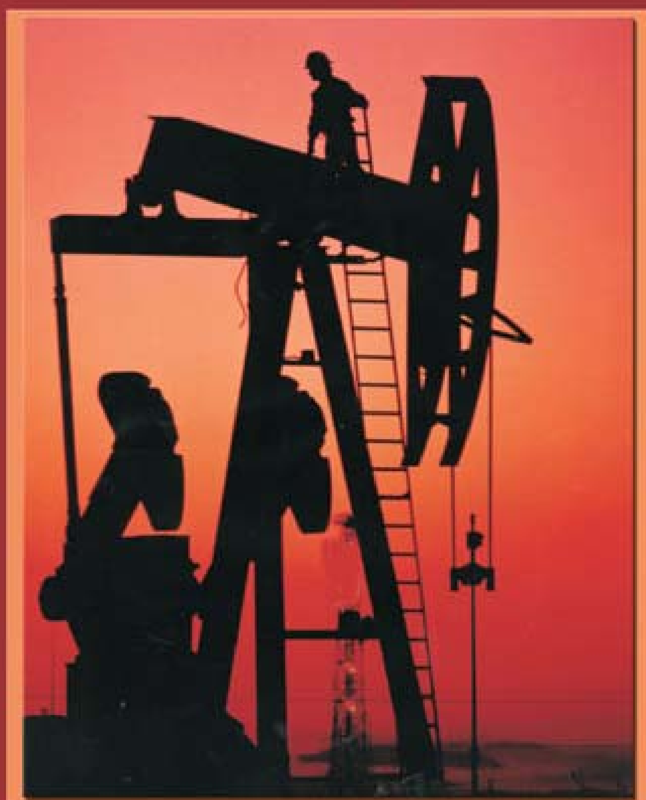
DOE/EIA-0383(2005)
February 2005

Annual Energy Outlook 2005



With Projections to 2025

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For Further Information . . .

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AEO2005 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early February 2005. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early February 2005, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are available at web site www.eia.doe.gov/bookshelf/docs.html and will be updated for *AEO2005* in the first few months of 2005.

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DOE/EIA-0383(2005)

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Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/

Preface

The *Annual Energy Outlook 2005* (*AEO2005*) presents midterm forecasts of energy supply, demand, and prices through 2025 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2005* reference case. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues, including legislation and regulations that have been enacted and some that are proposed. Next, the "Issues in Focus" section discusses key energy market issues and examines their potential impacts. In particular, it includes a discussion of the world oil price assumptions used in the reference case and four alternative world oil price cases examined in *AEO2005*. "Issues in Focus" is followed by "Market Trends," which provides a summary of energy market trends in the *AEO2005* forecast.

The analysis in *AEO2005* focuses primarily on a reference case, lower and higher economic growth cases, and four alternative oil price cases—a low world oil price case, an October oil futures case, and two high world oil price cases. Forecast tables for those cases are provided in Appendixes A through D. The major results for the alternative cases, which explore the impacts of varying key assumption in NEMS (such as rates of technology penetration), are summarized in Appendix E. Appendix F briefly describes NEMS and the alternative cases.

The *AEO2005* projections are based on Federal, State, and local laws and regulations in effect on or before October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation requiring funds that have not been appropriated) are not reflected in the projections. For example, the *AEO2005* forecast does not include the potential impacts of regulations proposed by the U.S. Environmental Protection Agency, such as the Clean Air Interstate Rule and the Clean Air Mercury Rule, that would address emissions from coal-fired power plants in the United States. In general, the historical data used for *AEO2005* projections are based on EIA's *Annual Energy Review 2003*, published in September 2004; however, data are taken from multiple sources. In some cases, only partial or preliminary 2003 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2004 and 2005 incorporate the short-term projections from EIA's September 2004 *Short-Term Energy Outlook*.

Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors use the *AEO2005* projections. They are published in accordance with Section 205c of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

The projections in the *Annual Energy Outlook 2005* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

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

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2005* 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, a complete and focused analysis of public policy initiatives.

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Overview

Key Energy Issues to 2025

The Energy Information Administration (EIA), in preparing model forecasts for its *Annual Energy Outlook 2005* (*AEO2005*), evaluated a wide range of current trends and issues that could have major implications for U.S. energy markets over the 20-year forecast period, from 2005 to 2025. Trends in energy supply and demand are linked with such unpredictable factors as the performance of the U.S. economy overall, advances in technologies related to energy production and consumption, annual changes in weather patterns, and future public policy decisions [*1*]. Among the most important issues identified as having the potential to affect the complex behavior of the domestic energy economy, oil prices and natural gas supply were considered to be of particular significance in increasing the uncertainty associated with the *AEO2005* reference case projections.

World crude oil prices—defined by the U.S. average refiner's acquisition cost of imported crude oil (IRAC)—reached a recent low of $10.29 per barrel (in 2003 dollars) in December 1998. For the next 3 years, crude oil prices ranged between just under $20 and just over $30 per barrel. Since December 2001, however, prices have increased steadily, to about $46 per barrel in October 2004.

Strong growth in the demand for oil worldwide, particularly in China and other developing countries, is generally cited as the driving force behind the sharp price increases seen over the past 3 years. Other factors contributing to the upward trend include a tight supply situation that has shown only limited response to higher prices; changing views on the economics of oil production; concerns about economic and political situations in the Middle East, Venezuela, Nigeria, and the former Soviet Union; and recent supply disruptions caused by weather events (Hurricane Ivan). The future path of prices is a key uncertainty facing world oil markets.

The *AEO2005* reference case assumes that world crude oil prices will decline as growth in consumption slows and producers increase their productive capacity and output in response to current high prices. In contrast, the October 2004 prices from the New York Mercantile Exchange (NYMEX) futures market (corrected for the difference between futures prices and the IRAC) imply that the annual average price in 2005 will exceed the 2004 average price level, and that prices will then decline only slowly over the next few years, resulting in 2010 prices higher than those projected in the *AEO2005* reference case. To evaluate the uncertainty associated with the future path of world oil prices, *AEO2005* includes alternative world oil price cases. A summary of the alternative world oil price cases included in *AEO2005* is provided in "Issues in Focus," page 40.

From 1986 to 2000, when U.S. natural gas consumption grew from 16.2 trillion cubic feet to a high of 23.3 trillion cubic feet, 40 percent of the increased demand was met by imports, predominantly from Canada. Based on the latest assessment from Canada's National Energy Board, however, it is unlikely that future production from Canada will be able to support a continued increase in U.S. imports.

In the *AEO2005* reference case, U.S. natural gas consumption is projected to grow from 22 trillion cubic feet in 2003 to almost 31 trillion cubic feet in 2025. Most of the additional supply is expected to come from Alaska and imports of liquefied natural gas (LNG). A key issue for U.S. energy markets is whether the investments and regulatory approvals needed to make those natural gas supplies available will be forthcoming, and what the ramifications will be if they are not. The *AEO2005* includes a restricted natural gas supply case to examine the implications of a possible future in which no Alaska natural gas pipeline is built, no new construction is started on additional LNG terminals, and production technology advances more slowly than it has in the past. The restricted natural gas supply case is also described in "Issues in Focus," page 66.

The following sections summarize the key trends in the *AEO2005* reference case and compare them with last year's reference case (*AEO2004*). A summary of the *AEO2005* reference case is provided in Table 1 on page 9.

Economic Growth

In the *AEO2005* reference case, the U.S. economy, as measured by gross domestic product (GDP), grows at an average annual rate of 3.1 percent from 2003 to 2025, slightly higher than the growth rate of 3.0 percent per year for the same period in *AEO2004*. Many of the determinants of economic growth are similar to those in *AEO2004*, but there are some important differences. Both the Federal funds rate and the nominal yield on the 10-year Treasury note are higher in the early years of the *AEO2005* forecast but generally lower after 2010; the industrial value of shipments reflects a more pessimistic forecast for industrial output in view of the downward adjustment in domestic production for some manufacturing sectors in the early 2000s; and the U.S. population forecast in *AEO2005* is higher, following the adoption of the interim population projections released by the U.S. Census Bureau in 2004.

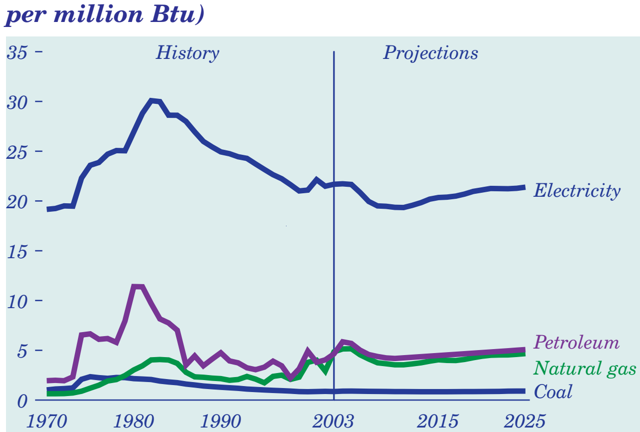
Energy Prices

In the *AEO2005* reference case, the annual average world oil price (IRAC) increases from $27.73 per barrel (2003 dollars) in 2003 to $35.00 per barrel in 2004 and then declines to $25.00 per barrel in 2010 as new supplies enter the market. It then rises slowly to $30.31 per barrel in 2025, about $3 per barrel higher than the *AEO2004* projection of $27.41 per barrel in 2025. In nominal dollars, the average world oil price is about $52 per barrel in 2025.

The *AEO2005* world oil price forecast is characterized by decreasing prices through 2010 and moderately increasing prices thereafter (Figure 1). This is consistent with a forecast that projects increases in world petroleum demand, from about 80 million barrels per day in 2003 to more than 120 million barrels per day in 2025, which is met by increased oil production both from the Organization of Petroleum Exporting Countries (OPEC) and from non-OPEC nations. *AEO2005* projects OPEC oil production of 55 million barrels per day in 2025, 80 percent higher than the 31 million barrels per day produced in 2003. The forecast assumes that OPEC will pursue policies intended to increase production, that sufficient resources exist, and that access and capital will be available to expand production. Non-OPEC oil production is expected to increase from 49 to 65 million barrels per day between 2003 and 2025.

Average wellhead prices for natural gas in the United States are projected generally to decrease, from $4.98 per thousand cubic feet (2003 dollars) in 2003 to $3.64 per thousand cubic feet in 2010 as the initial availability of new import sources and increased drilling expands available supply. After

Figure 1. Energy prices, 1970-2025 (2003 dollars per million Btu)



2010, wellhead prices are projected to increase gradually (Figure 1), to $4.79 per thousand cubic feet in 2025 (equivalent to about $8.20 per thousand cubic feet in nominal dollars). Growth in LNG imports, Alaska production, and lower 48 production from nonconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. The projected 2025 wellhead natural gas price in *AEO2005* is more than 30 cents per thousand cubic feet higher than the *AEO2004* projection, primarily as a result of lower assumed finding rates (reserve additions per well) for onshore resources.

In *AEO2005*, the combination of more moderate increases in coal production, expected improvements in mine productivity, and a continuing shift to low-cost coal from the Powder River Basin in Wyoming leads to a gradual decline in the average minemouth price, to approximately $17.00 per ton shortly after 2010. The price is projected to remain nearly constant between 2010 and 2020 (Figure 1), increasing after 2020 as rising natural gas prices and the need for baseload generating capacity lead to the construction of many new coal-fired generating plants. By 2025, the average minemouth price is projected to be $18.26 per ton, which is higher than the *AEO2004* projection of $16.82 per ton. The *AEO2005* projection is equivalent to an average minemouth coal price of $31.25 per ton in nominal dollars in 2025.

Average delivered electricity prices are projected to decline from 7.4 cents per kilowatthour (2003 dollars) in 2003 to a low of 6.6 cents per kilowatthour in 2011 as a result of an increasingly competitive generation market and a decline in natural gas prices. After 2011, average real electricity prices are projected to increase (Figure 1), reaching 7.3 cents per kilowatthour in 2025 (equivalent to 12.5 cents per kilowatthour in nominal dollars). In *AEO2004*, real electricity prices followed a similar pattern but were projected to be slightly lower in 2025, at 7.0 cents per kilowatthour. The higher electricity price projection in *AEO2005* results primarily from higher expected fuel costs for coal- and natural-gas-fired electricity generation, particularly in the later years of the forecast.

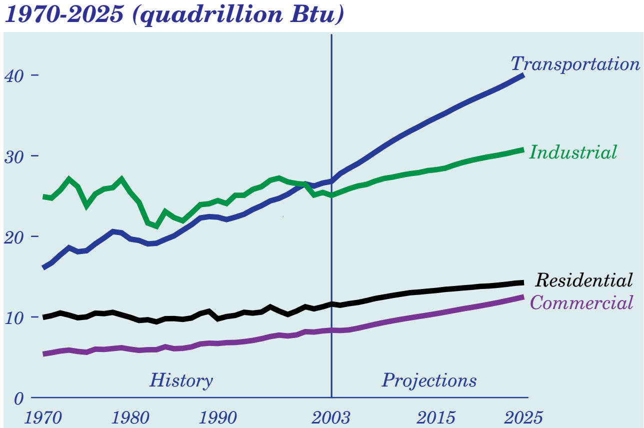
Energy Consumption

Total primary energy consumption in *AEO2005* is projected to increase from 98.2 quadrillion British thermal units (Btu) in 2003 to 133.2 quadrillion Btu in 2025 (an average annual increase of 1.4 percent). *AEO2004* projected energy consumption of 136.5 quadrillion Btu in 2025. Other than nuclear energy, the *AEO2005* projections for the consumption of all energy sources in 2025 are lower than those in *AEO-2004*. Among the most important factors accounting for the differences are higher energy prices, lower projected growth rates in industrial production, specific updates in the chemical and pulp and paper industries, revisions to the capital cost of generating technologies, and revisions to transportation sector vehicle miles traveled.

Consistent with population growth rates and household formation, delivered residential energy consumption is projected to grow from 11.6 quadrillion Btu in 2003 to 14.3 quadrillion Btu in 2025 (Figure 2), at an average rate of 0.9 percent per year between 2003 and 2025 (1.3 percent per year between 2003 and 2010, slowing to 0.8 percent per year between 2010 and 2025). The most rapid growth in energy demand in *AEO2005* is projected to be for electricity used to power computers, electronic equipment, and appliances. *AEO2005* includes changes in the residential sector that have offsetting influences on the forecast of energy consumption, including more rapid growth in the total number of U.S. households; higher delivered prices for natural gas, electricity, and distillate fuel; and a better accounting of additions to existing homes and the height of ceilings in new homes.

Consistent with the projected increase in commercial floorspace, delivered commercial energy consumption is projected to grow at an average annual rate of 1.9 percent between 2003 and 2025 (Figure 2), reaching 12.5 quadrillion Btu in 2025 (slightly more than the 12.2 quadrillion Btu projected in *AEO2004*). The most rapid increase in energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances. The higher forecast for commercial energy consumption in *AEO2005* results from a higher projected rate of growth in commercial floorspace, averaging 1.7 percent per year between 2003 and 2025, as compared with the projected average of 1.5 percent per year in *AEO2004*.

Figure 2. Delivered energy consumption by sector, 1970-2025 (quadrillion Btu)



Delivered industrial energy consumption in *AEO-2005* is projected to increase at an average rate of 1.0 percent per year between 2003 and 2025 (Figure 2), reaching 30.8 quadrillion Btu in 2025 (significantly lower than the *AEO2004* forecast of 33.4 quadrillion Btu). The *AEO2005* forecast includes slower projected growth in the dollar value of industrial product shipments relative to *AEO2004*, because of the slowdown in production growth in recent years and a reassessment of the prospects for growth in the chemical and pulp and paper industries.

Energy consumption in the transportation sector is projected to grow at an average annual rate of 1.8 percent between 2003 and 2025 in the *AEO2005* forecast (Figure 2), reaching 40.0 quadrillion Btu in 2025 (1.1 quadrillion Btu lower than the *AEO2004* projection). Two factors account for the reduction in projected transportation energy use from *AEO2004* to *AEO-2005*: first, expectations about light vehicle travel per capita have been reduced, based on new historical population and income data; and second, fuel economy data have been updated, resulting in a slightly improved average fuel economy for the light-duty vehicle stock over the forecast.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,657 billion kilowatthours in 2003 to 5,467 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year. Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the end-use sectors is partially offset in the *AEO2005* forecast by improved efficiency in these and other, more traditional electrical applications and by slower growth in electricity demand in the industrial sector.

Total demand for natural gas is projected to increase at an average annual rate of 1.5 percent from 2003 to 2025 (Figure 3), primarily as a result of increasing use for electricity generation and industrial applications, which together account for about 75 percent of the projected growth in natural gas demand from 2003 to 2025. Total projected consumption of natural gas in 2025 is 0.7 trillion cubic feet lower in *AEO2005* than was projected in *AEO2004*. The growth in demand for natural gas slows in the later years of the forecast (0.9 percent per year from 2015 to 2025, compared with 2.1 percent per year from 2003 to 2010), as rising natural gas prices lead to the construction of more coal-fired capacity for electricity generation.

In *AEO2005*, total coal consumption is projected to increase from 1,095 million short tons in 2003 to 1,508 million short tons in 2025—59 million short tons less than the *AEO2004* projection of 1,567 million short tons in 2025. From 2003 to 2025, coal consumption is projected to grow by 1.5 percent per year in the *AEO2005* forecast. The primary reason for the lower growth is an update of assumptions made about the relative capital costs of new coal- and natural-gas-fired power plants in the *AEO2005* forecast. In *AEO2005*, total coal consumption for electricity generation is projected to increase by an average of 1.6 percent per year, from 1,004 million short tons in 2003 to 1,425 million short tons in 2025, compared with the *AEO2004* projection of 1,477 million short tons in 2025.

Total petroleum demand is projected to grow at an average annual rate of 1.5 percent in the *AEO2005* forecast, from 20.0 million barrels per day in 2003 to 27.9 million barrels per day in 2025. In *AEO2005*, an increase of 0.3 million barrels per day in petroleum use for electricity generation in 2025, relative to the *AEO2004* projection, is more than offset by a reduction of 0.7 million barrels per day in total petroleum use in the industrial and transportation sectors in 2025—the result of projected higher energy prices, slower growth in industrial production, and improved average fuel economy for light-duty vehicles.

Total marketed renewable fuel consumption (including ethanol for gasoline blending, of which 0.2 quadrillion Btu is included with “petroleum products” consumption in Table 1), is projected to grow by 1.5 percent per year in *AEO2005*, from 6.1 quadrillion Btu in 2003 to 8.5 quadrillion Btu in 2025, as a result of State mandates for renewable electricity generation, higher natural gas prices, and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2025 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending. Despite higher fossil fuel prices, the projected demand for renewables in 2025 in *AEO2005* is 0.9 quadrillion Btu less than in *AEO2004*. Renewable generating technologies are not as competitive in *AEO2005*, because the costs for natural gas technologies are lower, wind technology costs are about 10 percent higher, and several geothermal projects that were assumed to be completed in the *AEO2004* forecast are not included in *AEO2005*.

Energy Intensity

Energy intensity, as measured by energy use per 2000 dollar of GDP, is projected to decline at an average annual rate of 1.6 percent in the *AEO2005* forecast, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 4). The rate of decline is faster in *AEO2005* than the projected rate of 1.4 percent per year in *AEO2004*, because higher energy prices in the *AEO-2005* forecast are projected to result in generally lower energy consumption and a more rapid shift of energy use away from industrial uses to energy services. The projected rate of decline in *AEO2005* falls between the historical averages of 2.3 percent per year from 1970 to 1986, when energy prices increased in real terms, and 0.7 percent per year from 1986 to 1992, when energy prices were generally falling.

Since 1992, energy intensity has declined on average by 1.9 percent per year. During this period, the role of energy-intensive industries in the U.S. economy has fallen sharply. The share of industrial output from the energy-intensive industries declined on average

Figure 3. Energy consumption by fuel, 1970-2025 (quadrillion Btu)

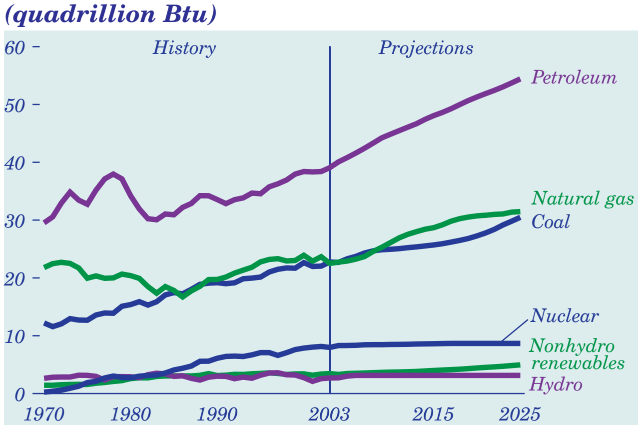
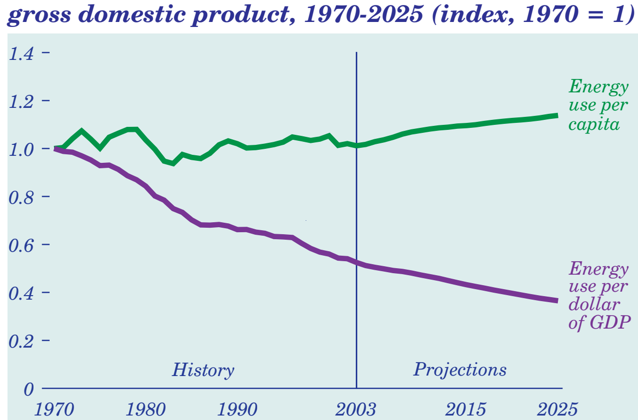


Figure 4. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



by 1.3 percent per year from 1992 to 2003. In the *AEO2005* forecast, the energy-intensive industries' share of total industrial output is projected to continue declining but at a slower rate of 0.8 percent per year, which leads to the projected slower annual rate of reduction in energy intensity.

Historically, energy use per person has varied over time with the level of economic growth, weather conditions, and energy prices, among many other factors. During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. Starting in the late 1980s and lasting through the mid-1990s, energy consumption per capita increased with declining energy prices and strong economic growth. Per capita energy use is projected to increase in *AEO2005*, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.5 percent per year between 2003 and 2025 in *AEO2005*, slightly less than was projected in *AEO2004* (0.7 percent per year), as a result of the higher energy prices in *AEO2005*.

The potential for more energy conservation has received increased attention recently as energy prices have risen. Although energy conservation is projected to be induced through energy price increases, *AEO-2005* does not assume policy-induced conservation measures beyond those in existing legislation and regulation, nor does it assume behavioral changes beyond those experienced in the past.

Electricity Generation

In *AEO2005*, the projected average price for natural gas delivered to electricity generators is 45 cents per million Btu higher in 2025 than was projected in *AEO2004*; however, the impact of the higher prices is offset by the assumption that capital costs for new natural-gas-fired power plants will be lower than assumed in *AEO2004*, as well as the inclusion of more recently completed and announced plans for gas-fired power plants. As a result, in *AEO2005*, projected cumulative capacity additions and generation from natural-gas-fired power plants are higher than in *AEO2004*, and capacity additions and generation from coal-fired power plants are lower. The *AEO2005* projection of 1,406 billion kilowatthours of electricity generation from natural gas in 2025 is 8 percent higher than in *AEO2004* (1,304 billion kilowatthours) and more than twice the 2003 level of about 630 billion kilowatthours (Figure 5). Less new gas-fired capacity is added in the later years of the forecast because of the projected rise in natural gas prices.

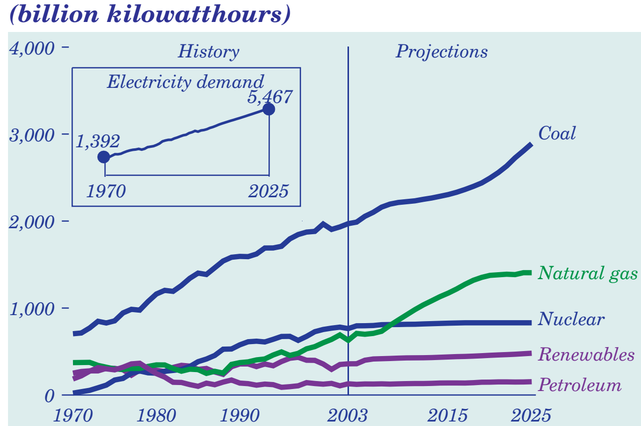
The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 16 percent in 2003 to 24 percent in 2025. The share from coal is projected to decrease from 51 percent in 2003 to 50 percent in 2025. *AEO2005* projects that 87 gigawatts of new coal-fired generating capacity will be constructed between 2004 and 2025 (compared with 112 gigawatts in *AEO2004*).

Nuclear generating capacity in *AEO2005* is projected to increase from 99.2 gigawatts in 2003 to 102.7 gigawatts in 2025—about the same as in *AEO2004*—as a result of uprates of existing plants between 2003 and 2025. All existing nuclear plants are projected to continue to operate, but new plants are not expected to be economical. Total nuclear generation is projected to grow from 764 billion kilowatthours in 2003 to 830 billion kilowatthours in 2025 in *AEO2005*.

The use of renewable technologies for electricity generation is projected to grow slowly, both because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. *AEO2005* also includes the extension of the production tax credit for wind and biomass through December 31, 2005, as enacted in H.R. 1308, the Working Families Tax Relief Act of 2004. *AEO2004* assumed that the production tax credit would end on December 31, 2003, its statutory expiration date at the time *AEO2004* was prepared.

Total renewable generation in *AEO2005*, including combined heat and power generation, is projected to grow from 359 billion kilowatthours in 2003 to 489 billion kilowatthours in 2025, increasing by 1.4 percent per year.

Figure 5. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand (Figure 6). Net imports are expected to constitute 38 percent of total U.S. energy consumption in 2025, up from 27 percent in 2003.

Projected U.S. crude oil production increases from 5.7 million barrels per day in 2003 to a peak of 6.2 million barrels per day in 2009 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Beginning in 2010, U.S. crude oil production begins to decline, falling to 4.7 million barrels per day in 2025.

Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the *AEO2005* forecast, increasing from 9.1 million barrels per day in 2003 to a peak of 9.8 million barrels per day in 2009, then declining to 8.8 million barrels per day in 2025 (Figure 7).

In 2025, net petroleum imports, including both crude oil and refined products, are expected to account for 68 percent of demand (on the basis of barrels per day), up from 56 percent in 2003. Despite an expected increase in distillation capacity at domestic refineries, net imports of refined petroleum products account for a growing portion of total net imports, increasing from 14 percent in 2003 to 16 percent in 2025 (as compared with 20 percent in *AEO2004*).

The most significant change in the *AEO2005* energy supply projections is in the outlook for natural gas, particularly domestic lower 48 onshore production and LNG imports. Domestic natural gas production increases from 19.1 trillion cubic feet in 2003 to 21.8 trillion cubic feet in 2025 in the *AEO2005* forecast; *AEO2004* projected 24.0 trillion cubic feet of domestic natural gas production in 2025.

The projection for conventional onshore production of natural gas is lower in *AEO2005* than it was in *AEO2004*, because of slower reserve growth, fewer new discoveries, and higher exploration and development costs. Lower 48 onshore natural gas production is projected to increase from 13.9 trillion cubic feet in 2003 to a peak of 15.7 trillion cubic feet in 2012 before falling to 14.7 trillion cubic feet in 2025. In *AEO2004*, lower 48 onshore production reached 16.3 trillion cubic feet in 2025.

Offshore natural gas production in 2025 is also somewhat lower in *AEO2005* than it was in the *AEO2004* forecast. Lower 48 offshore production, which was 4.7 trillion cubic feet in 2003, is projected to increase in the near term (to 5.3 trillion cubic feet by 2014) because of the expected development of some large deepwater fields, including Mad Dog, Entrada, and Thunder Horse. After 2014, offshore production is projected to decline to 4.9 trillion cubic feet in 2025.

Although the projection for net U.S. imports of natural gas from Canada in 2025 in *AEO2005* is about the same as in *AEO2004*, the pattern of growth is very different in *AEO2005*. *AEO2004* projected that the 2002 level of net Canadian imports (3.6 trillion cubic feet) could be sustained through 2012 before falling off. *AEO2005* expects net Canadian imports to decline from 2003 levels of 3.1 trillion cubic feet to about 2.5 trillion cubic feet in 2009, followed by an increase after 2010 to 3.0 trillion cubic feet in 2015 as a result of rising natural gas prices, the introduction of gas from the Mackenzie Delta, and increased production of coalbed methane. After 2015, because of reserve depletion effects and growing domestic demand in Canada, net U.S. imports are projected to decline to 2.6 trillion cubic feet in 2025. The *AEO2005* forecast reflects revised expectations about Canadian natural

Figure 6. Total energy production and consumption, 1970-2025 (quadrillion Btu)

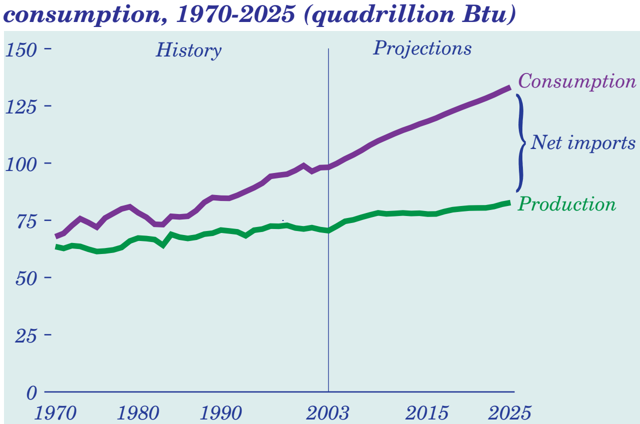
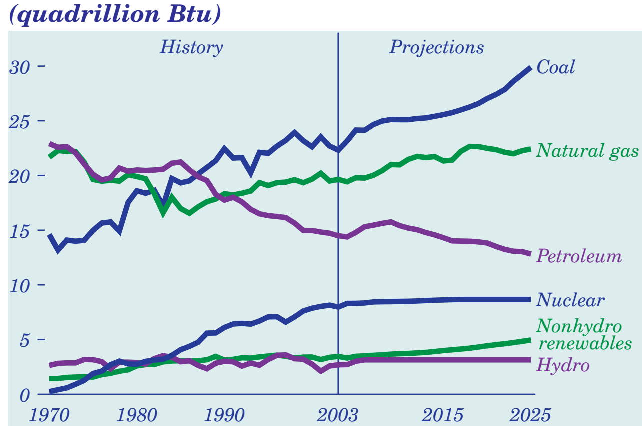


Figure 7. Energy production by fuel, 1970-2025 (quadrillion Btu)



gas production, particularly coalbed methane and conventional production in Alberta, based in part on data and projections from Canada's National Energy Board and other sources.

Growth in U.S. natural gas supplies will depend on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 6.6 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2016, Alaska's total production is projected to increase from 0.4 trillion cubic feet in 2003 to 2.2 trillion cubic feet in 2025. With the exception of the facility at Everett, Massachusetts, three of the four existing U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) are expected to expand by 2007; and additional facilities are expected to be built in New England and elsewhere in the lower 48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, including a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving a portion of the California market. Total net LNG imports to the United States and the Bahamas are projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025, about one-third more than the *AEO2004* projection of 4.8 trillion cubic feet.

As domestic coal demand grows in *AEO2005*, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,083 million short tons in 2003 to 1,488 million short tons in 2025. The *AEO2005* projection for coal production in 2025 is 55 million short tons less than in *AEO2004* because of revisions in the relative capital costs and efficiencies for new coal- and natural-gas-fired generating capacity in *AEO2005*, which lead to a lower projected level of coal demand than was projected in *AEO2004*, despite higher natural gas prices in *AEO2005*. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental coal production. In 2025, nearly two-thirds of coal production is projected to originate from the western States.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,789 million metric tons in 2003 to 8,062 million metric tons in 2025 in *AEO2005*, an average annual increase of 1.5 percent (Figure 8). The carbon dioxide emissions intensity of the U.S. economy is projected to fall from 558 metric tons per million dollars of GDP in 2003 to 397 metric tons per million dollars in 2025—an average decline of 1.5 percent per year. In comparison, *AEO2004* projected a 1.4-percent average annual decline in emissions intensity and 8,142 million metric tons of carbon dioxide emissions in 2025.

By sector, projected carbon dioxide emissions from the residential, commercial, and electric power sectors in 2025 are higher in *AEO2005* than they were in *AEO2004* because of higher projected energy consumption in each of those sectors (particularly, electricity consumption in the residential and commercial sectors and natural gas and petroleum consumption for electricity generation in the electric power sector), whereas *AEO2005* projects lower energy consumption in the industrial and transportation sectors in 2025 and lower carbon dioxide emissions in both sectors than were projected in *AEO2004*. In the electric power sector, the higher *AEO2005* projections for carbon dioxide emissions from natural gas and petroleum use for generation more than offset the lower projection for emissions from coal-fired generation. In total, however, the lower levels of carbon dioxide emissions projected for the industrial and transportation sectors in 2025 outweigh the higher levels projected for the other energy-consuming sectors, so that total emissions in 2025 are lower in the *AEO2005* forecast than they were in *AEO2004*. The *AEO* projections do not include future policy actions or agreements that might be taken to reduce carbon dioxide emissions.

Figure 8. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)

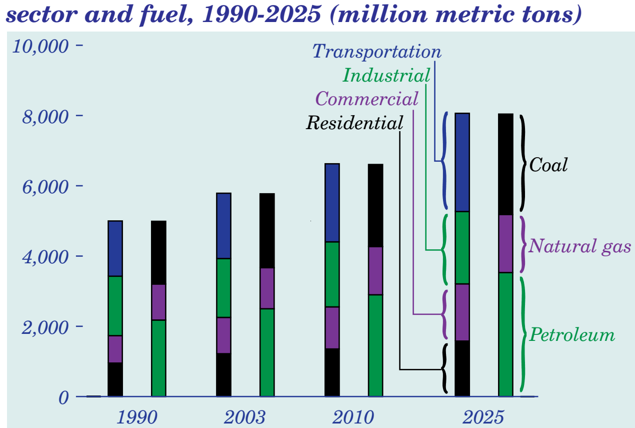


Table 1. Total energy supply and disposition in the *AEO2005* reference case: summary, 2002-2025

Energy and economic factors	2002	2003	2010	2015	2020	2025	Average annual change, 2003-2025
Primary energy production (quadrillion Btu)							
Petroleum	14.71	14.38	15.41	14.31	13.83	12.82	-0.5%
Dry natural gas	19.48	19.58	20.97	21.33	22.48	22.42	0.6%
Coal	22.70	22.66	25.10	25.56	27.04	29.90	1.3%
Nuclear power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable energy	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other	1.12	0.93	0.97	0.78	0.77	0.82	-0.5%
Total	**71.94**	**71.42**	**77.79**	**77.73**	**80.35**	**82.73**	**0.7%**
Net imports (quadrillion Btu)							
Petroleum	22.64	24.10	28.61	33.10	36.87	41.11	2.5%
Natural gas	3.59	3.32	5.06	7.19	8.08	8.87	4.6%
Coal/other (- indicates export)	-0.47	-0.43	-0.14	0.19	0.25	0.58	NA
Total	**25.75**	**26.99**	**33.53**	**40.47**	**45.21**	**50.55**	**2.9%**
Consumption (quadrillion Btu)							
Petroleum products	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural gas	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Coal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable energy	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Petroleum (million barrels per day)							
Domestic crude production	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Other domestic production	3.60	3.38	3.59	3.77	4.00	4.10	0.9%
Net imports	10.54	11.24	13.37	15.40	17.11	19.11	2.4%
Consumption	19.71	20.00	22.98	24.67	26.32	27.93	1.5%
Natural gas (trillion cubic feet)							
Production	19.03	19.13	20.49	20.85	21.97	21.91	0.6%
Net imports	3.50	3.24	4.94	7.02	7.89	8.66	4.6%
Consumption	22.98	21.95	25.44	27.96	29.95	30.67	1.5%
Coal (million short tons)							
Production	1,105	1,083	1,238	1,270	1,345	1,488	1.5%
Net imports	-23	-18	-9	3	7	20	NA
Consumption	1,066	1,095	1,229	1,273	1,352	1,508	1.5%
Prices (2003 dollars)							
World oil price (dollars per barrel)	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Domestic natural gas at wellhead (dollars per thousand cubic feet)	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Domestic coal at minemouth (dollars per short ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
Average electricity price (cents per kilowatthour)	7.4	7.4	6.6	6.9	7.2	7.3	-0.1%
Economic indicators							
Real gross domestic product (billion 2000 dollars)	10,075	10,381	13,084	15,216	17,634	20,292	3.1%
GDP chain-type price index (index, 2000=1.000)	1.041	1.060	1.218	1.373	1.563	1.814	2.5%
Real disposable personal income (billion 2000 dollars)	7,560	7,734	9,594	11,192	12,783	14,990	3.1%
Value of manufacturing shipments (billion 1996 dollars)	5,067	5,105	6,165	6,850	7,633	8,469	2.3%
Energy intensity (thousand Btu per 2000 dollar of GDP)	**9.73**	**9.47**	**8.51**	**7.78**	**7.13**	**6.57**	**-1.6%**
Carbon dioxide emissions (million metric tons)	**5,751**	**5,789**	**6,627**	**7,052**	**7,520**	**8,062**	**1.5%**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.
Source: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by the EIA are required to be policy-neutral, the projections in this *AEO2005* generally are based on Federal and State laws and regulations in effect on or before October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Examples of Federal and State legislation incorporated in the projections include the following:

- The National Appliance Energy Conservation Act of 1987
- The Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The Energy Policy Act of 1992 (EPACT)
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy production tax credit (PTC) to include geothermal and solar generation technologies
- The Military Construction Appropriations Act of 2005, which includes provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent PTC for wind and closed-loop biomass to December 31, 2005; tax deductions for qualified clean-fuel and electric vehicles; and changes in the rules governing oil and gas well depletion
- State of Alaska's Right-Of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002
- State programs for restructuring of the electricity industry.

AEO2005 assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2003 levels in nominal terms. *AEO2005* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2005* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2005* include the following:

- Standards for energy-consuming equipment that have been announced, including the 13 seasonal energy efficiency ratio (SEER) [*2*] for new central air conditioners and heat pumps that were recently reestablished by the U.S. Court of Appeals after originally being set in January 2001
- The new corporate average fuel economy (CAFE) standards for light trucks published by the National Highway Traffic Safety Administration (NHTSA) in 2003
- Federal Energy Regulatory Commission (FERC), Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore LNG terminals
- The new boiler limits established by the U.S. Environmental Protection Agency (EPA) on February 26, 2004, which limit emissions of hazardous air pollutants from industrial, commercial, and institutional boilers and process heaters by requiring that they comply with a Maximum Achievable Control Technology (MACT) floor.

AEO2005 includes the CAAA90 requirement of a phased-in reduction in vehicle emissions of regulated pollutants. In addition, *AEO2005* incorporates the CAAA90 requirement of a phased-in reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. *AEO2005* also incorporates nitrogen oxide (NO_x) boiler standards issued by the EPA under CAAA90. The 19-State NO_x cap and trade program in the Northeast and Midwest is also represented. Limits on emissions of mercury, which have not yet been promulgated, are not represented.

AEO2005 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000 under CAAA90. The Tier 2 standards for reformulated gasoline (RFG) were required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2005* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and a 100-percent requirement for ULSD thereafter (see Appendix F for more details). It also includes the new rules for nonroad diesel issued by the EPA on May 11, 2004, regulating nonroad diesel engine emissions and sulfur content in fuel. The *AEO2005* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The *AEO2005* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

More detailed information on recent legislative and regulatory developments is provided below.

13 SEER Standard for Central Air Conditioners and Heat Pumps

In January 2004, after years of litigation in a case that pitted environmental groups and Attorneys General from 10 States against the U.S. Secretary of Energy, the U.S. Court of Appeals for the Second Circuit reestablished the central air conditioner and heat pump standard originally set in January 2001 [*3*]. The Court's ruling, which struck down a May 2002 rollback of the 2001 standard to a 12 SEER, mandates that all new central air conditioners and heat pumps meet a 13 SEER standard by January 2006, requiring a 30-percent increase in efficiency relative to current law. The *AEO2005* reference case incorporates the 13 SEER standard as mandated by the Court's ruling.

In order to gauge the impact of the new standard on electricity consumption, consumer expenditures, and carbon dioxide emissions, a sensitivity case assuming a continuation of the previous 12 SEER standard was modeled. Table 2 shows the impacts of the 13 SEER standard assumed in the reference case, as compared with the 12 SEER standard assumed in the sensitivity case. As expected, the projections for electricity consumption and expenditures are lower in the reference case than in the 12 SEER case; however, the savings come at an additional cost to consumers. Through 2015 the additional costs of new equipment outweigh savings, resulting in a negative net present value for the 13 SEER standard (assuming a 7-percent real discount rate). In the long run, however, additional years of savings per unit provide a positive ($3.6 billion) net present value, meaning that the standard, on average, provides economic benefits to consumers in the form of reduced energy expenditures.

Table 2. Impacts of 13 SEER central air conditioner and heat pump standard compared with 12 SEER standard, 2006-2025

Projection	2015	2025	Cumulative 2006-2015	Cumulative 2006-2025
Electricity consumption savings (billion kilowatthours)	*11.1*	*16.6*	*59.6*	*211.7*
Energy bill savings (billion 2004 dollars)	*0.8*	*0.7*	*5.7*	*12.6*
Equipment cost increase (billion 2004 dollars)	*0.5*	*0.2*	*5.8*	*8.9*
Net present value (billion 2004 dollars)	—	—	*-0.1*	*3.6*
Increase in air conditioner stock efficiency (percent)	*5.6*	*6.8*	—	—
Carbon dioxide emissions reduction (million metric tons)	*1.1*	*-3.6*	*7.8*	*1.0*

The difference between projected carbon dioxide emissions in the two cases depends on the fuel mix associated with the electricity generation. In the near term, the reduction in electricity demand in the reference case is not large enough to change the pattern of capacity additions or fuel mix, and lower electricity demand causes a decrease in carbon dioxide emissions both in 2015 and cumulatively from 2006 to 2015 (Table 2). In later years, the amount of peak demand relative to baseload demand is lower in the reference case, and more coal-fired capacity is added at the expense of natural gas capacity. The change in fuel mix causes carbon dioxide emissions to increase, despite slightly lower levels of electricity demand. Emissions in 2025 are 3.6 million metric tons (0.2 percent) higher in the reference case, but cumulative emissions from 2003 through 2025 are 1.0 million metric ton lower than in the 12 SEER case (1 metric ton is equal to 1,000 kilograms).

