1.40	0.93	0.93	0.75	0.75	0.48	0.48	-4.3%	-4.3%
Lower 48 End of Year Reserves (billion barrels)	**16.82**	**14.69**	**14.64**	**14.87**	**14.77**	**14.33**	**14.09**	**-0.7%**	**-0.7%**
Natural Gas									
Lower 48 Average Wellhead Price (1996 dollars per thousand cubic feet)	**2.24**	**2.15**	**2.19**	**2.31**	**2.42**	**2.54**	**2.91**	**0.5%**	**1.1%**
Production (trillion cubic feet)									
U.S. Total	**19.00**	**22.25**	**22.21**	**24.70**	**24.49**	**27.44**	**26.49**	**1.5%**	**1.4%**
Lower 48 Onshore	13.07	15.30	15.41	17.33	17.42	18.99	18.82	1.6%	1.5%
Associated-Dissolved	1.84	1.39	1.39	1.27	1.27	1.19	1.19	-1.8%	-1.8%
Non-Associated	11.22	13.91	14.02	16.06	16.16	17.81	17.63	1.9%	1.9%
Conventional	7.96	10.18	10.26	11.77	11.78	12.32	11.81	1.8%	1.7%
Unconventional	3.26	3.73	3.76	4.30	4.38	5.49	5.82	2.2%	2.4%
Lower 48 Offshore	5.50	6.43	6.27	6.81	6.50	7.83	7.06	1.5%	1.0%
Associated-Dissolved	0.80	0.93	0.93	0.92	0.91	0.85	0.81	0.3%	0.1%
Non-Associated	4.70	5.49	5.34	5.89	5.59	6.98	6.25	1.7%	1.2%
Alaska	0.43	0.53	0.53	0.56	0.56	0.62	0.62	1.5%	1.5%
U.S. End of Year Reserves (trillion cubic feet)	**157.23**	**187.25**	**185.33**	**196.33**	**193.70**	**185.11**	**176.09**	**0.7%**	**0.5%**
Supplemental Gas Supplies (trillion cubic feet)	**0.12**	**0.11**	**0.11**	**0.05**	**0.05**	**0.05**	**0.05**	**-3.6%**	**-3.4%**
Total Lower 48 Wells (thousands)	**21.91**	**25.30**	**25.49**	**28.19**	**28.75**	**32.04**	**34.08**	**1.6%**	**1.9%**

Ft. = feet.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 may differ from published data due to internal conversion factors.

Sources: Energy Information Administration (EIA), AEO98 National Energy Modeling System runs AEO98B.D100197A, and RESCAP.D102497C.

Table F14. Key Results for Coal Mining Cost Cases

Prices, Productivity, and Wages	1996	2000			2010			2020		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (1996 dollars per short ton)	18.50	17.03	17.45	17.78	13.68	15.05	16.59	10.68	13.27	16.76
Delivered Price to Electric Generators (1996 dollars per million Btu)	1.29	1.18	1.20	1.22	1.00	1.09	1.19	0.83	0.97	1.16
Labor Productivity (short tons per miner per hour)	5.69	6.54	6.34	6.23	8.99	7.83	6.90	12.34	9.16	6.94
Labor Productivity (average annual growth from 1996)	N/A	3.6	2.8	2.3	3.3	2.3	1.4	3.3	2.0	0.8
Average Coal Miner Wage (1996 dollars per hour)	18.75	18.38	18.75	19.13	17.48	18.75	20.11	16.62	18.75	21.13
Average Coal Miner Wage (average annual growth from 1996)	N/A	-0.5	0.0	0.5	-0.5	0.0	0.5	-0.5	0.0	0.5

N/A = Not Applicable.

Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured.

Source: Energy Information Administration, AEO98 National Energy Modeling System runs LLCST.D100297A, AEO98.D100197A, and HLCST.D100297A.

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 is a response surface representation of the DRI/McGraw-Hill U.S. Quarterly Model.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

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.

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 8 energy-intensive industries, 7 are modeled in the Industrial Demand Module with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, and compressed natural gas by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to ex-

Table G1. Summary of the *AEO98* 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 1.3 percent, compared to the reference case growth of 1.9 percent.	Fully integrated	p. 35	
High Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent, compared to the reference case growth of 1.9 percent.	Fully integrated	p. 35	
Low World Oil Price	World oil prices are $14.43 per barrel in 2020, compared to $22.32 per barrel in the reference case.	Fully integrated	p. 36	
High World Oil Price	World oil prices are $28.71 per barrel in 2020, compared to $22.32 per barrel in the reference case.	Fully integrated	p. 36	
Residential: 1998 Technology	Future equipment purchases based on equipment available in 1998. Building shell efficiencies fixed at 1998 levels.	Standalone	p. 47	p. 210
Residential: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent by 2020. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 47	p. 210
Residential: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 47	p. 210
Commercial: 1998 Technology	Future equipment purchases based on equipment available in 1998. Building shell efficiencies fixed at 1998 levels.	Standalone	p. 48	p. 211
Commercial: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent by 2020. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 48	p. 211
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 48	p. 211
Industrial: 1998 Technology	Efficiency of plant and equipment fixed at 1998 levels.	Standalone	p. 49	p. 211
Industrial: High Technology	Energy intensity declines at an annual rate of 1.5 percent, compared to 1.1 percent in the reference case.	Standalone	p. 49	p. 211
Transportation: 1998 Technology	Efficiencies for new equipment in all modes of travel are fixed.	Standalone	p. 49	p. 212
Transportation: Advanced Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 49	p. 212
End-Use Demand: 1998 Technology	Combination of the residential, commercial, industrial, and transportation 1998 technology cases.	Fully integrated	p. 29	
End-Use Demand: High Technology	Combination of the residential and commercial advanced technology cost reduction cases, the industrial high technology case, and the transportation advanced technology case.	Fully integrated	p. 29	