Maximum Achievable Control Technology for New Industrial Boilers

As part of CAAA90, the EPA on February 26, 2004, issued a final rule—the National Emission Standards for Hazardous Air Pollutants (NESHAP)—to reduce emissions of hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers and process heaters [*4*]. The rule requires industrial boilers and process heaters to meet limits on HAP emissions to comply with a MACT "floor level" of control that is the minimum level such sources must meet to comply with the rule. The major HAPs to be reduced are hydrochloric acid, hydrofluoric acid, arsenic, beryllium, cadmium, and nickel. The EPA predicts that the boiler MACT rule will reduce those HAP emissions from existing sources by about 59,000 tons per year in 2005 [*5*].

The MACT standards apply to major sources of HAPs, or units that emit or have the potential to emit a single HAP at 10 tons or more per year or a combination of HAPs at 25 tons or more per year. The EPA estimates that 58,000 existing boilers and process heaters and 800 new boilers and process heaters built each year over the next 5 years will be subject to the rule. Existing boilers and process heaters must comply with the rule no later than 3 years after it is published in the *Federal Register*. In addition, the owners of existing units may petition for an extra year to comply. New boilers and process heaters must comply when they are brought on line. The final rule provides flexibility in compliance through averaging of emissions from multiple units on a single site and lowering of emissions by altering work practices, installing control devices, or physically removing toxics. Fuel switching is not an available option to meet the MACT floor level, because it may increase emissions of some HAPs while reducing the emissions of others.

The industries most affected by the rule will be furniture, paper, lumber, and electrical services, which together account for nearly 60 percent of the affected units. The EPA estimates the total nationwide capital costs for the final rule to be $1.4 billion to $1.7 billion over the first 5 years, with annualized costs between $690 million and $800 million.

New boilers are expected to meet the standards in the absence of the rule, and retrofit costs are anticipated to be relatively small in aggregate. Consequently, inclusion of the rule does not materially affect the *AEO2005* projection for the industrial sector.

Clean Air Nonroad Diesel Rule

On June 29, 2004, the EPA issued a comprehensive final rule regulating emissions from nonroad diesel engines and sulfur content in nonroad diesel fuel [*6*]. The nonroad fuel market makes up more than 18 percent of the total distillate pool. The rule applies to new equipment covering a broad range of engine sizes, power ratings, and equipment types. There are currently about 6 million pieces of nonroad equipment operating in the United States, and more than 650,000 new units are sold each year.

The rulemaking covers such equipment as tractors, bulldozers, graders, backhoes, heavy construction, mining, and logging equipment, airport tugs, locomotives, and commercial marine vessels. The regulations represent a tiered emissions reduction approach based on engine horsepower, with phased-in restrictions on emissions of particulate matter (PM), NO_x, and nonmethane hydrocarbons. The rule reduces diesel engine emissions by more than 90 percent and fuel sulfur content by 99 percent from current levels.

The regulation addresses emissions and fuels simultaneously to maximize emission reductions by integrating engine and fuel controls as a system. To meet the standards, engine manufacturers will be required to produce new engines with advanced emission control technologies similar to those already expected for on-road (highway) heavy trucks and buses. Refiners will be supplying new lower sulfur diesel fuels in both cases.

Emission Standards

By 2014, the new Tier 4 regulations will require nonroad diesel engines to cut emissions of pollutants by more than 90 percent [7]. Standards for new engines will be phased in starting with the smallest engines in 2008 until all but the very largest diesel engines meet both NO_x and PM standards in 2014 (Table 3). Some of the largest engines (750-plus horsepower) will have one additional year to meet the emissions standards.

The final rule includes flexibility provisions aimed at helping small engine manufacturers meet the requirements. The EPA Tier 4 standards do not require retrofitting older diesel engines currently in service and do not apply to diesel engines used in locomotives and marine vessels, but they do cover fuel requirements for those equipment categories.

In a separate action, the EPA took the first step toward proposing new emissions standards for diesel engines by issuing an Advanced Notice of Proposed Rulemaking on June 29, 2004 [8]. Contemplated standards would apply to marine diesels used in all new commercial, recreational, and auxiliary marine diesel engines except for very large engines used for propulsion of deep-sea vessels. For locomotives, both new and existing diesel units would require advanced emission control technologies similar to those for heavy-duty trucks and buses. The widespread availability of clean nonroad diesel fuel required under the new fuel standards will enable the use of advanced control technology on locomotive and marine engines.

The EPA estimates that anticipated compliance costs will vary with the size and complexity of equipment, in the range of 1 to 3 percent of total purchase price for most categories of nonroad diesel equipment [9]. The new nonroad diesel emission standards, when fully implemented, are expected to provide significant public health benefits.

Fuel Standards

The final rule, to be implemented in multiple steps, requires sulfur content for all nonroad locomotive and marine (NRLM) diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. It also establishes a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the action establishes a ULSD limit of 15 ppm in mid-2012, providing the refining industry flexibility to align fuel supply operations with all other on-road and nonroad ULSD fuel regulations, which take effect in mid-2010. After refiners, the new standards will apply to terminals, wholesalers, retailers, and end users in subsequent months as production flows through the distribution chain.

The nonroad diesel requirements have implications for the refining industry and, especially, for small refiners (defined as having less than 155,000 barrels per day of crude oil charge capacity and less than 1,500 corporate employees). Approximately 20 refiners fall into the small refiner category. They are dispersed across the country, with the largest concentration located in the Rocky Mountain Region. Small refiners are granted three additional years to meet the 500 ppm standard for NRLM diesel, starting in mid-2007 (Table 4). The challenges facing small refiners include additional time needed to secure capital funding, a need for longer leadtimes because of limited engineering expertise, and limits on the availability of contractors, who will be performing upgrades for major refiners.

Table 3. Final nonroad diesel emissions standards

Rated engine power	First year of standards or phase-in period	Particulate matter (grams per horsepower per hour)	Nitrogen oxides (grams per horsepower per hour)
Less than 25 horsepower	2008	0.30	—
25 to less than 75 horsepower	2013	0.02	3.5
75 to less than 175 horsepower	2012-2013	0.01	0.30
175 to less than 750 horsepower	2011-2013	0.01	0.30
750 horsepower or more	2011-2014	0.075	2.6 and 0.50
	2015	0.02 and 0.03	0.50

Note: Where a range of years is provided, 40 CFR 1039.102 prescribes a gradual phase-in whereby a cumulative percentage of total engines for a manufacturer must comply each year prior to the final year.

Table 4. Timeline for implementing nonroad diesel fuel sulfur limits

Fuel type and refiners	Mid-2007	Mid-2010	Mid-2012	Mid-2014 and after
Nonroad diesel				
Refiners other than small	500 ppm	15 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	15 ppm	15 ppm
Locomotive and marine diesel				
Refiners other than small	500 ppm	500 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	500 ppm	15 ppm

For early or overcompliance with the fuel sulfur standards, a regional averaging, banking, and trading program will be created; however, credits may not be used or traded for use outside the credit trading region in which they are generated [*10*]. For the 500 ppm standard beginning in mid-2007, small refiners outside the Northeast/Mid-Atlantic area can use credits to continue producing high-sulfur nonroad fuel until the credits expire in mid-2010. After mid-2014, small refiners must comply with the 15 ppm standard for NRLM diesel.

The rule recognizes certain exceptions. For Alaska, NRLM diesel covers only areas served by Federal highways. Rural and remote areas are not required to convert to ULSD until 2011. For stationary power sources, the rule excludes No. 4, 5, and 6 heavy distillates. In special marine situations, giant Category 3 ocean ship engines face a separate regulation expected by April 2007. Category 2 or 3 marine diesel engines using distillate with a distillation point over 700°F are excluded.

There are also special exceptions for transmix facilities on pipelines [*11*]. Because transmix facilities do not have sulfur removal equipment to clean up pipeline interface mixes, the final rule provides that they may produce fuels for sale into the NRLM markets that meet small refiner provisions, in order to avoid the burden of additional investment in treating equipment or returning mix to refineries for reprocessing. After the NRLM small refiner provisions expire in 2014, transmix processors may continue to sell 500 ppm fuel into the locomotive and marine market.

The rule also prescribes certain dyeing, tracking, and record keeping requirements to ensure that fuel is not diverted from authorized channels and that taxes are properly paid. The Internal Revenue Service ordinarily requires that fuel used in NRLM engines be dyed before leaving the terminal, to indicate its nontaxed status. Fuels that meet on-road diesel specifications but are destined for NRLM markets can leave the terminal undyed, provided that the tax is paid first. NRLM users can then apply for a tax refund. To minimize misfueling, a system of labels is prescribed on diesel retail pumps, fuel tank inlets, and dashboard and instrument panels, corresponding with the introduction of new diesel engines and equipment.

The EPA did not specify lubricity standards in the rule, because the industry has been working to finalize a universal standard for all diesel fuel. If the American Society for Testing and Materials does not establish a universal lubricity standard, a separate rulemaking applying to lubricity additives will be issued by the EPA.

Impacts of the Emission and Fuel Standards

The effects of the new NRLM diesel standards are represented in *AEO2005*. The National Energy Modeling System (NEMS) has been revised to reflect the nonroad rule and recalibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil and excluding jet fuel and kerosene). The nonroad rule, following closely on the heels of the highway diesel rule, represents an incremental tightening of the entire diesel pool that will cause demand for high-sulfur distillate to diminish over time while demand for ULSD (both highway and NRLM) increases.

After 2007, during the rule's implementation, the projections for refinery distillate production are slightly lower with the rule in place because of the more stringent and costly processing requirements, and imports of distillate are higher. For the composite distillate market, prices are slightly higher with the rule in place and vary by sector. Table 5 shows key projections for distillate fuel prices, production, and imports in the *AEO2005* reference case, which includes the new nonroad diesel rule, and in a sensitivity case that does not include the new rule.

Because heating oil is not subject to NRLM diesel rules, residential distillate prices are not expected to be affected significantly. Eventually, however, residential prices are projected to parallel those in other sectors as the distillate market converges toward a universal ULSD standard. More than two-thirds of all high-sulfur distillate use after 2010 is projected to be concentrated in the Northeast.

In the commercial and industrial sectors, distillate fuel prices after 2010 are projected to be higher with the rule in place. Nonroad diesel is a relatively small portion of commercial distillate use, but it dominates industrial use. Thus, the price impact is greater for the industrial sector. For the electric power sector there is little or no projected impact on distillate prices. Diesel prices in the transportation sector are projected to be about 2 cents per gallon higher in 2010-2012 because of the nonroad diesel sulfur reduction and about 3 cents per gallon higher in 2014, when the sulfur content of all NRLM diesel fuel is reduced to 15 ppm.

EPA estimates [*12*] place the added cost of ULSD for NRLM diesel use in the range of about 7 cents per gallon; however, the EPA expects the added cost to be offset by reduced engine maintenance expenses, lowering the net incremental impact to about 4 cents per gallon. The EPA estimates assume complete turnover of nonroad diesel engines by 2030.

American Jobs Creation Act of 2004

The American Jobs Creation Act of 2004 [*13*] was signed into law on October 22, 2004. Most of the 650 pages of the Act are related to tax legislation. Provisions pertaining to energy are described below.

Diesel Excise Taxes

Section 241 phases out an excise fuel tax of 4.3 cents per gallon on railroads and inland waterway transportation incrementally between January 1, 2005, and January 1, 2007. Under current law, diesel fuel used in trains and fuels used in barges on certain inland waterways are subject to an excise tax of 4.4 cents per gallon. Revenues from 4.3 cents of the tax are retained in the General Fund. The remaining 0.1 cent is put in the Leaking Underground Storage Tank Fund, which is scheduled to expire on March 31, 2005. *AEO2005* reflects the phaseout of these excise taxes.

Ethanol Tax Credits

Section 301 establishes the Volumetric Ethanol Excise Tax Credit (VEETC). Before this Act, gasoline blenders could choose between an income tax credit of 51 cents per gallon of ethanol blended or a reduced rate of Federal excise tax on each gallon of gasoline blended with ethanol. Thus, gasoline containing 10 percent ethanol would be taxed at 13.2 cents per gallon instead of the usual 18.3 cents per gallon in calendar year 2005. Gasoline blended with 5.7 percent or 7.7 percent ethanol would receive a proportionally smaller reduction in the excise tax. The VEETC is instead assessed at a rate of 51 cents per gallon of ethanol, and the entire excise tax is assessed on the finished gasoline. This gives several advantages over the existing structure. VEETC applies to any blend of ethanol and gasoline. It also applies to ethyl tertiary butyl ether (ETBE), a gasoline blending component made from ethanol. The excise tax exemption does not apply to blends containing less than 5.7 percent or more than 10 percent ethanol, such as E85. The income tax credit can be taken for ethanol used in such blends or to make ETBE, but not all gasoline blenders have sufficient Federal income tax liability to take the credit. The VEETC is effective through 2010; the excise tax reduction will expire in 2007. This section also extends the alcohol income tax credit through 2010. *AEO2005* includes these tax credits and, in addition, assumes that they will remain in force indefinitely, given that historically they have been extended when they expired.

Biodiesel Tax Credits

The VEETC also applies to biodiesel blends. A diesel fuel blender can claim a credit of $1 per gallon of biodiesel made from agricultural commodities such as soybean oil and can claim a credit of 50 cents per gallon of biodiesel made from recycled oil such as yellow grease. Section 302 extends income tax credits for biodiesel blending similar to the alcohol income tax credits. The VEETC provision for biodiesel and the biodiesel income tax credits expire after 2006. Section 302 is modeled in the *AEO2005* reference case.

Rural Electric Cooperatives Income Treatment

Current law gives tax-exempt status for rural electric cooperatives if at least 85 percent of the cooperative's income comes from amounts collected from members for the sole purpose of meeting losses and expenses

Table 5. Key projections for distillate fuel markets in two cases, 2007-2014

		Projections							
		2007		2010		2012		2014	
Supply and prices	2003	Reference case	No NRLM rule case	Reference case	No NRLM rule case	Reference case	No NRLM rule case	Reference case	No NRLM rule case
Distillate prices (2003 cents per gallon)									
Residential	132.7	120.4	120.5	114.9	114.2	115.1	115.8	117.0	117.0
Commercial	97.3	90.3	90.2	86.9	84.4	88.5	85.6	89.2	86.2
Industrial	100.2	94.2	93.8	93.3	86.9	98.3	88.0	98.5	89.1
Transportation	150.4	151.0	150.6	147.5	145.5	148.1	145.8	147.1	144.2
Electric Power	89.8	81.3	81.5	74.4	73.8	74.5	75.1	75.9	76.7
Composite	136.7	134.4	134.1	131.0	128.6	132.8	129.6	133.5	129.2
Distillate supply (million barrels per day)									
Refinery production	3.76	4.21	4.20	4.64	4.65	4.76	4.87	4.93	5.07
Imports	0.22	0.41	0.41	0.31	0.29	0.34	0.22	0.33	0.19

incurred in providing service to those members. Section 319 provides that, under certain actions approved or accepted by the FERC, gains realized by a rural electric cooperative from a voluntary exchange or involuntary conversion of certain property are excluded in determining whether that cooperative meets the 85-percent test. This provision applies only to the extent that the gain would qualify for deferred recognition under tax laws or the replacement property is used to generate, transmit, distribute or sell electricity or natural gas. This provision represents a level of detail that is not characterized in NEMS.

Low-Sulfur Diesel Fuel Production Credit

Sections 338 and 339 contain provisions allowing small business refiners a 25-percent credit for production of ultra-low-sulfur diesel fuel (15 parts sulfur per million or less), with additional provisions for expensing the remaining 75 percent of the capital investment. Current law does not provide a credit for the production of low-sulfur diesel fuel. The Act allows a small business refiner to claim a credit at a capture rate equal to about 5 cents per gallon for each gallon of low-sulfur diesel fuel produced in compliance with the Highway Diesel Fuel Sulfur Control Requirements law. The credit is a qualified business credit under Section 169(c) of the Act. The existing carry-back and carry-forward provisions for a qualified business credit apply [*14*]. The effective date for this provision is December 31, 2002.

Taxpayers may currently recover the cost of investments in refinery property through annual depreciation deductions. A separate expensing provision permits small business refiners to deduct as an expense up to 75 percent of the costs paid or incurred in making upgrades to comply with the EPA's Highway Diesel Fuel Sulfur Control Requirements.

Small business refiners (up to 205,000 barrels per day and up to 1,500 employees in refining) can claim a tax credit of up to 25 percent of the capital investment costs incurred since 2003 for producing ultra-low-sulfur diesel. Most of the credit would result from refining the first 155,000 barrels per day, with *pro rata* credits for the next 50,000 barrels. The credit expires 1 year after EPA's applicable ultra-low-sulfur diesel deadline or by the end of 2009. Because NEMS does no model individual companies, these tax provisions are not included in the *AEO2005* reference case.

Marginal Wells Tax Credit

Section 341 creates a new tax credit of up to $3 per barrel for the production of crude oil and a credit of up to $0.50 per thousand cubic feet for the production of natural gas from qualified marginal wells. A marginal well is defined as one that produces less than 25 barrels per day of oil equivalent and produces water at a rate not less than 95 percent of total well effluent. Full credit is provided to such marginal wells at reference prices less than or equal to $15 per barrel for oil and $1.67 per thousand cubic feet for natural gas [*15*]. The credit declines linearly to zero when reference prices, adjusted for inflation, reach $18 per barrel of oil and $2 per thousand cubic feet of natural gas. The tax credit applies to the first 1,095 barrels of oil equivalent produced, and the limit is reduced in proportion to the numbers of days in the taxable year for which the well is not in production. The tax credit takes effect in taxable years beginning after December 31, 2004. Because NEMS does not contain a separate marginal well category, the impact of this legislative provision is not quantified in *AEO2005*.

Green Building Bonds

Section 701 contains a brownfields demonstration program that provides tax-exempt status for facility bonds issued to finance qualified "green" buildings and sustainable design projects. The program, designed to encourage the use of solar photovoltaic and fuel cell generation, applies to bonds issued from January 1, 2005, through December 31, 2009; however, projects must be nominated by a State or local government and meet several criteria in addition to the specific green or sustainable criteria. For example, eligible projects must include a brownfields site, be of a certain size, provide a certain level of employment, not include a sports stadium or restaurant, and receive State or local government resources of at least $5 million. Because of the process involved and the site- and company-specific nature of the provision, it is not characterized in the *AEO2005* reference case.

Tax Incentives for Alaska Natural Gas Pipeline and Gas Processing Facilities

Section 706 provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. The expected return on equity for the pipeline was lowered to reflect this provision in *AEO2005*.

Section 707 extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide (CO_2) for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision would be effective for costs incurred after 2004. For *AEO2005*, lowering the expected charges for gas treatment on the North Slope captured this provision.

Extension and Expansion of the Production Tax Credit for Renewable Electricity

Section 710 expands application of the renewable electricity PTC to wind, closed-loop biomass, and poultry-litter plants in service by December 31, 2005 [*16*]. Eligibility for a modified PTC is also extended to geothermal, solar, small irrigation hydropower, open-loop biomass, municipal solid waste, and landfill gas facilities, also with a December 31, 2005, in-service date. This change has been incorporated in *AEO2005*.

Modified Alternative Minimum Tax Rules for the PTC and Alcohol Fuels Tax Credit

The law exempts the alcohol fuel tax credit (Section 40 of the Internal Revenue Code) and the first 4 years of the PTC (Section 45 of the Internal Revenue Code) from tax liability under the Alternative Minimum Tax (AMT), allowing businesses with AMT liability to recover the full value of the affected tax credits. This provision is not included in the *AEO2005* reference case, because EIA assumes that these tax credits are generally able to be used at full value.

Section 45 Tax Credit for Coal Products

The refined coal provisions in Section 710 establish Section 45 tax credits for producers of qualified refined coal products. The refined product must be at least 50 percent higher in market value than the coal or high-carbon fly ash feedstock, and combustion of the refined product must result in 20 percent less emissions of NO_x and either SO_2 or mercury than the feedstock. The refined coal must be sold for the purpose of creating steam. This provision represents a level of detail that is not characterized in NEMS.

Alcohol Alternative Minimum Tax

Section 711 allows the alcohol income tax credit, biodiesel income tax credit, and small ethanol producer income tax credit to offset liability under the AMT. The small ethanol producer credit applies only to firms with capacity of 15 million gallons per year or less. Because NEMS does not model individual tax obligations, these changes are not incorporated in the *AEO2005* reference case.

Suspension of Duties on Nuclear Steam Generators and Reactor Vessel Heads

Section 714 extends from January 31, 2006, to January 31, 2008, the period in which nuclear steam generators can enter the United States duty-free. The law allows nuclear reactor vessel heads to enter the United States duty-free through January 31, 2008, suspending the current 3.3-percent duty. This provision represents a level of detail that is not characterized in NEMS.

Disposition of Transmission Property to Implement FERC Restructuring

Section 909 allows companies to spread capital gains from the sale of transmission assets over 8 years. This provision applies to property sold by a utility to comply with FERC electricity market restructuring efforts. Money from the sale must be used to buy reinvestment property within 4 years of the initial transaction. This restructuring provision is not incorporated in the *AEO2005* reference case.

Tax Evasion Provisions

Subtitle C, Part III, of Title VIII of the Act contains 21 provisions related to fuel tax evasion. Some of the more pertinent provisions and economic impacts are described below. Because NEMS does not model oil and gas income statements, these changes are not incorporated into *AEO2005*.

- Section 853 relates to taxation of aviation-grade kerosene and moves the point of taxation of aviation fuel to the supply rack. Fuel used in commercial aviation that is removed from any refinery or terminal and placed directly into the fuel tank of an aircraft for use in commercial aviation will be taxed at 4.3 cents per gallon. The regulation also stipulates that certain refueler trucks, tankers, and tank wagons be treated as part of a terminal. The person who uses the fuel for commercial aviation will be liable for and pay the tax. These regulations apply after December 31, 2004, and have no stated expiration date.
- Sections 860 and 861 provide clarifications and requirements for exemptions from taxes imposed on the removal of taxable fuel from any refinery or terminal. These amendments take effect on March 1, 2005. Exemptions were already allowed for bulk transfers to registered terminals or refineries. Section 860 clarifies that the transfer must occur by pipeline or vessel. Clarification is provided for the registration of such pipelines or vessels, the requirement to display proof of

registration, and the penalties for failure to display registration.

- Section 870 covers tax refunds for re-refined transmix [*17*] and diesel fuel blendstocks that were previously taxed. This amendment applies to fuel removed, sold, or used after December 31, 2004, and it has no stated expiration date. The Act redefines diesel fuel contaminated with transmix as a taxable diesel fuel if it is suitable for use in a highway vehicle or train. If the fuel is re-refined and then sold into nonroad markets (tax-free), it can qualify for tax refunds.

Working Families Tax Relief Act of 2004

The Working Families Tax Relief Act of 2004 [*18*] was signed into law on October 13, 2004. Primarily, the Act reduces taxes for individuals and businesses. At least two provisions relate to energy.

Depletion of Marginal Properties

Section 314 extends to oil and gas an exemption for marginal properties from the 100 percent of net income limitation on the percentage of assets that can be depleted in a year for tax purposes. In computing taxable income, oil and gas producers generally receive a reasonable allowance for depletion and for depreciation of improvements, based on the amount of resource extracted. Under current law, the deduction cannot exceed 100 percent of taxable income from the property (computed without allowance for depletion). An exemption from the limitation, allowing the deduction to exceed 100 percent of taxable income for production from marginal properties expired on December 31, 2003.

This provision extends the exemption to January 1, 2006. The exemption is applicable only to "marginal production," which is defined as production coming from property that is a stripper well property or a property from which substantially all the production is heavy oil (weighted average gravity of 20 degrees API or less). A stripper well property is a property from which the average production per well is less than 15 barrels of crude oil equivalent per day. Because production from stripper well properties and production of heavy oil are not projected separately from total oil and gas production in the EIA modeling framework, the impact of this provision is not quantified in *AEO2005*.

Qualified Vehicles

Sections 318 and 319 repeal the phaseout of credits allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. For vehicles acquired in 2006, the 2004 and 2005 credits of $2,000 for clean fuel vehicles and $4,000 for electric vehicles are reduced by 75 percent. This provision is not included in *AEO2005*.

Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005

H.R. 4837, The Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005 [*19*], was signed into law on October 13, 2004. The Act provides for construction to support the operations of the U.S. Armed Forces and for military family housing. It also provides funds to help citizens in Florida and elsewhere in the aftermath of multiple hurricanes and other natural disasters. In addition, it authorizes construction of an Alaska Natural Gas Pipeline.

Alaska Natural Gas Pipeline Loan Guarantee

Section 116 gives the Secretary of Energy authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower 48 States. The authority would expire 2 years after the issuance of a final certificate of public convenience and necessity. In aggregate, the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction), (2) $18 billion dollars (indexed for inflation at the time of enactment), and (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The impact of the loan guarantee is reflected in *AEO2005* by a reduction of the expected return on debt and an increase in the percentage of pipeline costs financed through debt. Additional assistance related to the construction of the Alaska Natural Gas Pipeline is provided in the American Jobs Creation Act of 2004.

State Renewable Energy Requirements and Goals: Status Through 2003

As of the end of 2003, 15 States had legislated programs to encourage the development of renewable energy for electricity generation. Of the 17 programs (two States have multiple programs), 9 are renewable portfolio standards (RPS), 4 are renewable energy mandates, and 4 are renewable energy goals.

Renewable Portfolio Standards

The type of program used most frequently by the States is an RPS requiring that some specified percentage of electricity supply be provided by qualifying renewable energy sources (Table 6). Most State RPS programs were initiated when privately owned electric utilities were being deregulated, in order to ensure their continued investment in renewables.

Key differences among the State RPS programs include their definitions of qualifying renewables, alternatives to new renewable capacity, approaches to cost recovery, opt-out provisions, and enforcement mechanisms. For example, RPS definitions of qualifying renewable technologies vary widely among the States. Landfill gas, solar thermal electric, solar photovoltaic, and wind energy are acceptable in all nine RPS States, but the rules vary for other technologies. Some also include alternatives to new capacity, such as natural-gas-powered fuel cells or solar thermal water heating. Some favor certain renewable energy technologies, especially solar, by offering more than one credit per kilowatthour. This practice may stimulate favored technologies but reduce the effective size of the RPS if they are developed.

The States use several approaches for funding their RPS programs, including passing the higher costs directly to all utility ratepayers, applying charges on selected categories of sales, or encouraging voluntary purchases through "green power" programs. Most call for reducing or delaying RPS requirements if costs are excessive ("cost-outs"). They may also reduce or eliminate RPS requirements for non-cost reasons, such as if the entities are deemed not creditworthy or if existing contracts meet all the utility's requirements.

Most State RPS programs do not appear to have specific enforcement procedures, except for revoking operating licenses. Some provide for cost penalties for unmet requirements, payments into research and development funds, fines, and other sanctions; however, collaboration and cooperation appear to be the preferred enforcement tools. Through the end of 2003, no electric utility in any State had incurred a penalty for noncompliance with a State RPS.

Mandates

Four States have mandates that narrowly specify the new renewable capacity required (Table 6). Iowa's 1983 mandate, the oldest, ordered its three investor-owned utilities to develop 105 megawatts of new renewable energy capacity, with each utility's share based on its share of peak demand. Minnesota's 1994 mandate required Xcel Energy to acquire 425 megawatts of wind capacity by December 31, 2002, plus

Table 6. Basic features of State renewable energy requirements as of December 31, 2003

State	Part of deregulation	Initial year enacted	Beginning and last specified requirements	Accepts existing capacity	Out-of-State supply	Credit trading
Renewable Portfolio Standards						
Arizona	Yes	1996	0.2-1.1% of sales, 2001-2007	No	Solar only	Yes
California	No	2002	+1% of sales per year, to 20.0% by 2017	Yes	Yes	No
Connecticut	Yes	2003	6.5-10.0% of generation, 2003-2010	Yes	Yes	Yes
Maine	Yes	1997	30.0% of sales by 1999	Yes	Yes	Yes
Massachusetts	Yes	1997	1.0-4.0% of sales, 2003-2009	No	Yes	Yes
Nevada	No	2001	5.0-15.0% of sales, 2003-2013; 5% of requirements must be solar	Yes	Yes	Yes
New Jersey	Yes	1999	3.0-6.5% of sales, 2001-2008	Yes	Yes	Yes
New Mexico	No	2002	5.0-10.0% of sales, 2006-2011	Yes	Yes	Yes
Wisconsin	No	1999	0.5-2.2% of sales, 2001-2011	Yes	Yes	Yes
Mandates						
Iowa	No	1983	105 megawatts (no set date)	No	NS	No
Minnesota	No	1994	1,125 megawatts wind by 2010 + 125 megawatts biomass	No	Yes	No
Texas	No	1999	400-2,000 megawatts, 2003-2009	No	Yes	Yes
Wisconsin	No	1997	50 megawatts by 2000	No	No	No
Goals						
Hawaii	No	2001	9.0% of sales by 2010	Yes	NA	No
Illinois	No	2001	15.0% of sales by 2020	NS	No	No
Minnesota	No	2003	1.0-10.0% of sales, 2005-2015	NS	Yes	Yes
Pennsylvania	Yes	1998	Individual agreements with five utilities	NS	NS	NS

125 megawatts of biomass capacity, in exchange for storing additional nuclear waste at its Prairie Island plant. An additional 700 megawatts of new wind capacity has since been added to the mandate, some of which must come from small facilities (2 megawatts of capacity or less). The wind requirements are being met, but Minnesota's biomass requirements have not been met because of technological and financial difficulties. Additional legislation in 2003 requires a power purchase agreement for 10 to 20 megawatts of biomass energy, operational by 2005, at no more than $55 per megawatthour.

The 1999 renewable energy mandate in Texas requires the installation of 2,000 megawatts of new renewable generating capacity by 2009. The Texas mandate has resulted in more new renewable capacity than any other State-level requirement to date, including 1,180 megawatts of new wind capacity installed by the end of 2003 as well as small amounts of landfill gas and other renewable capacity. A fourth State, Wisconsin, in 1998 required four eastern utilities to install 50 megawatts of new renewable energy capacity by December 31, 2000, a requirement that was met by the utilities.

Voluntary Goals, Objectives, and Settlements

Four States—Hawaii, Illinois, Minnesota, and Pennsylvania—have instituted programs that encourage, but do not require, new renewable energy capacity (Table 6). Hawaii's 2001 goal resembles a typical RPS, except for the absence of penalties and the inability to obtain supplies from other States. Illinois in 2001 set targets for electricity production from qualified renewables; however, the goal is not supported by schedules, a menu of acceptable renewable technologies or alternatives other than solar and wind, compliance mechanisms, credit trading, or most of the other features of State RPS programs. In Minnesota, utilities other than Xcel are subject to the State's 2001 Renewable Energy Objective, which requires a "good faith effort" to increase renewable energy's contribution. The objective is considered a mandate for Xcel. In 1996, five Pennsylvania utilities settled restructuring cases on terms requiring a minimum percentage of renewables. Among these settlements, only the Pennsylvania Electric Company (PECO) energy program was implemented; however, the five utilities also established four sustainable energy funds that are reported to have supported development of significant amounts of new wind and other generating capacity.

Results

State renewable portfolio standards, mandates, and goals are all relatively new, with the majority just now entering their initial compliance years. Because of alternative compliance options and adjustments that would likely be made if renewable energy costs are found excessive in the future, it is difficult to assess the future impacts of these programs. Nevertheless, through the end of 2003, requirements or goals for new renewable energy capacity in 15 States has resulted in an estimated 2,335 megawatts of new renewable electricity supply (Table 7). Most of the new capacity is fueled by wind power (2,183 megawatts), with smaller amounts of landfill gas, hydroelectricity, biomass, and solar photovoltaic technologies. The 321 megawatts that entered service in the nine RPS States accounted for 14 percent of total new renewable energy capacity from RPS, mandates, and goals through 2003. State mandates—especially in Texas—have led to the development of 2,004 megawatts of renewable capacity, 86 percent of the total. Nearly 51 percent (1,186 megawatts) of all the new capacity was installed in Texas. Recognizing that States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new renewable energy capacity resulting from State RPS programs, mandates, and nonmandatory goals are reduced in *AEO2005*.

Update on State Air Emission Regulations That Affect Electric Power Producers

Several States have recently enacted air emission regulations that will affect the electricity generation sector. The regulations are intended to improve air quality in the States and assist them in complying with the revised 1997 National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulates. The affected States include Connecticut, Massachusetts, Maine, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oregon, Texas, and Washington. The regulations govern emissions of NO_x, SO_2, CO_2, and mercury from power plants.

Where firm compliance plans have been announced, State regulations are represented in *AEO2005*. For example, installations of SO_2 scrubbers and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) NO_x removal technologies associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. Overall, the *AEO2005* forecast includes 22 gigawatts of announced SO_2 scrubbers, 27 gigawatts of announced SCRs, and 3 gigawatts of announced SNCRs.

In addition to the existing regulations, Governor George Pataki of New York has announced proposed greenhouse gas reduction targets for the State of New York and has invited nine other States (Connecticut, Delaware, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont) to participate in a future "Northeast CO_2 cap and trade" program. The program requires only CO_2 trading among power plants but would also allow trading of other emissions allowances among power plants burning coal, natural gas, or oil. The first Commissioner-level meeting was held in September 2003, and a final agreement is expected to be in place by April 2005. Maryland and Pennsylvania are participating in discussions but have not committed to participation in the program.

Table 8 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the States that have enacted air emissions regulations more stringent than Federal regulations. State-level initiatives to limit greenhouse gas emissions without directly regulating the electricity generation sector, which are not discussed here, include the following: California law A.B. 1493, enacted in July 2002, which sets CO_2 pollution standards for 2009 model vehicles and those sold later (see "Legis.lation and Regulations,"page 27); Georgia's transportation initiative, which is focused on expanding the use of mass transit and other transportation sector measures; Minnesota's Releaf Program, which encourages tree planting as a way to reduce atmospheric CO_2 levels; Nebraska's carbon sequestration advisory committee, which proposes to sequester carbon through agricultural reform practices; North Carolina's program to develop new technologies for solid waste management practices that reduce emissions; RPS programs being adopted by several States (see discussion of State renewable energy requirements and goals, above); and Wisconsin's greenhouse gas emissions inventory.

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000, and revisions are being made on an ongoing basis. It limits SO_2 and NO_x emissions from all NO_x budget program (NBP) sources that are more than 15 megawatts or require fuel input greater than 250 million Btu per hour [*20*]. The regulation applies to the electricity generation sector, the cogeneration sector, and industrial units. The NO_x limit is 0.15 pound per million Btu of heat input. The SO_2 limit applies to NBP sources that are also Acid Rain Program sources, and

Table 7. Estimated capacity contributing to State renewable energy programs through 2003 (megawatts, nameplate capacity)

State	Biomass	Geo-thermal	Conven-tional hydro-electric	Landfill gas	Municipal solid waste	Ocean or tidal	Solar photo-voltaics	Wind	Other/ unknown	Total
Renewable Portfolio Standards										
Arizona	0	0	0	5	0	0	9	0	0	**14**
California	0	0	20	6	0	0	0	175	0	**201**
Connecticut	0	0	0	0	0	0	0	0	0	**0**
Maine	0	0	0	0	0	0	0	0	0	**0**
Massachusetts	0	0	0	8	0	0	0	1	0	**9**
Nevada	0	0	0	0	0	0	0	0	0	**0**
New Jersey	0	0	0	0	0	0	0	0	0	**0**
New Mexico	0	0	0	0	0	0	0	0	0	**0**
Wisconsin	0	0	0	3	0	0	0.02	94	0	**97**
Mandates										
Iowa	16	0	0	0	0	0	0	237	7	**260**
Minnesota	25	0	0	0	0	0	0	476	0	**501**
Texas	5	0	10	31	0	0	0.2	1,140	0	**1,186**
Wisconsin	7	0	0	0	0	0	0	50	0	**57**
Goals										
Hawaii	0	0	0	0	0	0	0	0	0	**0**
Illinois	0	0	0	0	0	0	0	0	0	**0**
Minnesota	0	0	0	0	0	0	0	0	0	**0**
Pennsylvania	0	0	0	0	0	0	0	10	0	**10**
Total	**53**	**0**	**30**	**53**	**0**	**0**	**9.22**	**2,183**	**7**	**2,335**
Share of Total	**2.3%**	**0%**	**1.3%**	**2.3%**	**0%**	**0%**	**0.4%**	**93.5%**	**0.3%**	**100.0%**

the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [*21*].

In May 2003, the Connecticut General Assembly passed legislation (Connecticut Public Act 02-64) requiring coal-fired power plants to remove 90 percent of the mercury from smokestack emissions (or a maximum of 0.6 pound of mercury emitted per trillion Btu input, which is equivalent to 0.005 to 0.007 pound per gigawatthour) by July 2008. The legislature has recommended that the State Department of Environmental Protection consider stricter limits by July 2012 [*22*].

Table 8. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	Activities	Emissions limits
Connecticut	Regulations for electric utility, industrial cogeneration, and industrial units	
	SO_2 emissions Phase I limit by 2002	0.55 pound per million Btu input
	SO_2 emissions Phase II limit by 2003	0.33 pound per million Btu input
	NO_x limit	0.15 pound per million Btu input
	Mercury emissions limit by July 2008	90% removal (or maximum of 0.6 pound mercury emitted per trillion Btu input, equivalent to 0.005-0.007 pound mercury per gigawatthour)
Maine	Regulation for greenhouse gas emissions reduction from all sectors	
	Greenhouse gas emissions by 2010	At 1990 levels
	Greenhouse gas emissions by 2020	10% below 1990 levels
	Greenhouse gas emissions in the "long term"	75% to 80% below 2003 levels
Massachusetts	Multi-pollutant cap for existing power plants	
	SO_2 emissions in 1999: 6.7 pounds per megawatthour	
	SO_2 cap 2004 or 2006 (depending on compliance strategy)	6.0 pounds per megawatthour
	SO_2 cap 2006 or 2008 (depending on compliance strategy)	3.0 pounds per megawatthour
	NO_x emissions in 1999: 2.4 pounds per megawatthour	
	NO_x cap 2004 or 2006 (depending on compliance strategy)	1.5 pounds per megawatthour
	CO_2 emissions (current): 2,200 pounds per megawatthour	
	CO_2 cap 2006 or 2008 (depending on compliance strategy)	1,800 pounds per megawatthour
	Mercury emissions cap, Phase I, January 2008	85% removal from 2004 levels or 0.0075 pound per gigawatthour
	Mercury emissions cap, Phase II, October 2012	95% removal from 2004 levels or 0.0025 pound per gigawatthour
Missouri	Summer NO_x regulations by May 2004	0.18 to 0.35 pound per million Btu input
New Hampshire	Regulation for existing fossil-fuel power plants	
	SO_2 emissions in 1999: 48,000 short tons	
	SO_2 cap 2006	7,289 short tons
	NO_x emissions in 1999: 9,000 short tons	
	NO_x cap 2006	3,644 short tons
	CO_2 emissions in 1990: 5,426 thousand short tons	
	CO_2 emissions in 1999: 5,594 thousand short tons	
	CO_2 cap 2006	5,426 thousand short tons
New Jersey	Greenhouse gas emissions in 1990: 136 million metric tons carbon dioxide equivalent	
	Greenhouse gas emissions 2005	3.5% below 1990
New York	Regulations for electric utilities, cogenerators, and industrial units	
	SO_2 Phase I limit January 2005, 25% below allocation	197,046 short tons
	SO_2 Phase II limit January 2008, 50% below allocation	131,364 short tons
	NO_x limit beginning in October 2004 (October 1 to April 30 cap)	39,908 short tons
North Carolina	Regulations for existing coal-fired plants only	
	SO_2 emissions in 1999: 429,000 short tons	
	SO_2 cap 2009	250,000 short tons
	SO_2 cap 2013	130,000 short tons
	NO_x emissions in 1999: 178,000 short tons	
	NO_x cap 2009	56,000 short tons
Oregon	CO_2 regulation for new or expanded power plants	675 pounds per megawatthour
Texas	Senate Bill 7, SO_2 and NO_x caps for grandfathered sources	
	SO_2 cap 2003	595,000 short tons
	NO_x cap 2003	302,000 short tons
Washington	CO_2 regulations for new fossil-fueled power plants	20% reduction over 30 years

In addition, Connecticut enacted a law in June 2004 called "An Act Concerning Climate Change," Public Act No. 04-252. The goal of the legislation is to reduce emissions of greenhouse gases from sources in Connecticut to 1990 levels by 2010 and to 10 percent below 1990 levels by 2020, and it establishes a process to determine reduction goals beyond 2020. The Act covers electricity generators, fleet vehicles, industrial facilities, and commercial establishments; however, there are no enforcement procedures in the law. There is a requirement for the Governor's Steering Committee on Climate Change to develop a Climate Action Plan by January 2005, and for the Commissioner of Environmental Protection to establish a regional greenhouse gas registry that will collect emissions data.