The National Energy Modeling System

The projections in the *Annual Energy Outlook 1998 (AEO98)* are generated with 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 the energy supply and demand, accounting for the economic competition between 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 models of NEMS function at the regional level: the 9 Census divisions for the end-use demand models; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and 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. This modularity allows 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 impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of July 1, 1997, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

In general, the *AEO98* projections were prepared by using the most current data available as of July 31, 1997. At that time, most 1996 data were available, but only partial 1997 data were available. Carbon emissions were calculated by using carbon coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1996*, published in October 1997 [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 *AEO98* 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 *AEO98* includes cogeneration in the industrial 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 *AEO98* projections for 1997 and 1998 incorporate short-term projections from the August update of EIA's *Short-Term Energy Outlook* (*STEO*), Third Quarter 1997 [2], published in July 1997. For short-term energy projections, readers are referred to the monthly updates of the *STEO*.

Table G1. Sumary of the *AEO98* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Low Nuclear	All reactors retire after 30 years of operation.	Partially integrated	p. 55	p. 214
Electricity: High Nuclear	Each reactor operates 10 years longer than assumed in the reference case.	Partially integrated	p. 55	p. 214
Electricity: High Demand	Electricity demand increases at an annual rate of 2.0 percent, compared to 1.4 percent in the reference case.	Partially integrated	p. 55	p. 214
Electricity: Low Fossil Technology	No new advanced fossil-fired generating technologies are assumed. Costs for conventional fossil-fired technologies are lower than in the reference case.	Fully integrated	p. 56	p. 214
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Fully integrated	p. 56	p. 214
Electricity: Competitive Pricing	Competitive pricing is phased in over 10 years in all regions of the country.	Fully integrated	p. 21	p. 215
Electricity: Low Gas Price Competitive Pricing	Competitive pricing is combined with the rapid oil and gas technology case assumptions.	Fully integrated	p. 22	p. 215
Electricity: High Gas Price Competitive Pricing	Competitive pricing is combined with the slow oil and gas technology case assumptions.	Fully integrated	p. 22	p. 215
Electricity: 5-Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 5 percent of total generation by 2020.	Fully integrated	p. 24	p. 215
Electricity: 10-Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 10 percent of total generation by 2020.	Fully integrated	p. 24	p. 215
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	Fully integrated	p. 58	p. 216
Oil and Gas: Slow Technology	Cost, finding rate, and resource base growth parameters adjusted for slower improvement.	Fully integrated	p. 64	p. 218
Oil and Gas: Rapid Technology	Cost, finding rate, and resource base growth parameters adjusted for more rapid improvement.	Fully integrated	p. 64	p. 218
Oil and Gas: Moderate Resource	Expansion of oil and natural gas inferred reserves and shallow Gulf of Mexico resources adjusted for slower improvement.	Fully integrated	p. 65	p. 218
Oil and Gas: High Reformulated Gasoline	Reformulated gasoline demand increases by 10 percent in Census divisions 1 through 7 (areas east of the Rocky Mountains).	Partially integrated	p. 15	p. 220
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.3 percent, compared to the reference case growth of 2.0 percent. Real wages decrease by 0.5 percent annually, compared to constant real wages in the reference case.	Standalone	p. 70	p. 220
Coal: High Mining Cost	Productivity increases at an annual rate of 0.8 percent, compared to the reference case growth of 2.0 percent. Real wages increase by 0.5 percent annually, compared to constant real wages in the reference case.	Standalone	p. 70	p. 220

plicitly assess the penetration of alternatively-fueled vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are four primary submodules—capacity planning, fuel dispatching, finance and pricing, and load and demand-side management. Nonutility generation and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module. All CAAA90 compliance options are explicitly represented in the capacity expansion and dispatch decisions. Both new generating technologies and renewable technologies compete directly in these decisions.

Renewable Fuels Module

The Renewable Fuels Module includes submodules that provide explicit representation of the supply of biomass (including wood and energy crops), municipal solid waste (including landfill gas), wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It contains natural resource supply estimates and provides cost and performance criteria to the Electricity Market Module. The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and nonmarketed nonelectric renewables.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from tight gas formations, Devonian shale, and coalbeds. This framework analyzes cash flow and profitability to compute investment and drilling in each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports with Canada and Mexico and liquefied natural gas imports and exports. 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 capacity expansion requirements. Core and noncore markets are explicitly represented for natural gas transmission. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for 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 new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

The Coal Market Module 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 4 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 1998

Table G1 provides a summary of the cases used to derive the *AEO98* 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 the NEMS model (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 on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in *AEO98*. These assumptions 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 will be available via the EIA Home Page on the Internet and on the EIA CD-ROM, along with regional results and other details of the projections.