Maine. Maine enacted a climate change statute—"An Act to Provide Leadership in Addressing the Threat of Climate Change" (Public Law 2003, Chapter 237, H.P. 622, L.D. 845)—in June 2003 [*23*]. The statute requires the establishment of a greenhouse gas emissions inventory for State-owned facilities and State-funded programs and calls for a plan to reduce emissions to 1990 levels by 2010. It specifies that carbon emission reduction agreements must be signed with at least 50 businesses and nonprofit organizations by January 2006, and that Maine must participate in a regional greenhouse gas registry. The goals of the statute are a reduction of greenhouse gases to 1990 levels by January 2010, a reduction to 10 percent below 1990 levels by 2020, and a reduction to 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Protection to submit to the Legislature a State climate action plan to meet the goals of the statute [*24*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants"), approved in May 2001 [*25*], apply to six existing older power plants in Massachusetts. There are two options for utilities to comply with the regulations: either "repower" (defined as replacing existing boilers with new ones that meet the environmental standards, switching fuel to low-sulfur coal, or switching from coal to natural gas); or choose a standard path that includes installing low-NO_x burners, installing SO_2 scrubbers, and installing SCR or SNCR equipment.

The rule offers an incentive for a fuel shift by delaying the compliance deadline to October 2008 for any facility choosing to repower. Plants using other techniques, such as pollution control equipment, must comply by October 2006. The SO_2 standard is 6.0 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering) and 3.0 pounds per megawatthour by October 2006 (standard) or October 2008 (repowering). The NO_x standard is 1.5 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering). The SO_2 and NO_x regulations are considered by the State to be more stringent than CAAA90 would imply. Most of the facilities are choosing the repowering mode rather than the standard mode of compliance. Compliance plans have been submitted for the six power stations affected: Brayton Point, Salem Harbor, Somerset, Mount Tom, Canal, and Mystic stations [*26*].

The CO_2 standard annual facility cap is based on 3 years of data as of October 2004 (standard) or October 2006 (repowering) and an annual facility rate of 1,800 pounds CO_2 per megawatthour as of October 2006 (standard) or October 2008 (repowering) [*27*]. Credits for off-site reductions of CO_2 emissions can be obtained through carbon sequestration or renewable energy projects. The Massachusetts Department of Environmental Protection is developing regulations that would determine what projects could qualify as reductions. Greenhouse gas banking and trading regulations are also being developed. Plants that fail to achieve the reductions may purchase emissions credits.

The State of Massachusetts published final mercury emissions regulations in June 2004 that apply to the State's four largest existing coal-fired power plants (Brayton Point, Mount Tom, Salem Harbor, and Somerset Station) [*28*]. The regulations require compliance with at least one of the following standards: reduce mercury emissions by 85 percent from 2004 levels by January 2008 or a facility average mercury emissions rate of 0.0075 pound per gigawatthour or less. The affected facilities must reduce their mercury emissions by 95 percent from 2004 levels by October 2012, or achieve a facility average mercury emissions rate of 0.0025 pound per gigawatthour or less. The Massachusetts mercury emissions regulations are more stringent than EPA's proposed mercury emissions regulations as of January 2004 (69 CFR 4651).

Missouri. The Missouri NO_x rule, "Emission Limitation and Emissions Trading of Oxides of Nitrogen" (Rule 10 CSR 10-6.350) applies to fossil-fueled capacity larger than 25 megawatts. The emissions cap is based on a unit's heat input. Power plants had to be in compliance by May 2004. Allowances can be banked, with some restrictions, and some exchange of allowances is allowed [*29*]. The seasonal NO_x limits (from May to September of each year) vary by county and generally range from 0.18 to 0.35 pound per million Btu.

New Hampshire. New Hampshire has enacted legislation—the "Clean Power Act" (House Bill 284)—to reduce emissions of SO_2, NO_x, CO_2, and mercury from existing fossil-fuel-burning steam-electric power plants. Governor Jeanne Shaheen signed the Act into law in May 2002, and implementing regulations have been finalized [*30*]. The legislation applies to the State's three existing fossil-fuel power plants only and does not apply to new capacity. The plants must either reduce emissions, purchase emissions credits from plants outside New Hampshire that have achieved such reductions, or use some combination of these strategies. Compliance plans submitted to the New Hampshire Department of Environmental Services are under review.

One of the affected plants is Schiller, a 150-megawatt coal-burning power plant made up of three 50-megawatt units. Part of the compliance action, the "Northern Wood Power Project," is the conversion of one of Schiller's 50-megawatt units from coal to a fluidized-bed combustor that will burn biomass. The converted power plant will burn wood chips, sawmill residue, and other woody material. The action is, in part, a result of the Massachusetts RPS program, under which plants in States neighboring Massachusetts can convert from coal to biomass and qualify for the program. Thus, Schiller's conversion from coal to biomass counts toward meeting both the Massachusetts RPS and the New Hampshire multi-pollutant requirements. The conversion, which is expected to cost $70 million (about $1,500 per kilowatt), is planned for completion by the end of 2005.

The SO_2 annual cap under New Hampshire's Clean Power Act is 7,289 short tons by 2006, which amounts to a 75-percent reduction from Phase II Acid Rain legislation requirements and an 85-percent reduction from 1999 emission levels. The NO_x annual cap is 3,644 short tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 short tons by 2006, which amounts to a 3-percent reduction from 1999 levels.

New Jersey. New Jersey's goal is to reduce Statewide emissions of greenhouse gases from all sectors by 3.5 percent from 1990 levels by 2005. "Covenants" have been signed, pledging organizations to reduce their greenhouse gas emissions in accordance with the State goal [*31*].

New York. New York's "Acid Deposition Reduction Budget Trading Programs"—Title 6 NYCRR Parts 237 and 238—were approved by the State Environmental Board in March 2003 and became effective in May 2003 [*32*], but implementation of the rule has been delayed by a court order. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all CAAA90 Title IV sources, including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions were limited to 39,908 short tons beginning in October 2004. This is a non-ozone season cap (October 1 to April 31), based on the same rate (0.15 pound per million Btu) as the NO_x cap in the current State emissions regulation. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 to 25 percent below Title IV allocations (197,046 short tons); Phase II, beginning in January 2008, increases the limit to 50 percent below Title IV allocations (131,364 short tons) [*33*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits.

North Carolina. The General Assembly of North Carolina has passed the "Clean Smokestacks Act"—officially called the "Air Quality/Electric Utilities Act" (S.B. 1078)—which requires emissions reductions from 14 existing coal-fired power plants in the State. It was signed into law in June 2002. Under the Act, North Carolina power companies must reduce NO_x emissions from 178,000 short tons in 1999 to 56,000 short tons by 2009 and SO_2 emissions from 429,000 short tons in 1999 to 250,000 short tons by 2009 and 130,000 short tons by 2013. Progress Energy Carolinas, Inc., and Duke Power have submitted compliance plans to the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. The utilities will comply with the Act by installing scrubbers and SNCR technology at their plants. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control, with SNCR costs ranging from $4.93 to $63.70 per kilowatt and scrubber costs ranging from $113 to $414 per kilowatt [*34*].

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommends the development of standards and plans to control them. In 2003, the Department of Air Quality prepared reports on mercury [*35*] and CO_2 [*36*] emissions reductions for the State, in the first of three sets of reports to be submitted to the Environmental Management Commission and the Environmental Review Commission. The objective of the 2003 report was to provide general background on the topic of climate change and to define the scope of efforts needed to meet the legislative requirements. The 2004 and 2005 reports will build on this background, report on any developments in the Federal Government, and recommend courses of action that may follow [*37*].

The Act also requires North Carolina to persuade other States and power companies to reduce their emissions to similar levels and on similar timetables. The Act specifically mentions that discussions should be held with the Tennessee Valley Authority (TVA) to determine its emissions reduction policies. A meeting was held between the Department of Environment and Natural Resources/Department of Air Quality and TVA in August 2002 to discuss actions planned by TVA that would be comparable to the Clean Smokestacks Act. TVA presented its plans to add scrubbers to five additional power plants, primarily in the eastern portion of the TVA system, beginning with its Paradise plant in 2006. TVA plans to complete installation of the new scrubbers by 2010. TVA also plans to install the first eight SCR systems for NO_x control and to have 25 boiler units controlled by 2005, which will reduce NO_x emissions during the ozone season by 75 percent.

Oregon. Oregon has established its first formal State standards for CO_2 emissions from new electricity generating plants. The standards apply to power plants and non-generating facilities that emit CO_2. The Oregon Energy Facility Siting Council originally adopted the rules pursuant to House Bill 3283, which was passed by the Oregon legislature in June 1997, and has subsequently updated the rules, most recently in April 2002 [*38*]. For baseload natural gas plants and non-baseload plants, the standard CO_2 emission rate is 675 pounds per megawatthour, 17 percent below the rate for the most efficient natural-gas-fired plants currently in operation in the United States. The Council has not set CO_2 emission standards for baseload power plants using other fossil fuels. As of 2002, about 90 percent of Oregon's electricity was from hydroelectricity and natural gas and about 8 percent was from coal [*39*].

The Council's definition of a natural-gas-fired facility allows up to 10 percent of the expected annual energy to be provided by an alternative fuel, most likely distillate fuel. Proposed facilities may meet the requirement through cogeneration, using new technologies, or purchasing CO_2 offsets from carbon mitigation projects. It is possible to offset all excess CO_2 emissions through cogeneration offsets alone, and there are no limitations on the geographic location or types of CO_2 offset projects. The Council has set a monetary value that the generators may pay to buy offsets ($0.85 per short ton CO_2, equivalent to $3.12 per ton carbon, set in September 2001) [*40*]. This equates to an offset cost of 0.88 mill per kilowatthour [*41*].

Texas. Texas Senate Bill 7 (S.B. 7) imposes NO_x and SO_2 caps for grandfathered fossil fuel power plants [*42*]. The SO_2 annual cap is 595,000 short tons (East: 532,000, West: 63,000, and El Paso: 0 short tons). The NO_x annual cap is 302,000 short tons (East: 256,000, West: 44,000, and El Paso: 2,000 short tons), both of which had to have been achieved by May 2003. The State-wide caps have been met.

Washington. Washington's House Bill 3141, signed into law in May 2004, requires 20 percent of their CO_2 emissions from new power plants to be offset. Plant owners can either directly or indirectly invest in CO_2 mitigation projects, such as forest preservation or the conversion of buses from diesel to natural gas. Power plant CO_2 emissions must be reduced by 20 percent over a 30-year period. CO_2 emissions can be offset by payments to an independent qualified organization, by direct purchase of permanent carbon credits, or by direct investment in CO_2 mitigation projects. The rate of payment to third parties is fixed at $1.60 per metric ton CO_2 [*43*]. The Washington State Energy Facility Site Evaluation Council may adjust the rate every 2 years, but any decrease or increase may not exceed 50 percent of the current rate.

California Greenhouse Gas Emissions Standards for Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The law requires that the California Air Resources Board (CARB) develop and adopt, by January 1, 2005, greenhouse gas emission standards for light-duty vehicles that provide the maximum feasible reduction in emissions. In estimating the feasibility of the standard, CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the standard.

Tailpipe emissions of CO_2, which are directly proportional to vehicle fuel consumption, account for the vast majority of total greenhouse gas emissions from vehicles. A.B. 1493 does not mandate the sale of any specific technology and prohibits the use of the following as options for greenhouse gas reduction: mandatory trip reductions; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; reductions in vehicle weight; or a limitation or reduction on the speed limit on any street or highway in the State. Given these limitations and the preponderant share of total vehicle greenhouse gas emissions resulting from fuel consumption, improvements in fuel economy are the only practical way to attain any standard that requires a significant reduction in emissions.

CARB released a report on August 6, 2004, detailing the reasons for the proposed rulemaking, providing light vehicle regulations to be considered for adoption, and outlining the required analyses used to develop the proposed regulations. The standards for light-duty vehicle greenhouse gas emissions were adopted in September 2004. The auto industry opposes A.B. 1493 and has filed suit against CARB, stating that the California greenhouse gas emissions standards are preempted by a Federal statute that gives the U.S. Department of Transportation the only authority to regulate fuel economy [*44*]. Given the uncertainty surrounding the possible outcome of this litigation, the A.B. 1493 greenhouse gas emission standards are not represented in the *AEO2005* reference case; however, the standards were analyzed to estimate the potential impact on vehicle prices, greenhouse gas emissions, regional energy demand, and regional fuel prices.

A.B. 1493 Regulation

The greenhouse gas emission standards adopted in September 2004 incorporate emissions associated with vehicle operation, air conditioning operation, refrigerant emissions from the air conditioning system, and upstream emissions associated with the production of vehicle fuel. The emission standards apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The standards, specified in terms of CO_2 equivalent emissions, apply to two size classes of vehicles: (1) passenger cars and small light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less, and (2) heavy light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The CO_2 equivalent emission standard for heavy light trucks also includes noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulation adopted in September 2004 sets near-term emission standards, phased in between 2009 and 2012, and mid-term emission standards, phased in between 2013 and 2016. After 2016, the emissions standards are assumed to remain constant. Table 9 summarizes the CO_2 equivalent standards.

The regulations allow for CO_2 emission reduction credits that can be earned and traded for 2000 through 2008 model year vehicles. If a manufacturer decides to opt into the program before 2009, credits will be earned if average CO_2 equivalent emissions for that manufacturer's fleet are lower than the 2012 standards. The regulations also provide flexibility in complying with the CO_2 emission standards. Manufacturers can apply for alternative compliance credits for eligible 2009 vehicles and later model years if those vehicles achieve greenhouse gas reductions through the use of alternative fuels. In addition, credits are provided for the use of advanced leak reduction air conditioning components and for the use of HFC-152a as the refrigerant. The regulations also set light vehicle nitrous oxide (N_2O) and methane (CH_4) emission standards.

For this analysis, the CO_2 equivalent emission standards were converted to miles per gallon fuel economy equivalents (Table 10) [*45*]. The fuel economy equivalents shown in Table 10 assume that manufacturers will earn the maximum allowable air conditioning credits. The methodology used to estimate the fuel economy equivalents assumes that manufacturers will meet the N_2O and CH_4 standards and includes CO_2 equivalent emissions associated with N_2O and CH_4 emissions, which are generated by the exhaust

Table 9. CARB CO_2 equivalent emission standards for light-duty vehicles, model years 2009-2016

Tier	Model Year	CO_2 equivalent emission standard (grams per mile): Passenger cars and small light trucks (under 3,751 pounds)	Heavy light trucks (3,751 to 8,500 pounds)
Near term	2009	323	439
	2010	301	420
	2011	267	390
	2012	233	361
Mid-term	2013	227	355
	2014	222	350
	2015	213	241
	2016	205	332

catalyst and incomplete combustion. The fuel economy equivalent standards are assumed to remain constant after 2016.

Analysis and Results

Two cases were developed to measure the potential impact of the California light vehicle greenhouse gas emission standards on energy demand, fuel prices, and vehicle prices. The *A.B. 1493 California-only case* assumes that only California will adopt the new standards. The *A.B. 1493 extended case* assumes that New York, Maine, Massachusetts, and Vermont will also adopt the California standards for greenhouse gas emissions for light-duty vehicles. Those States have already adopted California emissions standards applicable to other types of vehicle emissions [*46*].

Both cases examined here assume that fuel economy impacts are limited to those States adopting the regulation and that the fuel economy and sales mix of vehicles sold in non-adopting States remain at levels achieved in the *AEO2005* reference case. Although not addressed in this analysis, it is conceivable that State-based fuel economy regulation could cause unintended shifts in light vehicle markets. State-specified fuel economy standards might inadvertently provide manufacturers an opportunity to maintain or increase profits through the sale of larger, less efficient vehicles (sport utility vehicles, minivans, and large cars) in areas that do not adopt the California standards, while complying with the nationally based CAFE standards.

As noted above, A.B. 1493 allows CO_2 emission credits for early compliance and for the sale of alternative-fuel vehicles. However, this analysis does not attempt to quantify the impact that either would have on the fuel economy required to meet the CO_2 equivalent emission standards.

Impacts on Vehicle Sales and Prices

For States adopting A.B. 1493, it is projected that advanced technologies implemented in conventional light-duty vehicles will account for the majority of the fuel economy improvements needed to achieve the required reductions in CO_2 emissions. For cars, in addition to the fuel economy gains achieved through advanced conventional technologies, increased sales of hybrid and diesel vehicles will be required to meet the fuel economy goal. Relative to the projections in the *AEO2005* reference case, hybrid car sales in those States adopting A.B. 1493 are projected to increase from 5.8 percent to 11.0 percent of total new car sales in 2016, and diesel car sales are projected to increase from 0.3 percent to 0.9 percent of total new car sales in 2016.

As a result of increased use of advanced conventional technologies and increased market penetration of hybrid and diesel vehicles, the average price of a new car in 2016 is projected to increase by $1,860, and the average price of a new truck is projected to increase by $500 (2003 dollars) in both cases in the analysis. These cost estimates do not include the costs associated with credits earned from improved air conditioning systems or the emission control equipment needed to achieve the N_2O and CH_4 emission standards. They do account for increased demand for heavier vehicles, improved performance, and increased fuel economy that is projected to continue throughout the forecast period in the *AEO2005* reference case.

The EIA projections for vehicle sales and price impacts can be compared with those reported in the CARB staff analysis [*47*], which estimates that the average price of new passenger cars and small light trucks will increase by $1,064, and the average price of a new heavy light truck will increase by $1,029, in

Table 10. CARB fuel economy equivalent standards for light-duty vehicles, model years 2009-2016

		Fuel economy equivalent standard (miles per gallon)	
Tier	Year	Passenger cars and small light trucks (<3,751 pounds loaded vehicle weight)	Heavy light trucks (3,751 pounds loaded vehicle weight to 8,500 pounds gross vehicle weight)
Near term	2009	26.4	19.5
	2010	28.3	20.4
	2011	31.8	21.9
	2012	36.2	23.6
Mid-term	2013	36.3	23.6
	2014	37.1	23.9
	2015	38.6	24.5
	2016	39.9	25.2

2016 compared with the price of a model year 2009 base vehicle. Comparisons of the 2016 model year vehicle price to the 2009 base vehicle price implicitly assume that continued consumer demand for increased vehicle weight and performance will have no impact on the cost of complying with the regulation. CARB provided no information about its assumptions for fuel economy, weight, and performance ratings for the 2009 base vehicle.

Impacts on Transportation Energy Use and CO_2 Equivalent Emissions

In the A.B. 1493 California-only case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.15 million barrels per day (0.7 percent) and CO_2 equivalent emissions would be reduced by 21 million metric tons (0.8 percent) relative to the *AEO2005* reference case projections. In the A.B. 1493 extended case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.22 million barrels per day (1.1 percent) and CO_2 equivalent emissions by 33 million metric tons (1.2 percent) relative to the *AEO2005* reference case projections.

The CARB staff analysis provides estimated emissions reduction impacts for 2020 and 2030, which allow for a direct comparison with EIA's results for 2020. In the A.B. 1493 California-only case, EIA projects that 2020 light vehicle CO_2 equivalent emissions would be reduced by 14.9 million metric tons (Table 11). CARB's analysis determined that by 2020 CO_2 equivalent emissions from light-duty vehicles would be reduced by 29 million metric tons, approximately double EIA's estimate [*48*].

The difference in projected reductions in CO_2 equivalent emissions in the two analyses can be explained by three key factors. The first is the projected distribution of cars and light trucks in use. The CARB analysis projects that, in 2020, passenger cars and light trucks under 3,750 pounds loaded vehicle weight (so-called "small light trucks") would account for approximately 80 percent of the light-duty vehicle stock and associated vehicle miles traveled. Specifically, passenger cars account for 63.6 percent of the total stock, small light trucks account for 18.2 percent of the total stock, and heavy light trucks account for 18.1 percent of the total stock [*49*]. In comparison, EIA's analysis projects that passenger cars would account for 46.5 percent of the light vehicle stock, and all light trucks, which are predominantly over 3,750 pounds loaded vehicle weight, would account for 53.5 percent [*50*]. This is significant because, as shown in the CARB analysis, passenger cars and small light trucks are required to meet the more stringent CO_2 equivalent standard, which will result in greater projected emission reductions.

Although NEMS does not specifically model light trucks less than 3,750 pounds loaded vehicle weight, light trucks are disaggregated by vehicle class. The fuel economy equivalent standards shown in Table 10 were modified to reflect an assumption that light trucks under 3,750 pounds gross vehicle weight would account for 12.3 percent of new light truck sales [*51*]. As a result, the light truck fuel economy equivalent standard used in EIA's analysis would increase to 26.4 miles per gallon by 2016.

The second significant difference between the two analyses is projected baseline fuel economy. Although no data were available for the baseline fuel economy projected in the CARB analysis, CARB staff informed EIA that their baseline for greenhouse gas emissions from light-duty vehicles does not project increases in new light vehicle fuel economy [*52*]. The *AEO2005* reference case projects that new car fuel economy will increase from 29.5 miles per gallon in 2003 to 30.6 miles per gallon in 2020, and that new light truck fuel economy will increase from 21.8 miles per gallon in 2003 to 24.1 miles per gallon in 2020. As a result, the EIA projection of baseline fuel economy improvement reduces the amount of CO_2 that can be saved by the

Table 11. Comparison of key factors in the CARB and EIA analyses, 2020

Projection	CARB: Passenger cars and small light trucks	CARB: Heavy light trucks	CARB: Total	EIA: Passenger cars	EIA: Light trucks	EIA: Total
CO_2 equivalent emission reductions						
Million metric tons	22.2	6.8	**29.0**	5.8	9.1	**14.9**
Percent of total	76.6	23.4	**100.0**	39.0	61.0	**100.0**
Distribution of light-duty vehicle stock (percent of total)	81.9	18.1	**100.0**	46.5	53.5	**100.0**
Distribution of light-duty vehicle miles traveled (percent of total)	82.1	17.9	**100.0**	47.4	52.6	**100.0**

A.B. 1493 standards relative to savings available under the CARB baseline assumption of no change in new vehicle fuel efficiency.

The third significant difference between the analyses is the projected impact of improved air conditioning systems on the reduction of CO_2 equivalent emissions. The CARB analysis includes CO_2 equivalent emission reductions associated with improved air conditioning. EIA's analysis assumes that manufacturers will use the maximum allowable air conditioning credits, but it does not explicitly model air conditioning systems or associated emissions. Analyses of the credits allowed for this technology indicate that approximately 4 to 7 percent of the total CO_2 equivalent emission reductions reported by CARB could be attributed to improved light vehicle air conditioning systems.

Regional Impacts on Transportation Fuel Supply and Prices

Relative to the *AEO2005* reference case, the A.B. 1493 California-only case projects reduced consumption of gasoline and diesel fuel in 2025 by 153,000 and 6,000 barrels per day, respectively, in Census Division 9 [*53*]. As a result, production of gasoline in 2025 is projected to decrease by 34,000 barrels per day, with an additional reduction of 109,000 barrels per day in gasoline imports. The balance of the difference results from changes in interregional transfers. Diesel fuel production in Census Division 9 is projected to decrease by 7,000 barrels per day in 2025. The reduction in diesel supply is slightly greater than the reduction in diesel consumption due to refinery optimization for gasoline production. As a result, disproportionate reductions in gasoline demand, as projected in the A.B. 1493 California-only case, affect the production of diesel even though the demand for diesel fuel is not projected to fall by as much.

A.B. 1493 has little projected impact on diesel prices in Census Division 9. Because the reduction in gasoline demand causes an almost equal reduction in supply in the A.B. 1493 California-only case, the average gasoline price for Census Division 9 between 2016 and 2025 is projected to be 0.6 cents per gallon lower, than projected in the *AEO2005* reference case.

The A.B. 1493 extended case, which applies the same light vehicle greenhouse gas reduction requirements to selected States in Census Divisions 1 and 2 in addition to California, projects reduced consumption of gasoline and diesel fuel in 2025, by 88,000 and 4,000 barrels per day, respectively, in the New England and Mid-Atlantic regions [*54*]. This demand reduction results in a similar reduction in gasoline imports to the two regions, although the projected reduction of 74,000 barrels per day in gasoline imports is less than the reduction in demand. In contrast to Census Division 9, Census Divisions 1 and 2 are traditionally more integrated to fuel supplies from other refining regions. As such, a reduction in gasoline consumption of 4.5 percent (or 88,000 barrels per day) in Census Divisions 1 and 2, relative to the *AEO2005* reference case, represents a reduction of only 0.9 percent when a broader market east of the Rocky Mountains including Census Divisions 1 through 7 (or Petroleum Administration for Defense Districts 1 through 3) is considered. The A.B. 1493 extended case has negligible impact on gasoline and diesel prices in Census Divisions 1 and 2.

Conclusion

Analysis of two A.B. 1493 cases indicates small national impacts on energy demand and fuel prices. The impact of A.B. 1493 could be more or less significant depending on manufacturer behavior, consumer response, and the number of States assumed to adopt the program if its legality is upheld. Because the required improvements in car fuel economy are much more stringent then those required for light trucks, above 3,750 pounds, a category that includes 88 percent of total light truck sales, consumer preference for larger high performance vehicles could spur further increases in the demand for light trucks, which counters the intent of the regulation. Further complicating the issue is the behavior of vehicle manufacturers with respect to their fiduciary responsibility to comply with nationally-based CAFE standards while also meeting niche market CO_2 emissions requirements. These issues, coupled with pending National Highway Traffic Safety Administration modifications to the current CAFE structure and the legal challenges facing A.B. 1493, create significant uncertainty with respect to the evaluation of the new California regulation.

Multi-Pollutant Legislation and Regulations

The 108th Congress proposed and debated a variety of bills addressing pollution control at electric power plants but did not pass any of them into law. In addition, the EPA currently is preparing two regulations—a proposed Clean Air Interstate Rule (pCAIR) and a Clean Air Mercury Rule (CAMR)—to address emissions from coal-fired power plants. Several States also have taken legislative actions to limit pollutants from power plants in their jurisdictions. This section discusses three Congressional air pollution bills and the EPA's pCAIR and CAMR regulations.

Clear Skies Act of 2003, Clean Air Planning Act of 2003, and Clean Power Act of 2003

Several bills introduced in the 108th Congress proposed to regulate emissions of NO_x, sulfur dioxide (SO_2), mercury, and CO_2 from electric power plants. EIA received a request from Senator James M. Inhofe to conduct an analysis of S. 843, the Clean Air Planning Act of 2003, introduced by Senator Thomas Carper; S. 366, the Clean Power Act of 2003, introduced by Senator James Jeffords; and S. 1844, the Clear Skies Act of 2003, introduced by Senator Inhofe. The emissions targets and implementation timetables proposed in the bills are summarized in Table 12.

A report on the results of EIA's analysis [*55*] was released in May 2004. The analysis in the report was based on the assumptions used in *AEO2004*, which differed from those used in *AEO2005*. One of the most significant differences for the electricity sector is in projected natural gas prices. In *AEO2005*, the reference case projection for wellhead natural gas prices in 2025 is more than 30 cents higher than the *AEO2004* projection, primarily as a result of lower assumed finding rates (reserve additions per well) for onshore resources. The following summary of EIA's Inhofe-Carper-Jeffords analysis is based on the *AEO2004* projections.

To comply with the provisions of S. 1844, the Clear Skies Act (Inhofe), electricity producers would be expected to rely primarily on adding emissions control equipment to existing generators. Switching fuels from coal to natural gas and renewables would be expected to play a relatively small role. Producers would be expected to begin reducing mercury emissions before 2010 in order to take advantage of the early credit program included in S. 1844; however, emissions of mercury would remain above the 15-ton target in 2018, because the bill also specifies an "allowance price safety valve." Among the three bills analyzed by EIA, total costs to the electric power industry and projected impacts on electricity prices are lowest for S. 1844.

S. 843, the Clean Air Planning Act (Carper) would impose more stringent limits on emissions of SO_2, NO_x, and mercury than those proposed in S. 1844. In addition, S. 843 proposes a cap on CO_2 emissions. Emissions control equipment added to existing generators would also be expected to play an important role in compliance strategies under S. 843, but fuel switching from coal to natural gas and renewables would play a more important role. In addition, the impacts would be sensitive to the availability and cost of greenhouse gas offsets. Because of this uncertainty, two separate cases were included in EIA's analysis of S. 843—one (Carper domestic) assuming that only domestic offset programs would be approved and another (Carper international) assuming that both domestic and international offsets would be available. Overall, the resource costs and electricity price impacts under S. 843 were projected to be larger than those under S. 1844.

S. 366, the Clean Power Act (Jeffords), includes a more stringent cap on CO_2 emissions, which would be expected to make switching from coal to natural gas, renewables, and nuclear especially important in compliance strategies. S. 366 would require all older power plants to be retrofitted with emissions control

Table 12. Emissions targets in multi-pollutant legislation

Emissions	S. 1844, Clear Skies Act (Inhofe)	S. 843, Clean Air Planning Act (Carper)	S. 366, Clean Power Act (Jeffords)
NO_x	2.19 million tons in 2008 1.79 million tons in 2018	1.87 million tons in 2009 1.7 million tons in 2013	1.51 million tons in 2009
SO_2	4.4 million tons in 2010 3.0 million tons in 2018	4.5 million tons in 2009 3.5 million tons in 2013 2.25 million tons in 2016	2.25 million tons in 2009
Mercury	34 tons in 2010 15 tons in 2018	24 tons in 2009 10 tons in 2013	5 tons in 2008
CO_2	No cap	2,332 million metric tons CO_2 (636 million metric tons carbon equivalent) in 2009 2,244 million metric tons CO_2 (612 million metric tons carbon equivalent) in 2013	1,863 million metric tons CO_2 (508 million metric tons carbon equivalent) in 2009

equipment, even if emissions of SO_2, NO_x, and mercury fell below the respective aggregate reduction targets as a result of fuel switching. The early timing and stringency of the emissions limits, among other factors, would lead to the largest resource cost and electricity price impacts among the three bills. Because of the higher projected electricity prices under S. 366, consumers would also be expected to reduce their use of electricity.

Table 13 shows a summary of EIA's analysis results. Significantly, power plant emissions of NO_x in 2025 were projected to remain at about the levels of the respective phase 2 targets under S. 843 (1.7 million tons) and S. 1844 (1.79 million tons) shown in Table 12, because neither bill would be expected to provide significant opportunity for economical banking of NO_x allowances. Only under S. 366, which requires emissions controls at all plants over 40 years old, were NO_x emissions in 2025 projected to fall below the bill's emission target of 1.51 million tons shown in Table 12.

SO_2 emissions from electric power plants were projected to be reduced under the provisions of each of the three bills, as well as in the *AEO2004* reference case. Under S. 843 and S. 1844, however, SO_2 emissions in 2025 were projected to remain above the bills' target levels because of allowances banked from the existing SO_2 reduction program. Under S. 366, SO_2 emissions in 2025, like NO_x emissions, were projected to fall below the bill's target level.

Average retail electricity prices in 2025 were projected to be 3.2 percent higher under S. 1844 than in the *AEO2004* reference case forecast, and they were projected to be as much as 7.8 percent higher under S. 843 (Figure 9). Much larger price impacts were projected under S. 366—47 percent above reference case prices in 2010 and 27 percent above reference case prices in 2025—primarily because the proposed limit on CO_2 emissions at 1990 levels in 2009 would require rapid transformation of the Nation's power plant capacity from coal to natural gas, renewables, and nuclear fuel.

Proposed Clean Air Interstate Rule

The EPA's proposed CAIR [*56*] was published in the *Federal Register* [*57*] in January 2004 and in a supplemental notice [*58*] in June 2004. pCAIR is intended to reduce the atmospheric interstate transport of fine particulate matter ($PM_{2.5}$) and ozone. SO_2 and NO_x are precursors of $PM_{2.5}$. NO_x is also a precursor to the formation of ground-level ozone. pCAIR would require 29 States and the District of Columbia to develop plans to reduce SO_2 and/or NO_x emissions. The proposed rules would apply to all fossil-fuel-fired boilers and turbines serving electrical generators with capacity greater than 25 megawatts that provide electricity for sale. The proposed rules also would apply to combined heat and power (CHP) units that are larger than 25 megawatts, that sell at least one-third of their potential electrical output, and that meet certain operating and efficiency criteria. Table 14 shows the pCAIR emissions caps and timetables for meeting the caps.

Under pCAIR, the States would be responsible for allocating NO_x emissions allowances and taking the lead in pursuing enforcement actions, and they would have flexibility in choosing the sources to be controlled. They could meet the emissions reduction requirements either by joining the EPA-managed cap

Table 13. Key projections from EIA's 2004 analysis of proposed multi-pollutant control bills, 2025

Projection	2003	2025: AEO2004 reference case	2025: S. 1844	2025: S. 843 Carper international	2025: S. 843 Carper domestic	2025: S. 366
Total U.S. emissions						
NO_x (million tons)	4.1	3.7	1.8	1.7	1.7	0.61
SO_2 (million tons)	10.6	9.0	3.6	2.8	2.9	1.2
Mercury (tons)	49.7	54.6	29.0	10.0	10.0	3.7
CO_2 (million metric tons)	2,286	3,272	3,164	2,905	2,720	1,733
Electricity generation by fuel (billion kilowatthours)						
Coal	1,971	3,008	2,861	2,467	2,280	1,363
Nuclear	764	824	824	824	824	1,261
Natural gas	632	1,287	1,350	1,576	1,579	1,394
Renewables	350	537	597	758	930	1,310
Average retail electricity price (2002 cents per kilowatthour)	7.4	6.9	7.1	7.2	7.4	8.7

and trade programs for power plants, or by achieving reductions through emissions control measures on sources in other sectors (industrial, transportation, residential, or commercial), or on a combination of electricity generating units and sources in other sectors.

To participate in the cap and trade program, the States would be required to regulate power plant emissions within their boundaries. The EPA would be responsible for assigning State emissions budgets, reviewing and approving State plans, and administering the emissions and allowance tracking systems. State rules could allow sources currently subject to the CAAA90 Title IV rules and to the NO_x State Implementation Plan (SIP) Call trading program to use allowances banked from those programs before 2010 for compliance with pCAIR. pCAIR also would require additional reductions in NO_x emissions for States affected by the NO_x SIP Call.

The EPA plans to meet the SO_2 emission reduction requirements by implementing a progressively more stringent retirement ratio on SO_2 allowances for electricity generating units of different vintages under the CAAA90 Title IV acid rain program. New SO_2 allowances would not be issued under pCAIR; power plants would instead use the current pool of SO_2 allowances issued under Title IV. Allowances issued for vintage years 2004 through 2009 could be retired on a 1-to-1 basis, but allowances issued for vintage years 2010 through 2014 would have to be retired on a 2-to-1 basis, requiring 2 Title IV allowances to be retired for each ton of SO_2 emissions. Allowances issued for vintage years 2015 and later would be retired on a basis of approximately 2.9 to 1. This retirement procedure is proposed in order to integrate the pCAIR rules with the existing Title IV SO_2 emissions reduction program.

NO_x emissions would be treated differently, with State emissions caps to be based on each State's share of region-wide heat input. In addition, new NO_x allowances would be issued, and banked SIP Call allowances could be traded under pCAIR.

pCAIR Analysis

Although the *AEO2005* reference case does not assume enactment of pCAIR, an alternative case has been developed to analyze its potential impacts. The pCAIR sensitivity case assumes the adoption of pCAIR emissions caps on SO_2 and NO_x and the proposed SO_2 allowance vintaging methodology. The caps are assumed to be imposed on all electricity generators and CHP units that sell electricity to the grid, and it is assumed that electricity producers would opt to participate in the EPA cap and trade program rather than relying on State emission reduction programs. Other than those assumptions, the pCAIR case uses the *AEO2005* reference case assumptions.

Table 15 compares the key results of the pCAIR case and the *AEO2005* reference case. In 2025, the pCAIR case results in a 46-percent reduction in national NO_x emissions from their 2003 level and a 63-percent reduction in SO_2 emissions from the 2003 level.

NO_x allowance prices are projected to increase in the pCAIR case. In the reference case, the NO_x SIP Call affects States primarily in the Northeast with a summer season NO_x cap. In the pCAIR case, the SIP Call caps are replaced by the pCAIR NO_x caps, which affect a different combination of States and are annual limits. Because the NO_x allowance prices under the two inherently different programs cannot be compared, Table 15 shows only the allowance prices under pCAIR.

SO_2 allowance prices are projected to be significantly higher in the pCAIR case than in the reference case, which assumes continuation of the currently enacted

Figure 9. Projected electricity prices under proposed multi-pollutant control bills, 2010, 2020, and 2025 (2002 cents per kilowatthour)

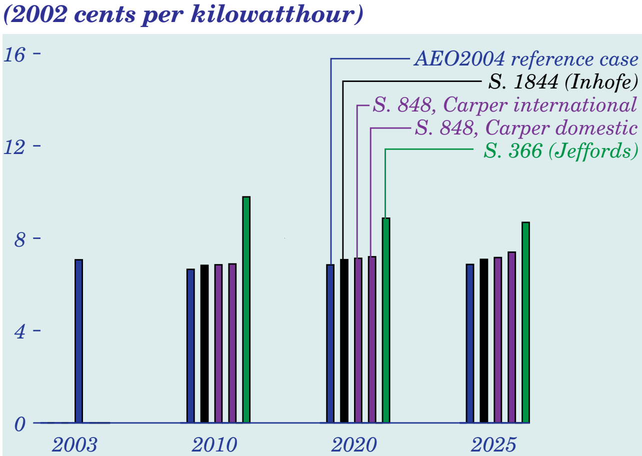


Table 14. Historical emissions and proposed future caps for the combination of affected pCAIR States (million tons)

Emissions	Emissions in 2002	Emissions cap in 2010	Emissions cap in 2015
NO_x	3.78	1.60	1.33
SO_2	9.39	3.86	2.71

CAAA90 allowance program. The higher SO_2 allowance prices in the pCAIR case reflect the need for utilities to reduce emissions to lower levels than currently required under CAAA90.

One of the key results of the pCAIR case is that electric power producers would be required to install significantly more pollution control equipment than in the reference case. To comply with the pCAIR limits in SO_2 emissions, electricity producers are projected to install flue gas desulfurization (FGD) scrubbers on nearly 100 gigawatts more coal-fired capacity than in the reference case through 2025. Similarly, to meet the pCAIR NO_x limits, SCR equipment is projected to be installed on about 60 gigawatts more coal-fired capacity than in the reference case. In the reference case, total coal-fired capacity in the United States is projected to grow from 314 gigawatts in 2003 to 398 gigawatts in 2025. Thus, in the pCAIR case, roughly one-third of all coal-fired power plants would be retrofitted with FGD and SCR equipment by 2025. The pCAIR case does not project a significant change in the fuel mix for electricity generation in 2025 relative to that in the reference case, showing only a slight reduction in coal use, a small increase in natural gas use, and a small increase in renewable fuel use (Figure 10).

Only modest changes in regional coal production are projected in the pCAIR case (Figure 11). In both the reference and pCAIR cases, coal production increases from 2003 to 2025. Relative to the reference case, the pCAIR case projects a decrease in Appalachian coal production of about 2 percent in 2025, a decrease in Interior coal production of about 13 percent (24 million tons), and an increase in Western coal production of about 1.1 percent, based on the generally lower sulfur content of Western than Appalachian and Interior coal resources.

After the first phase of the pCAIR emissions caps begins to take effect in 2010, average U.S. retail electricity prices are projected to be higher by a maximum of 2.3 percent in the pCAIR case than in the reference case, with a similar difference in projected resource costs for the electric power sector (the amount that power companies spend on fuel, capital, and operations and maintenance). Projected resource costs

Table 15. Key electricity sector projections from EIA's analysis of proposed pCAIR regulations, 2015 and 2025

Projection	2003	2015 AEO2005 reference case	2015 pCAIR case	2025 AEO2005 reference case	2025 pCAIR case
Total U.S. emissions					
NO_x (million tons)	4.1	4.1	2.1	4.3	2.2
SO_2 (million tons)	10.6	9.0	4.7	9.0	3.9
Allowance prices (2003 dollars per ton)					
NO_x	—	—	2,524	—	2,789
SO_2	172	290	1,160	247	1,463
Coal-fired capacity retrofits (gigawatts)					
Flue gas desulfurization	0	26	107	27	128
Selective catalytic reduction	0	70	131	74	133

Figure 10. Projected electricity generation by fuel in two cases, 2025 (billion kilowatthours)

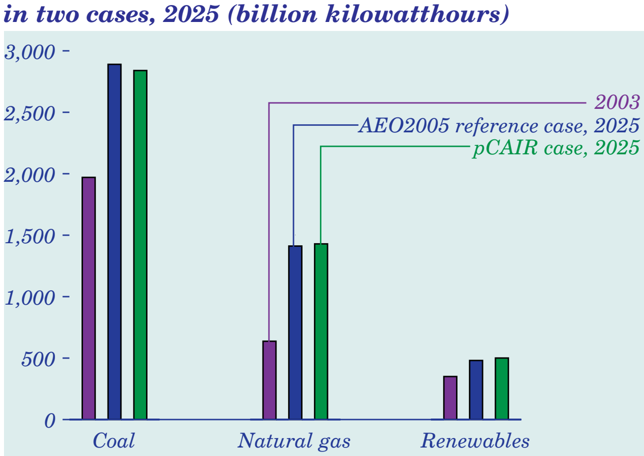
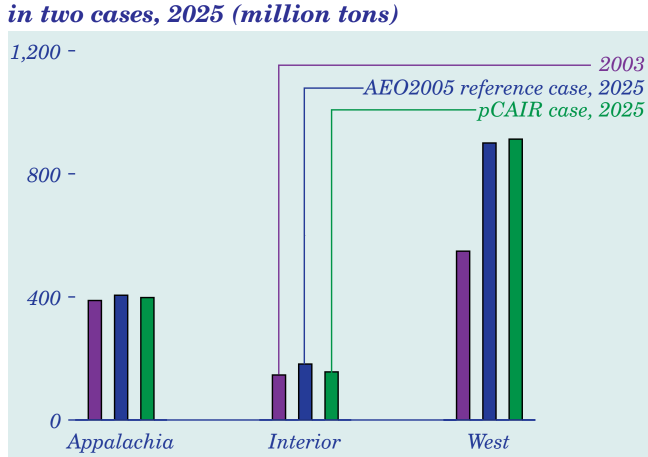


Figure 11. Projected coal production by region in two cases, 2025 (million tons)



from 2010 through 2025 are higher by a maximum of $3.5 billion per year (about 2.5 percent) in the pCAIR case than in the *AEO2005* reference case.