Building sector assumptions

The buildings sector includes both residential and commercial structures. Both the National Appliance Energy Conservation Act of 1987 (NAECA), the Energy Policy Act of 1992 (EPACT), and the Climate Change Action Plan (CCAP) contain provisions which impact future buildings sector energy use. The provisions with the most significant effect are minimum equipment efficiency standards. These standards require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels which change over time. The manufacture of equipment that does not meet the standards is prohibited.

Residential assumptions. The NAECA minimum standards [3] 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
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, increasing to 9.7 in 2001
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993 and to 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990
- Natural gas water heaters—a 0.54 energy factor in 1990.

Improvements to existing building shells are based on both energy prices and assumed annual efficiency increases. New building shell efficiencies relative to existing construction vary by main heating fuel and assumed annual increases. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 13 percent and 27 percent, respectively, by 2020 relative to the 1993 stock average. For space cooling, the corresponding increases are 10 percent and 23 percent for existing and new buildings. Building codes relevant to CCAP are represented by an increase in the shell integrity of new construction over time.

Other CCAP programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs, which are cooperative efforts between the EPA and home builders and energy appliance manufacturers, encourage the development and production of highly energy-efficient housing and equipment. At fully funded levels, residential CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 28 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 8 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO98* reference case, three cases using only the residential module of NEMS were developed to examine the effects of equipment and building shell efficiencies on residential sector energy use:

- The *1998 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1998. Building shell efficiencies are assumed to be fixed at 1998 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. Building shell efficiencies are assumed to increase by 50 percent over the reference case level by 2020.
- The *advanced technology cost reduction case* assumes that the best technology within a given end use and fuel combination will experience a 35-percent reduction in purchase costs. Most of the decline will occur within the 10-year period following a technology's introduction. Building shells will be at best available technology case levels.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [4]. Minimum standards for representative equipment types are:

- Central air-conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard (January 1994)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and a 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 5 percent and 7 percent, respectively, by 2020 relative to the 1992 averages.

The CCAP programs recognized in the *AEO98* reference case include 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 via discount parameters for controlling cost-based equipment retrofit decisions for various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO98* version of the commercial module includes end-use-specific segmentation of discount rates. At fully funded levels, commercial CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 25 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be just over 9 million metric tons in 2010, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO98* reference case, three cases using only the commercial module of NEMS were developed to examine the effects of equipment and building shell efficiencies on commercial sector energy use:

- The *1998 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1998. Building shell efficiencies are assumed to be fixed at 1998 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. Building shell efficiencies are assumed to increase by 50 percent over the reference case level by 2020.
- The *advanced technology cost reduction case* assumes that the two best technologies within a given end use and fuel combination will experience a 35-percent reduction in purchase costs. Most of the decline will occur within the 10-year period following a technology's introduction. Building shells will be at best available technology case levels.

Industrial sector assumptions

Compared to the building sector, there are relatively few regulations which target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1998 [5]. These standards have been incorporated into the Industrial Demand Module through the analysis of process efficiencies for new industrial processes. These standards are expected to lead to significant improvements in efficiency since it has been estimated that electric motors account for about 60 percent of industrial process electricity use.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector. Note that the potential impacts of the Climate Wise Program are also included in the CCAP impacts. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. For their annual update, the program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 20 billion kilowatthours and non-electric consumption by 193 trillion Btu by 2000. However, since the energy savings associated with the voluntary programs in the CCAP are, to a large extent, already contained in the *AEO98* baseline, total CCAP energy savings were reduced. Consequently, CCAP is assumed to reduce electricity consumption by 9 billion kilowatthours and non-electric energy consumption by 48 trillion Btu. The non-electric energy is assumed to be 85 percent natural gas.

For 2010, the program offices estimated electricity savings of 79 billion kilowatthours and fossil fuel savings of 359 trillion Btu. For the reason cited above, these estimates for *AEO98* were revised to 41 billion kilowatthours for electricity and 90 trillion Btu for fossil fuels. In this situation, carbon emissions would be reduced by about 8 million metric tons (1 percent) in 2010.

High technology and 1998 technology cases. From 1960 to 1994, the decline in the 10-year moving average for aggregate industrial energy intensity was 1.2 percent, with a standard deviation of 1.1 percent. Thus, a change of 1 standard deviation would approximately double the decline in intensity. The *high technology case* emulates this result by approximately doubling the projected rates of decline in energy intensity for the energy-intensive industries. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output remains the same as in the reference case, aggregate intensity falls by only 1.5 percent annually.

The *1998 technology case* holds the energy efficiency of plant and equipment constant at the 1998 level over the forecast.

Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for the two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The projections appearing in this report assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally-fueled automobile fleet operators—Federal, State, and local governments, and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [6]. 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 realize 25 percent of total purchases by 1998 and 75 percent by 2000. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1997, increasing to 90 percent by 1999. 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. It is assumed that the municipal and private business fleet mandates begin in 2002 at 20 percent and scale up to 70 percent by 2005.

In addition to these requirements, the State of California has delayed the Low Emission Vehicle Program, which now requires that 10 percent of all new vehicles sold by 2003 meet the "zero emissions requirements." At present, only electric-dedicated vehicles meet these requirements. Originally, Massachusetts and New York adopted this program. The projections currently assume that only California and Massachusetts have formally delayed the Low Emission Vehicle Program.

The projections assume that these regulations represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of these vehicles, should vehicle cost, fuel efficiency, range, and performance characteristics make them desirable.