Proposed Clean Air Mercury Rule

The EPA's CAMR (proposed as the Utility Mercury Reductions Rule) [*59*] for controlling mercury emissions from new and existing coal-fired power plants was published in the *Federal Register* [*60*] in January 2004 and in a supplemental notice [*61*] in March 2004. Nickel emissions from new and existing oil-fired power plants would also be capped under the proposed rule; however, as of 2002 only 2.3 percent of the electricity generated in the United States was from oil-fired units, and 50.2 percent was from coal-fired units [*62*]. Therefore, the focus in this section is on the proposed regulations applicable to coal-fired units. Power plants with capacity greater than 25 megawatts and CHP units that are larger than 25 megawatts and sell at least one-third of their electricity would be subject to CAMR.

The EPA estimates that CAMR, using a cap and trade approach, would reduce mercury emissions by nearly 70 percent when fully implemented. Two alternative approaches were proposed for reducing mercury emissions. The first, which would require the installation of MACT under CAAA90 Section 112, would reduce annual emissions from the electricity generation sector by about 29 percent, from 48 tons in 2002 to 34 tons in 2008. The second approach would modify Section 112 to allow regulation of mercury emissions under a cap and trade program. The program would be implemented in two phases, with a banking provision that would allow for reductions as early as 2010 and a second phase that would set a cap of 15 tons in 2018.

Under the cap and trade approach, States would submit plans to the EPA to demonstrate that they would meet their assigned State-wide mercury emissions budgets. With EPA approval, the States could then participate in the cap and trade program. Allowances would be allocated by the States to power companies, which could either sell or bank any excess allowances. The EPA proposed a safety valve price of $2,187.50 per ounce of mercury ($35,000 per pound), adjusted annually for inflation. The price of allowances would effectively be capped at that level, and power plant operators could buy allowances at any time at the safety valve price, reducing the State's budget in the future. Public comments on CAMR have been received, and the EPA expects to issue the final rules in March 2005.

Climate Stewardship Act of 2004

Senators John McCain and Joseph I. Lieberman introduced the Climate Stewardship Act of 2003 (S. 139) in the U.S. Senate in 2003. S. 139 would establish regulations to limit U.S. emissions of greenhouse gases [*63*], primarily through a program of tradable emission allowances and related emissions reporting requirements. In October 2003, Senators McCain and Lieberman proposed an amended version of the bill, S.A. 2028, which included the first phase of emissions reductions beginning in 2010 as proposed in S. 139 but removed references to a second phase of reductions beginning in 2016. On October 30, 2003, the Senate voted 43-55 to reject the measure. In July 2004, the Senators submitted the bill as the Climate Stewardship Act of 2004 (S.A. 3546), intending it as an amendment to legislation on class action lawsuits (S. 2062); however, the proposed amendment was tabled. Senator McCain has stated his intention to continue resubmitting the Climate Stewardship Act until it is passed by the Senate.

In March 2004, Representative Wayne Gilchrest submitted a version of the same bill, also called the Climate Stewardship Act of 2004, in the U.S. House of Representatives (H.R. 4067). It was cosponsored by 70 other Representatives. The House bill is essentially the same as the most recent Senate version, S.A. 3546. H.R. 4067 has been referred to the House Science Committee and Energy and Commerce Committee.

Overview

The Climate Stewardship Act of 2004 [*64*] would establish a system of tradable allowances to reduce greenhouse gas emissions. The bill includes requirements for mandatory emissions reporting by covered entities and for voluntary reporting of emissions reduction activities by noncovered entities; a national greenhouse gas database and registry of reductions; and a research program on climate change and related activities. The emissions allowance program would apply to most greenhouse gas emissions sources, the exceptions being those in the residential sector and entities in all sectors whose annual emissions are less than a certain threshold. Entities not directly covered by the allowance program would nevertheless be affected by its impacts on energy prices and the economy as a whole, as well as by the program's incentives to reward voluntary reductions of emissions.

The bill defines the covered sectors for the emission allowance program as the commercial, industrial, electric power, and transportation sectors [*65*]. Covered entities in the commercial, industrial, and electricity sectors are those that emit, from any single facility, greenhouse gas emissions from stationary sources exceeding 10,000 metric tons carbon dioxide equivalent per year [*66*]. In effect, this threshold would exempt most entities in the agriculture and commercial sectors. All petroleum used for transportation within the United States would be covered, and refiners would be responsible for submitting allowances for emissions related to petroleum sold for transportation use. Producers and importers of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride would be required to submit allowances for emissions associated with their products, subject to the 10,000 metric ton threshold.

The bill provides for the exemption of emission sources if the EPA deems their measurement or estimation to be impractical. This exemption would most likely apply to a large share of U.S. nitrous oxide and methane emissions, because many of their sources are difficult or uneconomical to measure.

Emission Allowance Program

The market-driven system of emission allowances proposed in the Climate Stewardship Act of 2004 would control greenhouse gas emissions by creating a fixed number of tradable emission allowances each year. The EPA is charged with establishing the regulations to create the tradable allowances, and the bill defines many of the provisions governing the allowances. The bill would provide entities with options for banking and borrowing allowances; for limited use of registered reductions from noncovered entities in lieu of allowances [*67*]; and for obtaining allowance allocation credits to reward past emissions reductions and early action reductions. The bill would establish a nonprofit Climate Change Credit Corporation (CCCC) to facilitate the market in emission allowances, to buy and sell allowances, and to distribute proceeds from sales to mitigate the economic impacts of the program. The Secretary of Commerce would be responsible for allocating allowances to the covered sectors and to the CCCC, subject to the final approval of Congress.

Each emission allowance would provide the right for an entity to emit one ton of greenhouse gases, measured in carbon dioxide equivalent units based on 100-year global warming potential. The number of allowances created each year would effectively establish a cap on total U.S. emissions; however, with the banking of allowances for future use permitted under the bill, emissions in any year could differ from the number of allowances issued [*68*]. The bill would require individual covered entities to submit allowances equal to their emissions but would not otherwise limit their emissions. An entity's emission allowance obligation would be based on its reported annual emissions, mandated under the program. The bill calls for the future development of emissions measurement and verification procedures that could be used to audit an entity's allowance obligation. Entities would be able to buy and sell allowances and to bank allowances for future use. Under limited conditions, covered entities could borrow against future emissions reductions [*69*].

Emission Caps

The bill specifies emission allowance caps based on aggregate emissions for the covered sectors in 2000, excluding emissions from the residential sector, the agriculture sector, and U.S. territories [*70*]. The bill specifies the total number of annual allowances at 5,896 million metric tons carbon dioxide equivalent, adding the phrase "reduced by the amount of emissions of greenhouse gases in calendar year 2000 from noncovered entities." This wording leaves the level of allowances that establishes the cap open to interpretation and questions of emissions accounting. Noncovered entities are those that have no facilities with annual emissions above 10,000 metric tons carbon dioxide equivalent; neither the identification of those entities nor their aggregate level of emissions in 2000 is known precisely. Because noncovered entities would not be required to report emissions, their emissions could be estimated only by subtracting covered entities' reported emissions from estimates of total emissions. Noncovered emissions would also include emissions from sources the EPA deemed impractical to measure. Under these definitions, the level of emissions from noncovered sources would be unknown, and the number of allowances to be created after adjusting for noncovered emissions is uncertain.

In a June 2003 analysis of S. 139 [*71*], EIA estimated that approximately 75 percent of total U.S. greenhouse gas emissions would be covered under the bill. The impact of the bill on total emissions would depend on growth in noncovered emissions and how covered entities made use of alternative compliance provisions, such as registered increases in carbon sequestration.

Allowance Allocation, Allowance Banking, and Alternative Compliance Provisions

The allocation of emission allowances to covered sectors and entities is not completely fixed by the bill. Some of the Government-issued allowances would be distributed directly to covered entities, and the rest would go to the CCCC. A number of criteria for allocating emissions allowances are defined in the bill, but neither the total percentage of allowances to be distributed free nor the share to be distributed to each of the covered sectors is specified. The bill does, however, describe an allocation procedure to reward entities for registered emissions reductions made since 1990 and reductions made in advance of the 2010 start date. Entities with creditable reductions would be granted a corresponding increase in their future allocations of allowances for the compliance period beginning in 2010. Credits for early action would not affect the overall compliance cap, only the allocation of free allowances to covered entities. Nevertheless, this provision would provide an incentive to reduce emissions early in exchange for future allowance allocations.

The bill's allowance trading and alternative compliance provisions would result in markets for emission allowances and registered offset credits. The market for allowances and related incentives should result in a market-clearing price for allowances that would reflect both the cost of reducing emissions and the flexibility of allowance banking. Because allowances could be sold or held for future use, covered entities would have an incentive to reduce emissions under the bill, even if they were allocated sufficient allowances to cover their annual emissions. Some entities would find it economical to over-comply and sell or bank emission allowances, depending on the cost of emissions reduction opportunities, future expansion plans, and expectations about future allowance prices.

A market for the alternative compliance emission credits, or offsets, would also provide economic incentives for noncovered entities to reduce emissions and register their reductions. The bill would allow covered entities to submit such registered credits in place of up to 15 percent of their allowance obligations. Offsets could be registered by domestic sources as well as from other countries that have greenhouse gas emissions limits and comparable allowance trading provisions in place. The allowance offsets could also come from increases in biological carbon sequestration, such as through reforestation, and to a limited extent from changes in agricultural practices to increase net carbon sequestration in the soil [*72*]. Offsets would likely sell at or below the price for allowances. Suppliers competing to meet the limited demand for offsets could bid down the offset price to a level below the allowance price.

Energy Market Impacts

Energy consumers would incur higher effective costs of using energy as a result of the bill's allowance program. In the transportation sector, end-use consumers would face higher delivered prices of refined products when refiners passed on the cost of allowances required for emissions of petroleum-based fuels sold for transportation [*73*]. Covered entities in the commercial, industrial, and electric power sectors would implicitly face a higher cost of consuming fossil energy, because they would be required to obtain allowances for carbon dioxide emitted in direct fuel use. To the extent that electricity generators could pass through the opportunity cost of allowances and related incremental capital costs to their customers, electricity prices would increase in all consuming sectors. The increased energy costs, whether incorporated in delivered prices or reflected implicitly as opportunity costs of consuming energy, would affect all energy sectors of the economy.

The energy cost impacts on consumers and businesses could be substantially reduced by actions of the CCCC, which would be tasked to use proceeds from allowance sales to diminish the economic impact of the program. The extent to which the CCCC could funnel allowance proceeds back into the economy would depend on the allocation of allowances it received. The bill leaves the allocation of available allowances between the CCCC and covered entities unspecified. The CCCC share of allowances would be determined on an annual basis by the Secretary of Commerce, subject to approval by the Congress.

The funds collected by the CCCC could be dispersed to energy consumers by various methods, including cash rebates, rebates for energy-efficient appliances, subsidies, and general transition assistance to displaced workers. The bill specifies that the CCCC must allocate a percentage of the proceeds from allowances to provide transition assistance to dislocated workers and communities; however, the transition assistance amount probably would be a small fraction of the total allowance proceeds collected. The remaining proceeds would be returned to the economy, possibly as rebates. As a result, the bill has the potential to compensate consumers to some extent for higher direct energy costs and the indirect impacts of higher prices for non-energy goods and services.

Issues in Focus

Introduction

This section of the *Annual Energy Outlook* provides in-depth discussions of topics related to specific assumptions underlying the reference case forecast. In particular, the discussions focus on new methods or data that have led to significant changes in modeling approaches for the reference case. In addition, this section provides a more detailed examination of alternative cases.

World Oil Price Cases

World oil prices in *AEO2005* are set in an environment where the members of OPEC are assumed to act as the dominant producers, with lower production costs than other supply regions or countries. Non-OPEC oil producers are assumed to behave competitively, producing as much oil as they can profitability extract at the market price for oil. As a result, the OPEC member countries will be able effectively to set the price of oil when they can act in concert by varying their aggregate production. Alternatively, OPEC members could target a fixed level of production and let the world market determine the price.

The behavior and ability of OPEC member countries to set the price of oil will be influenced by many factors about which there is considerable uncertainty. These factors include the forces that will drive world oil demand, such as the rate of economic growth in the developed and developing world and the degree to which oil demand is linked to economic growth. The behavior of each major non-OPEC producer and changes in technologies that use or find and extract oil also will be important. Each of these factors will also be influenced by the market strategy that the OPEC members choose for OPEC in the aggregate or for themselves. For example, a strategy targeting relatively low prices and high market share would reduce the risk that new oil conservation or development technologies might be developed. It also would reduce the incentive for individual OPEC members to exceed their output quotas and reduce the risk that world economic growth might be slowed. With such a strategy, OPEC members would face little risk of losing market power, but their revenues and profits would be relatively low.

Conversely, if OPEC members jointly limited production to maintain high prices and low market share, new oil conservation or exploration and production technologies might be developed. Such a strategy would also increase the incentive for individual OPEC members to exceed their output quotas, cause importing countries to enact oil consumption reduction policies, and increase the likelihood that world economic growth would be slowed. While this strategy could result in relatively high revenues and profits in the short term, it would also be a relatively high-risk strategy.

World Oil Prices in AEO2005

World oil prices in *AEO2005* are defined on the basis of "average refiner acquisition cost" of imported oil to the United States (IRAC). The IRAC price tends to be a few dollars less than the widely cited West Texas Intermediate (WTI) spot price, and in recent months it has been as much as 6 dollars a barrel lower than the WTI. For the first 11 months of 2004, WTI averaged $41.31 per barrel and IRAC averaged $36.28 per barrel (in nominal dollars).

Approach

The *AEO* develops world oil price scenarios through an iterative process that examines the reasonableness of candidate oil price paths and their impacts on world oil supply and demand. The *AEO* process also considers the stated OPEC basket price target range, as well as ongoing discussions among OPEC members regarding possible changes to it.

The *AEO2005* reference case assumes a moderate market strategy between low-price, low-risk market share maximization and high-price, high-risk profit maximization. Alternative cases, in which different oil market behaviors are assumed, are also considered in *AEO2005*, including the October oil futures case, high A and B world oil price cases, and a low world oil price case. As with all of the projections in *AEO2005*, the oil price forecasts do not represent an assessment of what will happen, but rather, an assessment of what might happen under various scenarios. Higher or lower price paths are possible, and short-term price volatility in oil markets, which *AEO* scenarios do not attempt to model, is likely to continue.

World Oil Demand. Key inputs for projecting world oil demand—for example, the worldwide demand for various energy services (heating, cooling, transportation, etc.)—are estimated using EIA's System for Analysis of Global Energy Markets (SAGE) [*74*]. SAGE is an integrated set of regional models that provides a technology-rich basis for estimating regional energy supply and demand. For each region, estimates of end-use energy service demands (e.g., car, commercial truck, and heavy truck road travel; residential lighting; steam heat requirements in the paper industry; etc.) are developed on the basis of economic and demographic projections. Projections of energy demand are estimated on the basis of each region's existing energy use patterns, the existing stock of energy-using equipment, and the characteristics of available new technologies, as well as new sources of primary energy supply.

While oil products are used for many energy services (i.e., heating, steam generation, electricity generation, etc.) and as industrial feedstocks, the major use of petroleum products is for transportation. As a result, the worldwide demand for transportation services is the key driver for oil demand. In turn, the demand for transportation services in the various regions and countries represented in SAGE is driven by the projected level of income per capita, complemented by other important region-specific factors, such as the state of the transportation infrastructure. For the industrialized countries with well-developed transportation networks, demand for transportation services is influenced primarily by projected income levels and lifestyles; for developing countries, the lack of transportation infrastructure can be a significant constraint.

Table 16 summarizes by region and country the projected average annual growth rates for real GDP and oil demand, and the resulting oil intensity, in the *AEO2005* reference case from 2003 to 2025 [*75*]. The table also shows region and country shares of world GDP and oil demand in 2003 and 2025. As shown, total world GDP is projected to grow at an average annual rate of 3.1 percent, with the developing and former Soviet Union (FSU) countries generally projected to grow at higher rates, while the industrialized countries generally grow at slower rates. Total world oil demand is projected to grow more slowly, at 1.9 percent annually. World oil intensity declines by 1.2 percent per year.

Because of the differences in projected growth rates for GDP and oil demand, the developing countries are expected to play a growing role in the world economy and oil markets. In 2003, the industrialized countries accounted for 77 percent of world GDP and 57 percent of total world oil consumption. It is projected that in 2025 real GDP in industrialized countries will account for 68 percent of world GDP and 48 percent of total oil demand. In contrast, developing countries are projected to account for 28 percent of world GDP in 2025, up from 20 percent in 2003. Similarly, oil demand in developing countries is projected to account for 45 percent of world oil demand in 2025, up from 36 percent in 2003.

Table 16. Projected growth in world gross domestic product, oil consumption, and oil intensity in the AEO2005 reference case, 2003-2025

	Real GDP			Oil consumption			Oil intensity		
	Percent of world GDP		Annual growth, 2003-2025 (percent)	Percent of world oil use		Annual growth, 2003-2025 (percent)	Oil use (thousand Btu) per 1997 U.S. dollar of GDP		Annual growth, 2003-2025 (percent)
Country/region	2003	2025		2003	2025		2003	2025	
Industrialized countries									
United States	29.3	29.3	3.1	25.6	23.6	1.5	4.0	2.9	-1.5
Canada	2.3	2.2	2.7	2.7	2.3	1.2	5.3	3.8	-1.5
Mexico	1.4	1.7	4.1	2.5	2.9	2.5	8.3	5.9	-1.5
Western Europe	28.6	23.3	2.1	17.9	13.0	0.5	2.9	2.0	-1.7
Japan	13.4	9.9	1.7	7.0	4.8	0.2	2.4	1.7	-1.5
Australia/New Zealand	1.7	1.7	3.0	1.3	1.4	2.2	3.5	3.0	-0.7
Total	**76.8**	**68.2**	**2.5**	**57.0**	**48.1**	**1.1**	**3.4**	**2.5**	**-1.4**
Former Soviet Union and Eastern Europe									
Former Soviet Union	2.1	2.6	4.1	5.2	5.4	2.0	11.5	7.3	-2.0
Eastern Europe	1.2	1.5	4.0	1.8	1.7	1.8	6.7	4.2	-2.1
Total	**3.3**	**4.1**	**4.1**	**7.0**	**7.1**	**1.9**	**9.7**	**6.2**	**-2.0**
Developing Countries									
China	4.1	7.5	5.9	7.0	10.6	3.9	7.7	5.0	-1.9
India	1.7	2.7	5.2	2.8	4.4	4.1	7.4	5.9	-1.1
South Korea	1.8	2.3	4.2	2.7	2.4	1.4	6.9	3.8	-2.7
Other Asia	4.0	5.3	4.4	7.2	8.8	2.9	8.3	6.0	-1.5
Middle East	1.9	2.1	3.7	7.0	7.5	2.2	17.3	12.7	-1.4
Africa	2.0	2.4	4.1	3.4	3.9	2.5	7.9	5.7	-1.5
South/Central America	4.5	5.5	4.1	5.9	7.1	2.8	6.0	4.6	-1.2
Total	**19.9**	**27.8**	**4.7**	**36.0**	**44.8**	**2.9**	**8.3**	**5.7**	**-1.7**
Total World	**100.0**	**100.0**	**3.1**	**100.0**	**100.0**	**1.9**	**4.6**	**3.5**	**-1.2**

The projected growing role of the developing countries in the world economy and oil markets makes understanding the impact of economic growth on oil demand critically important. The sensitivity of oil demand to income is often characterized by what economists refer to as the income elasticity of demand, defined as the percentage change in oil demand with respect to the percentage change in real income. A rough approximation of the relative sizes of income elasticities for the different countries and regions represented in SAGE can be calculated from Table 16 by dividing the 2003 to 2025 average annual growth in oil demand by the average annual growth in real GDP. This calculation yields an income elasticity of demand of approximately 0.6 for the developing countries, compared with 0.4 for the industrialized countries [*76*].

The implication that oil demand in developing countries will be more responsive to changes in economic and income growth is consistent with research, but there is a great deal of uncertainty about the level of response. The response of oil demand to income growth and changes in oil prices has been examined in a number of empirical studies. The estimates of income elasticities in those studies vary widely, depending on the time period under study, the groups of countries considered, and the econometric specifications used [*77*]. Although the empirical evidence is not conclusive, and the magnitude of income elasticity estimates varies widely, most studies have found that developing countries generally have higher income elasticities than the industrialized economies.

Studies have shown both greater and smaller responses in developing countries than is reflected in SAGE. For example, Gately and Huntington found that the income elasticity of demand for oil in developing countries ranged from 0.5 to 1.0, depending on the groups of developing countries being considered [*78*]. The Gately and Huntington study, as well as most other empirical studies, used historical data and employed a single-equation reduced-form framework relating oil demand changes to changes in income, or income per capita, and oil prices in various lag formulations.

Such formulations may not fully capture the changes that have occurred in world economies or technologies in recent years, nor reflect how these changes might affect the future. For example, in an era of increased globalization and rapid technology transfer across countries, empirical estimates derived from historical data and simplified model formulations may not fully capture the more rapid transfer of new, efficient technologies from the industrialized countries to the developing countries that is likely to occur in the future. In contrast, the inferred income elasticities approximated in this report are based on projections coming from a structural model that explicitly incorporates the technical and cost relationships projected to exist between energy service demands by end-use sectors and the supply of energy. The model also represents region-specific factors that may encourage or inhibit demand for oil, such as transportation infrastructure constraints that are likely to arise as developing economies grow. One key assumption is that vehicles sold in both developing and industrialized countries in the future will be more fuel efficient than they were in the past.

World Oil Supply. Once oil demand has been estimated by region and country, the levels of regional non-OPEC conventional and nonconventional oil production are developed to be consistent with the assumed world oil price path and assumptions regarding proved oil reserves, undiscovered oil, and reserve growth. The gap between projected world oil consumption and non-OPEC oil production determines the call on OPEC producers. Production from individual OPEC suppliers is estimated based on information regarding proved reserves, project development schedules, long-term development plans, and production economics in each country or region. Production capacity estimates reflect both projected levels of supply and historical utilization rates. Several Persian Gulf OPEC producers, including Saudi Arabia, Kuwait, and the United Arab Emirates, are assumed to have production capacity utilization rates of 90 to 95 percent, while non-OPEC producers are assumed to use all of their capacity. Other OPEC producers are assumed to fall between these extremes.

The growth in non-OPEC oil supplies has played a significant role in the erosion of OPEC's market share over the past three decades, as non-OPEC supply has become increasingly diverse. North America dominated growth in non-OPEC supply in the early 1970s, the North Sea and Mexico evolved as major producers in the 1980s, and much of the new production since the 1990s has come from Latin America, West Africa, and the former Soviet Union. Non-OPEC supply from proved reserves is expected to increase steadily from 48.8 million barrels per day in 2003 to 65.0 million barrels per day in 2025 in the reference case.

The expectation in the late 1980s and early 1990s was that non-OPEC production in the longer term would stagnate or decline gradually in response to resource constraints. The relatively low cost of developing oil resources in OPEC countries (especially those in the Persian Gulf region) was considered such an overwhelming advantage that non-OPEC production potential was viewed with considerable pessimism. In actuality, however, despite several periods of relatively low prices, non-OPEC production has risen every year since 1993, growing by more than 8.2 million barrels per day between 1993 and 2003. Three factors are generally given credit for the impressive resiliency of non-OPEC production: development of new exploration and production technologies, efforts by the oil industry to reduce costs, and efforts by governments in non-OPEC countries to promote exploration and development by encouraging outside investors with attractive financial terms.

It is expected that oil prices will remain high enough that non-OPEC producers will be able to continue to increase output profitably, producing an additional 6.8 million barrels per day by 2010 in the reference case when compared with 2003. Much of the increased non-OPEC production is expected to come from Africa and Central and South America.

No one doubts that fossil fuels are subject to depletion and that depletion leads to scarcity, which in turn leads to higher prices; however, there are many resources that are not heavily exploited because they cannot be produced economically at low prices and with existing technologies. With higher prices, the development of such resources could become profitable. Ultimately, a combination of escalating prices and technological enhancements can make more resources economical. Much of the pessimism about oil resources has been focused entirely on conventional resources. However, there are substantial nonconventional resources, including production from oil sands, ultra-heavy oils, gas-to-liquids technologies, coal-to-liquids technologies, biofuel technologies, and shale oil, which can serve as a buffer against prolonged periods of very high oil prices. Total nonconventional liquids production in 2025 is projected to be 5.7 million barrels per day in the reference case, up from 1.8 million barrels per day in 2003.

Comparison of Projections

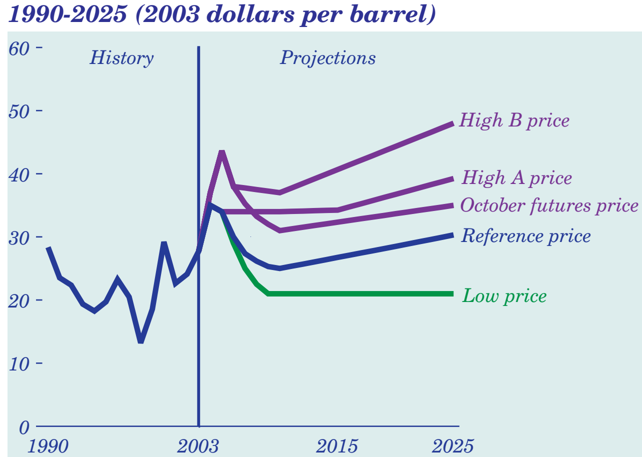
The world oil price cases in *AEO2005* are designed to address the uncertainty about the market behavior of OPEC. They are not intended to span the full range of possible outcomes. The cases are defined as follows:

- *Reference case.* Prices in 2010 are projected to be about $10 per barrel lower than current prices (2003 dollars) as both OPEC and non-OPEC producers add new production capacity over the next 5 years. After 2010, oil prices are projected to rise by about 1.3 percent per year, to more than $30 per barrel in 2025.
- *October oil futures case*. Prices in the near term rise through 2005, and then resume a growth trend similar to the reference case. The results of this case, which are similar to the reference case in the long term, are compared with the reference case results in the text box on page 44.
- *High A world oil price case*. Prices are projected to remain at about $34 per barrel through 2015 and then increase on average by 1.4 percent per year, to more than $39 per barrel in 2025.
- *High B world oil price case*. Projected prices continue to increase through 2005 to $44 per barrel, fall to $37 in 2010, and rise to $48 per barrel in 2025.
- *Low world oil price case*. Prices are projected to decline from their high in 2004 to $21 per barrel in 2009 and to remain at that level out to 2025.

World oil price projections in the five cases are shown in Figure 12. A detailed tabular summary and comparison of each of the oil price cases with the reference case is provided in Appendixes C and D.

Reference World Oil Price Case. In the reference case, the assumption is that the OPEC members will continue to demonstrate a disciplined production approach that reflects a strategy of price defense in which the larger producers are willing to increase or decrease production levels to maintain fairly stable prices (in real dollar terms) to discourage the development of alternative crude oil supplies or energy

Figure 12. World oil prices in the reference, October oil futures, high A, high B, and low oil price cases, 1990-2025 (2003 dollars per barrel)



The October oil futures case

The *AEO2005* reference case assumes that world crude oil prices will decline as consumption slows and producers increase their productive capacity and output in response to current prices. In October 2004, however, NYMEX oil futures prices implied that the average annual oil price in 2005 will exceed its 2004 level before falling back somewhat, to levels that still would be above those projected in the reference case. To evaluate the likely effects of that possible price path on the U.S. energy economy, *AEO2005* includes an October oil futures case, which is based on an extrapolation of oil prices loosely corresponding to the recent mid-term profile of prices on the NYMEX futures market.

In the October oil futures case, world crude oil prices are assumed to average $44 per barrel in 2005 (in 2003 dollars) before falling to about $31 per barrel in 2010—about $6 per barrel higher than the reference case projection. Prices are assumed to remain above those in the reference case over the entire projection and to be about $5 per barrel higher than the reference case projection in 2025, at $35 per barrel.

The *AEO2005* reference case and October oil futures case are based on different assumptions about oil production by the members of OPEC—higher in the reference case and lower in the October oil futures case—reflecting uncertainty about future levels of production from the Persian Gulf region. OPEC members are assumed to be the principal source of the marginal supply needed to meet increases in demand; consequently, OPEC member country production varies more than non-OPEC production in response to changes in demand requirements. OPEC member country production in 2025 is projected to be about 55 million barrels per day in the reference case and about 50 million barrels per day in the October oil futures case.

U.S. domestic consumption of petroleum in 2025 is projected to be slightly lower in the October oil futures case than in the reference case (27.3 million and 27.9 million barrels per day, respectively). Most of the difference is the result of lower projected demand for transportation fuels in the October oil futures case. In 2025, total demand for petroleum in the U.S. transportation sector is projected to be 19.5 million barrels per day in the October oil futures case, compared with 19.8 million barrels per day in the reference case.

Higher oil prices in the October oil futures case are projected to have a small impact on U.S. economic activity, primarily in the first 5 years of the forecast. From 2005 to 2010, U.S. GDP is a cumulative $194 billion (about 0.3 percent) lower in the October oil futures case than in the reference case. By 2025, however, the GDP projections are nearly identical in the reference and October oil futures cases. The projections for electricity and natural gas prices are not appreciably different in the two cases, which differ primarily in their projections for the delivered price of petroleum products, with impacts mainly in the transportation sector.

In response to higher oil prices, total domestic petroleum supply in 2025 is projected to be higher in the October oil futures case (9.3 million barrels per day) than in the reference case (8.8 million barrels per day), which in combination with the lower demand projection leads to a lower projected level of total petroleum imports in the October oil futures case. Including crude oil and refined products, total net imports in the October oil futures case (18.0 million barrels per day) are 1.1 million barrels per day lower than in the reference case (19.1 million barrels per day in 2025). As a result, the import share of total U.S. petroleum demand is 66 percent in the October oil futures case, compared with 68 percent in the reference case. In 2003, the import share of U.S. demand was 56 percent.

In the U.S. energy market, the transportation sector consumes about two-thirds of all petroleum products and the industrial sector about one-quarter. The remaining 10 percent is divided among the residential, commercial, and electric power sectors. With limited opportunities for fuel switching in the transportation and industrial sectors, large price-induced changes in U.S. petroleum consumption are unlikely, unless changes in petroleum prices are very large or there are significant changes in the efficiencies of petroleum-using equipment. The results of the October oil futures case indicate that sustained increases in world oil prices would have to be significantly greater than those assumed for this case in order to have a major impact on projected U.S. energy use.

sources, allow for continued robust worldwide economic growth, and maintain compliance with quotas, particularly by smaller OPEC producers. It is also assumed that OPEC producers will achieve sufficient oil revenues to expand production capacity enough to keep prices in a range of $27 to $30 per barrel in 2003 dollars, near the high end of the current OPEC price target range. Their current level of proven reserves (870 billion barrels) is sufficient to meet the implied production levels.

In the medium term, there is enough resource potential in non-OPEC countries to allow non-OPEC oil production to continue growing. Over the longer term, it is estimated that it will be harder for non-OPEC producers to continue to increase production. Assuming reference case prices, the search for alternatives and unconventional liquids will be limited, while demand will continue to grow. Therefore, OPEC members will have to make up the production difference (Figure 13). To satisfy the remaining global demand for oil at the given reference case prices, OPEC production will have to increase from 30.6 million barrels per day to 55.1 million barrels per day, an average annual increase in production of 2.7 percent. This is projected to result in an increase in OPEC's market share from 39 percent in 2003 to 46 percent in 2025, as cheaper sources of non-OPEC oil are depleted.

Table 17 summarizes the main features of the reference case in terms of cumulative production volumes, cumulative revenues, and the sum of the discounted cumulative revenues (at a 5-percent discount rate) from 2003 to 2025 [*79*]. The OPEC and non-OPEC countries are aggregated by major regions.

The reasoning behind the assumed prices and production patterns in the reference case can be questioned. If OPEC members have sufficient market power and cohesiveness to set world prices, why would they not try to set higher oil prices? If OPEC comprised a group of producer countries with similar oil reserves, resource depletion time horizons, geopolitical concerns, and no fear of alternatives to oil at higher prices, then a more limited production strategy that maximizes economic profits in the short to medium term would appear more plausible. In the absence of these conditions, however, and given the difficulty of enforcing tight production goals to limit output, a reasonable strategy is to maintain stable prices that discourage oil alternatives while limiting the risk that member countries will exceed their quotas.

Another issue is whether OPEC members will be able to finance the investments needed to expand their output as projected in the reference case. While some OPEC producer countries are currently closed to foreign involvement in the exploration and development of oil resources, it is expected that they will be able to attract foreign capital, if needed, while retaining

Figure 13. OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)

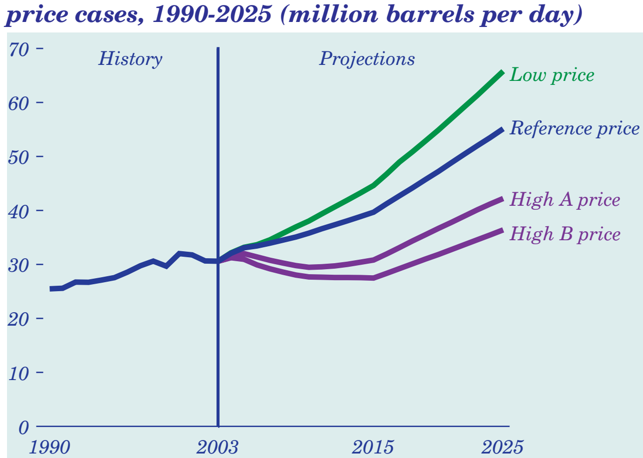


Table 17. Key projections in the reference case, 2003-2025

Country/region	World oil production (billion barrels): 2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	World oil revenues (trillion 2003 dollars): Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	9.0	208.3	0.2	5.9	3.4
Former Soviet Union and Eastern Europe	3.8	6.5	123.2	2.5	3.5	1.9
Developing countries	5.4	8.2	157.5	2.0	4.4	2.5
Total	**17.8**	**23.7**	**489.0**	**1.3**	**13.8**	**7.9**
OPEC						
Middle East	7.6	14.0	235.4	2.8	6.6	3.7
Other OPEC	3.5	6.1	107.6	2.5	3.0	1.7
Total	**11.2**	**20.1**	**343.1**	**2.7**	**9.7**	**5.4**
Total World	**29.0**	**43.9**	**832.1**	**1.9**	**23.4**	**13.2**

sovereignty over their energy resources. The markets for financial capital have provided sufficient resources in similar situations in the past, especially when there are strong incentives from both the demand and supply sides. The current experience of China, which did not attract much financial capital in the past, is an example of what can happen with the appropriate economic incentives or when the motivations are strong. Other historical examples include the flow of foreign capital to Latin America in the 1980s and East Asia in the 1990s.

There are also factors that may encourage countries in the Middle East to open up their energy sectors to foreign participation in one form or another. For example, Saudi Arabia, for some time now, has been lobbying to gain admission to the World Trade Organization. One of the conditions that Saudi Arabia needs to fulfill to gain entry is to open up its economy, especially its financial markets. The opening up of the United Arab Emirates to foreign financial capital and its creation of an export trade zone provide another example of how the economic environment can change.

High A World Oil Price Case. In the high A world oil price case, the OPEC countries in aggregate are assumed to maintain a relatively constant share of the world oil market. There are a number of ways that a constant market share for the OPEC countries might result over the projection period. First, more cohesion among OPEC members could begin to place greater emphasis on short-term profit maximization, with more control on member output, as might occur if a mechanism were devised to enable stricter enforcement of quotas. This cohesion might be reinforced by a perception that the incremental non-OPEC oil resource development costs are quite high and that the resource base is limited, and thus that there is less risk from non-OPEC producers in the long term. Second, some large producer countries in OPEC might not be able to finance sufficient development and enlargement of productive capacity because of competing social infrastructure demands on government budgets.

In this case, the world oil price would tend to reflect the projected incremental cost of non-OPEC oil and rise faster than in the reference case—from about $28 per barrel in 2003 to more than $39 per barrel in 2025 in real terms, an average annual increase of 1.6 percent from 2003 to 2025. As a result of higher world oil prices, world oil demand in 2025 is projected to be lower in the high A world oil price case than in the reference case (115 million barrels per day and 120 million barrels per day, respectively). Table 18 summarizes the main features of the high A world oil price case.

For OPEC members, cumulative production of almost 280 billion barrels in the high A world oil price case is projected to bring in $9.9 trillion (in 2003 dollars), as compared with cumulative production of 343 billion barrels and revenues of $9.7 trillion in the reference case. Although the high A world oil price case appears to be more attractive to OPEC producers than the reference case in terms of economic profits, the sustainability of the higher prices over the projection period is uncertain. Higher prices would create greater incentive for OPEC countries to exceed quotas, greater likelihood of increased conventional and unconventional oil production in non-OPEC countries, and greater possibility of increased conservation measures in oil-consuming countries, induced both by higher prices and by public policy measures.

Table 18. Key projections in the high A world oil price case, 2003-2025

	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	10.0	221.1	0.7	7.8	4.6
Former Soviet Union and Eastern Europe	3.8	7.1	132.2	2.9	4.7	2.7
Developing countries	5.4	9.2	170.4	2.4	6.0	3.5
Total	**17.9**	**26.3**	**523.7**	**1.8**	**18.5**	**10.8**
OPEC						
Middle East	7.6	10.5	189.8	1.5	6.7	3.9
Other OPEC	3.5	4.9	90.6	1.5	3.2	1.9
Total	**11.1**	**15.4**	**280.4**	**1.5**	**9.9**	**5.8**
Total World	**29.0**	**41.7**	**804.1**	**1.7**	**28.4**	**16.6**

While the *AEO* cases are developed under the assumption of unchanged policy in consuming countries, major oil exporters may expect that higher prices would spur policy responses in oil-importing nations. Based on these considerations, economically rational producers would be likely to apply higher discount rates when evaluating the revenue stream associated with the high A world oil price case than that associated with the reference case. Taking this difference into account, key OPEC producers might accept the reference price case.

High B World Oil Price Case. There is a great deal of uncertainty about the size and availability of crude oil resources, particularly conventional resources, the adequacy of investment capital, and geopolitical trends. While the high A world oil price case tries to reflect the uncertainty in some of these variables, some analysts argue that the higher prices seen in recent years will be sustained and represent a fundamental change in the market. The high B world oil price case was completed to evaluate the impact of world oil prices that remain close to current levels for the foreseeable future.

The high B world oil price case assumes a continued rise in prices through 2005, followed by a gradual decline to 2010 and then strong increases through 2025. The near-term prices reflect the trends observed in oil futures on the NYMEX for WTI during October 2004, where crude oil futures prices exceeded 2004 levels in 2005 before falling back somewhat, but to levels well above those projected in the *AEO2005* reference case. The world oil price in the high B case is assumed to be $2 higher than in the reference case in 2004, or $37 per barrel, to grow to about $44 per barrel in 2005 before falling to $37 in 2010, and then to rise to $48 per barrel in 2025, compared with $30 in the reference case and $39 in the high A world oil price case.

The high B world oil price case reflects an assumption that OPEC producers will be less able or willing to expand their productive capacity and that their output growth will be constrained considerably (Table 19). As a result, the OPEC members are projected to lose market share over time, in contrast to the high A world oil price case, where their market share remains constant over time. OPEC member country production is projected to grow from 30.6 million barrels per day in 2003 to 36.6 million barrels per day in 2025, compared with 55.1 million barrels per day in the reference case and 42.4 million barrels per day in the high A world oil price case. The worldwide impacts on energy supply in the high B case are more uncertain because of limited experience with sustained periods of high world oil prices. Nevertheless, roughly one-half of the difference between OPEC member country production in the reference and high B world oil price cases is projected to be made up for by non-OPEC countries (Figure 14). The remaining difference reflects the reduction in oil demand resulting from higher prices, as well as increased production of synthetic oil from coal and natural gas and nonconventional liquids.

Undiscounted cumulative revenues from OPEC member country production in the high B world oil price case exceed those in the reference and high A world oil price cases, despite lower production; however, the high B case is projected to result in significant impacts on world energy demand and alternative sources of supply, including increased production from synthetic fuels. In addition, strong cohesiveness among OPEC members would be required to maintain the strict production quotas implicit in the high

Table 19. Key projections in the high B world oil price case, 2003-2025

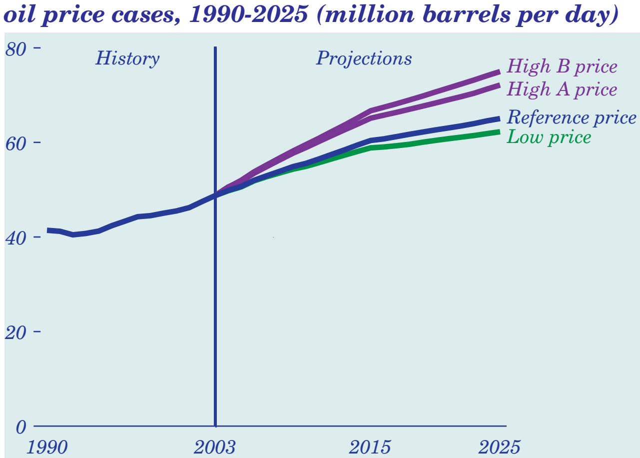
	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	10.2	225.0	0.8	9.2	5.4
Former Soviet Union and Eastern Europe	3.8	7.2	133.4	2.9	5.5	3.1
Developing countries	5.4	9.5	173.1	2.6	7.2	4.1
Total	**17.9**	**26.9**	**531.5**	**1.9**	**21.9**	**12.6**
OPEC						
Middle East	7.6	9.0	171.9	0.8	7.1	4.2
Other OPEC	3.5	4.3	83.3	1.0	3.4	2.0
Total	**11.1**	**13.4**	**255.2**	**0.9**	**10.5**	**6.2**
Total World	**29.0**	**40.3**	**786.7**	**1.5**	**32.4**	**18.8**

B case. As a result, the uncertainty and risk associated with this case for individual OPEC members suggest that a higher rate is appropriate for discounting the projected revenue stream.