Projections for both personal travel [7] and freight travel [8] are based on the assumption that modal shares, for example, personal automobile travel versus mass transit, remain stable over the forecast and track recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled 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 100 percent by 2010; and the aging of the population, which will slow the growth in vehicle-miles traveled. These projections incorporate recent data which indicate that retirees are driving far more than retirees of a decade ago.

Climate Change Action Plan. There are four CCAP programs that focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy; (3) promote telecommuting; and (4) develop fuel economy labels for tires. The combined assumed effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO98* reference case is a 1.6-percent reduction in vehicle-miles traveled (273 trillion Btu) by 2010, with a net carbon reduction of 5.3 million metric tons. The fuel economy tire labeling program improved new fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 1 trillion Btu by 2010 and a carbon reduction of 19,000 metric tons.

1998 technology case. The *1998 technology case* assumes that new fuel efficiency levels are held constant through the forecasts horizon for all modes of travel.

Advanced technology case. The *advanced technology case* assumes the cost and performance criteria from the efficiency case in the U.S. Department of Energy (DOE) interlaboratory study, S*cenarios of U.S. Carbon Reductions* [9] for air, freight, marine, and rail travel and from the DOE Office of Energy Efficiency and Renewable Energy for light-duty vehicles. The case includes new technologies including a high-efficiency advanced light-duty diesel vehicle with attributes similar to gasoline engines; electric and electric hybrid vehicles with higher efficiencies, lower costs, and earlier introduction dates than in the reference case, and fuel cell light-duty vehicles. In the freight sector, the case assumes technologies including advanced drag reduction, reduced weight, and engines such as the advanced turbocompound diesel engines and the lean burn diesel LE-55 engine all with shorter market penetration periods and lower cost-effectiveness criteria—from a range of $8 to $10.50 to $6 per gallon of distillate. The case also assumes increasing load factors and an increase in efficiency of 40 percent above the 1996 level for aircraft.

Both cases were run with only the Transportation Demand Module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand was captured.

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 26 fossil, renewable, and nuclear generating technologies included in these projections. Technologies represented include those currently available as well as those that are assumed to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking where it is assumed that the selection of new plants to be built is based on least cost subject to environmental constraints. The levelized lifetime cost, including fuel costs, is evaluated and is used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which will be available via the EIA Home Page on the Internet and on the EIA CD-ROM.

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 by 2000. Utilities are assumed to comply with the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. The costs for FGD equipment average approximately $192 per kilowatt, in 1996 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

The reference case assumes a transition to competitive pricing in California, New York, and the New England States. Although other States are allowing consumers to choose their electricity suppliers, the regional configuration assumed in the reference case prevents the representation of competitive markets in the regions that include those States. Nevertheless, the reference case assumes that, in California, electricity prices will remain constant at nominal 1996 levels between 1998 and 2001 for commercial and industrial customers, whereas residential customers will see a 10-percent reduction from 1996 prices in 1998; that there will be a transition from regulated to competitive prices between 2002 and 2007; and that the market will be fully competitive by 2008. Similarly, in New York and New England, the transition period is assumed to be from 1998 through 2007, with fully competitive pricing of electricity beginning in 2008. 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 competitive prices in these regions will be the marginal cost of generation, and the distribution of prices across economic sectors is the same as that for regulated prices.

Competitive cost of capital. To capture the increased risks that new power plant operators are expected to face in a competitive market, the cost of capital for the generation sector is assumed to be 100 basis points higher than that for the transmission and distribution sector. In addition, 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 have reported plans to spend more than $2.2 billion per year by 2000.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to voluntarily reduce their greenhouse gas emissions between now and 2000. These efforts cover a wide variety of programs, including increasing demand-side management (DSM) investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out-of-service, planting trees, and purchasing emission offsets from international sources. To the degree possible, each one of the participation agreements was examined to determine if the commitments made were addressed in the normal reference case assumptions or whether they were addressable in NEMS. Programs like tree planting and emission offset purchasing are not addressable in NEMS. With regard to the other programs, they 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, life extend a plant, cancel a previously planned plant, build a new plant, or switch fuel at a plant. These data are inputs to NEMS. Thus, programs that would affect these areas are reflected in 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.

Nuclear power. There are no nuclear units actively under construction in the United States, and *AEO98* does not assume any new units becoming operational in the forecast period.

In the reference case, the majority of nuclear units are assumed to operate until the expiration of their licenses; however, recent experience has indicated that utilities will retire units before their license expiration dates for a variety of reasons, including either operating costs or refurbishment costs that are excessively high. Therefore, *AEO98* assumes that 24 currently operating reactors will be retired before their licenses expire. The units selected for early retirement are among the first generation of plants to come on line and, generally, have high operating costs or have not received equipment repairs, such as steam generator replacement, that are likely to be required for extended operation. The early retirement dates vary from 2 to 10 years before the license expiration date. Two standalone side cases were developed with alternate retirement dates for nuclear units. The *low nuclear case* assumes that all reactors retire after 30 years of operation, while the *high nuclear case* assumes 10 additional years of operation for each reactor beyond the operating lives assumed in the reference case.

The average nuclear capacity factor in 1996 was 76 percent and is expected to increase throughout the forecast, to as high as 85 percent in 2020. Capacity factor assumptions are developed at the unit level, and improvements or decrements are forecast based on the age of the reactor. Unit level projections are aggregated to the regional level for use in the model. The capacity factor is calculated over time, based on the units operable in each year; therefore, as units are retired, the average capacity factor will increase if the retiring units are those with lower performance.

Fossil-steam retirement assumptions. Using current and historical data from FERC Form 1, existing plants whose combined operating and fuel costs exceed 4 cents per kilowatthour are identified for retirement. These plants are then retired annually in equal numbers between 1999 and 2010. After 2010, only units reported by utilities as candidates for retirement are retired.

High electricity demand case. The *high electricity demand case*, which is a standalone case, assumes that the demand for electricity grows by 2.0 percent annually between 1996 and 2020, compared with 1.4 percent in the reference case. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth. The high electricity demand case is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not effected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the Electricity Market Module in the high electricity demand case.

High and low fossil technology cases. The high and low fossil technology cases are standalone, partially integrated cases. These cases use cost estimates for fossil-fuel-based technologies provided by the DOE Office of Fossil Energy. In the high fossil technology case, capital costs for coal gasification combined-cycle units and molten carbonate fuel cells are assumed to be lower than the reference case while advanced combustion turbine and advanced combined-cycle unit costs are higher than the reference case. No new advanced fossil-fired generators are assumed to come online during the projection period in the low fossil technology case. In both the high and low fossil technology cases, generating technologies other than those for which capital costs were provided by DOE's Office of Fossil Energy are assumed to use the same technological optimism and learning factors as the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and technological optimism and learning factors are described in the detailed assumptions which will be available via the Internet (ftp:// ftp.eia.doe.gov/pub/forecasting/aeo98/ aeo98asu.pdf) and on the EIA CD-ROM.

Competitive pricing cases. The three competitive pricing cases assume that all regions of the country will gradually move toward marginal-cost-based pricing, as discussed in the "Issues in Focus" section of this report. Competitive pricing is phased in over 10 years (1998-2007) by computing a weighted average of the traditional average-cost-based price and a price based on marginal costs. The weighting factor changes over time—initially weighting the average-cost-based price more heavily, then decreasing the weight over the phase-in period—until the price is based solely on marginal costs. Other than the pricing methodology, the reference competitive case is based on the assumptions of the *AEO98* reference case. The two additional competitive scenarios have assumptions corresponding to the rapid and slow technology cases developed for the oil and gas supply sector. These cases incorporate alternative assumptions about improvement in natural gas recovery and distribution technology, and they lead to different gas price projections. Therefore, the cases are referred to as the *low gas price competitive case* and the *high gas price competitive case*. All competitive pricing cases are fully integrated runs, allowing feedback between the demand and supply models.

Renewable portfolio standard cases. Two cases were run in which a minimum level of nonhydroelectric renewable generation was required. In the first case, the minimum percentage of renewable generation (defined as generation from wind, biomass, geothermal, solar thermal, photovoltaic, and landfill gases divided by total sales multiplied by 100) increased from 2 percent to 5 percent over the period 2001 through 2020 inclusive. In the second case, the minimum percentage of renewable generation increased from 2 percent to 10 percent from 2001 to 2020 inclusive. Both cases were fully integrated runs, in which all the modules were used. As in the reference case, New York, California, and New England had marginal-cost-based pricing for electricity, while the all the other regions were assumed to use the average cost methodology for electricity prices.

Renewable Technology	Reference Case	High Renewables
2000 Overnight Capital Costs[a] (1996 Dollars)		
Biomass IGCC	2,683	2,027
Geothermal	1,755	1,303
Solar Thermal	3,130	3,634
Solar Photovoltaic	4,484	3,955
Wind	1,008	767
2000 Annual Average Capacity Factor[b] (Percent)		
Biomass IGCC	80	80
Geothermal	80	80[c]
Solar Thermal	42	42
Solar Photovoltaic	28	21
Wind	30	37
2020 Overnight Capital Costs[a] (1996 Dollars)		
Biomass IGCC	1,850	1,333
Geothermal	1,546	1,042
Solar Thermal	2,751	2,578
Solar Photovoltaic	2,612	1,334
Wind	735	669
2020 Annual Average Capacity Factor[b] (Percent)		
Biomass IGCC	80	80
Geothermal	80	80[c]
Solar Thermal	42	77
Solar Photovoltaic	30	21
Wind	38	47

[a]Overnight capital costs plus project contingencies but without resource constraints (elasticities), region 13, California. Costs for specific years differ by region and by degree of penetration of the technology in specific modeling runs.

[b]For region 13, California, capacity factors differ by time of day, season, region and for specific years. For solar photovoltaics, lower costs and lower capacity factors in the high renewables case reflect changes from fixed flat plate modules to less expensive but also less efficient thin-film collectors.

[c]DOE assumes increasing capacity factors, all greater than 90 percent.

Renewable fuels assumptions

Energy Policy Act of 1992. Under EPACT, the Renewable Fuels Module (RFM) provides a renewable electricity production credit of 1.5 cents per kilowatthour for electricity produced by wind, applied to plants becoming operational between January 1, 1994, and June 30, 1999, and continuing for 10 years [10]. EPACT and the RFM also include a 10 percent investment tax credit for solar and geothermal technologies that generate electric power [11].