The projections in the high B world oil price and reference cases are compared in the text box on page 49. It is important to stress the uncertainties and limitations of this case. The market conditions in the high B world oil price case fall outside the range of experience best represented in NEMS. In particular, some of the modeling uncertainties and limitations about the case are as follows:

- The level of economic production of oil from both conventional sources and unconventional sources (such as oil sands) is subject to considerable uncertainty, particularly with sustained oil prices at much higher levels than in the reference case.
- The effects of global competition for natural gas through pipelines, LNG, and gas-to-liquids (GTL) are highly uncertain in an environment of high sustained oil prices. For example, stranded gas (gas production at sites without access to pipelines) that might otherwise be economical to export as LNG could potentially become economical to process as GTL. These impacts on world natural gas supply cannot be evaluated endogenously with the present versions of EIA's U.S. and global energy models; however, an adjustment to the assumed cost profile of LNG imports to the United States has been incorporated to reflect the potential market impact. As model development is able to continue, additional analytical capability in this area would be a high priority.
- Prospects for synthetic petroleum—GTL and coal-to-liquids (CTL) may be constrained by plant siting issues that have not been investigated, such as waste disposal and limited water supplies.
- The worldwide economic and political response to a regime of prolonged high oil prices is uncertain, as is the long-term effect on domestic economic growth.
- EIA's modeling of petroleum consumption reflects observed patterns of use and consumer preferences, as well as existing and foreseeable technologies. Consumer and manufacturer behavior in the face of sustained high oil prices may depart from the patterns on which the model is based. For example, there could be shifts to smaller, more efficient vehicles, more penetration of alternative-fuel vehicles, and a shift in the demand for vehicular travel to other travel modes, such as from truck to rail freight.
- High world oil prices and high natural gas prices may spur unforeseen technological innovation and adoption, but quantifying these possibilities remains a challenge.

Figure 14. Non-OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)



Low World Oil Price Case. The low world oil price case reflects a future market where all oil production becomes more competitive and plentiful. There are several ways in which this could come about. First, the OPEC countries could become less cohesive, with each producer attempting to sell as much of its productive capacity as the market will allow. In this sense, the low world oil price case is exactly the opposite of the high A world oil price case. Another possibility would be a decline in the costs of non-OPEC oil production or the viable development of competitive alternatives. To forestall the penetration of alternatives and other sources of competition, OPEC would lower its price band and increase production.

The world oil price (in 2003 dollars) is projected to decline from about $28 per barrel in 2003 to $21 per barrel in 2009 in the low world oil price case, and to stay at that level through 2025. As a result of increased competition between OPEC members or a conscious attempt to increase market share, the market share of OPEC's member countries increases from 39 percent in 2003 to 51 percent in 2025. Within OPEC, nearly all producers, except for Indonesia, which has limited remaining resources, are projected to increase production at an average annual rate of 3 percent or higher over the 2003 to 2025 period. The average annual growth in production by OPEC members over the same period is 3.5 percent. The low world oil prices in this case cause world oil demand to increase from 80 million barrels per day in 2003 to

Comparison of projections in the reference and high B world oil price cases

Higher crude oil prices spur greater exploration and development of domestic oil supplies, reduce demand for petroleum, and slow the growth of oil imports in the high B world oil price case compared to the reference case. Total domestic petroleum supply in 2025 is projected to be 2.2 million barrels a day (25 percent) higher in the high B case than in the reference case. Production in the high B case includes 1.2 million barrels a day in 2025 from synthetic petroleum fuel produced from coal and natural gas. Total net imports in 2025, including crude oil and refined products, are reduced from 19.1 million barrels a day in the reference case to 15.2 in the high B case. As a result, the projected import share of total U.S. petroleum demand in 2025 is 58 percent in the high B world oil price case, compared with 68 percent in the reference case. In 2003, the import share of U.S. petroleum demand was 56 percent.

With the steep, prolonged rise in crude oil prices in the high B world oil price case, the worldwide potential for natural gas and coal-based synthetic fuels would become viable, with implications for imported U.S. supplies of LNG. In the reference case, the United States is expected to become increasingly dependent on LNG, with imports projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025. In the high B case, GTL conversion of stranded natural gas could compete favorably with liquefaction, thus reducing the potential supply of LNG worldwide. As a result, LNG supplied to the United States is projected to be priced higher in the high B world oil price case, leading to higher average end-use natural gas prices than in the reference case and to a 51-percent reduction in projected imports of LNG in 2025. The projected average *delivered* price of natural gas in 2025 (in 2003 dollars) is $7.35 per thousand cubic feet in the high B world oil price case, compared with $6.77 in the reference case.

The higher oil and natural gas prices in the high B world oil price case result in a greater reliance on domestic gas supply, along with a reduction in the projected growth of natural gas consumption. Domestic dry gas production in 2025 in the high B case increases to 23.5 trillion cubic feet, 8 percent higher than the reference case projection of 21.8 trillion cubic feet. In addition, the high price of oil in the high B case results in favorable economics for GTL domestically, leading to an additional 0.7 trillion cubic feet of natural gas consumption for GTL in 2025, offsetting some of the reduction in end-use demand that would result from higher natural gas prices.

The higher natural gas prices in the high B world oil price case would promote greater use of coal technologies for new electricity generation plants, leading to an increase in projected coal consumption of 69 million short tons in 2025 compared to the reference case. In addition, CTL technology to produce petroleum fuels is expected to become economical in the high B world oil price case, resulting in additional coal consumption of 209 million short tons in 2025.

CTL plants are assumed to employ integrated gasification and combined-cycle power generation to produce synthesis gas, process steam, and electric power. CTL plants are considered to be combined heat and power plants, supplying surplus electricity as well as power for on-site use. As a result, an increase of 25 gigawatts of generating capacity from CTL plants is projected in the high B world oil price case. In aggregate, CTL plants are estimated to produce 1 million barrels a day of synthetic liquid fuel in 2025 in the high B world oil price case.

U.S. petroleum demand is reduced in the high B world oil price case, but the modest response to the price changes reflects the limited opportunities for fuel switching in the transportation and industrial sectors, which account for about 90 percent of U.S. oil consumption. Total petroleum consumption is projected to change by only 3 percent in 2010, compared to the reference case, despite a 22-percent higher average price of refined petroleum in 2010. In 2025, petroleum demand is 6 percent lower in the high B world oil price case, and average refined petroleum prices are 32 percent higher.

About two-thirds of the difference in projected petroleum consumption between the reference and high B world oil price cases in 2025 is represented by gasoline. There is very little difference between the projections of demand for transportation uses of diesel and jet fuel, which together accounted for one-third of the petroleum used in the transport sector in 2003. The demand for diesel fuel to move freight in trucks, rail, and shipping is relatively insensitive to price changes, as the equipment used is long-lived and the prospects of efficiency improvements for freight carriers are more limited than

(continued on page 50)

Comparison of projections in the reference and high B world oil price cases (continued)

those for passenger transportation. In addition, there is some projected increase in rail and shipping in the high B world oil price case as a result of increased coal use in the electricity sector, offsetting some of the fuel saved by efficiency improvements in the freight truck fleet. Potential energy savings beyond those projected in the high B world oil price case would be possible if there were greater shifts among modes of travel, such as increased use of rail in place of trucking.

The demand for jet fuel is expected to be insensitive to price increases through 2025, as air travel growth is constrained by the availability of airport capacity in that time frame. The changes in fuel costs are unlikely to bring air travel demand down below the limits imposed by available airport capacity, eliminating much of the expected price response. The reduction in jet fuel between the reference and the high B world oil price cases, 1.6 percent in 2025, occurs primarily due to adoption of technology to increase aircraft efficiency.

Growth in projected gasoline demand in the high B world oil price case is lower than the reference case, as consumers respond to higher increased fuel costs by reducing the number of vehicle miles traveled and by purchasing more efficient automobiles. The projected price of gasoline in 2025 in the high B world oil price case is $2.01 a gallon (2003 dollars), compared to $1.59 in the reference case. As a result, average fuel economy of new, light-duty vehicles in 2025 increases from 26.9 miles per gallon in the reference case to 28.2 in the high B world oil price case. Even greater fuel economy improvements might occur under a high price scenario if consumers and manufacturers departed from recent trends and shifted to smaller, less powerful vehicles, or if there was a greater penetration rate of hybrid and diesel vehicles than is projected. However, at gasoline prices at or below $2.00 a gallon, significant changes in consumer behavior are not expected.

The U.S. economy is sensitive to oil price spikes, and several recessions have followed supply disruptions in recent decades; however, gradual changes in oil prices are less damaging to long-term economic growth, because the economy has more time to adjust. The projected impact on real GDP in the high B world oil price case, compared to the reference case, is $53 billion (2000 dollars) in 2010 (0.4 percent) and $32 billion in 2025 (0.2 percent). The macroeconomic results suggest that the U.S. economy would continue to fare well in the face of rising oil prices, provided that prices rose gradually over a long period of time; however, this analysis does not consider the potential impacts on the United States of worldwide economic disruption that might occur as a result of sustained high oil prices.

128 million barrels per day in 2025, an average annual increase of 2.2 percent.

Given the projected state of technology, projected reserves, and their relatively higher cost structures, non-OPEC producers would be expected to increase output at a slower rate in the low world oil price case than in the reference case (Figure 14). Starting from a production level of 49 million barrels per day in 2003, non-OPEC oil output is projected to grow at an average annual rate of 1.1 percent in the low price case, to 62 million barrels per day in 2025. Table 20 summarizes the main features of the low world oil price case.

The low oil price case is the most favorable of the *AEO2005* oil price cases in terms of economic welfare, because the world oil price is projected to be closer to its marginal cost. It is less favorable, however, from the producers' point of view. Relative to the reference case, OPEC members would end up producing 11 percent more oil over the 2003 to 2025 period and earning roughly 11 percent less in cumulative revenues. Further, with a decline in oil prices there would be less exploration activity at the margin, a tendency for more cohesion in OPEC, and lower penetration of alternative fuels.

Changing Trends in the Bulk Chemicals and Pulp and Paper Industries

Compared with the experience of the 1990s, rising energy prices in recent years have led to questions about expectations of growth in industrial output, particularly in energy-intensive industries. Given the higher price trends, a review of expected growth trends in selected industries was undertaken as part of the production of *AEO2005*. In addition, projections for the industrial value of shipments, which were based on the Standard Industrial Classification (SIC) system in *AEO2004*, are based on the North American Industry Classification System (NAICS) in *AEO2005*. The change in industrial classification leads to lower historical growth rates for many industrial sectors. The impacts of these two changes are

Table 20. Key projections in the low world oil price case, 2003-2025

	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	8.5	202.8	0.0	4.7	2.9
Former Soviet Union and Eastern Europe	3.8	6.3	121.1	2.3	2.7	1.6
Developing countries	5.4	7.9	153.8	1.8	3.5	2.1
Total	**17.8**	**22.7**	**477.8**	**1.1**	**10.9**	**6.5**
OPEC						
Middle East	7.6	16.9	264.0	3.7	5.9	3.4
Other OPEC	3.5	7.1	117.7	3.2	2.6	1.5
Total	**11.2**	**24.0**	**381.7**	**3.5**	**8.6**	**4.9**
Total World	**29.0**	**46.7**	**859.5**	**2.2**	**19.5**	**11.4**

highlighted in this section for two of the largest energy-consuming industries in the U.S. industrial sector—bulk chemicals and pulp and paper.

Output growth rates for the pulp and paper industry and the bulk chemical industry have been revised downward in *AEO2005* to align better with historical trends. Models for both industries in NEMS have also been revised to reflect recent trends in their specific production processes. In combination, these changes have had an important impact on the *AEO2005* forecast for industrial energy consumption.

The scope of activities included in the industrial sector (which includes agriculture, mining, construction, and manufacturing) and how they are defined have changed with the move to NAICS. For example, publishing, logging, and manufacturers' administrative and auxiliary services that are not co-located with manufacturing establishments are no longer covered in the manufacturing sector but are now included in the commercial sector. Under NAICS, the manufacturing sector is about 3 percent smaller in terms of value and 4 percent smaller in terms of employment than under SIC in 1997, the only year for which economic census data are available for both classification systems.

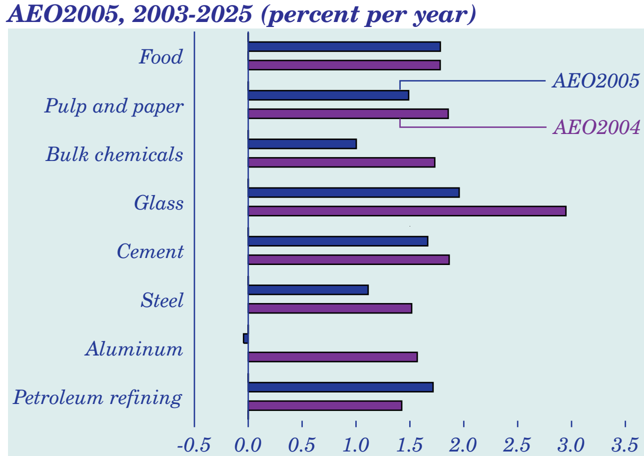
The *AEO2005* industrial forecast reflects both changes in economic conditions and changes in historical growth rates as a result of the move from SIC to NAICS. The projected growth rates for most energy-intensive industries are lower in *AEO2005* than in *AEO2004*, in part because the historical growth rates have been revised downward. Figure 15 compares the growth rates projected for selected energy-intensive industries in *AEO2005* and *AEO2004*.

Pulp and Paper

AEO2004 projected that paper final product would grow by an average of 1.9 percent annually from 2003 to 2025; however, the intermediate steps in the industry, and the energy use associated with them, were expected to grow at different rates as the mix of technologies changed and costs shifted. For example, between 2003 and 2025, kraft pulping was projected to grow by 2.1 percent per year while semi-chemical pulping grew by 0.9 percent per year. Mechanical pulping was projected to decline by 0.5 percent per year over the same period.

From 1983 to 2000, paper and board production grew by 2.1 percent per year while total pulping grew by only 1.1 percent per year. Although long-term data for the individual pulping steps is limited, kraft pulping, because of its superior technology [*80*], is the primary pulping method, accounting for 86 percent of

Figure 15. Projected growth in output for energy-intensive industries in AEO2004 and AEO2005, 2003-2025 (percent per year)



virgin pulping in 2002. Between 1996 and 2002, kraft pulping increased while semi-chemical pulping declined, and mechanical pulping dropped by more than 20 percent [*81*].

Growth in final paper and board production, coupled with slower growth or a decline in the intermediate pulping steps, is made possible by increases in recovered paper and imports of market pulp. Consumption of recovered paper at paper and board mills increased by 5 percent annually from 1983 to 2002, and the United States has gone from being a net exporter of market pulp in 1997 to a net importer in 2002, importing about 15 percent more than it exports [*82*].

The *AEO2004* results were reviewed relative to the trends outlined above, and revisions were made as necessary. As a result of the changes made and a lower forecast of growth in final industrial production in *AEO2005*, waste pulping, which consists of recovered paper and market pulp, is projected to grow by 2.0 percent per year from 2003 to 2025; mechanical pulping is projected to decline by 0.8 percent per year; and semi-chemical and kraft pulping are projected to grow by 0.7 percent per year and 1.4 percent per year, respectively. Pulp and paper output is projected to grow by 1.5 percent per year.

The most notable impact of these revisions and updates is that the projected growth of purchased electricity for the pulp and paper sector falls to only 0.1 percent per year in *AEO2005*, from 0.6 percent per year in *AEO2004* (Figure 16). The use of all fuels in the pulp and paper industry is projected to grow more slowly (or decline faster) in *AEO2005* than in *AEO2004*. Total energy consumption for the pulp and paper industry is projected to grow at an annual rate of 0.9 percent per year from 2003 to 2025 in *AEO2005*, compared with 1.4 percent per year in *AEO2004*.

Bulk Chemicals

The bulk chemical industry is dependent on natural gas and petroleum as material inputs (feedstocks) and as fuels for heat and power. The bulk chemical industry model used for *AEO2005* was revised to address separately the four subsectors of the bulk chemical industry: inorganic, organic, resins, and agricultural chemicals [*83*]. Figure 17 compares the projected output growth rates for each component of the bulk chemical industry in *AEO2004* and *AEO2005*.

The growth rate for the total bulk chemical industry is projected to be 1.0 percent per year in *AEO2005*, compared with 1.7 percent per year in *AEO2004*. The largest changes are for the inorganic and agricultural chemicals components of the bulk chemical industry. The inorganic chemicals industry is a mature industry [*84*] that has grown slowly over the past several years. Its limited growth prospects are better represented in *AEO2005*, where the projected growth rate for inorganic chemicals is close to zero as compared with 1.4 percent per year in *AEO2004*. The agricultural chemicals subsector, which includes the production of nitrogenous fertilizers, has faced increased competition from foreign suppliers due to relatively high U.S. natural gas prices [*85*]. The *AEO2005* forecast reflects the current competitive situation. This update reduced projected growth from 1.3 percent per year in *AEO2004* to 0.6 percent per year in *AEO2005*. The organic and resins components have exhibited a tendency toward increasing use of imports of energy-intensive intermediate products in preference to domestically manufactured products [*86*], and that tendency is reflected in a lower assumed energy intensity for new or replacement plant.

Figure 16. Projected growth in energy consumption for the pulp and paper industry in AEO2004 and AEO2005, 2003-2025 (percent per year)

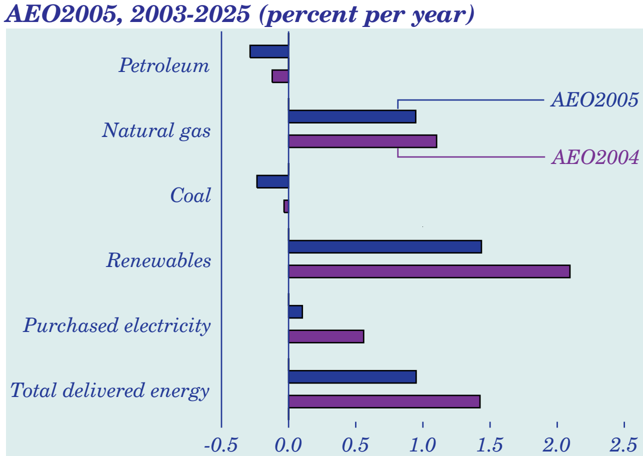
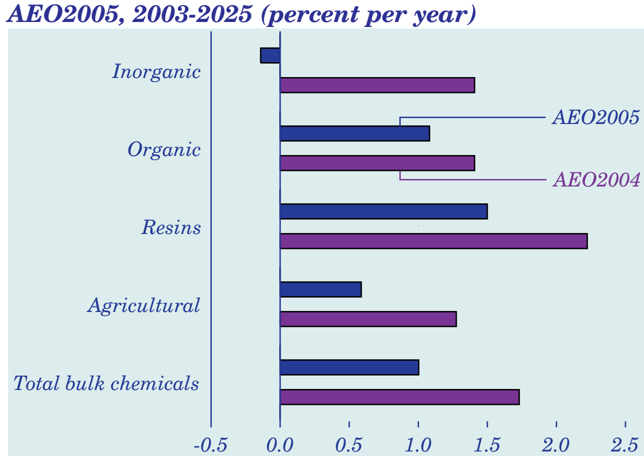


Figure 17. Projected output growth for components of the bulk chemicals industry in AEO2004 and AEO2005, 2003-2025 (percent per year)



The combination of lower projected output growth and a shift to less energy-intensive production processes leads to lower projected growth in energy consumption for the bulk chemical industry in *AEO2005* than was projected in *AEO2004* (Figure 18). Despite these changes, however, the bulk chemical industry remains the largest energy-consuming industry in the industrial sector. In 2003, the bulk chemical industry consumed 6.3 quadrillion Btu of energy (including feedstocks), and that total is projected to grow to 7.5 quadrillion Btu in 2025, about 1 quadrillion Btu less than was projected in *AEO2004*. Feedstock consumption is projected to increase from 3.5 quadrillion Btu in 2003 to 4.3 quadrillion Btu in 2025 in the *AEO2005* forecast, 0.4 quadrillion Btu less than was projected in *AEO2004*.

In summary, the transition from SIC to NAICS, reduced rates of output growth, and revised modeling have reduced the *AEO2005* projection of industrial energy consumption in 2025 by 2.6 quadrillion Btu (8 percent) from the *AEO2004* projection. Lower natural gas consumption accounts for about two-thirds of the difference between the two projections.

Fuel Economy of the Light-Duty Vehicle Fleet

The U.S. fleet of light-duty vehicles consists of cars and light trucks, including minivans, sport utility vehicles (SUVs) and trucks with gross vehicle weight less than 8,500 pounds. The fuel economy of light-duty vehicles is regulated by the CAFE standards set by NHTSA. Currently, the CAFE standard is 27.5 miles per gallon (mpg) for cars and 20.7 mpg for light trucks. The most recent increase in the CAFE standard for cars was in 1990, and the most recent increase in the CAFE standard for light trucks was in 1996.

There has been little improvement in the average fuel economy of new cars and light trucks sold in the United States over the past 15 years (Figure 19), but the combined average fuel economy for all new light-duty vehicles has declined steadily because of an increase in sales of light trucks. Since 1987, the average fuel economy of new light-duty vehicles sold has remained relatively constant, averaging 28.5 mpg for cars and 21.1 mpg for light trucks. For model year 2003, cars achieved the highest measured CAFE to date, averaging 29.4 mpg. The highest light truck CAFE was achieved in 1987 at 21.7 mpg, but light truck CAFE has been increasing in recent years, to 21.6 mpg for model year 2003 [*87*]. The fuel economy of light trucks is expected to improve over the next 3 years, because NHTSA announced new standards in April 2003 that increased the requirements to 21.0 mpg for model year 2005, 21.6 mpg for model year 2006, and 22.2 mpg for model years 2007 and beyond.

Although the relatively flat fuel economy for cars and light trucks over the past 15 years may suggest little technological improvement, this is not the case. Instead, technological advances have led to significant improvements in vehicle performance and increases in vehicle size, while generally maintaining or slightly increasing fuel economy. Based on NHTSA data, the average new car in 1990 achieved 28.0 mpg, had a curb weight of 2,906 pounds, and produced 132 horsepower. In 2002, average new car fuel economy was 3.2 percent higher at 28.9 mpg, curb weight was 8.7 percent higher at 3,159 pounds, and engine size was 30.0 percent higher at 171 horsepower [*88*]. Thus, although fuel economy improvements have been minimal, the introduction of advanced

Figure 18. Projected growth in energy consumption for the bulk chemicals industry by energy source in AEO2004 and AEO2005, 2003-2025 (percent per year)

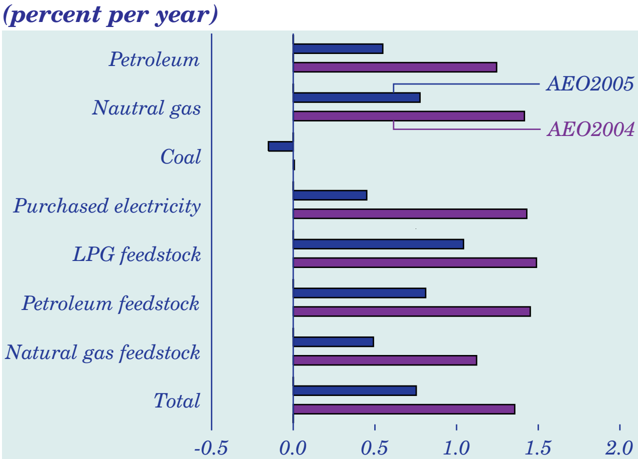
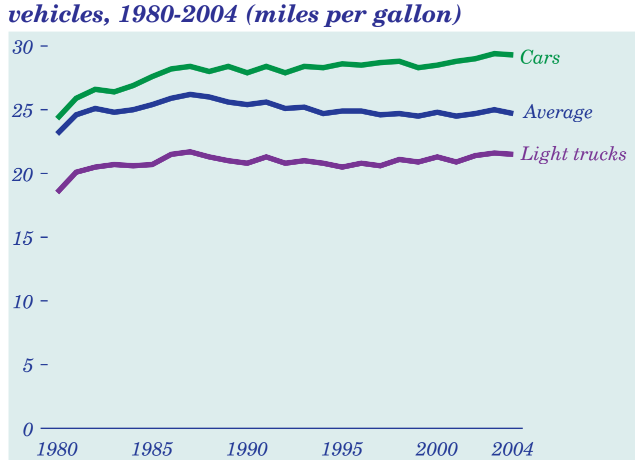


Figure 19. Average fuel economy for new light-duty vehicles, 1980-2004 (miles per gallon)



technologies (including variable valve timing and lift, electronic engine and transmission controls, lock-up torque converters, and five-speed automatic transmissions) have produced significant improvement in engine and transmission efficiency, allowing substantial increases in new car size and performance. Data from the EPA show similar performance trends. For example, from 1990 to 2002, average new car horsepower per cubic inch displacement, a measure of engine efficiency, increased by 28.6 percent, from 0.83 to 1.07, as a result of implementation of advanced technologies and improved engine designs [*89*].

Similar improvements in vehicle attributes have also occurred for light trucks. In 1990, the average new light truck achieved 20.8 mpg, had a curb weight of 4,005 pounds, and produced 151 horsepower. In 2002, the average fuel economy for new light trucks was 4.8 percent higher at 21.8 mpg, curb weight was 13.5 percent higher at 4,547 pounds, and engine size was 45.7 percent higher at 220 horsepower. As in the case of cars, manufacturers have provided improved fuel economy for light trucks while increasing vehicle size and performance by implementing advanced technologies. From 1990 to 2002, light truck horsepower per cubic inch displacement increased by 37.4 percent, from 0.67 to 0.92.

In addition to increases in weight and performance, the mix of new vehicles sold has changed dramatically over the past 20 years. In 1983, cars accounted for 76.5 percent of new light-duty vehicles sold; in 2003, they accounted for only 47.2 percent. In addition, sales of subcompact cars, as a percent of total new vehicles sold, decreased from 20.5 percent in 1983 to 2.8 percent in 2003. Compact, midsize, and large car sales as a percent of total new light-duty vehicle sales have also declined.

Since 1983, sales of new light trucks, including SUVs, have increased significantly. In 2002, light trucks made up the majority of new light-duty vehicle sales. Increases in light truck sales over the past 20 years can be attributed to increased consumer demand for vehicle utility, seating capacity, ride height, and perceived safety. Coupled with low fuel prices, this trend has provided a favorable market for new light trucks, with sales of SUVs and minivans accounting for most of the increase in light truck sales. In 1983, SUVs accounted for 2.9 percent of new light-duty vehicle sales; in 2003, SUVs accounted for 27.0 percent of new light-duty vehicle sales and represented the largest segment of the light-duty vehicle market. Similarly, sales of minivans have grown dramatically. In 1983, minivans accounted for 0.1 percent of new light-duty vehicle sales; in 1994, they reached a peak share of 9.2 percent; and in 2003 their share was 6.5 percent of new light-duty vehicle sales [*90*].

Although significant improvements have been made in light-duty vehicle engine and transmission efficiency, consumer demand for increased performance and vehicle size, coupled with the growth of the light truck market, has resulted in an average new light-duty vehicle fuel economy that peaked at 26.2 mpg in 1987. New light-duty vehicle fuel economy declined steadily throughout the 1990s, to a low of 24.5 mpg in 1999, followed by an increase to 25.0 mpg for model year 2003 vehicles.

The *AEO2005* reference case projects that, in addition to increases in market penetration of advanced technologies, sales of hybrid and diesel vehicles will continue to increase. As a result, new car fuel economy in 2025 is projected to average 31.0 mpg, and new light truck fuel economy is projected to average 24.6 mpg—increases of 5.4 percent for cars and 14.1 percent for light trucks over the respective model year 2003 CAFE levels. Similar to historic trends, average engine power output is projected to increase to 215 horsepower for new cars sold in 2025 (26.3 percent higher than model year 2003) and 243 horsepower for new light trucks sold in 2025 (18.0 percent higher than model year 2003). Light truck sales are projected to account for 58.6 percent of new light-duty vehicle sales in 2025, and as a result the average fuel economy for all new light-duty vehicles sold is projected to increase by 7.2 percent, to 26.9 mpg in 2025.

Recent introductions of more efficient crossover vehicles (SUVs with design features more similar to those of cars than trucks), increasing consumer interest in environmentally friendly vehicles, the possibility of sustained high fuel prices, and increasing consumer demand for improvements in vehicle performance and luxury all will influence the future of light-duty vehicle sales and fuel economy. In addition, carbon emission regulations for light-duty vehicles that have been issued in eight U.S. States and Canada would require improvements in vehicle fuel economy starting in 2009 that go beyond those required by current U.S. CAFE standards. (*AEO2005* does not include the impact of these carbon emission regulations, because their future is uncertain. The auto industry has filed suit against the regulations established in California, contending that only the Federal Government has the authority to set vehicle fuel economy standards. See "Legislation and Regulations," page 27.) NHTSA is also considering modification of light truck CAFE standards, which could result in the redefinition of a light truck as well as a restructuring of the standards to be based on vehicle weight and/or size.

In summary, considerable uncertainty surrounds the future of light-duty vehicle fuel economy. Fuel prices, the market success of hybrid and diesel vehicles, continued increases in consumer demand for light trucks and better vehicle performance, potential new fuel economy standards, and future regulation of carbon dioxide emissions all have potentially significant impacts on the automobile industry and the vehicles that will be manufactured and sold in the future.

U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*91*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output.

AEO2005 projects energy-related carbon dioxide emissions, which represented approximately 84 percent of total U.S. greenhouse gas emissions in 2002. Projections for the other greenhouse gases are based on an EPA "Business-as-Usual" (BAU) case cited in the Addendum to the *Global Climate Change Policy Book* [*92*] released with the Global Climate Change Initiative. Those projections are based on several EPA-sponsored studies conducted in the preparation of the U.S. Department of State's *Climate Action Report 2002* [*93*, *94*, *95*, *96*]. Table 21 combines the *AEO2005* reference case projections for energy-related carbon dioxide emissions with the projections for other greenhouse gases.

According to the combined emissions projections in Table 21, the greenhouse gas intensity of the U.S. economy is expected to decline by 14 percent from 2002 to 2012 and by 30 percent from 2002 to 2025 in the reference case. The Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require an emissions reduction of about 366 million metric tons carbon dioxide equivalent from the projected level in the reference case.

Although *AEO2005* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent intensity reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, carbon dioxide emissions in 2012 are projected to be 129 million metric tons less than the reference case projection. As a result, U.S. greenhouse gas intensity would fall by 15.5 percent from 2002 to 2012, still somewhat short of the Administration's goal of 18 percent (Figure 20). An 18-percent decline in intensity is projected to occur by 2014 in the integrated high technology case, as compared with 2015 in the reference case.

Impacts of Temperature Variation on Energy Demand in Buildings

In the residential and commercial sectors, heating and cooling account for more than 40 percent of

Table 21. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025

	Projection			Percent Change	
Measure	2002	2012	2025	2002-2012	2002-2025
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,750	6,812	8,062	18.5	40.2
Methane	599	609	606	1.7	1.1
Nitrous oxide	323	342	382	5.7	18.3
Gases with high global warming potential	144	284	624	97.5	334.0
Other carbon dioxide and adjustments for military and international bunker fuel	60	82	93	37.2	56.9
Total greenhouse gases	**6,876**	**8,128**	**9,767**	**18.2**	**42.1**
Gross domestic product (billion 2000 dollars)	10,075	13,869	20,292	37.7	101.4
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 2000 dollars of gross domestic product)	682	586	481	-14.1	-29.5

end-use energy demand. As a result, energy consumption in those sectors can vary significantly from year to year, depending on yearly average temperatures.

In long-term energy forecasting, an average of the heating and cooling degree-days data for the previous 30 years is ordinarily used as a proxy for "normal" weather [*97*]. Both heating and cooling degree-days have shown a slight warming trend since 1973 (Figure 21), although no warming trend is evident from an examination of the long-term data since 1930. The direction of year-to-year fluctuations in U.S. average heating degree-days and in U.S. average cooling-degree days do not appear to be correlated; however, both the lowest yearly average for heating degree-days and the highest yearly average for cooling degree-days were recorded in 1998. The coldest winter over the 1973-2003 period (1978) was 11 percent colder than the average, and the warmest winter (1998) was 12 percent warmer than the average. The coolest summer (1976) was 16 percent cooler than the average, and the warmest summer (1998) was 15 percent warmer than the average.

The *AEO2005* reference case uses the 30-year average of heating and cooling degree-days from the National Oceanic and Atmospheric Administration at the State level, adjusted for State population forecasts through 2025, to represent future temperatures (previous *AEO*s used Census division forecasts). As a result of State population shifts, population-weighted heating degree-days are projected to decline by 3.2 percent, and population-weighted cooling degree-days are projected to increase by 4.1 percent from 2003 to 2025, relative to the weather normal average assumed in 2005, because the population is projected to shift to States with warmer climates.

To estimate the possible impact of warmer or colder weather on energy use in the residential and commercial sectors, two alternative cases were examined: a warmer case assuming above-average temperatures and a cooler case assuming below-average temperatures throughout the projection period. For this analysis, it was assumed that State-level heating and cooling degree-days would reach the average of the five warmest or coolest levels that have occurred over the past 30 years by 2025. It was also assumed that warmer winters would coincide with warmer summers, and vice versa. Figures 22 and 23 show the projected trends in heating and cooling degree-days from 2005 to 2025 in the reference, warmer, and cooler cases. Compared with the reference case forecast, heating degree-days are projected to be 11 percent higher in the cooler case and 12 percent lower in the warmer case by 2025, and cooling degree-days are projected to be 17 percent higher in the warmer case and 16 percent lower in the cooler case.

The impacts of the assumptions in the warmer and cooler weather cases on projected energy consumption in the residential and commercial sectors are mixed, because warmer winters reduce demand for space heating (generally fossil fuels) and warmer summers increase demand for space cooling (generally electricity), whereas colder winters and summers do the opposite. Figure 24 shows the impacts of the two cases on electricity consumption (including conversion losses) and direct fossil fuel consumption.

Given that fossil-fuel-fired space heating is the largest use of energy in the two buildings sectors, it is not surprising that the cumulative change in the two weather cases is greatest for fossil fuels. The cumulative change in fossil fuel consumption in the buildings

Figure 20. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2025 (percent)

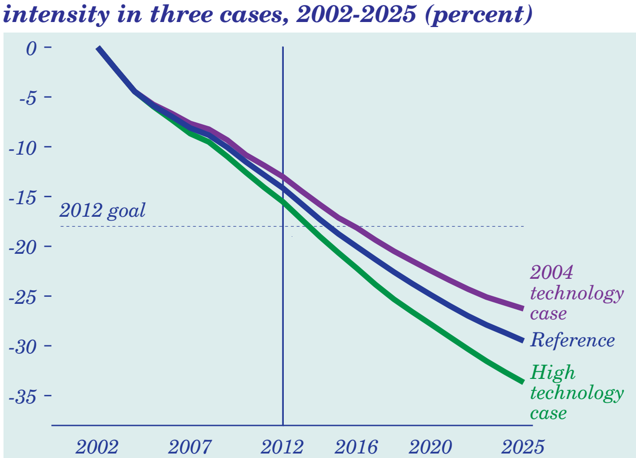
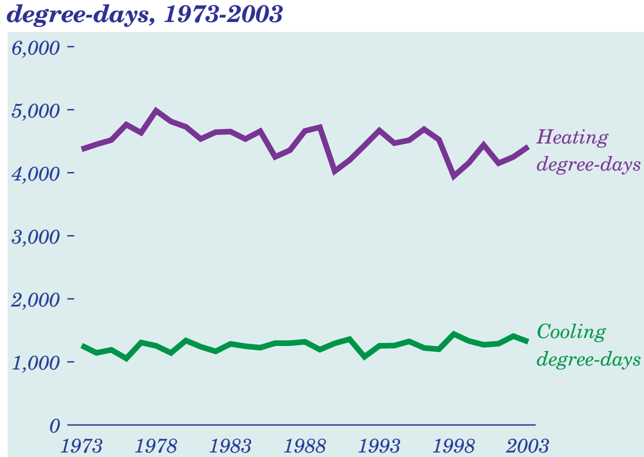


Figure 21. U.S. average heating and cooling degree-days, 1973-2003



sector in the warmer and colder cases represents 2.4 and 1.9 percent, respectively, of the cumulative amount of fossil fuels used in the buildings sector from 2006 through 2025. For electricity, the cumulative change is 0.2 percent of the cumulative amount of electricity (including conversion losses) used in the buildings sector in both cases between 2006 and 2025. The much lower change for electricity is due to the fact that much less of the electricity load is temperature dependent—only 16 percent, compared with 62 percent for fossil fuels. For example, many of the major end-use services that are not temperature dependent, such as lighting, refrigeration, and office equipment, are powered almost exclusively by electricity.

Changes in projected energy demand in the warmer and cooler cases also affect the projections of energy prices. Relative to the *AEO2005* reference case, average residential and commercial electricity prices in the cooler case are 0.7 percent and 0.5 percent lower

Figure 22. Projected U.S. average heating degree-days in three cases, 2000-2025

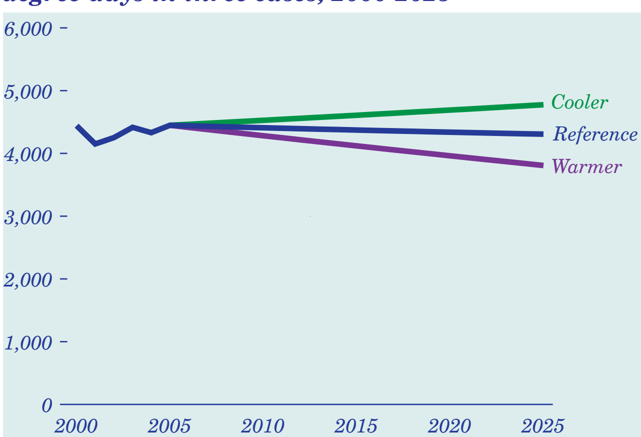
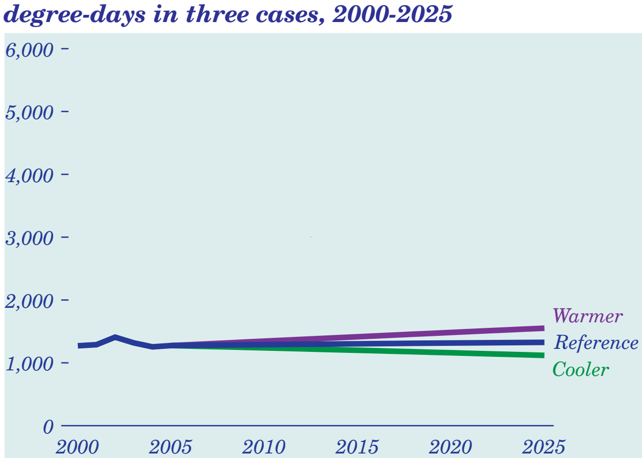


Figure 23. Projected U.S. average cooling degree-days in three cases, 2000-2025

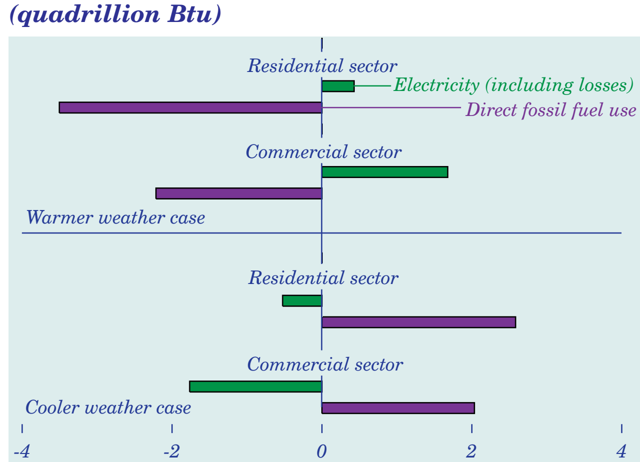


over the projection period, respectively, as summer peak demand is reduced by decreases in air conditioning use. In the warmer case, average electricity prices to residential and commercial customers over the period from 2006 to 2025 are 0.8 percent and 0.9 percent higher, respectively, as summer peak load is increased.

The changes in electricity demand are not evenly distributed throughout the year; there is a much greater change in peak demand than there is in total demand. This also affects the amount of electric generating capacity needed, which is based on an assumed reserve over the peak demand. In the warmer case, peak demand in 2025 is 4.8 percent higher than in the reference case, resulting in a 3.5-percent increase in overall electricity generation capacity, although total demand in 2025 is only 0.5 percent higher than in the reference case. As a result, higher average electricity prices are projected, due to the increased costs of capacity without an equal increase in generation. The incremental cost is spread over relatively few additional kilowatthours. In the colder case, projected peak demand in 2025 is 4.4 percent lower than in the reference case, and total capacity is 3.2 percent lower, although total demand is only 0.7 percent lower. In this case, total costs are lower due to fewer new capacity additions, but total demand is again almost the same, and average prices are lower.