Supplemental Additions. AEO98 includes 1,780 megawatts of assumed new generating capacity using renewable resources, including 1,140 megawatts of planned new capacity not reported among EIA data collections and 640 megawatts assumed by EIA to be built for reasons not incorporated in the NEMS, such as for investment, testing, for distributed applications, or in response to state mandates. Total supplementals include 119 megawatts biomass, 66 megawatts geothermal, 11 megawatts landfill gas, 545 megawatts solar photovoltaic, 185 megawatts solar thermal, and 854 megawatts wind.

International learning. New for *AEO98*, capital costs for all new electricity generating technologies— fossil, nuclear, and renewable—decrease in response to foreign as well as domestic experience, to the extent the new plants reflect technologies and firms also competing inside the United States. International learning effects this year include 1,229 megawatts advanced combined cycle, 88 megawatts advanced combustion turbine, 101 megawatts geothermal, 48 megawatts wind, and 2 megawatts biomass integrated combined cycle capacity in operation, under construction, or under contract for construction outside the United States.

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 nearly halt the expansion of U.S. hydroelectric power. Although solar, wind, and geothermal resources are theoretically very large, economically accessible resources are much less available. Solar energy (direct normal insolation) for thermal applications is considered economically amenable only in drier regions, west of the Mississippi River; photovoltaics, however, can be considered 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, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [12], enumerating winds among average annual wind-speed 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 thermal conversion factor (Btu content per weight of fuel). Municipal solid waste resources are limited by the amount of the waste that is managed by other methods, such as recycling or landfills, and by the impact of waste minimization as a strategy for addressing the waste problem.

New for *AEO98*, EIA incorporates in NEMS recognition of higher costs (proxies for supply elasticities) for uses of biomass and wind resources as generating capacity consumes more of the available resources. Costs increase in response to (1) increasing costs as natural resource quality declines, such as from wind turbulence, more difficult land access, or declining land quality, (2) increasing costs of local and regional transmission network improvements, and (3) market conditions increasing costs of alternative land uses, including for crops, recreation, or environmental or cultural preferences. Although the effects generally apply only with very large capacity increases not experienced in *AEO98*, some wind costs in California are increased this year in response to these factors.

High renewables case. For the *high renewables case*, EIA incorporates approximations of the DOE Office of Energy Efficiency and Renewable Energy's August 1997, draft technology characterizations of lower capital and operating costs and higher efficiencies (capacity factors) for new renewable energy generating technologies than used in the reference case [13]. EIA also assumes that 305 megawatts geothermal capacity at The Geysers (California) expected to retire before 2020 will continue producing through 2020. Finally, EIA assumes that the share of landfill gas used for energy production rises to 50 percent by 2020, rather than to 40 percent, as in the reference case. All other technologies and other NEMS modeling characteristics remain unchanged. Capital cost and efficiency differences for 2000 and 2020 are as shown in the table on the following page.

Non-electric renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [14] (RECS) and data from the *Characteristics of New Housing: 1993*, published by the Bureau of the Census [15]. The RECS data provide a benchmark for Btu of wood use in 1993. The Census data are used to develop the forecasts of new housing units utilizing wood. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump consumption is also based on the latest RECS and Census data; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Solar thermal consumption for water heating is also represented by displaced primary energy relative to an electric water heater.

Exogenous projections of active and passive solar technologies and geothermal heat pumps in the commercial sector are based on projections from the National Renewable Energy Laboratory [16]. Industrial use of renewable energy is primarily the use of wood and wood byproducts in the paper and lumber industries as well as a small amount of hydropower for electricity generation.

Oil and gas supply assumptions

Domestic oil and gas economically recoverable resources. The assumed resource levels are based on analyses of estimates of the economically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior and the National Petroleum Council (NPC) [17]. The values are given as beginning-of-the-year 1990, because that is the initial year of the model execution. They have been derived from estimates based in other years (USGS, 1/1/94; MMS, 1/1/95; NPC, 1/1/91) by adjusting for reserve additions in the intervening years.

Economically recoverable resources are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional or nonconventional techniques, under specified economic conditions. Estimates were developed on a regional basis. Total unproved oil resources are assumed to be 92 billion barrels with 1990 technology and 102 billion barrels with 2020 technology. Total unproved gas resources are assumed to be 870 trillion cubic feet with 1990 technology and 1,186 trillion cubic feet with 2020 technology. Unproved resources comprise inferred reserves and undiscovered resources. Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves. Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that the undiscovered recoverable resource target will expand and the effective cost of supply activities will be reduced. The increase in recovery is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques.

The initially recoverable oil and gas resource volumes in both known and undiscovered fields are projected to increase through 2020 in all cases. Ultimate recovery from the initial stock of inferred reserves in all cases except the moderate resource case is assumed to expand over the period of the forecast, exceeding the published estimates from the USGS and MMS. Economically recoverable resources for currently undiscovered fields are assumed, with one exception, to expand by 2020 to the level of current technically recoverable volume estimates released by the USGS and MMS. Recoverable resources in shallow waters in the Gulf of Mexico are assumed in all cases except the slow and rapid technology cases and the moderate resource case to achieve a level of about 40 percent greater than the volume estimated by the MMS to be technically recoverable. These adjustments to the USGS and MMS estimates are based on nontechnical considerations that support domestic supply growth to the levels necessary to meet projected demand levels.

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 from roughly 1 to 2.5 percent. These technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability.