Because changes in annual energy demand vary depending on season and fuel type in the two weather cases, it follows that changes in energy expenditures will vary as well. As shown in Figure 24, demand for fossil fuel and electricity change in opposite directions relative to the reference case in the two temperature

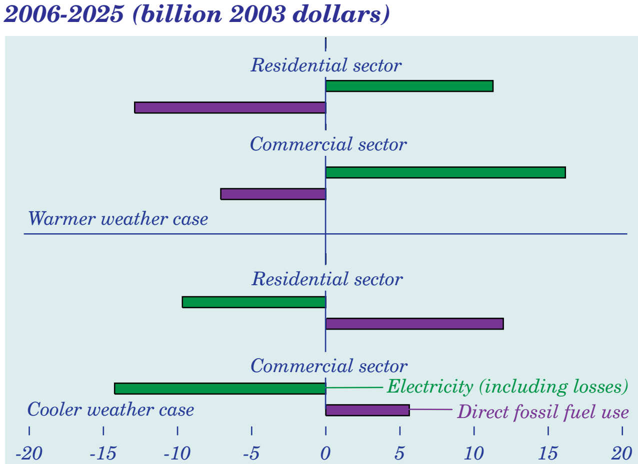
Figure 24. Cumulative projected change from the reference case in buildings sector electricity and fossil fuel use in two cases, 2006-2025 (quadrillion Btu)



sensitivity cases. Figure 25 shows the changes in projected present value of expenditures for electricity and fossil fuels in the residential and commercial sectors in the warmer and colder cases. The present value of commercial electricity expenditures changes the most, but the difference, as a percentage of current commercial electricity expenditures, reaches only 1.3 percent over the present value of all future expenditures on electricity in the sector. The present value of residential energy expenditures increases by $2.3 billion in the cooler case, meaning that consumers could expect to pay more money for their household energy use over the projection period. In the warmer case, the present value of residential energy expenditures decreases by $1.6 billion, reflecting the larger heating requirements relative to cooling requirements in the sector.

In summary, average yearly temperatures that are warmer or cooler than expected would have mixed impacts on energy consumption and expenditures in the residential and commercial sectors if the changes were directionally the same in the heating and cooling seasons. Warmer summer temperatures would increase demand for air conditioning, and warmer winter temperatures would decrease demand for heating. Because space heating accounts for more energy use than air conditioning on the basis of sales volumes, heating fuels tend to be more affected by changes in temperature than do cooling fuels; however, given the relatively high delivered price of electricity compared to fossil fuels, changes in energy consumption tend to affect electricity more on the basis of total expenditures.

Figure 25. Present value of projected change from the reference case in buildings sector expenditures for electricity and fossil fuel use in two cases, 2006-2025 (billion 2003 dollars)



The projections in the warmer and cooler weather cases show that energy consumption and expenditures are sensitive to changes in temperature. It should be noted, however, that the changes projected are relatively small relative to the sector totals. Accordingly, in the colder case, cumulative carbon dioxide emissions from 2003 to 2025 are projected to be only 0.1 percent higher than in the reference case, and in the warmer case they are projected to be only 0.2 percent lower than in the reference case.

Production Tax Credit for Renewable Electricity Generation

In the late 1970s and early 1980s, environmental and energy security concerns were addressed at the Federal level by several key pieces of energy legislation. Among them, the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, required regulated power utilities to purchase alternative electricity generation from qualified generating facilities, including small-scale renewable generators; and the Investment Tax Credit (ITC), P.L. 95-618, part of the Energy Tax Act of 1978, provided a 10-percent Federal tax credit on new investment in capital-intensive wind and solar generation technologies [*98*].

EPACT included a provision that addresses problems with the ITC—specifically, the lack of incentives for operation of wind facilities. EPACT introduced the renewable electricity PTC, a credit based on annual production of electricity from wind and some biomass resources. The initial tax credit of 1.5 cents per kilowatthour (1992 dollars) for the first 10 years of output from plants entering service by December 31, 1999, has been adjusted for inflation and is currently valued at 1.8 cents per kilowatthour (2003 dollars) [*99*, *100*].

The original PTC applied to generation from taxpaying owners of new wind plants and biomass power plants using fuel grown in a "closed-loop" arrangement (crops grown specifically for energy production, as opposed to byproducts of agriculture, forestry, urban landscaping, and other activities). In its early years, the PTC had little discernable effect on the wind and biomass industries it was designed to support (Figure 26). Although there have not been any commercial closed-loop generators, by 1999, when the provision was originally set to expire, U.S. wind capacity had begun growing again, and the PTC supported the development of more than 500 megawatts of new wind capacity in California, Iowa, Minnesota, and other States. Wind power development was also encouraged by State-level programs, such as the mandate in Minnesota for 425 megawatts of wind power by 2003 as part of a settlement with Northern States Power (now Xcel Energy) to extend on-site storage of nuclear waste at its nuclear facility [*101*].

In 1999, the PTC was allowed to expire as scheduled, but within a few months it was retroactively extended through the end of 2001 [*102*], and poultry litter was added to the list of eligible biomass fuels. Although wind power development slowed significantly in 2000, 2001 was a record year with as much as 1,700 megawatts installed [*103*]. Again, State and local programs, including a significant renewable energy mandate program in Texas, also supported new wind installations.

The PTC was allowed to expire again on December 31, 2001, while Congress worked on a comprehensive new energy policy bill. It was retroactively extended a second time to December 31, 2003, as part of an omnibus package of extended tax credits passed in response to the economic downturn and terrorist attacks of 2001 [*104*].

Like the 1999 expiration and extension, the extension of the PTC in 2002 was followed by a lull in wind power development; however, in 2003, the year leading up to the expiration, the wind industry saw significant growth of almost 1,700 megawatts [*105*], approaching the record set in 2001. Significantly, while many 2003 builds still relied on multiple incentives (for example, the PTC plus a State program) to achieve economic viability, some (in Oklahoma and other States) were developed with little government support beyond the PTC [*106*].

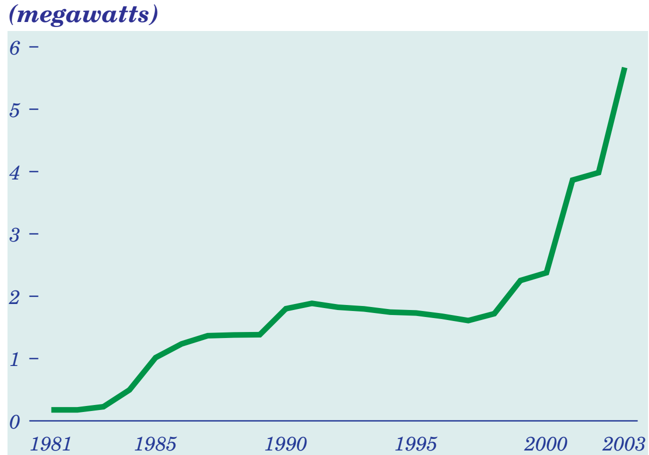
An extension of the PTC program to eligible plants entering service on or before December 31, 2005, was passed as part of the Working Families Tax Relief Act of 2004 (P.L. 108-311). In addition, the American Jobs Creation Act of 2004 (P.L. 108-357) expanded the credit to other renewable resources, such as open-loop biomass, geothermal, and solar electricity, as detailed below.

With reductions in capital costs and increases in capacity factors [*107*], wind power technology has improved since the introduction of the ITC and PTC. It is likely that the installations spurred by those incentives allowed the industry to “learn by doing” and thus contributed to improvement of the technology. There were, however, other factors that contributed to cost reductions during the period, including government-funded research and development and large markets for wind power technology that were created by subsidy programs in other countries, especially, Denmark and Germany.

The *AEO2005* reference case, assuming no extension of the PTC beyond 2005 (as provided for in current law as of October 31, 2004), projects that the levelized cost of electricity generated by wind plants coming on line within the next few years would range from approximately 4.5 cents per kilowatthour at a site with excellent wind resources [*108*] to 6.0 cents per kilowatthour at less favorable sites. To incorporate the effect of the current 1.8-cent tax credit over the 10-year eligibility period for those wind plants, the projections account for both the tax implications and the time value of the subsidy. As a tax credit, the PTC represents 1.8 cents per kilowatthour of tax-free money to a project owner. If the owner did not receive the tax credit and wanted to recoup that 1.8 cents with taxable revenue from electricity sales, 2.8 cents would have to be added to the sales price of each kilowatthour, assuming a 38-percent marginal tax rate.

Applying the same assumptions used to derive the 4.8-cent total levelized cost of wind energy over a 20-year project life, the levelized value of the PTC to a wind project owner is approximately 2.1 cents per kilowatthour. Similarly, the lower value of the PTC for other resources could be expected to reduce the levelized cost of prime geothermal sites from 4.4 to 3.6 cents per kilowatthour, and to reduce the levelized cost of a new dedicated biomass plant burning low-cost eligible urban or agricultural waste from 5.1 to 4.5 cents per kilowatthour. Solar projects with high capital costs and relatively low capacity factors probably would benefit more from the available 10-percent investment tax credit than from the PTC (Table 22).

Figure 26. U.S. installed wind capacity, 1981-2003 (megawatts)



In the reference case, the projected levelized cost for electricity from new natural gas combined-cycle plants is 4.7 cents per kilowatthour, and for new coal-fired plants the projected cost in 2010 is 4.3 cents per kilowatthour [*109*]. The value of the incremental fuel and capacity displaced by wind power in 2010 is 4.3 cents per kilowatthour in the reference case. Thus, it is easy to see how the PTC could make wind plants an attractive investment in the mid-term electricity market.

In view of the history of past PTC extensions, another extension beyond the current 2005 expiration date seems well within the realm of possibility. Given the uncertainty regarding the long-term fate of the PTC, EIA examined one possible outcome for an extension of the PTC. The PTC extension case is not meant to represent any expectation about future policy decisions regarding the PTC, but rather to provide a useful indication of the impacts of the PTC program on future energy markets relative to the reference case forecast, which assumes no extension of the PTC beyond 2005. This case is based on an "as-is" extension to 2015 of the expanded renewable electricity PTC program, as expanded by the American Jobs Creation Act of 2004 to facilities placed in service by the end of 2015.

The current PTC law provides a tax credit of 1.8 cents per kilowatthour for the first 10 years of operation to new wind plants, dedicated biomass plants burning closed-loop fuel or poultry litter, and certain approved fossil fuel plants co-firing with closed-loop renewable fuels. A credit of 1.8 cents per kilowatthour is provided for the first 5 years of operation to new geothermal and solar plants [*110*], and a credit of 0.9 cent per kilowatthour is provided for the first 5 years of operation to new dedicated biomass plants burning a wide variety of "open-loop" fuels, such as urban wood wastes, landscaping wastes, agricultural residues, and forestry residues. Landfill gas and municipal solid waste mass-burn facilities are eligible for the "open-loop" credit as well, although this would preclude taking advantage of other tax credits offered to some of those facilities.

Table 22. Levelized costs of new conventional and renewable generation in two cases, 2010 (2003 cents per kilowatthour)

Generation source	*Reference case*	*PTC extension case*
Combined cycle	*4.7*	*4.5*
Combustion turbine	*7.0*	*6.8*
Coal	*4.3*	*4.3*
Geothermal	*4.4*	*3.6*
Photovoltaic	*21.0*	*21.0*
Solar thermal	*12.6*	*12.6*
Open-loop biomass	*5.1*	*4.5*
Wind	*4.8*	*2.9*
Avoided cost of geothermal or biomass	*4.4*	*4.0*
Avoided cost of wind	*4.3*	*4.0*

Each of the credits is modeled as specified in the law, with the exception of the "closed-loop" credits for dedicated biomass plants and approved co-firing applications, the tax credit for photovoltaics, and the credit for refined coal. Because of the long establishment times and relative expense of energy crops, it is assumed that there will be no dedicated, closed-loop biomass plants able to take advantage of an extension of the PTC to 2015. Furthermore, the eligibility of co-firing plants to take advantage of the credit is to be determined on a case-by-case basis by the Department of Energy, and determining which or how many plants will be able to qualify is beyond the scope of this analysis. This analysis assumes that no PTC is given for co-firing. Geothermal, utility-owned photovoltaics, and solar thermal power applications are all eligible for *either* the PTC or the ITC. In the case of photovoltaics, which has very high investment costs and relatively low annual output per unit capacity, the ITC is estimated to be the more valuable of the two tax credits, and it is assumed that it will be preferred over the PTC. EIA does not currently provide projections for refined coal markets.

The PTC extension case assumes an uninterrupted extension of the PTC through 2015. As indicated above, the PTC has historically been subject to a series of expirations with retroactive extension for short periods (typically, 2 years per extension). The resulting uncertainty for the relatively long-term cycle of electricity market investment may have a significant impact on the ability of the industry to exploit the subsidy. The observed "packing" of construction in the last 6 months or so of each new eligibility window may serve to increase investment cost. In addition, uncertainty about the future availability of the PTC may affect infrastructure investment decisions that could lead to fuller realization of cost-reduction opportunities [*111*].

In the PTC extension case, wind power has the largest projected gains, although landfill gas, geothermal, and dedicated, open-loop biomass resources all are projected to see some capacity expansion. Installed wind capacity in 2015 is almost 63 gigawatts in the PTC extension case, compared to 9.3 gigawatts in the reference case. This 580-percent increase in capacity results in a 650-percent increase in generation from the reference case projection for 2015 (206 billion kilowatthours in the PTC extension case compared to 27 billion kilowatthours in the reference case).

In 2015, geothermal capacity in the PTC extension case (3.23 gigawatts) is more than 20 percent greater than in the reference case (2.66 gigawatts), resulting in 30 percent more electricity generation from geothermal resources in 2015 (Table 23). With limited availability of new sites, new landfill gas capacity in 2015 is only 50 megawatts greater in the PTC extension case than the reference case projection of 3,630 megawatts. Although new dedicated biomass capacity in 2015 is almost 65 percent greater in the PTC extension case than in the reference case (3.39 gigawatts compared to 2.06 gigawatts), total biomass generation in the electric power sector in 2015 is only 10 percent higher than in the reference case (33.13 billion kilowatthours compared to 30.01 billion kilowatthours). This is largely a result of a significant decline in the use of biomass for co-firing applications, as the dedicated plants receiving the tax credit generally are expected to have a competitive advantage over co-firing plants in obtaining open-loop fuel.

Although geothermal capacity and dedicated biomass capacity in the PTC extension case continue to grow after the assumed 2015 expiration of the PTC, wind capacity expansion all but stops when the PTC expires. Because geothermal and biomass compete as baseload resources, their relative economics in the 2015 to 2025 time frame are similar in the reference and PTC extension cases; however, both benefit from reduced technology costs as a result of "learning-by-doing." Wind, on the other hand, competes as an intermittent resource, with much of its generation displacing intermediate-load energy rather than peak or baseload energy. Initially, the displaced load consists of a significant amount of natural-gas-fired generation, with a relatively high fuel cost; however, after significant gas-fired generation is displaced, more coal-fired generation (with lower fuel costs) is displaced. In the PTC extension case, the avoided cost of wind generation is reduced by as much as 15 percent in 2020 from the reference case projection.

The total incremental cost to the U.S. Treasury of extending the PTC from 2005 to 2015 is estimated at $17 billion in lost tax revenue (all cumulative money calculations are in 2003 dollars, discounted at 7

Table 23. Renewable electricity capacity and generation in two cases, 2005, 2015, and 2025

Projection	2005 Reference case	2005 PTC extension case	2015 Reference case	2015 PTC extension case	2025 Reference case	2025 PTC extension case
Electric power sector net summer capacity (gigawatts)						
Conventional hydropower	78.1	78.1	78.2	78.2	78.2	78.2
Geothermal	2.2	2.2	2.7	3.2	4.6	5.3
Municipal solid waste	3.4	3.4	3.6	3.7	3.7	3.7
Wood and other biomass	1.8	1.8	2.1	3.4	4.5	5.6
Solar thermal	0.4	0.4	0.5	0.5	0.5	0.5
Solar photovoltaic	0.1	0.1	0.2	0.2	0.4	0.4
Wind	8.2	8.2	9.3	63.0	11.3	63.0
Total renewable	94.1	94.1	96.5	152.1	103.1	156.6
Total electric power industry	945	945	967	1,014	1,145	1,186
Electric power sector generation (billion kilowatthours)						
Conventional hydropower	288.4	288.4	300.5	300.6	301.1	301.1
Geothermal	12.1	12.1	16.1	21.0	32.8	38.3
Municipal solid waste	24.3	24.3	26.1	26.5	26.5	26.9
Wood and other biomass	20.6	20.7	30.0	33.1	37.4	44.5
Dedicated plants	10.1	10.1	11.7	19.8	27.3	35.4
Co-firing	10.6	10.6	18.3	13.3	10.1	9.1
Solar thermal	0.7	0.7	0.9	0.9	1.0	1.0
Solar photovoltaic	0.1	0.1	0.5	0.5	1.0	1.0
Wind	23.6	23.6	27.3	205.7	34.5	205.7
Total renewable	369.8	369.8	401.4	588.3	434.2	618.5
Coal	2,054	2,054	2,305	2,275	2,890	2,802
Natural gas	699	699	1,172	1,054	1,403	1,331
Total net generation to the grid	3,890	3,890	4,676	4,708	5,522	5,545

percent per year unless otherwise noted). The electric power industry incurs $12 billion in cumulative additional costs through 2025 in the PTC extension case compared to the reference case; however, this additional expense is more than compensated for by the subsidy. Because the net effect of the PTC extension is a slight reduction in end-use electric power prices, electricity consumers save about $37 billion in end-use electricity expenditures through 2025 in the PTC extension case compared to reference case. In addition, the assumed PTC extension significantly reduces demand for natural gas in the electric power sector, lowering natural gas prices for all consumers. Total natural gas expenditures by consumers other than electric utilities are reduced by $13 billion through 2025 in the PTC extension case compared to the reference case. About $16 billion of the $17 billion in taxpayer cost is allocated to wind energy resources as a result of both the significantly higher level of PTC-induced wind generation and the higher PTC value and claim period for wind projects than for geothermal or open-loop biomass projects.

Distributed Generation in Buildings

Distributed generators installed by residential and commercial customers may supply electricity alone (generation) or electricity as well as heat or steam (CHP). On-site generators can have several advantages for electricity customers:

- If redundant capability is installed, reliability can be much higher than for grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses, such as space heating and water heating.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower both current energy bills and, presumably, energy bills in future competitive markets, when peak prices will be set by the most expensive generator supplying power to the grid.

Currently, distributed generation provides a very small share of residential and commercial electricity requirements in the United States. The *AEO2005* reference case projects a significant increase in electricity generation in the buildings sector, but distributed generation is expected to remain a small contributor to the sector's energy needs. Although the advent of higher energy prices or more rapid improvement in technology could increase the use of distributed generation relative to the reference case projection, the vast majority of electricity used in buildings is projected to continue to be purchased from the grid.

The *AEO2005* buildings models represent several grid-connected distributed generation technologies either as simple generation or as CHP, including conventional technologies such as oil or gas engines and combustion turbines and new technologies such as solar photovoltaics (PV), fuel cells, and microturbines. PV systems are the most costly of the distributed technologies for buildings on the basis of installed capital costs; however, once the systems are installed, no fuel costs are incurred. Petroleum-based generation is often used for emergency power backup in the commercial sector, but potential issues related to localized emissions make it less appropriate than natural-gas-based generation for continuous operation.

The projected adoption of distributed generation technologies in the buildings sector is based on forecasts of the economic returns from their purchase to meet baseload electricity needs (also thermal needs in the case of CHP) and on estimated participation in programs aimed at fostering distributed generation [*112*]. A detailed cash flow analysis is used to estimate the number of years needed to achieve a positive cumulative cash flow. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment over a 30-year period from the time of the investment decision. The analysis includes the assumption that if more electricity is generated than needed, the excess can be sold to the grid [*113*].

Economic penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. Program-related purchases are based on estimates from the Department of Energy's Million Solar Roofs program, the Department of Defense fuel cell demonstration program, State RPS and other renewable energy programs and goals, and locally targeted initiatives, such as the Spire Solar Chicago program.

Table 24 shows projected installed capital costs [*114*] and electrical conversion efficiencies [*115*] for several of the distributed generation technologies represented in the buildings sector models. All fossil-fuel-fired systems are assumed to be used in CHP applications to take advantage of waste heat produced in the generation process. The costs and performance of fossil-fuel-fired CHP and PV systems are assumed to improve over time in the *AEO2005* projections, with emerging technologies (fuel cells, microturbines, and PV) showing the most improvement. Technology learning is also expected to occur for the emerging technologies, allowing for additional cost declines if cumulative shipments increase sufficiently [*116*].

Market Factors

The availability of technologies does not guarantee their widespread adoption. Many factors enter into the decision whether to purchase grid-supplied electricity to meet all of a building's power needs or to invest in a distributed generation system. Some of the issues that affect the market for distributed generation are discussed below.

Economics, Technology, and Suitability. In most instances, purchasing electricity is currently more economical for residential and commercial consumers than investing in distributed generation systems. On average, buildings sector sites are much smaller than industrial sites, and they are limited to technologies that have been more expensive and less efficient than larger CHP. Commercial firms generally have fewer operating hours per year and lower load factors than industrial firms, limiting the annual hours of system operation in which the higher first costs can be recouped. In addition, few types of buildings applications involve the steady thermal requirements that maximize the efficiency and economics of CHP systems.

Recent increases in fuel prices have further dampened enthusiasm for new CHP systems in buildings. Although fuel costs are not an issue with PV systems, their high installed capital cost limits economic viability to areas with high electricity prices and/or program-based incentives that offset a significant portion of the added investment costs. To the extent that deregulated retail electricity markets may pass along hourly or seasonal variation in the cost of producing electricity, such as time-of-day or real-time pricing, distributed generation applications may see further economic opportunities to offset higher energy costs; however, the adoption of such rate structures on a widespread basis in the residential and commercial sectors is currently highly uncertain.

All the fossil-fuel-fired distributed generation technologies represented in the reference case are assumed to be CHP systems; however, based on a January 2000 report prepared by ONSITE SYCOM Energy Corporation, only about 5 percent of existing commercial buildings in the United States have technically adequate electric demand and thermal loads to meet the criteria for CHP [*117*]. Considering the possibility of cost-effective CHP systems in smaller sizes and the advent of systems that include heat-activated cooling [*118*] increases the potential market for CHP adoption, but conditions would need to change from those represented in the reference case to encompass a much larger share of the commercial sector, let alone to make CHP systems economically attractive to meet residential consumers' everyday power and heating needs.

The amount of electricity a PV system can produce depends on the quality of the solar resource, as well as the size and efficiency of the system. On an annual basis, a PV system in Alaska would, in general, produce less electricity than an identical system in Arizona. The suitability of PV also depends on the ability to site the system to take advantage of the sunlight available. In addition, although PV systems tend to generate power during some of the peak electricity demand hours, their value in offsetting peak power costs may be somewhat less than that of fossil-fueled systems, because their output cannot be controlled with sufficient precision to follow real-time pricing signals or match a time-of-day tariff structure.

Regulation. Another factor to be considered when an investment in distributed generation technology is being made is the regulatory environment. Requirements for permits and approvals for distributed generation systems vary widely by State, technology,

Table 24. Projected installed costs (2003 dollars per kilowatt) and electrical conversion efficiencies (percent) for distributed generation technologies by year and technology, 2004, 2010, 2020, 2025

	2004		2010		2020		2025	
Technology	Cost	Efficiency	Cost	Efficiency	Cost	Efficiency	Cost	Efficiency
Residential photovoltaic	8,600	14	6,200	18	3,814	22	3,180	22
Commercial photovoltaic	6,250	14	4,750	18	3,178	22	2,650	22
Commercial fuel cell	5,200	36	2,500	49	1,800	51	1,450	52
Natural gas turbine	1,860	22	1,679	24	1,567	27	1,539	28
Natural gas engine	1,130	32	1,030	33	930	34	915	34
Natural gas microturbine	1,773	28	1,415	36	870	38	818	39

fuel, and project size. Researching and responding to a wide range of requirements is a hurdle for project development, adding expense to an already capital-intensive endeavor. Requirements can range from emissions and siting regulations to local building, zoning, and fire codes to local utility interconnection policies, exit fees, and standby rates [*119*].

Interconnection. The electric grid was not designed for two-way energy flow or storing energy at the distribution level. Consequently, utilities have implemented interconnection policies for the safe and reliable operation of the local grid when distributed generation units are interconnected to it. Some States are proposing to follow the requirements recently set forth by the Institute of Electrical and Electronics Engineers in IEEE 1547, “Standard for Distributed Resource Interconnects with Electric Power Systems” [*120*]. Others are developing their own interconnection standards. Still others have no standards, and procedures in those States are defined by individual electric utilities. Although some utilities have simplified the processes for small distributed generation projects (below 30 to 40 kilowatts), utilities generally require an interconnection study to be completed as part of the planning process for an installation.

Emissions. Restrictions may also be imposed on emissions from fossil-fuel-fired on-site generation that could contribute to smog and acid rain. Basic permitting and emission control requirements vary by State and whether a site falls within an emissions nonattainment zone with significant air quality problems [*121*]. Most States do not require permits for small units or units with small amounts of emissions. The threshold for such exemptions varies by State. In addition, distributed generation equipment that requires a permit is likely to require some emission limitations or controls. Systems that use fuel oil typically have higher “fuel-based” emissions than those that run on natural gas, making permitting and control costs a larger issue for those systems.

Reference Case Projections

The *AEO2005* reference case includes residential and commercial distributed generation projections at the national level and for the nine Census divisions [*122*], using the assumptions and methodology described above. At the national level, there is currently little residential capacity for electricity generation from fossil fuels. Existing capacity consists primarily of emergency backup generators to provide electricity for minimum basic needs in the event of power outages. Generating capacity in the commercial sector is also primarily for emergency backup; however, some electricity supply and peak generation is reported. EIA’s 1999 Commercial Buildings Energy Consumption Survey (CBECS) estimated that about 0.7 percent of all commercial buildings (1.6 percent of all commercial floorspace) use generators for purposes other than emergency backup.

Fossil-fuel-fired commercial generating facilities larger than 1 megawatt reported generating 7.0 billion kilowatthours of electricity in 2002 and 6.3 billion kilowatthours in 2003, about 0.5 percent of the sector’s electricity needs [*123*]. The reference case projects an 80-percent increase in electricity supplied annually by fossil-fuel-fired distributed generation in the buildings sector, to 11.3 billion kilowatthours in 2025, but distributed generation still is expected to meet less than 1 percent of the electricity requirements for buildings nationally.

Generation from natural gas turbines at commercial facilities is projected to remain essentially constant throughout the forecast. Gas turbines are viewed as a “mature” technology that is expected to show only modest improvement over the forecast, and, in addition, few commercial facilities have power and thermal needs or operating hours that would warrant investment in a large CHP system such as a gas turbine. Although engines are expected to remain a popular choice for commercial CHP, the adoption of microturbines and fuel cells is projected to increase later in the forecast period, reflecting projected cost declines and technological progress for these emerging technologies. With reference case electricity and fossil fuel prices, the vast majority of residential consumers are not expected to purchase fossil-fuel-fired distributed generation systems to meet their daily electricity requirements.

The reference case projections for grid-connected PV incorporate current national incentives for commercial sector systems, including an Investment Energy Tax Credit and favorable depreciation treatment [*124*]. The effects of regional and local incentives are estimated through projections for program-related purchases of PV systems. Although *AEO2005* projections are limited to grid-connected systems, EIA estimates that remote PV applications (off-grid power systems) representing as much as 134 megawatts of electricity generation capacity were in service in 2002, in addition to another 362 megawatts of PV generating capacity in specialized applications, such as communications and transportation [*125*].

In the reference case, electricity generation from PV systems in the buildings sector is projected to increase at an average annual rate of 17 percent, to 3.7 billion kilowatthours in 2025 (Figure 27). New installations through 2010 are expected to result from program-related purchases that generally include incentives to help defray the high capital costs associated with the technology. Later in the forecast, as a result of projected cost declines combined with favorable tax treatment, PV systems are projected to become economically attractive without additional subsidies in regions where electricity costs are relatively high.

Delivered energy prices vary by geographical region in the United States and are expected to continue to differ by region throughout the forecast horizon. Variations in electricity prices, fossil fuel prices, and the relative difference between electricity and fossil fuel prices result in significant differences in the projected adoption of distributed generation technologies by region. Public policies and incentive programs differ by State and region as well, adding to the expected regional variation in distributed generation.

The use of fossil-fuel-fired distributed generation technologies in CHP applications is projected to grow fastest in regions with high electricity prices and relatively moderate natural gas prices (Figure 28). Although the Mountain Census division is projected to show the fastest rate of growth in the reference case, 5.0 percent per year between 2003 and 2025, the Pacific Census division is projected to show the greatest increase in generation, 1.6 billion kilowatthours. Census divisions with relatively low electricity prices, such as the East South Central division, show little growth.

Near-term adoption of PV systems in the buildings sector is expected to be concentrated in regions that exhibit some combination of the following: active programs to foster the development of PV, high electricity rates, and sufficient periods of sunlight to maintain PV electricity production. For example, in addition to abundant sunshine in many parts of California, the California Energy Commission's rebate program, funded by a System Benefits Charge, refunds up to one-half of the installed cost of PV systems. States with RPS programs that require a percentage of electricity generation to be provided from renewable energy sources often offer "extra credit" for PV that increases its attractiveness [*126*]. The Pacific Census division, the current leader in PV electricity generation, is expected to show the greatest increase in the *AEO2005* reference case, with projected PV generation of more than 1 billion kilowatthours in 2025 (Figure 28). In the New England and Middle Atlantic Census divisions, where high electricity prices are projected, the use of distributed PV systems is projected to increase by more than 20 percent from 2003 to 2025.

Alternative Cases

Technology Improvement. The buildings sector 2005 technology and high technology cases included in *AEO2005* examine the sensitivity of the projections to different technology assumptions in combination with reference case energy prices and economic assumptions [*127*]. These cases alter residential and commercial assumptions for distributed generation technologies, end-use equipment, and building shell measures, focusing only on technological progress in the buildings sector. In the 2005 technology case,

Figure 27. Projected buildings sector electricity generation by selected distributed resources in the reference case, 2003-2025 (billion kilowatthours)

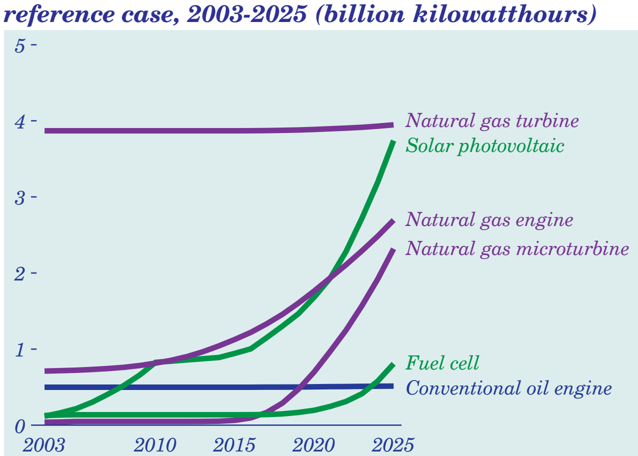
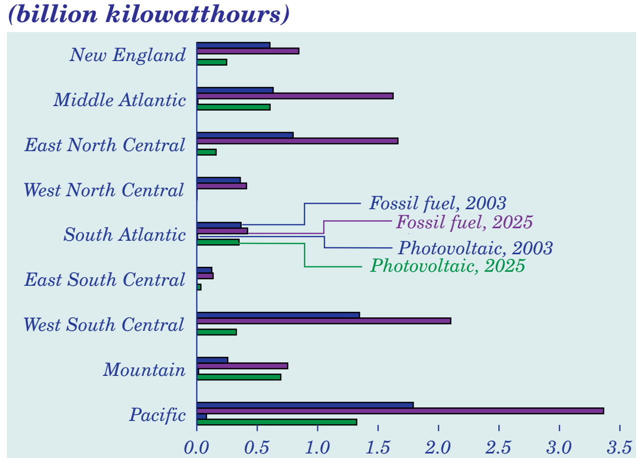


Figure 28. Projected buildings sector generation by fossil fuel-fired and photovoltaic systems by Census division in the reference case, 2003 and 2025 (billion kilowatthours)



which assumes no further technological improvements, fossil-fuel-fired CHP is projected to total 7.2 billion kilowatthours in 2025, a 14-percent increase from 2003 but 37 percent (4.2 billion kilowatthours) lower than the reference case projection (Table 25). Similarly, PV generation is projected to total 1.4 billion kilowatthours in 2025, 62 percent (2.3 billion kilowatthours) lower than reference case projection.

The buildings high technology case is based on more optimistic assumptions for emerging distributed generation technologies, allowing greater cost declines as shipments increase [*128*]. The high technology assumptions result in projected generation of 11.8 billion kilowatthours from fossil-fuel-fired CHP in 2025, 4 percent higher than the reference case projection. PV generation is projected to total 4.7 billion kilowatthours in 2025 in the high technology case, 25 percent higher that the reference case projection.

Energy Prices. In the *AEO2005* low world oil price case, lower prices for petroleum lead to lower projected electricity prices. As a result, more consumers are expected to purchase electricity rather than invest in distributed generation systems. In the low world oil price case, generation from fossil-fuel-fired CHP in buildings is projected to total 10.9 billion kilowatthours in 2025 (400 million kilowatthours less than in the reference case), and PV generation is projected to total 3.6 billion kilowatthours (100 million kilowatthours less than in the reference case)—both 4 percent lower than the corresponding reference case projections (Table 25). In the high world oil price case, projected electricity and natural gas prices are slightly higher than in the reference case for most of the forecast period. As a result, in 2025, generation from fossil-fuel-fired CHP in buildings is projected to total 11.8 billion kilowatthours, 4 percent (500 million kilowatthours) higher than the reference case projection, and PV generation is projected to total 3.9 billion kilowatthours, 4 percent (100 million kilowatthours) more than in the reference case.

Restricted Natural Gas Supply Case

The restricted natural gas supply case provides an analysis of the energy-economic implications of a scenario in which future gas supply is significantly more constrained than assumed in the reference case. Future natural gas supply conditions could be constrained because of problems with the construction and operation of large new energy projects, and because the future rate of technological progress could be significantly lower than the historical rate. Although the restricted natural gas supply case represents a plausible set of constraints on future natural gas supply, it is *not* intended to represent what is likely to happen in the future.

The restricted natural gas supply case assumes the following constraints on natural gas supply:

- The Alaska natural gas pipeline is not built and put into operation by 2025.
- No new U.S. regasification terminals for LNG are built during the forecast, but the proposed expansions of existing U.S. terminals are permitted to go into operation as currently scheduled, along with any new LNG terminals already under construction.
- The future rates of technological progress for oil and gas exploration and development for both conventional and unconventional gas are one-half of the historical rates assumed in the reference case.

The restricted supply case assumes that the Alaska natural gas pipeline is not built during the forecast period either because of public opposition to this project and/or a perception by potential project sponsors that there are significant risks associated with such a project that more than outweigh the potential rewards. Potential risks include the possibilities that pipeline construction costs could be significantly higher than currently estimated, and that future lower 48 natural gas prices could be considerably lower than either current prices or expected future prices.

The restricted supply case assumes that public opposition to the construction of new U.S. LNG regasification terminals would preclude their construction. Existing terminals are assumed to proceed with their expansion plans, based on the assumption that LNG operations at existing terminals have lower financial risk and are more acceptable to the public. Any new LNG terminals already under construction are assumed to be completed in the restricted supply

Table 25. Buildings sector distributed electricity generation in alternative cases: difference from the reference case in 2025 (billion kilowatthours)

Projection	Fossil-fuel-fired generation	Photovoltaic generation
Buildings 2005 technology case	-4.2	-2.3
Buildings high technology case	0.5	0.9
Low world oil price case	-0.4	-0.1
High world oil price case	0.5	0.1

case. In particular, Excelerate's EnergyBridge project in the Gulf of Mexico is under construction, in the sense that the LNG tankers are under construction, along with the docking buoy, which attaches the tanker to the pipeline. The Excelerate EnergyBridge project, the only new terminal represented in the restricted supply case, is assumed to become operational in 2006. The volume of LNG imported into Canada and Mexico is assumed to be identical in the restricted supply and reference cases.

The restricted supply case assumes limits on the degree to which technology could enhance the productivity of future oil and natural gas supply operations. For example, current technology permits producers to recover between 75 and 85 percent of the in-place gas in conventional expansion gas reservoirs. Clearly, the highest theoretical recovery is 100 percent. Similarly, while seismic technology to access underground geologic formations can still be improved, there could be diminishing economic returns to such advances, because it is unlikely that, even with such advances, seismic technology would be able to determine, for example, whether an adequate reservoir seal existed at the appropriate point in geologic time to permit the capture and retention of hydrocarbons.

Although the future rate of oil and gas technological progress might be considerably less than the historical rate, it is unlikely that there would be no technological progress in the future, given the competitive nature of the oil and gas business and continued private and public investment in research and development. Consequently, the restricted supply case assumes a rate of technological progress that is 50 percent lower than the historical rate. It is also assumed that the oil and gas industry in Canada would operate in the same technology environment as U.S. oil and gas producers. Consequently, the lower rate of technological improvement has the same impact on oil and gas exploration and development in Canada as in the United States.

Wellhead Natural Gas Prices. The assumptions used in the restricted natural gas supply case result in significantly higher projections of lower 48 wellhead natural gas prices. In 2015 and 2025, projected wellhead gas prices are 23 percent and 31 percent higher, respectively, in the restricted supply case than in the reference case (Figure 29). In 2015, the restricted supply case projects a wellhead price of $5.13 per thousand cubic feet (2003 dollars), compared with the reference case price of $4.16 per thousand cubic feet. Similarly, in 2025, the restricted supply case projects a wellhead price of $6.29 per thousand cubic feet, compared with the reference case price of $4.79 per thousand cubic feet.

Natural Gas Consumption. The high wellhead prices projected in the restricted supply case significantly reduce projected natural gas consumption (Figure 30). In the reference case, total U.S. natural gas consumption increases throughout the forecast, from 22.0 trillion cubic feet in 2003 to 30.7 trillion cubic feet in 2025. In the restricted supply case, total U.S. gas consumption grows from 2003 levels to a peak of 26.0 trillion cubic feet in 2014, then declines in the remainder of the forecast, to 24.5 trillion cubic feet in 2025.

All end-use sectors are projected to consume less natural gas in the restricted supply case. The electric power sector shows the greatest reduction in consumption because of the availability of other

Figure 29. Lower 48 average wellhead natural gas price in two cases, 2000-2025 (2003 dollars per thousand cubic feet)

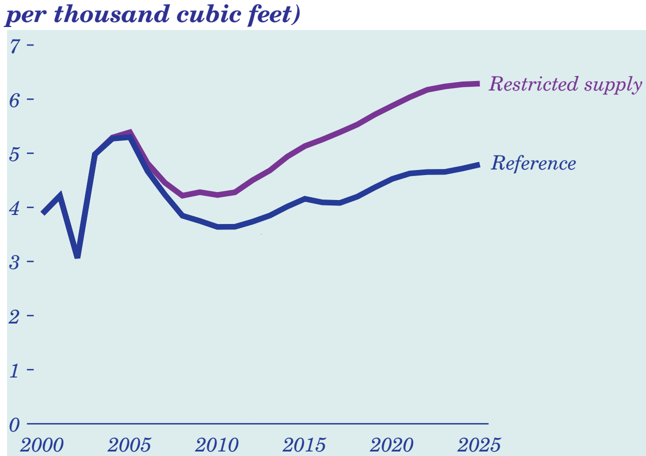
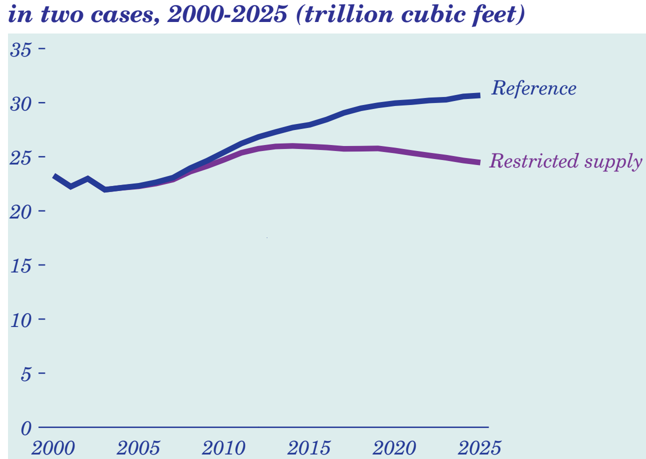


Figure 30. Total U.S. natural gas consumption in two cases, 2000-2025 (trillion cubic feet)



generating options. In 2025, projected natural gas consumption in the electric power sector is 4.3 trillion cubic feet lower in the restricted supply case than in the reference case (5.1 trillion cubic feet and 9.4 trillion cubic feet, respectively). The electric power sector accounts for almost 70 percent of the total reduction in projected gas consumption in 2025 in the restricted supply case and is largely responsible for the shape of the total gas consumption trend in that case (Figure 31). Specifically, natural gas consumption in the electric power sector is projected to peak in 2014 at 7.1 trillion cubic feet in the restricted supply case, then decline steadily to 5.1 trillion cubic feet in 2025.

The high natural gas prices in the restricted supply case both reduce the projected level of gas-fired electric generation capacity and reduce the use of the gas-fired generating plants already in operation. More coal-fired and renewable energy capacity is projected to be built as a result of the higher natural gas prices: 451 gigawatts of coal-fired capacity through 2025, as compared with 394 gigawatts in the reference case, and 114 gigawatts of renewable capacity in 2025, as compared with 103 gigawatts in the reference case.

The second largest decline in projected end-use natural gas consumption in the restricted supply case is in the industrial sector, with total projected consumption of 8.3 trillion cubic feet in 2025, as compared with 9.0 trillion cubic feet in the reference case. Industrial CHP production falls sharply as a result of the higher natural gas prices, from 123 billion kilowatthours in the reference case to 93 billion kilowatthours in the restricted supply case in 2025, which further reduces natural gas consumption.