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, oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and growth in the undiscovered economic resource base were adjusted. The two cases were created by varying parameters that represent the effects of technological progress on U.S. drilling lease equipment and operating costs from their statistically estimated values by one standard deviation (based on the standard error associated with each estimated parameter).

Statistically estimated values for U.S. finding rates were similarly varied (although additional transformations of these statistically estimated values, based on analyst judgment, were subsequently required prior to their use as parameters within the *AEO98* analytic framework). Parameters for growth in the U.S. undiscovered economic resource base (which are not statistically derived) were also varied, in proportion to the changes in the technological progress parameters affecting finding rates (reserves found per well).

All other parameters in the model were kept at their reference case values, including success rates, technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas (LNG) and natural gas trade between the United States and Canada and Mexico. Specific detail by region and resource category is presented in the supplementary tables to the *Annual Energy Outlook 1998*, which will be available in December 1997 on EIA's FTP site (ftp://ftp.eia.doe.gov/pub/forecasting/aeo98/ aeo98tables).

Moderate resource case. The *moderate resource case* was created to isolate the sensitivity of the *AEO98* projections to a change in the assumed rates of technological progress affecting the growth in lower 48 unproved resources. The resource assumptions in this case vary from the reference case in two ways: (1) the initial estimate of inferred reserves does not increase over the forecast period, and (2) the expansion of undiscovered economically recoverable oil and gas resources in the shallow regions of the Gulf of Mexico is capped at the technologically recoverable resource levels, derived from the MMS appraisal. All other parameters in the model were kept at their reference case values.

Climate Change Action Plan (CCAP). The CCAP includes a program promoting the capture of methane from coal mining activities to reduce carbon emissions. The methane would be marketed as part of the domestic natural gas supply. This program began in 1995. The *AEO98* assumption is that it reaches a 2010 production level of 29 billion cubic feet and a level of 36 billion cubic feet by 2020.

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. The Alaska Natural Gas Transportation System is assumed to come on line no earlier than 2005 and only after the U.S.-Canada border price reaches $3.82, in 1996 dollars per thousand cubic feet. The liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have an operating capacity of 311 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen when economically justified, but not before 1998. Should these facilities reopen, total liquefied natural gas operating capacity would increase to 794 billion cubic feet.

Natural gas transmission and distribution assumptions. Consistent with industry restructuring, the methodology employed in solving for the market equilibrium assumes that marginal costs are the basis for determining market-clearing prices for nonfirm service markets. Firm service market prices are based on average cost of service rates minus a credit (to account for capacity release) that credits a share of the revenue from nonfirm services to holders of firm capacity should those revenues exceed costs.

Firm transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing rate base (the test for determining whether or not to build new capacity is based on incremental rates, however). Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels, cost of capital, and assumed industry efficiency improvements. It is assumed that, independent of changes in costs related to the cost of capital and consumption levels, distributor costs for firm service customers will decline by 1 percent per year through 2015.

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above that included in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety. (Refurbishment costs include any expenditures for repair and/or replacement of existing pipe.) Reductions in operations and maintenance costs and total administrative and general costs as a result of efficiency improvements are accounted for on the basis of historical trends.

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 at $0.52 (1996 dollars) per thousand cubic feet.

CCAP initiatives to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are reflected in the methodology for the pricing of pipeline services. This methodology is consistent with FERC's receptivity to alternative ratemaking and its desire to provide an atmosphere that fosters efficient capacity release. Provisions of the CCAP to expand the Natural Gas Star program (Action 32) are assumed to recover 35 billion cubic feet of natural gas per year by the year 2000 that otherwise might be lost to fugitive emissions. This is phased in by recovering an additional 7 billion cubic feet per year from 1997 through 2000, and by recovering the full 35 billion cubic feet from 2000 through the end of the forecast period.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large 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 [18] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of these costs because demand for these products is less price-responsive than for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for new fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. These additional costs are determined in the representation of refinery operations by incorporating specifications and demands for these fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption based on market share assumptions for each Census Division. The expected oxygenated gasoline market shares assume wintertime participation of carbon monoxide nonattainment areas beginning in 1993 and statewide participation in Minnesota beginning in 1997. Oxygenated gasoline represents about 4 percent of gasoline demand in the forecast.

Starting in 1995, reformulated gasoline (RFG) is assumed to be consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas in 13 States and the District of Columbia that voluntarily opted into the program [19]. Reformulated gasoline projections also reflect a statewide requirement in California beginning in 1996. The reformulated gasoline is assumed to account for about 31 percent of annual gasoline sales throughout the *AEO98* forecast.

Reformulated gasoline reflects the “Complex Model” definition as required by the EPA. *AEO98* projections also reflect California's statewide requirement for severely reformulated gasoline beginning in 1996. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 “antidumping” requirements aimed at preventing traditional gasoline from becoming more polluting.

AEO98 assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 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 1996 nominal levels (a decline in real terms).

AEO98 assumes that the 54-cent-per-gallon tax credit for gasoline blended with ethanol will not expire and will remain constant in nominal terms throughout the forecast.

AEO98 assumes that refining capacity expansion may occur on the East and West coasts, as well as the Gulf Coast. In previous forecasts, capacity expansion has been constrained in PAD districts I (East Coast) and V (West Coast), assuming that no growth would occur in those areas.