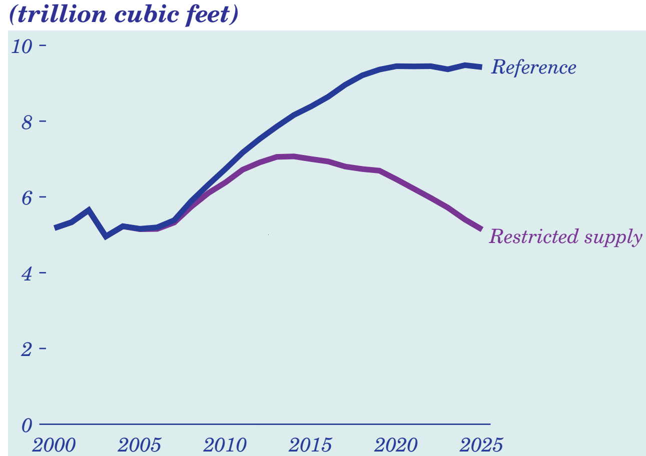
Projected natural gas consumption in the residential and commercial sectors is also reduced from reference case levels in the restricted supply case, again due to higher gas prices. Residential gas consumption in 2025 is projected to be 5.4 trillion cubic feet in the restricted supply case, compared with 6.0 trillion cubic feet in the reference case. Natural gas prices to residential consumers are 12 percent higher in the restricted supply case than in the reference case in 2015 and 19 percent higher in 2025, and residential electricity prices are 4 percent and 2 percent higher in 2015 and 2025, respectively.

Commercial gas consumption in 2025 is projected to be 3.8 trillion cubic feet in the restricted supply case, compared with 4.1 trillion cubic feet in the reference case. The higher natural gas prices in the restricted supply case prompt commercial consumers to invest in more efficient equipment or to switch to heating oil for their space heating and water heating needs, relative to the reference case. Commercial facilities also are expected to find natural-gas-fired CHP less attractive, with projected gas-fired electricity generation in the sector 17 percent (1.7 billion kilowatthours) lower in 2025 than projected in the reference case. Even with the actions described above, projected energy expenditures in the commercial sector in the restricted supply case are 5 percent higher than in the reference case in 2025, because the higher prices more than offset the reduced consumption volumes.

Natural Gas Supply. The supply of natural gas available to U.S. consumers comes from both domestic production and net imports. In the restricted natural gas supply case, the availability of future domestic gas production is constrained by the assumed absence of an Alaska natural gas pipeline and by rates of technological progress that are 50 percent lower than those observed historically. Natural gas imports are constrained by the assumption that only the currently scheduled proposed expansions of existing U.S. terminals are permitted to go into operation, along with new LNG terminals already under construction. Imports from Canada are constrained by the assumption of low rates progress in oil and gas exploration and recovery technologies.

The restricted supply case significantly reduces future LNG imports in comparison with the reference case projections (Figure 32). Net LNG imports in 2025 are projected to be 2.5 trillion cubic feet in the restricted supply case, compared with 6.4 trillion cubic feet in the reference case. Currently planned expansions at the four existing LNG terminals and

Figure 31. U.S. natural gas consumption for electric power generation in two cases, 2000-2025 (trillion cubic feet)



the construction and operation of the Excelerate EnergyBridge terminal are responsible for the increase in future LNG imports projected in the restricted supply case, relative to the 0.4 trillion cubic feet of net LNG imports in 2003. The restriction on new LNG terminals reduces LNG's share of total U.S. gas supply in 2025 from 21 percent in the reference case to 10 percent in the restricted supply case.

The higher natural gas prices projected in the restricted supply case have a mixed impact on net imports of natural gas from Canada. In the near term, the higher prices are projected to stimulate Canada's production, and from 2015 to 2020, U.S. imports of natural gas from Canada are projected to average about 340 billion cubic feet per year more in the restricted supply case than in the reference case. After 2020, a larger drop in net imports from Canada is projected in the restricted supply case than in the reference case, and projected net imports in 2025 are lower in the restricted supply case than in the reference case (2.3 trillion cubic feet and 2.5 trillion cubic, respectively).

With higher U.S. wellhead prices projected in the restricted supply case, Mexico is projected to become a net exporter of natural gas to the United States after 2019, rather than being a net importer as projected in the reference case. In 2025, net exports from Mexico to the United States are projected to be about 400 billion cubic feet of natural gas per year in the restricted supply case, compared with about 250 billion cubic feet per year of net imports from the United States in the reference case.

Total U.S. production of natural gas in 2025 is projected to be 19.1 trillion cubic feet in the restricted supply case, compared with 21.8 trillion cubic feet in the reference case (Figure 33). About 70 percent of the difference is directly attributable to the assumption that there would be no Alaska gas pipeline constructed in the restricted supply case.

In the lower 48 States, projected natural gas production is not significantly different in the restricted supply and reference cases, because the higher prices projected in the restricted supply case largely offset the lower assumed rate of technological progress. The restricted supply case projects total lower 48 gas production of 18.8 trillion cubic feet in 2025, 4 percent less than projected in the reference case. Most of the reduction in projected lower 48 conventional gas production—about 270 billion cubic feet in 2025 in the restricted supply case relative to the reference case—occurs offshore.

Unconventional gas production is sensitive to technological progress, because technological improvements could, for example, significantly improve the recovery rate of the unconventional gas in-place. Generally, there is more opportunity for technological progress to expand the economically recoverable unconventional resource base than the economically recoverable onshore conventional gas resource base. Offshore gas production is also sensitive to the future rate of technological progress, especially in the deepwater Gulf of Mexico. For example, technological improvements could reduce the development time necessary to bring oil and gas fields into operation and could make smaller oil and gas deposits profitable to produce.

Although projected lower 48 natural gas production in the restricted supply case is not significantly different from that in the reference case, the absence of an Alaska gas pipeline does reduce total U.S. gas

Figure 32. U.S. net imports of liquefied natural gas in two cases, 2000-2025 (trillion cubic feet)

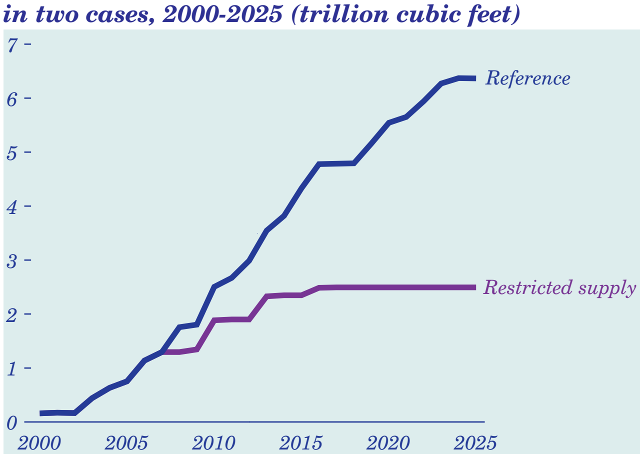
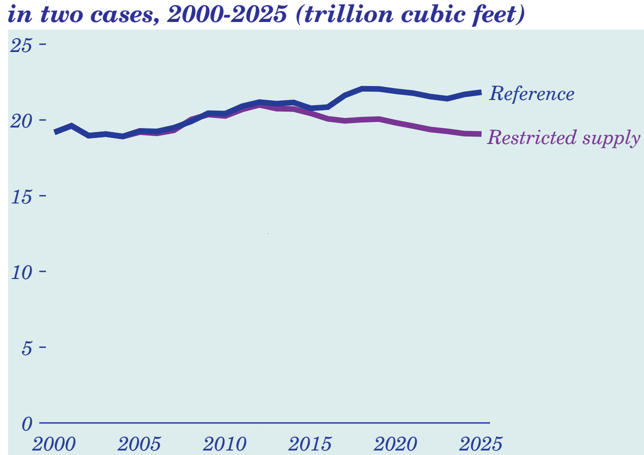


Figure 33. Total U.S. natural gas production in two cases, 2000-2025 (trillion cubic feet)

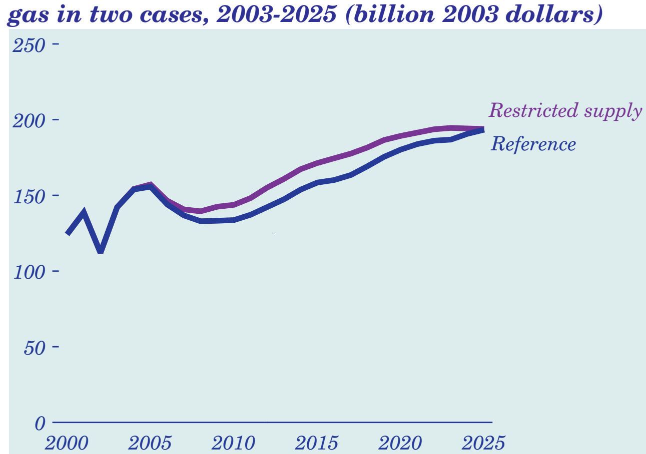


production throughout the forecast by 4 percent from 2003 through 2025. From an estimated technically recoverable natural gas resource base of 1,337 trillion cubic feet (as of January 1, 2003), 34 percent is projected to be produced in the restricted supply case, as compared with 36 percent in the reference case.

Electricity Prices and Consumption. In 2003, natural-gas-fired facilities provided 16 percent of the electricity generated in the United States. The reference case projects that gas-fired facilities will provide 25 percent of the electricity generated in 2025, compared with 14 percent in the restricted natural gas supply case. Because natural gas accounts for a significant portion of total electricity generation throughout the projections, higher natural gas prices increase future delivered electricity prices above those projected in the reference case. Although gas consumption in the electricity sector peaks in 2014 in the restricted supply case, the greatest difference in projections for the delivered price of electricity between the two cases is in 2018, when the price in the restricted supply case is 6 percent (0.4 cent per kilowatthour in 2003 dollars) higher than in the reference case.

Natural Gas Expenditures. The restricted natural gas supply case is projected to increase natural gas prices to a level that induces consumers to reduce their purchases of natural gas. Given the long lifetime of most gas-consuming equipment, the adjustment to higher gas prices would be relatively slow. Consequently, the negative impacts of high natural gas prices are more apparent in the nearer term than toward the end of the forecast. For example, the higher gas prices in the restricted supply case causes total projected U.S. end-use expenditures for natural gas to increase to $171 billion in 2015—equal to 1.1 percent of GDP—compared with $158 billion (1.0 percent of GDP) in the reference case (Figure 34). The greatest difference in gas consumption expenditures between the two cases, $13.4 billion, is projected in 2016. In 2025, when overall gas consumption is reduced in the restricted supply case, total end-use expenditures for natural gas are projected to be only $1.0 billion more than in the reference case.

Figure 34. Total end-use expenditures on natural gas in two cases, 2003-2025 (billion 2003 dollars)



Market Trends

The projections in the *Annual Energy Outlook 2005* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

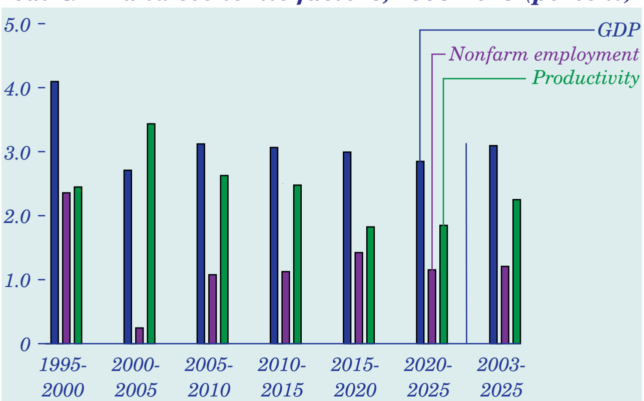
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics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

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2005* 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, a complete and focused analysis of public policy initiatives.

Strong Economic Growth Is Expected To Continue

Figure 35. Average annual growth rates of real GDP and economic factors, 1995-2025 (percent)



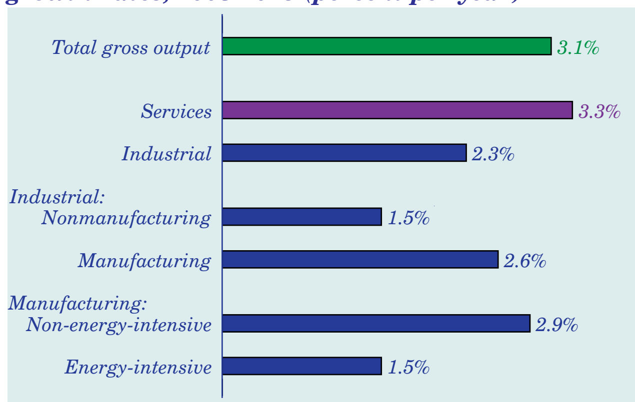
The output of the Nation's economy, measured by GDP, is projected to grow by 3.1 percent per year between 2003 and 2025 (with GDP based on 2000 chain-weighted dollars) (Figure 35). The labor force is projected to increase by 0.9 percent per year between 2003 and 2025. Labor productivity growth in the nonfarm business sector is projected at 2.2 percent per year.

Compared with the second half of the 1990s, the rates of growth in GDP and nonfarm employment were lower from 2000 through 2002. Economic growth has been more robust since 2003. Real GDP growth was 3.0 percent in 2003 and is expected to be 4.4 percent in 2004. The economy is expected to stabilize at its long-term growth path between 2005 and 2010. Total population growth (including armed forces overseas) is expected to remain fairly constant after 2003, growing by 0.8 percent per year on average. Labor force growth is expected to slow as a result of demographic changes, but more people over 65 are expected to remain in the work force. Nonfarm business productivity growth has been strong recently, averaging 3.8 percent per year from 2000 to 2003. Productivity growth from 2003 to 2025 is expected to average more than 2 percent per year, supported by investment growth of 5.1 percent per year.

From 2003 through 2025, disposable income is projected to grow by 3.1 percent per year and disposable income per capita by 2.2 percent per year. Nonfarm employment is projected to grow by 1.2 percent per year, and employment in manufacturing is projected to shrink by 0.6 percent per year.

Service Sectors Lead Output Growth, Industrial Output Growth Is Slower

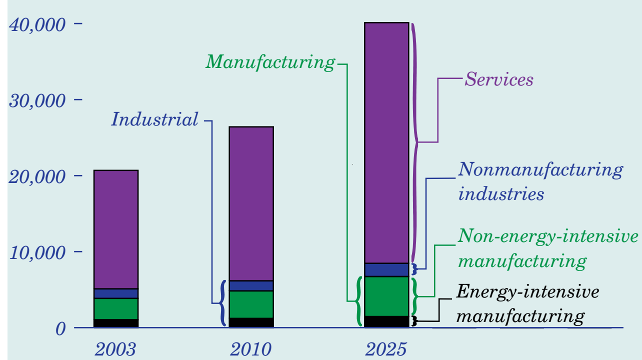
Figure 36. Sectoral composition of output growth rates, 2003-2025 (percent per year)



From 2003 to 2025, industrial output in real value terms is projected to grow by 2.3 percent per year, compared with 3.3-percent average annual growth in the services sector (Figure 36). Manufacturing output is projected to grow by 2.6 percent per year and nonmanufacturing output (agriculture, mining, and construction) by 1.5 percent per year. The energy-intensive manufacturing sectors [*129*] are expected to grow more slowly (1.5 percent a year) than the non-energy-intensive manufacturing sectors (2.9 percent per year).

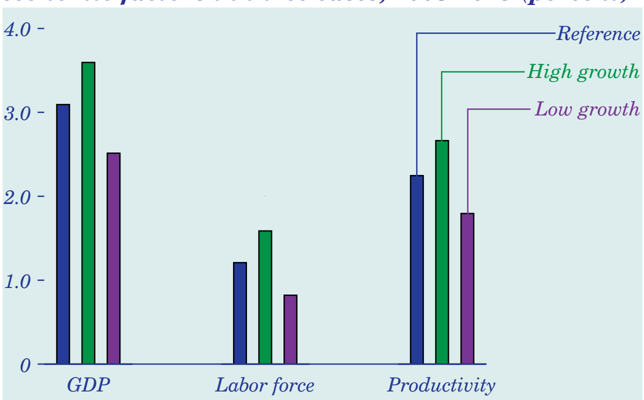
In *AEO2005*, the sectoral classification of the value of industrial output has been changed. In addition, the definition of services has been expanded to include the cost of goods in the wholesale and retail sectors. The industrial sector's share of total output is expected to fall from 25 percent in 2003 to 21 percent in 2025, and the manufacturing share of total output is projected to fall from 19 percent in 2003 to 17 percent in 2025 (Figure 37).

Figure 37. Sectoral composition of gross output, 2003, 2010, and 2025 (billion 1996 dollars)



High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 38. Average annual real growth rates of economic factors in three cases, 2003-2025 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2005* includes high and low economic growth cases in addition to the reference case (Figure 38). The high and low growth cases are intended to show the projected effects of alternative growth assumptions on energy markets. Economic variables in the alternative cases—including GDP and its components, disposable income, interest rates, productivity, population, prices, wages, and employment—are modified, in a consistent framework, from those in the reference case.

The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.6 percent per year), and productivity (2.7 percent per year) from 2003 through 2025. With higher productivity gains and employment growth, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow at a higher rate (3.6 percent per year) than in the reference case (3.1 percent). GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case.

The low economic growth case assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.8 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 2003 through 2025, and growth in GDP per capita is projected to average only 1.9 percent per year.

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

Figure 39. Average annual real GDP growth rate, 1970-2025 (percent, 22-year moving average)

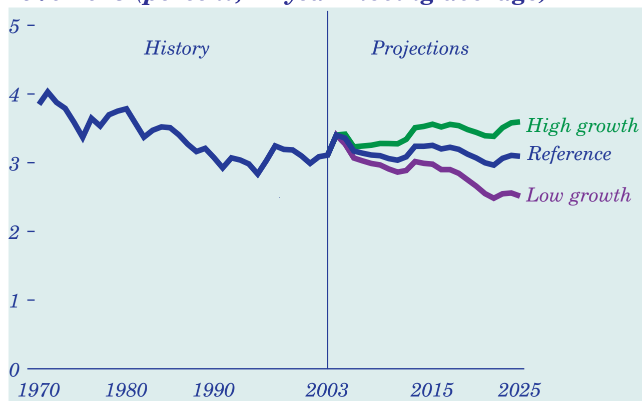
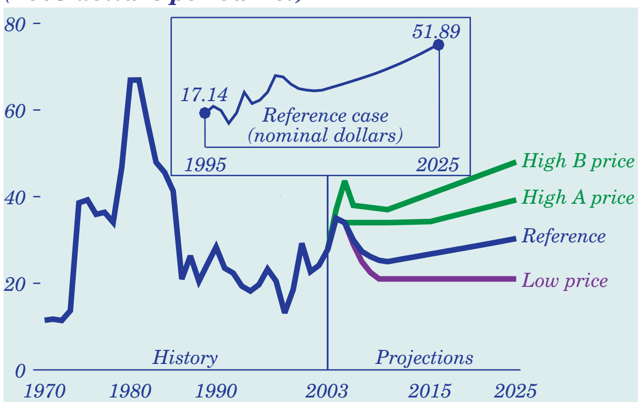


Figure 39 shows the trend in the 22-year moving average annual real growth rate for GDP, including projections for the three *AEO2005* cases. The value for each year is calculated as the annual compound growth rate over the preceding 22 years. The 22-year average shows major long-term trends in GDP growth by smoothing out the more volatile year-to-year changes (although periods that start or end in recession years can show more volatile changes in the growth rate). Annual real GDP growth has fluctuated considerably around the trend. The high and low growth cases capture the possibility of different paths for long-term output growth.

One reason for the variability of the forecasts is the composition of economic output, reflected by real growth rates of consumption and investment relative to overall GDP growth over the 2003-2025 period. In the reference case, consumption is projected to grow by 2.7 percent per year, while investment grows at a 5.1-percent annual rate. In the high growth case, with relatively lower interest rates, growth in investment is projected to average 5.8 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, combined with higher labor force growth, yield higher aggregate economic growth than projected in the reference case. In the low growth case, with relatively higher interest rates, annual growth in investment expenditures is projected to average only 4.0 percent. Lower investment growth rates imply slower capital accumulation. With the labor force also growing more slowly, aggregate economic growth is expected to be significantly lower than projected in the reference case.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 40. World oil prices in four cases, 1970-2025 (2003 dollars per barrel)

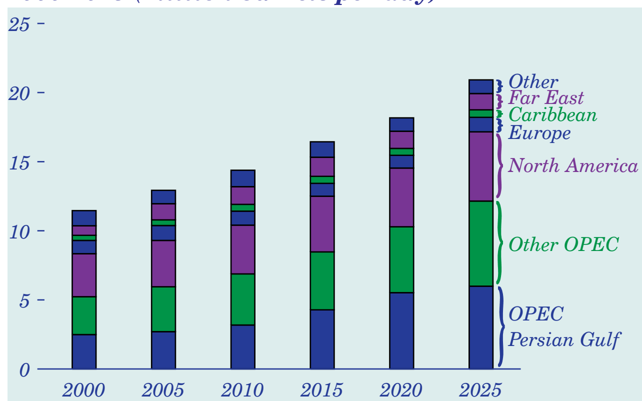


The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. Four *AEO2005* cases with different price paths allow an assessment of alternative views on the future of oil prices (Figure 40). In the reference case, with both OPEC and non-OPEC producers scheduled to add new production capacity over the next 5 years, prices in 2010 are projected to be more than $10 per barrel lower than current prices (all prices in 2003 dollars per barrel). After 2010, oil prices are projected to rise by about 1.3 percent per year, to more than $30 per barrel in 2025. (In nominal dollars, the reference case price is about $52 in 2025.) In the low price case, prices are projected to decline from their high in 2004 to $21 per barrel in 2009 and to remain at that level out to 2025. The high A price case projects that prices will remain at about $34 through 2015 and then increase on average by 1.4 percent per year, to more than $39 per barrel in 2025. In the high B case, world oil prices are projected to fall from current levels to $37 per barrel in 2010 and then rise to $48 per barrel in 2025.

Projected prices in all four cases are higher than in *AEO2004* [*130*], reflecting recent improved production discipline by OPEC members and limited ability of other producers to expand production despite increasing demand and high utilization rates that have led to higher prices. The price projections in the high A and B cases are sufficiently robust to encourage greater market penetration of alternative energy supplies.

Oil Imports Reach More Than 20 Million Barrels per Day by 2025

Figure 41. U.S. gross petroleum imports by source, 2000-2025 (million barrels per day)



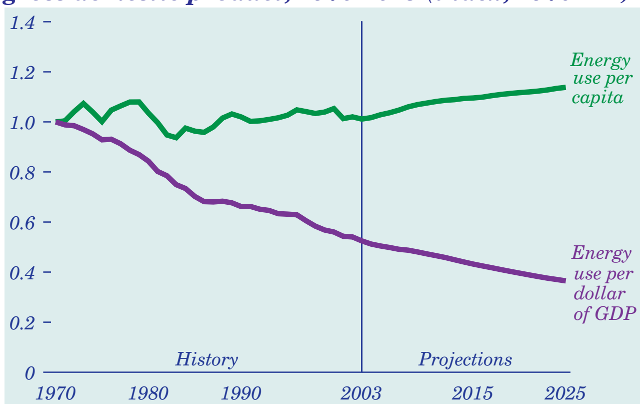
Total U.S. gross petroleum imports are projected to increase in the reference case from 12.3 million barrels per day in 2003 to 20.2 million in 2025 (Figure 41). Crude oil accounts for most of the increase in imports, because distillation capacity at U.S. refineries is expected to be more than 5.5 million barrels per day higher in 2025 than it was in 2003. Gross imports of refined petroleum, including refined products, unfinished oils, and blending components, are expected to increase by almost 60 percent from 2003 to 2025.

Crude oil imports from the North Sea are projected to decline gradually as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico are expected to continue, with much of the Canadian contribution coming from the development of its enormous oil sands resource base. West Coast refiners are expected to import small volumes of crude oil from the Far East to replace the declining production of Alaskan crude oil. The Persian Gulf share of total gross petroleum imports, 20.4 percent in 2003, is expected to increase to almost 30 percent in 2025; and the OPEC share of total gross imports, which was 42.1 percent in 2003, is expected to be above 60 percent in 2025.

Most of the increase in refined product imports is projected to come from refiners in the Caribbean Basin, North Africa, and the Middle East, where refining capacity is expected to expand significantly. Vigorous growth in demand for lighter petroleum products in developing countries means that U.S. refiners are likely to import smaller volumes of light, low-sulfur crude oils.

Average Energy Use per Person Increases in the Forecast

Figure 42. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



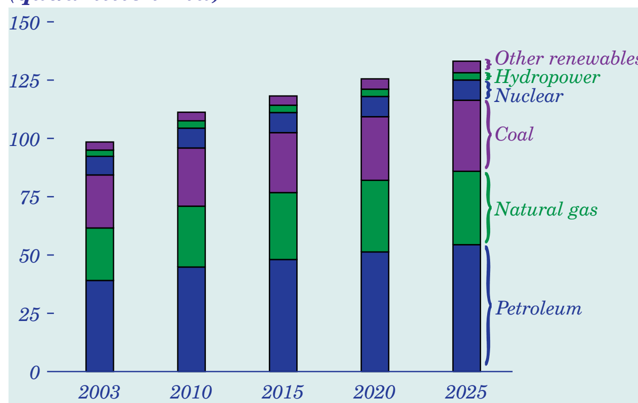
Energy intensity, as measured by energy use per 2000 dollar of GDP, is projected to decline at an average annual rate of 1.6 percent, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 42). The projected rate of decline falls between the average rate of 2.3 percent from 1970 through 1986, when energy prices increased in real terms, and the 0.7-percent rate from 1986 through 1992, when energy prices were generally falling. Since 1992, energy intensity has declined on average by 1.9 percent per year.

During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. From the late 1980s through the mid-1990s, with declining energy prices and strong economic growth, per capita energy use increased. Since the mid-1990s, energy consumption per capita has declined in some years and increased in others. Per capita energy use is projected to increase in the *AEO2005* forecast at an average annual rate of 0.5 percent, with growth in demand for energy services only partially offset by efficiency gains.

The potential for more energy conservation has received increased attention recently as energy prices have risen. *AEO2005* does not assume policy-induced conservation measures beyond those in existing legislation and regulation, nor does it assume behavioral changes that could result in greater energy conversation, beyond those experienced in the past.

Petroleum and Natural Gas Lead Increases in Primary Energy Use

Figure 43. Primary energy use by fuel, 2003-2025 (quadrillion Btu)



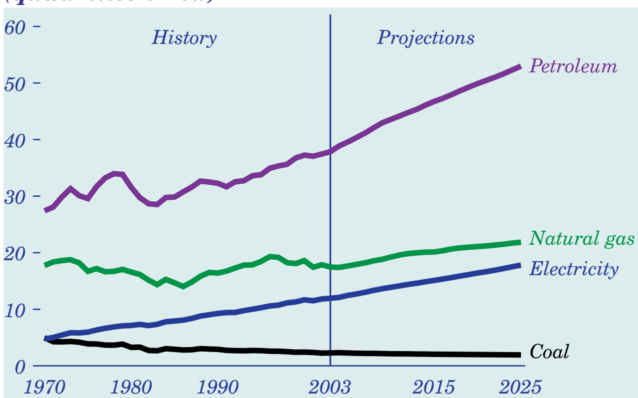
Total primary energy consumption, both in the end-use sectors and for electric power generation, is projected to grow from 98.2 quadrillion Btu in 2003 to 133.2 quadrillion Btu in 2025 (Figure 43). Petroleum consumption increases from 39.1 quadrillion Btu in 2003 to 54.4 quadrillion Btu in 2025, with about 80 percent of the increase expected in fuel use for transportation and the remainder in the industrial, commercial, and electricity generation sectors.

Natural gas consumption grows from 22.5 quadrillion Btu in 2003 to 31.5 quadrillion Btu in 2025. Over 50 percent of the expected increase is for electric power generation. Although some growth in other uses is also expected, particularly for industrial applications, their share of total natural gas use is projected to decline as a result of strong growth in demand in the electricity generation sector. Electricity generation is also expected to account for most of the growth in coal consumption, from 22.7 quadrillion Btu in 2003 to 30.5 quadrillion Btu in 2025. Much of the increase is expected after 2010, when higher natural gas prices make coal a more competitive fuel for power plants.

Smaller increases are projected for nuclear energy and primary renewable energy consumption. No new nuclear facilities are projected to be built before 2025, but higher capacity factors at existing plants lead to an expected increase from 8.0 quadrillion Btu in 2003 to 8.7 quadrillion Btu in 2025. Use of renewable energy from nonhydropower sources is projected to grow from 3.4 quadrillion Btu in 2003 to 5.4 quadrillion Btu in 2025 as a result of State mandates for renewable electricity generation, higher natural gas prices, and renewable energy production tax credits.

Petroleum and Electricity Lead Growth in Energy Consumption

Figure 44. Delivered energy use by fuel, 1970-2025 (quadrillion Btu)



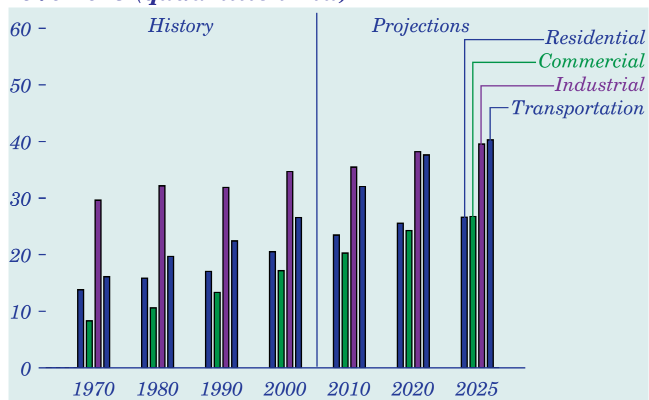
Consumption of petroleum products, mainly for transportation, makes up the largest share of delivered energy use in the residential, commercial, industrial, and transportation sectors in the *AEO2005* forecast (Figure 44). Total delivered energy use (excluding energy used for generation in the electric power sector) grows by 1.5 percent per year on average from 2003 to 2025, and transportation sector energy use grows by 1.8 percent per year. Transportation use grew by 2.0 percent per year in the 1970s and more slowly in the 1980s as a result of rising fuel prices and new Federal fuel economy standards. Stable fuel prices and a lack of new fuel economy standards are expected to reduce fuel economy gains in the forecast, while population growth and more travel per capita increase demand for gasoline.

Growth in delivered electricity consumption is slowed by efficiency improvements and by market saturation of end uses such as air conditioning in some regional markets.

Natural gas use is projected to grow at a slower rate than overall delivered energy demand, in contrast to its more rapid growth during the 1990s. As a result, natural gas is expected to meet 22 percent of total end-use energy requirements in 2025, compared with 24 percent in 2003. End-use demand for energy from renewables such as wood and ethanol is projected to grow by 1.2 percent per year as a result of continued competition from traditional purchased fuels.

U.S. Primary Energy Use Exceeds 133 Quadrillion Btu per Year by 2025

Figure 45. Primary energy consumption by sector, 1970-2025 (quadrillion Btu)



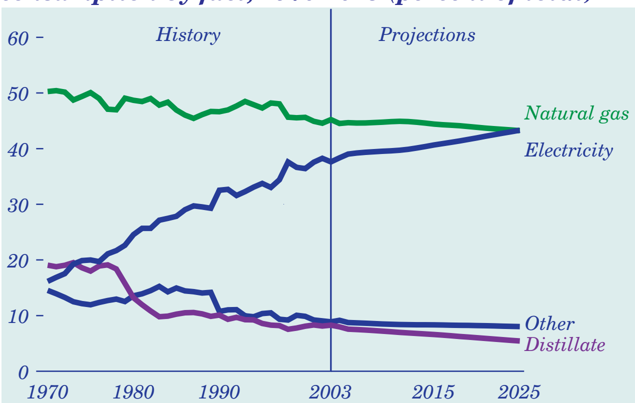
Primary energy use in 2025 (including electricity generation losses) is projected to be 133.2 quadrillion Btu in 2025 in the reference case, 36 percent higher than in 2003 (Figure 45). In the early 1980s energy prices rose, and sectoral energy consumption grew relatively little. After the early 1980s, however, declining real energy prices contributed to a marked increase in energy consumption. With higher energy prices since the late 1990s, energy consumption has again slowed.

Primary energy demand in the residential sector is projected to grow at one-third the expected growth rate for GDP and in the commercial sector at almost two-thirds the GDP growth rate. Demand for energy is expected to grow more rapidly in the transportation sector than in the buildings sectors as a result of increased per capita travel and slower fuel efficiency gains. Assumed efficiency gains, higher real energy prices, and structural shifts between industries are projected to cause industrial demand for primary energy to grow more slowly than GDP.

To bracket the uncertainty inherent in any long-term forecast, alternative cases were used to highlight the sensitivity of the forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Projected oil use for transportation in the high A world oil price case is 5.8 percent lower than in the low world oil price case in 2025, as consumer choices favor more fuel-efficient vehicles and the demand for travel services is reduced slightly. For 2025, the projection of transportation energy use in the high economic growth case is 13.2 percent greater than in the low economic growth case.

Electricity Share Expected To Match Natural Gas in Residential Energy Use

Figure 46. Residential delivered energy consumption by fuel, 1970-2025 (percent of total)



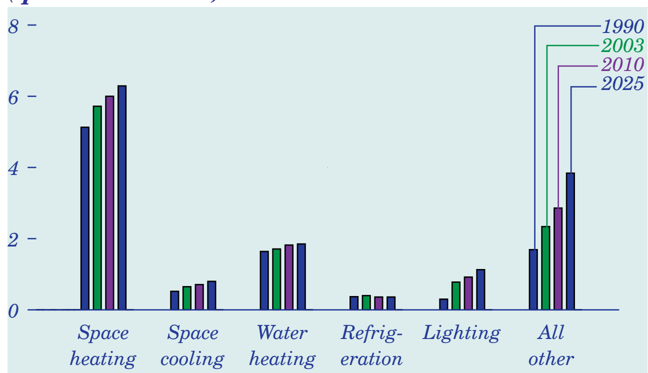
Residential delivered energy use is projected to increase by 23 percent between 2003 and 2025 (9 percent by 2010). Most (68 percent) of the growth results from increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 46).

Natural gas use in the residential sector is projected to grow by 1.1 percent per year from 2003 to 2010 and 0.6 percent per year from 2010 to 2025 while losing share in residential delivered energy consumption. Average natural gas prices from 2003 to 2025 are projected to be 14 percent below 2004 prices (7 percent below 2003), remaining competitive with heating oil. The number of homes heated with natural gas is projected to increase by more than the number heated with electricity or oil. Distillate use is projected to fall by 19 percent between 2003 and 2025, as energy efficiency gains outpace the increase in the number of homes using oil for space heating applications.

Newly built homes today are, on average, 13 percent larger than the existing housing stock, with correspondingly greater needs for heating, cooling, and lighting. Under current building codes and appliance standards, however, energy use per square foot is typically lower for new construction than for the existing stock. Further reductions in residential energy use per square foot could result from additional gains in equipment efficiency and more stringent building codes, requiring more insulation, better windows, and more efficient building designs.

Efficiency Standards Moderate Residential Energy Use

Figure 47. Residential delivered energy consumption by end use, 1990, 2003, 2010, and 2025 (quadrillion Btu)



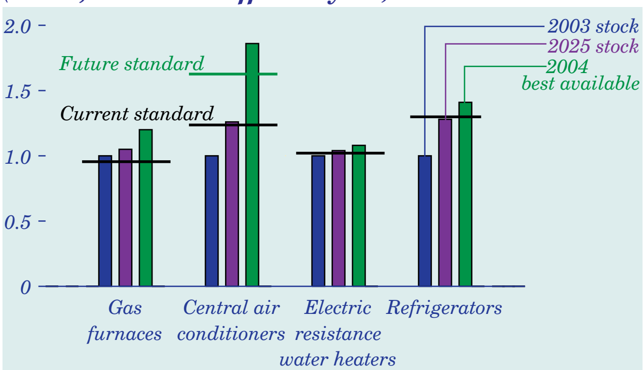
Delivered energy use for space heating grew by 0.8 percent per year from 1990 to 2003 (Figure 47). Future growth is expected to be slowed by higher equipment efficiency and more stringent building codes. Gains in building shell efficiency are projected to reduce demand for space heating per household by about 7 percent in 2010 and 16 percent in 2025 relative to 2003; however, those improvements are offset to a degree by better accounting of additions to existing homes and by the increased height of ceilings in new homes.

A variety of appliances are now subject to minimum efficiency standards, including heat pumps, air conditioners, furnaces, refrigerators, and water heaters. Current (July 2001) standards for a typical residential refrigerator limit electricity use to 510 kilowatthours per year. Energy use for refrigeration is projected to decline by 1.4 percent per year from 2003 to 2010 and 0.5 percent per year to 2025 as older refrigerators are replaced with new models. With no new standards for refrigerators assumed in the forecast, the decline slows when large numbers of the older, less efficient units have been replaced.

The "all other" category, which accounted for 20 percent of residential delivered energy use in 2003, is projected to account for 27 percent in 2025. Voluntary programs, both within and outside the appliance industry, are expected to forestall even larger increases. At annual rates of 2.9 percent from 2003 to 2010 and 2.3 percent from 2003 to 2025, growth in the "all other" demand category is projected to exceed the growth rates of other components through 2025.

Available Technologies Can Slow Growth in Residential Energy Use

Figure 48. Efficiency indicators for selected residential appliances, 2003 and 2025 (index, 2003 stock efficiency =1)

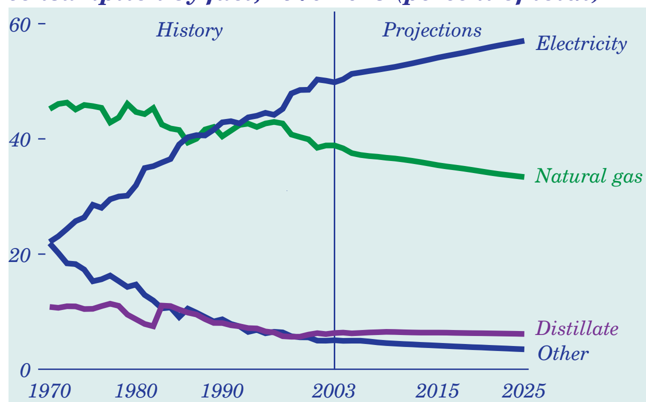


The *AEO2005* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 2003 stock, ensuring an increase in stock efficiency (Figure 48) without any additional new standards. Future updates to the Federal standards could have a significant effect on residential energy consumption, but they are not included in the reference case. The new efficiency standards for water heaters, clothes washers, central air conditioners, and heat pumps that were announced in January 2001 are included in the reference case.

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

Electricity Share of Commercial Energy Use Is Expected To Increase

Figure 49. Commercial delivered energy consumption by fuel, 1970-2025 (percent of total)

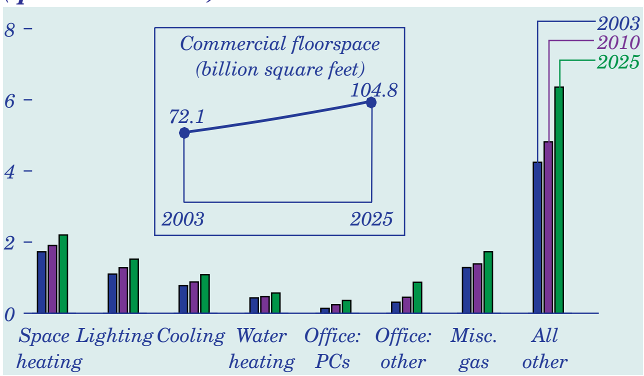


Recent trends in commercial sector fuel shares are expected to continue, with growth in overall consumption similar to its pace over the past two decades (Figure 49). Commercial delivered energy use (excluding primary energy losses in electricity generation) is projected to grow by 1.9 percent per year between 2003 and 2025, slightly faster than the projected growth rate for commercial floorspace of 1.7 percent. Energy consumption per square foot is projected to show little increase, with efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements expected to balance the effects of a projected increase in demand for electricity-based services and a slow rise in energy prices after 2010.

Electricity accounted for 50 percent of commercial delivered energy consumption in 2003, and its share is projected to increase to 57 percent in 2025. Expected efficiency gains in electric equipment are projected to be offset by the continuing penetration of new technologies and greater use of office equipment. Natural gas, which accounted for 39 percent of commercial energy consumption in 2003, is projected to decline to a 33-percent share by the end of the forecast. Distillate fuel oil, which accounted for 10 percent of commercial demand in the years before deregulation of the natural gas industry, made up only 6 percent of commercial energy demand in 2003. The distillate fuel share is projected to remain at 6 percent in 2025, as fuel oil continues to compete with natural gas for space and water heating uses. With conventional fuel prices projected to increase only slowly, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Commercial Efficiency Gains Are Not Expected To Balance Demand

Figure 50. Commercial delivered energy consumption by end use, 2003, 2010, and 2025 (quadrillion Btu)

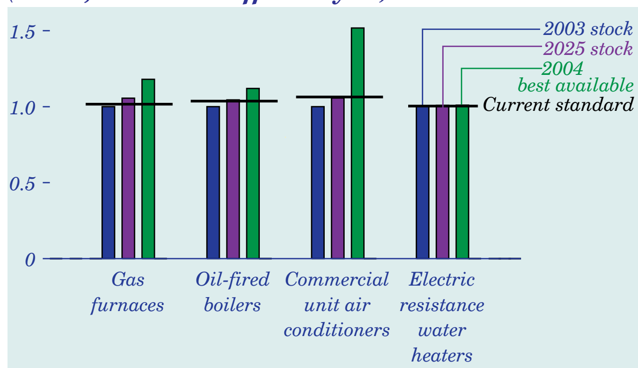


Energy use for the major commercial end uses is projected to increase slightly, as growth in requirements outpaces the adoption of more energy-efficient equipment. Minimum efficiency standards, which contribute to projected efficiency improvements in space heating, space cooling, water heating, and lighting, moderate the expected growth in overall commercial energy demand. A projected increase in building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 50).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers is projected to grow by 4.5 percent per year and for other office equipment, such as copiers, fax machines, and larger computers, by 4.8 percent per year through 2025. The growth in electricity use for office equipment reflects a trend toward more powerful equipment, increases in the market for commercial electronic equipment, and, while electricity prices fluctuate somewhat (declining between 2005 and 2011 and increasing later), generally low real electricity prices. Natural gas use for such miscellaneous uses as cooking and self-generated electricity is expected to grow by 1.4 percent per year. New telecommunications technologies and medical imaging equipment are projected to increase electricity demand in the "all other" end-use category, which also includes ventilation, refrigeration, minor fuel consumption, and energy use for a myriad of other uses, such as municipal water services, service station equipment, elevators, and vending machines. Annual growth of 1.9 percent is expected for the "all other" category.