High reformulated gasoline case. The sensitivity of gasoline prices to higher RFG consumption was explored in an alternative case. RFG consumption in the reference case is based on current participation in the Federal RFG program, although increased participation in the program may result from the 1997 revision of ground-level ozone standards. The revised standards are expected to increase the number of areas in violation of the standards, thereby increasing the interest in using RFG as a solution. The EPA will be assessing air quality data for the next several years and will not publish the list of areas in violation of the new standards until 2000. The alternative case assumes that after 2003, RFG consumption in Census divisions 1 through 7 is 10 percent higher than in the reference case. Census Divisions 1 through 7 lie east of the Rocky Mountains and contain the 37 States that participated in the Ozone Transport Assessment Group, which included the increased use of RFG in its 1997 recommendations to the EPA.

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 deep. On a national basis, labor productivity is assumed to improve on average at a rate of 2.0 percent per year, declining from an annual rate of 5.8 percent in 1996 to approximately 1.6 percent over the 2010 to 2020 period. In two alternative mining cost cases that were run to examine the impacts of different labor productivity and labor 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 high and low mining cost cases were developed by adjusting the *AEO98* reference case productivity path by 1 standard deviation, although productivity growth rates were adjusted gradually (with full variation from the reference case phased in by 2000). The resulting national average productivities attained in 2020 (in short tons per hour) were 12.34 in the *low mining cost case* and 6.94 in the *high mining cost case*, compared with 9.16 in the *reference case*.

In the reference case, labor wage rates for coal mine production workers are assumed to remain constant in real terms over the forecast period. In the alternative low and high mining cost cases, wages were assumed to decline and increase by 0.5 percent per year in real terms, respectively.

The mining cost cases were run without allowing demands to shift in response to changing prices. If demands had been allowed to shift, the price changes would be smaller, since minemouth prices vary with the levels of capacity utilization required to meet demand.

Notes

[1] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, DOE/ EIA-0573(96) (Washington, DC, October 1997).

[2] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(97/3Q) (Washington, DC, July 1997), and web site www.eia.doe.gov/ emeu/steo/pub/upd/aug97/index.html.

[3] 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..

[4] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[5] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[6] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[7] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[8] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[9] 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 Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology*: Quality Metrics 98 (June 17, 1997).

[10] National Energy Policy Act of 1992, P.L. 102-486, Title I , Section 1914.

[11] National Energy Policy Act of 1992, P.L. 102-486, Title I , Section 1916.

[12] 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 Schwartz, M.N.; Elliott, O.L.; and Gower, G.L.; *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992*, October 19-23, 1992, Seattle.

[13] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, draft, *Renewable Energy Technology Characterizations*, Vol. 1, (Washington, DC, February 1997), as updated in internal revisions, Summer 1997.

[14] Energy Information Administration, *Household Energy Consumption and E penditures 1993*, DOE/ EIA-0321(93) (Washington, DC, 1995).

[15] U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1993* (Washington, DC, 1994).

[16] National Renewable Energy Laboratory, "Baseline Projections of Renewables Use in the Buildings Sector," prepared for the U.S. Department of Energy under Contract DE-AC02-83CH10093 (December 1992).

[17] Goutier, Donald L., et al., U.S. Department of the Interior, U.S. Geological Survey, *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC, 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 1996); Cooke, Larry W., U.S. Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91--0051 (July 1991); National Petroleum Council, Committee on Natural Gas, *The Potential for Natural Gas in the United States, Volume II, Source and Supply* (Washington, DC, December 1992).

[18] Estimated from National Petroleum Council, *U.S. Petroleum Refining Meeting Requirements for Cleaner Fuels and Re-*

fineries, Volume I (Washington, DC, August 1993). Excludes operation and maintenance base costs prior to 1996.

[19] 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: Arizona, Connecticut, Delaware, Kentucky, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1996.

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.277
Consumption	million Btu per short ton	20.845
Coke Plants	million Btu per short ton	26.800
Industrial	million Btu per short ton	21.950
Residential and Commercial	million Btu per short ton	23.118
Electric Utilities	million Btu per short ton	20.495
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.180
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	5.346
Motor Gasoline[2]	million Btu per barrel	5.206
Jet Fuel (Kerosene)	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas	million Btu per barrel	3.625
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks	million Btu per barrel	5.630
Unfinished Oils	million Btu per barrel	5.800
Imports[2]	million Btu per barrel	5.280
Exports[2]	million Btu per barrel	5.719
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.495
Natural Gas		
Production, Dry	Btu per cubic foot	1,028
Consumption	Btu per cubic foot	1,028
Non-electric Utilities	Btu per cubic foot	1,029
Electric Utilities	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,022
Exports	Btu per cubic foot	1,022
Electricity Consumption	**Btu per kilowatthour**	**3,412**

[1]Conversion factors vary from year to year. 1995 values are reported.
[2]Conversion factors vary from year to year. 2000 values are reported.
[3]Conversion factors vary from year to year. Values shown are for units entering service in 2000.
Source: Energy Information Administration, AEO98 National Energy Modeling System run AEO98B.D100197A.

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	X	1.609 344	=	kilometers (km)
Miles				
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules(J)
Quatrillion Btu	X	23.510 877 5	=	milliion 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 (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96)(Washington DC, July 1997), Table B1 and EIA, *International Energy Outlook 1997,* DOE/EIA-0484 (97) (Washington, DC, April 1997).

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 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table B2, and EIA,Statistics and Methods Group.