Current Technologies Provide Potential Energy Savings

Figure 51. Efficiency indicators for selected commercial equipment, 2003 and 2025 (index, 2003 stock efficiency=1)

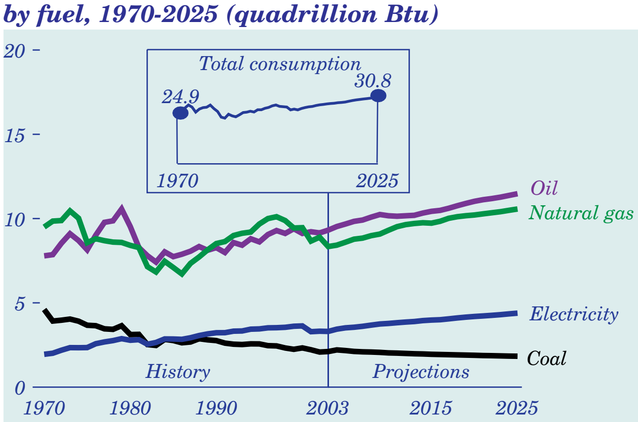


The stock efficiency of energy-using equipment in the commercial sector, as illustrated by the index shown in Figure 51, is projected to increase in the *AEO2005* reference case. As equipment is replaced and new buildings are built, technology advances are expected to reduce commercial energy intensity in most end-use services, although the long equipment service lives for many technologies moderate the pace of efficiency improvement in the forecast. For the majority of equipment covered by the Energy Policy Act of 1992, the existing Federal efficiency standards are higher than the average efficiency of the 2003 stock, ensuring some increase in the stock average efficiency as new equipment is added. A variety of commercial technologies, such as air-cooled air conditioners and gas-fired boilers, are currently being considered for more stringent standards. Future updates to the Federal standards could have significant effects on commercial energy consumption, but they are not included in the reference case.

Currently available technologies have the potential to reduce commercial energy consumption significantly. Improved heat exchangers for oil-fired boilers can raise efficiency by 8 percent over the current standard; and the use of multiple compressors and enhanced heat exchanger surfaces can increase the efficiency of unit air conditioners by more than 50 percent. When a business is considering an equipment purchase, however, the additional capital investment required for the most efficient technologies often carries more weight than do future energy savings, limiting the adoption of more efficient technologies.

Industrial Energy Use Could Grow by 24 Percent by 2025

Figure 52. Industrial delivered energy consumption by fuel, 1970-2025 (quadrillion Btu)

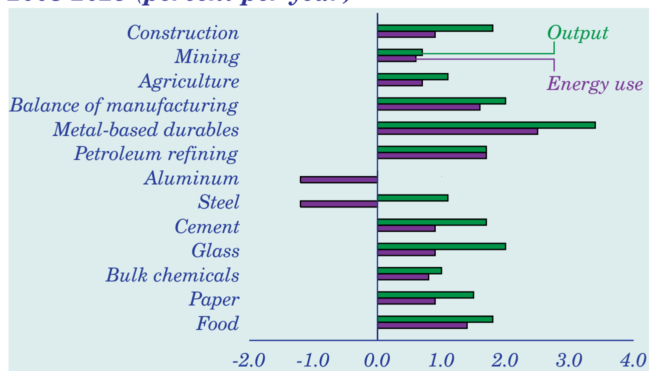


Industrial sector delivered energy consumption increased from 24.5 quadrillion Btu in 1990 to 26.4 quadrillion Btu in 2000, but economic recession in 2001 and rising natural gas prices had reduced industrial energy use to 24.9 quadrillion Btu in 2003. Natural gas use fell by 1.1 quadrillion Btu, accounting for most of the decline. With high natural gas prices expected to continue, industrial use is not projected to surpass its 1997 peak until after 2020.

Delivered energy use in the industrial sector (including agriculture, mining, construction, and traditional manufacturing) is projected to increase by 1.0 percent per year from 2003 to 2025 (Figure 52). Electricity (for machine drive and some production processes) and natural gas are the major energy sources used for heat and power in the industrial sector. Industrial use of purchased electricity is projected to increase by 1.3 percent per year from 2003 to 2025. Delivered natural gas prices in the industrial sector in 2025 are projected to be lower than in 2004; consequently, industrial natural gas use is expected to increase by 1.1 percent per year from 2003 to 2025. Petroleum use in the industrial sector is projected to grow by 1.0 percent per year from 2003 to 2025, whereas coal use is expected to decline by 0.6 percent per year as new steelmaking technologies continue to reduce demand for metallurgical coal. Coal use for boiler fuel is expected to remain essentially flat. Renewable energy (predominantly biomass) is the fastest growing industrial fuel in the forecast at a rate of 1.5 percent per year, but its share of the sector's delivered energy use remains small, at 8 percent in 2025.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 53. Average growth in manufacturing output and delivered energy consumption by sector, 2003-2025 (percent per year)

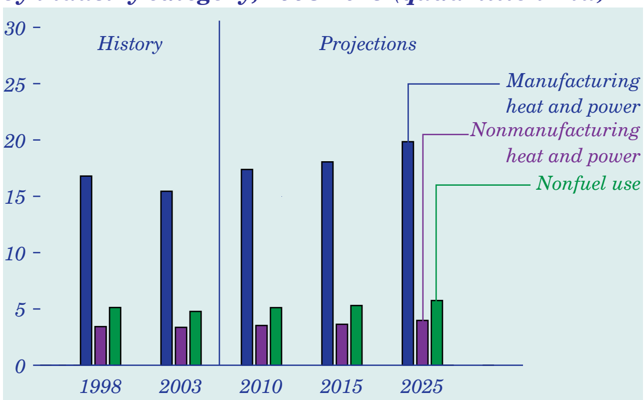


In *AEO2005*, industrial output is based on the North American Industry Classification System rather than the Standard Industrial Classification used in previous *AEO*s. The new classifications reduce manufacturing output by 3 percent in 1997 and lead to reduction in the historical growth rates for some industries. In the *AEO2005* forecast, industrial output grows at an average rate of 2.3 percent per year from 2003 to 2025, and growth in output growth varies widely by industry, from no growth in the aluminum industry to 3.4 percent in the metal-based durables industry (Figure 53). Metal-based durables, including fabricated metal products, machinery, electronic and electric products, and transportation equipment, accounted for one-third of industrial output in 2003.

Energy consumption growth also varies widely among specific industries. For example, the steel industry is expected to rely increasingly on scrap-based steelmaking techniques with lower energy requirements, and the aluminum industry is assumed to add no new primary smelting capacity, which is the most energy-intensive component of aluminum manufacturing. Relatively low output growth is also projected for both steel and aluminum, and as a result, energy consumption in both the steel and aluminum industries is projected to decline. The metal-based durables industry is projected to have the most rapid growth in energy consumption, at 2.5 percent per year, but its energy use accounts for only 7 percent of all industrial energy consumption in 2025.

Industrial Energy Use Grows Steadily in the Projections

Figure 54. Industrial delivered energy consumption by industry category, 1998-2025 (quadrillion Btu)



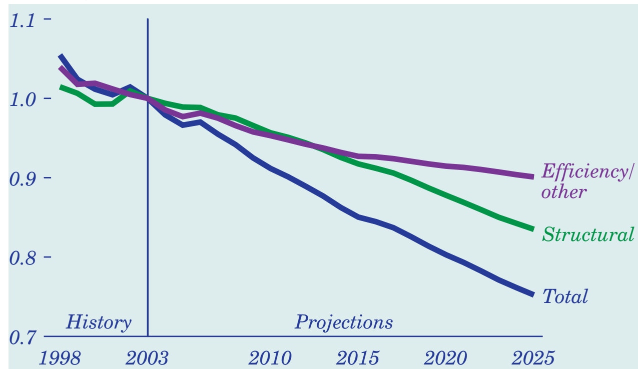
Two-thirds of the energy consumed in the industrial sector is used to provide heat and power for manufacturing. Of the remainder approximately 14 percent is used for nonmanufacturing heat and power, and 19 percent goes to nonfuel uses, such as raw materials and asphalt (Figure 54).

Nonfuel use of energy (feedstocks and asphalt) in the industrial sector is projected to grow at a slightly slower rate than heat and power consumption (0.8 percent and 1.1 percent per year, respectively). The feedstock portion of nonfuel use is projected to grow by 0.9 percent per year, marginally slower than the growth of output from the bulk chemical industry (1.0 percent per year through 2025), because of changes in the product mix. In 2025, feedstock consumption is projected to total 4.3 quadrillion Btu. Asphalt use is projected to grow by 0.7 percent per year, to 1.4 quadrillion Btu in 2025. The construction industry is the principal consumer of asphalt for paving and roofing. Asphalt use grows more slowly than construction output (1.8 percent per year through 2025), because not all construction activities require asphalt.

Petroleum refining, bulk chemicals, and pulp and paper are the largest consumers of energy for heat and power in the industrial sector. These three energy-intensive industries used 11.7 quadrillion Btu of energy (including feedstocks) in 2003. Energy use for petroleum refining grows more rapidly than any other energy-intensive industry, by 1.7 percent per year through 2025. Growth in energy use for the bulk chemicals and pulp and paper industries is projected at 0.8 percent and 0.9 percent, respectively.

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

Figure 55. Components of improvement in industrial delivered energy intensity, 1998-2025 (index, 2003 = 1)

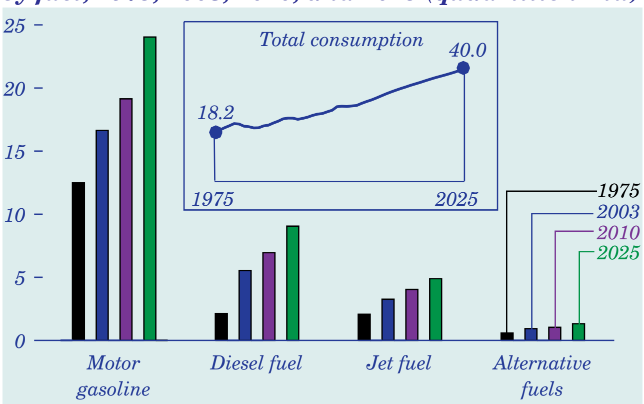


Changes in industrial energy intensity (consumption per unit of output) can be separated into two components. One reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of industrial value of shipments. The use of more energy-efficient technologies, combined with relatively slow growth in the energy-intensive industries, has dampened growth in industrial energy consumption over the past decade. Thus, despite a 25-percent increase in industrial output, energy use in the sector grew by only 2 percent between 1990 and 2003.

Industrial value of shipments is projected to grow by 2.3 percent between 2003 and 2025. The share of total industrial shipments attributed to the energy-intensive industries is projected to fall from 21 percent in 2003 to 17 percent in 2025. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial energy intensity would decline. Figure 55 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*131*]. From 2003 to 2025, industrial delivered energy intensity is projected to drop by 25 percent. The changing composition of industrial output is expected to result in a drop in energy intensity of approximately 16 percent by 2025. Thus, almost two-thirds of the expected change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with projected increases in equipment and production efficiencies.

Alternative Fuels Make Up 2.2 Percent of Light-Duty Vehicle Fuel Use in 2025

Figure 56. Transportation energy consumption by fuel, 1975, 2003, 2010, and 2025 (quadrillion Btu)



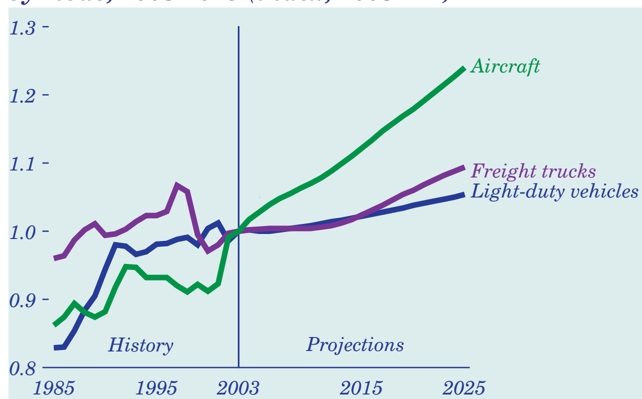
Energy demand for transportation is projected to grow from 27.1 quadrillion Btu in 2003 to 40.0 quadrillion Btu in 2025 (Figure 56). In the reference case, motor gasoline use increases by 1.7 percent per year from 2003 to 2025, when it makes up 60 percent of transportation energy use. Alternative fuels are projected to displace 207,000 barrels of oil equivalent per day [*132*] in 2010 and 280,500 barrels per day (2.2 percent of light-duty vehicle fuel consumption) in 2025, in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is expected to be sustained, however, by low prices relative to the rate of inflation and slower fuel efficiency gains for conventional cars, vans, pickup trucks, and sport utility vehicles than were achieved in the 1980s.

Assumed industrial output growth of 2.3 percent per year from 2003 to 2025 leads to an increase in freight truck use, with a corresponding 2.3-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield an annual increase in air travel of 2.2 percent from 2003 to 2025 and a 1.9-percent average annual increase in jet fuel use.

Demand for light-duty vehicle fuels is projected to increase from 16.2 quadrillion Btu in 2003 to 24.5 quadrillion Btu in 2025. Light-duty diesel vehicles are assumed to meet the emission standards for diesel fuel, and diesel fuel grows from 1.5 percent of total light-duty vehicle fuel consumption in 2003 to 4.4 percent in 2025. Alternative fuels, consisting mostly of ethanol used in gasoline blending (71 percent in 2025) and liquefied petroleum gas (14 percent) grow from 1.7 percent of the 2003 total to 2.2 percent in 2025.

Average Horsepower for New Cars Is Projected To Grow by 26 Percent

Figure 57. Transportation stock fuel efficiency by mode, 2003-2025 (index, 2003 = 1)



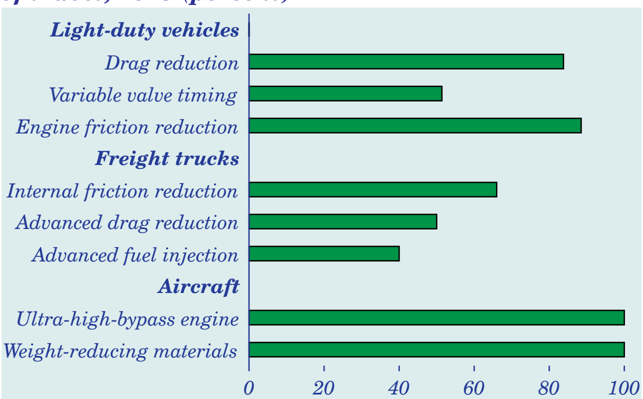
Fuel efficiency is projected to improve more rapidly from 2003 to 2025 than it did during the 1990s. Fuel economy for the light-duty vehicle stock is projected to improve by 5 percent, and for the stock of freight trucks from 6.0 miles per gallon in 2003 to 6.6 in 2025 (Figure 57). No changes are assumed in currently promulgated fuel efficiency standards for cars and light trucks. Low fuel prices and higher personal incomes are expected to increase the demand for larger, more powerful vehicles, with average horsepower for new cars projected to be 26 percent above the 2003 average in 2025 (Table 26). Advanced technologies and materials are expected to provide increased performance and size while improving new vehicle fuel economy [*133*]. Advanced technologies are projected to boost the average fuel economy of new light-duty vehicles by about 1.8 miles per gallon, to 26.9 miles per gallon in 2025 from 25.1 miles per gallon in 2003.

Table 26. New car and light truck horsepower ratings and market shares, 1990-2025

	Cars			Light trucks		
Year	Small	Medium	Large	Small	Medium	Large
1990						
Horsepower	119	145	176	132	157	185
Sales share	0.60	0.28	0.12	0.48	0.21	0.30
2003						
Horsepower	149	184	224	181	193	241
Sales share	0.54	0.33	0.13	0.31	0.34	0.35
2010						
Horsepower	171	211	247	208	212	276
Sales share	0.50	0.35	0.15	0.30	0.34	0.35
2025						
Horsepower	188	233	265	223	219	284
Sales share	0.50	0.35	0.15	0.30	0.34	0.35

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 58. Technology penetration by mode of travel, 2025 (percent)



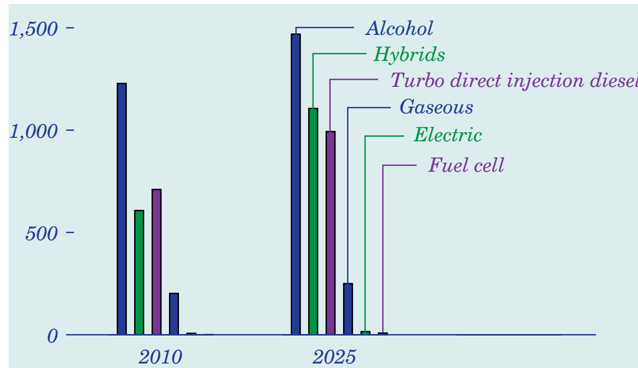
Fuel economy for new light-duty vehicles is projected to be 26.9 miles per gallon in 2025 (automobiles 31.0 miles per gallon, light-duty trucks 24.6 miles per gallon) as a result of advances in fuel-saving technologies (Figure 58). Three of the most promising would provide more than 4 percent higher fuel economy each: advanced drag reduction, variable valve timing and lift, and technologies that reduce internal engine friction. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and reduced engine friction increases engine efficiency through more efficient designs, bearings, and coatings that reduce resistance between moving parts.

Due to concerns about economic payback, the trucking industry is more sensitive to the marginal cost of fuel-efficient technologies; however, several technologies can increase fuel economy significantly, including components to reduce internal friction (2-percent improvement), advanced drag reduction (2 percent), and advanced fuel injection systems (5 percent). These technologies are expected to penetrate the heavy-duty truck market by 2025. Advanced technology penetration is projected to increase the average fuel efficiency of new freight trucks from 6.1 miles per gallon in 2003 to 6.8 miles per gallon in 2025.

New aircraft fuel efficiencies are projected to increase by 19 percent from 2003 levels by 2025. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Are Projected To Reach 19 Percent of Sales by 2025

Figure 59. Sales of advanced technology light-duty vehicles by fuel type, 2010 and 2025 (thousand vehicles sold)

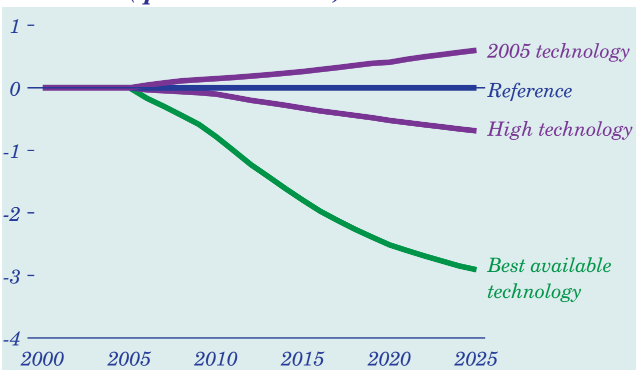


Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 3.8 million vehicle sales per year and make up 19.1 percent of total light-duty vehicle sales in 2025. Alcohol flexible-fueled vehicles are projected to continue to lead advanced technology vehicle sales, at 1.5 million vehicles in 2025 (Figure 59). Hybrid electric vehicles (specifically designed to use electric motors and batteries in combination with a combustion engine to drive the vehicle), introduced into the U.S. market by two manufacturers in 2000, are anticipated to sell well: 607,000 units are projected to be sold in 2010, increasing to 1.1 million units in 2025. Sales of turbo direct injection diesel vehicles are projected to increase to 710,000 units in 2010 and 1 million units in 2025.

About 80 percent of advanced technology sales are as a result of Federal and State mandates for fuel economy standards, emissions programs, or other energy regulations. Currently, manufacturers selling alcohol flexible-fueled vehicles receive fuel economy credits that count toward compliance with corporate average fuel economy regulations. In the *AEO2005* forecast, the majority of projected gasoline hybrid, fuel cell, and electric vehicle sales result from compliance with low-emission vehicle programs in California, New York, Maine, Vermont, and Massachusetts. *AEO2005* does not include the impacts of California Assembly Bill 1493, which effectively sets carbon emission standards for light-duty vehicles, because of uncertainty about the State's ability to enforce the standards.

Advanced Technologies Could Reduce Residential Energy Use

Figure 60. Variation from reference case delivered residential energy use in three alternative cases, 2003-2025 (quadrillion Btu)



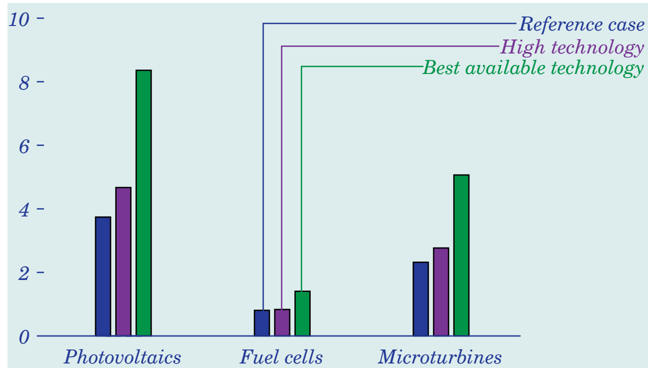
The reference case includes the effects of several policies aimed at increasing residential end-use efficiency, including minimum efficiency standards and voluntary energy savings programs to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2005 technology case, assuming no increase in efficiency of equipment or building shells beyond that available in 2005, 4 percent more energy would be required in 2025 than projected in the reference case (Figure 60).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected residential delivered energy use in 2025 is 20 percent lower than in the reference case and 24 percent lower than in the 2005 technology case. Through 2025, projected additional investment of $442 billion relative to that in the reference case would be necessary to save a projected $139 billion in energy costs in the best available technology case [*134*].

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

Advanced Technologies Could Slow Electricity Sales Growth for Buildings

Figure 61. Buildings sector electricity generation from advanced technologies in alternative cases, 2025 (billion kilowatthours)



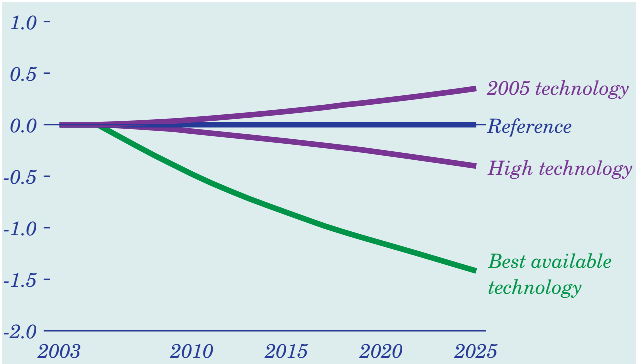
Alternative technology cases for the residential and commercial sectors include varied assumptions for the availability and market penetration of advanced distributed generation technologies (solar photovoltaic systems, fuel cells, and microturbines). Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing system efficiency and the attractiveness of the advanced technologies, particularly in alternative cases with more optimistic technology assumptions.

In the high technology case, buildings are projected to generate 1.4 billion kilowatthours (8 percent) more electricity in 2025 than in the reference case (Figure 61), most of which offsets residential and commercial electricity purchases. In the best available technology case, projected electricity generation in buildings in 2025 is 8.0 billion kilowatthours (47 percent) higher than in the reference case. In the 2005 technology case, assuming no further technological progress or cost reductions after 2005, electricity generation in buildings in 2025 is 6.5 billion kilowatthours (38 percent) lower than projected in the reference case.

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

Advanced Technologies Could Reduce Commercial Energy Use

Figure 62. Variation from reference case delivered commercial energy use in three alternative cases, 2003-2025 (quadrillion Btu)

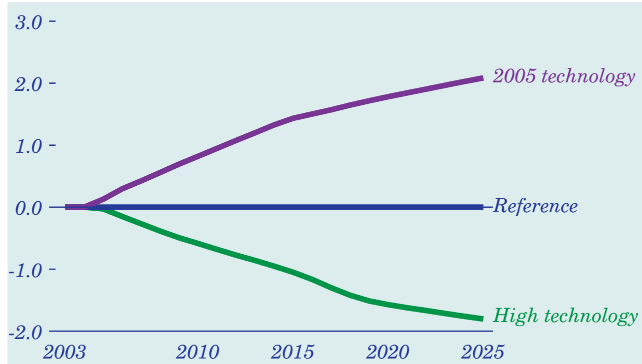


The *AEO2005* reference case incorporates efficiency improvements for commercial equipment and building shells, which help to limit the projected rate of increase in commercial energy intensity (delivered energy use per square foot of floorspace) to 0.2 percent per year over the forecast. The 2005 technology case assumes that future equipment and building shells will be no more efficient than those available in 2005. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at a faster rate than assumed in the high technology case.

In the 2005 technology case, projected energy use in 2025 is 3 percent higher than the 12.5 quadrillion Btu in the reference case (Figure 62), as a result of an 0.3-percent average annual increase in commercial delivered energy intensity. The high technology case projects a 3-percent energy savings in 2025 relative to the reference case, with little change in energy intensity from 2003 to 2025. In the best available technology case, commercial delivered energy intensity is projected to improve by 0.4 percent per year, and projected energy use in 2025 is 11 percent lower than in the reference case. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. In 2025, commercial solar photovoltaic systems are projected to generate more than twice as much electricity in the best technology case as in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 63. Variation from reference case delivered industrial energy use in two alternative cases, 2003-2025 (quadrillion Btu)



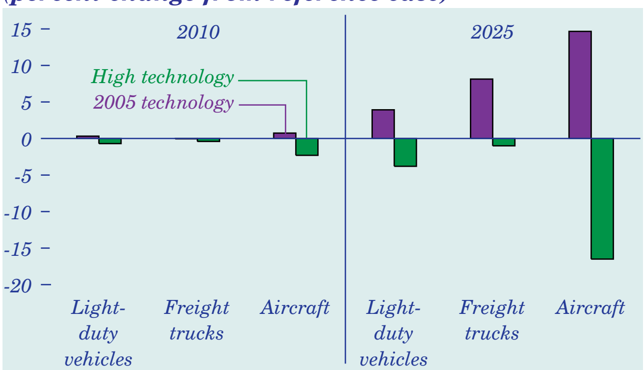
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected output growth in metal-based durables (3.4 percent per year), driven primarily by investment and export-related demand, is a key factor. In the reference case, this non-energy-intensive group of industries grows more than twice as fast as the energy-intensive sectors (1.5 percent per year).

In the high technology case, 1.8 quadrillion Btu less energy is used in 2025 than for the same level of output in the reference case. Industrial energy intensity improves by 1.6 percent per year through 2025 in this case, compared with 1.3-percent annual improvement in the reference case (Figure 63). Industrial cogeneration capacity is projected to increase more rapidly in the high technology case (2.7 percent per year) than in the reference case (2.2 percent per year).

In the 2005 technology case, industry is projected to use 2.1 quadrillion Btu more energy in 2025 than in the reference case. Energy efficiency remains at the level achieved by new equipment in 2005, but average efficiency still improves as old equipment is retired. Aggregate industrial energy intensity is projected to decline by 1.0 percent per year because of reduced efficiency gains. The change in industrial structure is the same in the 2005 technology and high technology cases as in the reference case, because the same macroeconomic assumptions are used for the three cases, but the relative effects of the change varies, accounting for 63 percent of the change in intensity in the reference case, 52 percent in the high technology case, and 83 percent in the 2005 technology case.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 64. Changes in projected transportation fuel use in two alternative cases, 2010 and 2025 (percent change from reference case)

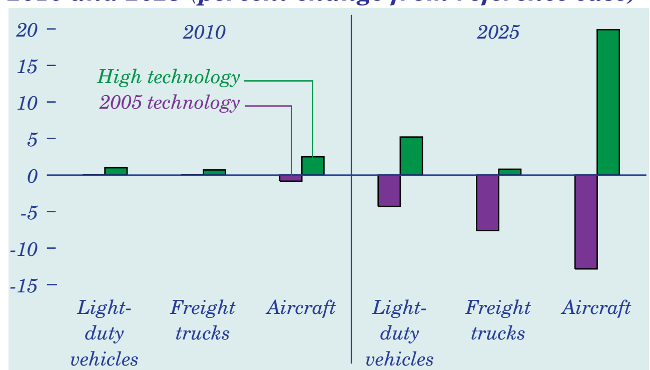


In the *AEO2005* reference case, delivered energy use in the transportation sector is projected to increase from 27.1 quadrillion Btu in 2003 to 40.0 quadrillion Btu in 2025. In the high technology case, the projection for 2025 is 1.9 quadrillion Btu (4.7 percent) lower, with about 54 percent (1.0 quadrillion Btu) of the difference attributed to efficiency improvements in light-duty vehicles (Figure 64) as a result of increased penetration of advanced technologies, including variable valve lift, electrically driven power steering pumps, and advanced electronic transmission controls. Similarly, projected fuel use by heavy freight trucks in 2025 is 0.1 quadrillion Btu lower in the high technology case than in the reference case, and advanced aircraft technologies are projected to reduce fuel use for air travel by 0.7 quadrillion Btu in 2025.

In the 2005 technology case, with new technology efficiencies fixed at 2005 levels, efficiency improvements can result only from stock turnover. As a result, total delivered energy demand for transportation in 2025 is 2.3 quadrillion Btu (5.8 percent) higher in 2025 in the 2005 technology case than projected in the reference case. Projected fuel use for air travel in 2025 is 0.7 quadrillion Btu (15 percent) higher in the 2005 technology case than in the reference case, and freight trucks are projected to use 0.6 quadrillion Btu (8.3 percent) more fuel in 2025 [*135*].

Technology Assumptions Include Improvements in Vehicle Efficiency

Figure 65. Changes in projected transportation fuel efficiency in two alternative cases, 2010 and 2025 (percent change from reference case)



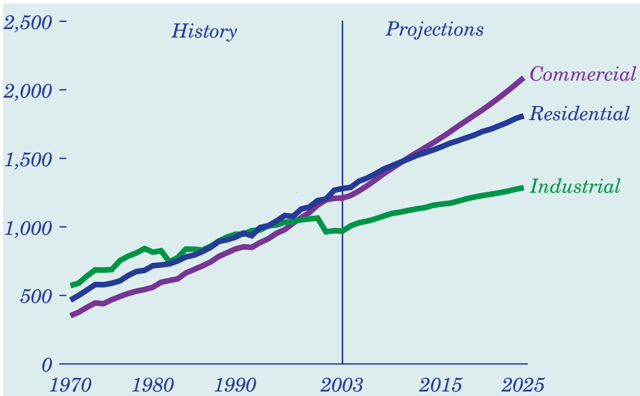
The high technology case assumes lower costs and higher efficiencies for new transportation technologies. Advances in conventional technologies are projected to increase the average fuel economy of new light-duty vehicles in 2025 from 26.9 miles per gallon in the reference case to 28.8 miles per gallon in the high technology case. The average efficiency of the light-duty vehicle stock is 20.3 miles per gallon in 2010 and 22.1 miles per gallon in 2025 in the high technology case, compared with 20.1 miles per gallon in 2010 and 21.0 miles per gallon in 2025 in the reference case (Figure 65).

For freight trucks, average stock efficiency in the high technology case is 0.6 percent higher in 2010 and 1.0 percent higher in 2025 than the reference case projection of 6.6 miles per gallon. Advanced aircraft technologies increase projected aircraft efficiency by 3 percent in 2010 and 20 percent in 2025 relative to the reference case projections.

In the 2005 technology case, the average fuel economy of new light-duty vehicles is projected to be 24.9 miles per gallon in 2025, and the projected average for the entire light-duty vehicle stock is 20.1 miles per gallon in 2025. For freight trucks, the projected average stock efficiency in 2025 is 6.1 miles per gallon. Aircraft efficiency in 2025 is projected to average 59.7 seat-miles per gallon in the 2005 technology case, compared with 68.5 seat-miles per gallon in the reference case.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 66. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



Total electricity sales are projected to increase at an average annual rate of 1.9 percent in the *AEO2005* reference case, from 3,481 billion kilowatthours in 2003 to 5,220 billion kilowatthours in 2025 (Figure 66). From 2003 to 2025, annual growth in electricity sales is projected to average 1.6 percent in the residential sector, 2.5 percent in the commercial sector, and 1.3 percent in the industrial sector.

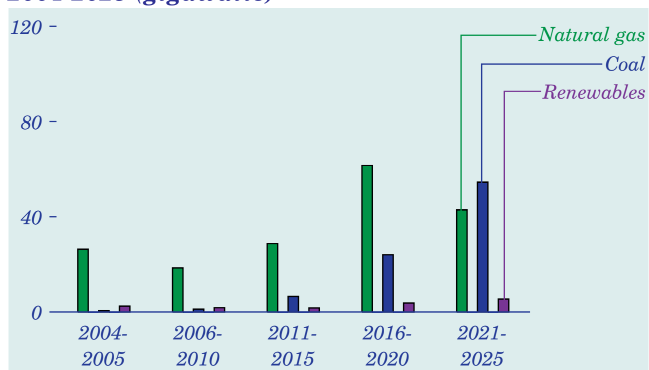
The average size of homes is projected to be larger in 2025 than in 2003 in terms of both square footage and ceiling height, with corresponding increases in electricity use for heating, cooling, and lighting. In addition, expected population shifts to warmer climates increase the amount of electricity used for air conditioning, although the projected increases are mitigated in part by the implementation of a more stringent efficiency standard for air conditioners and heat pumps in 2006.

Projected efficiency gains for electric equipment in the commercial sector are offset by the continuing penetration of new telecommunications technologies and medical imaging equipment, increased use of office equipment, and more rapid additions of floorspace.

Although electricity use is projected to increase with the growth of industrial output, increases in electricity sales to the industrial sector are expected to be offset by a 2.7-percent average annual increase in onsite generation.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 67. Electricity generation capacity additions by fuel type, including combined heat and power, 2004-2025 (gigawatts)



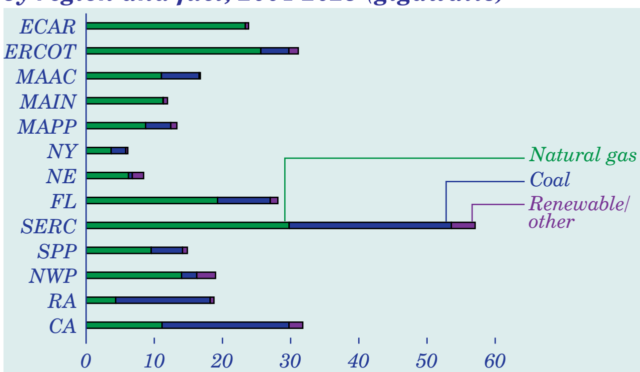
With growing electricity demand and the retirement of 43 gigawatts of inefficient, older generating capacity, 281 gigawatts of new capacity (including end-use combined heat and power) will be needed by 2025. Most retirements are expected to be older oil- and natural-gas-fired steam capacity, along with smaller amounts of older oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not competitive with newer natural gas combustion turbine or combined-cycle capacity.

More than 60 percent of new capacity additions are projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technologies (Figure 67). More than 80 percent of the capacity additions will be needed after 2010, when the current excess of generation capacity has been reduced. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become increasingly competitive, accounting for nearly one-third of the capacity expansion expected in the reference case. Most of the new coal capacity is expected to use advanced pulverized coal technology and to begin operation after 2015. About 16 gigawatts of capacity using advanced clean coal technology, with higher capital costs but relatively low fuel costs, is also expected to be added.

About 5 percent of the projected capacity expansion consists of renewable generating units. Another 7 gigawatts of distributed generation, mostly gas-fired microturbines, is also expected to be added by 2025. Oil-fired steam plants with higher fuel costs and lower efficiencies are expected to be used only for new industrial combined heat and power capacity.

Capacity Additions Are Expected To Be Required in All Regions

Figure 68. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2004-2025 (gigawatts)



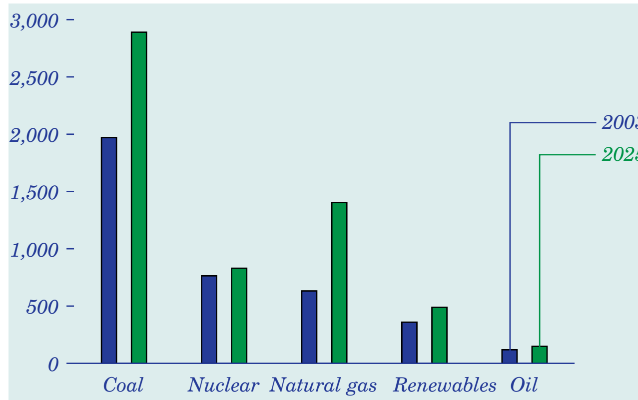
Most areas of the United States currently have excess generation capacity, but all the electricity demand regions (see Appendix G for definitions) are expected to need additional, currently unplanned, capacity by 2025 (Figure 68). Some new plants already are under construction, nearly all of which are expected to be completed by 2010.

The need for new capacity is expected to be greatest in the Southeast and the West. Although comparatively small geographically, the Southeast accounts for about 30 percent of projected total demand in 2025 and a comparable share of expected capacity additions. The size of the region's electricity market is the principal reason for the amount of new capacity required, and the projected growth in its demand for electricity growth is also slightly higher than the national average. The West, which geographically is the largest electricity demand region, currently represents less than 20 percent of the Nation's total electricity demand, but it accounts for 25 percent of projected capacity additions. Relatively strong growth in demand is projected for the West.

Capacity additions in the Southeast and the West are expected to be considerably more diverse than in the other areas of the country, where most additions are projected to be natural-gas-fired capacity. Almost all additions of coal-fired and renewable capacity are expected to be in these two areas. Of the 87 gigawatts of new coal-fired capacity, the Southeast and West account for 36 percent and 40 percent, respectively. Nationally, new renewable generating capacity is expected to total 15 gigawatts, with 28 percent and 34 percent located in the Southeast and West.

Natural Gas and Coal Meet Most Needs for New Electricity Supply

Figure 69. Electricity generation by fuel, 2003 and 2025 (billion kilowatthours)



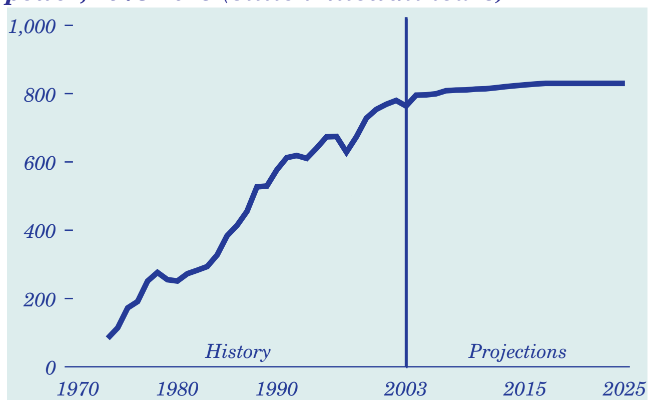
Coal-fired power plants are expected to continue supplying most of the Nation's electricity through 2025 (Figure 69). In 2003, coal-fired plants (including utilities, independent power producers, and end-use combined heat and power) accounted for 51 percent (1,970 billion kilowatthours) of all electricity generation. Their output is projected to increase to 2,890 billion kilowatthours in 2025, while their share of total generation declines to 50 percent as a result of a rapid increase in natural-gas-fired generation.

In compliance with environmental regulations, about one-third of existing coal-fired capacity has been fitted with scrubbers to reduce sulfur dioxide emissions, and another 27 gigawatts of currently existing capacity is expected to have scrubbers in 2025. A total of 87 gigawatts of new coal-fired capacity is projected to be added in the reference case, mostly after 2010, as natural gas prices continue to rise. Nuclear generation, currently the second-largest source of electricity, is expected to increase modestly, as a result of additional improvements in plant performance and expansions of existing capacity, before leveling off after 2017.

Natural gas is expected to have the largest increase in its share of total electricity generation, from 17 percent in 2003 to 20 percent in 2010 and 24 percent in 2025, and by 2010 it is expected to overtake nuclear power as the second-largest source of electricity production. Generation from renewable sources, including hydropower, is projected to increase by 36 percent from 2003 to 2025, but its share of total electricity supply is projected to decline from 9 percent in 2003 to 8 percent in 2025.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

Figure 70. Electricity generation from nuclear power, 1973-2025 (billion kilowatthours)



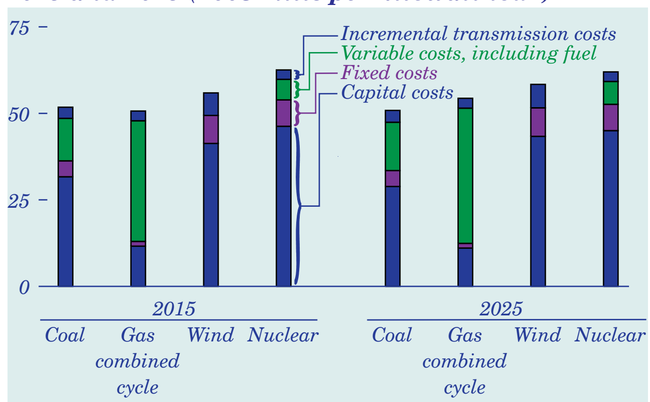
The United States currently has 104 commercial nuclear reactors licensed to operate, providing about 20 percent of the total 3,690 billion kilowatthours of electricity generated in 2003 (Figure 70). The performance of U.S. nuclear units has improved recently; the national average capacity factor rose to 90 percent in 2002 before dropping slightly to 88 percent in 2003. It is assumed that performance improvements will continue even as the plants age, leading to a weighted average capacity factor of 92 percent after 2010.

In the reference case, no nuclear units are projected to be retired from 2003 to 2025. Nuclear capacity grows slightly, due to assumed increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 8 applications for power uprates in 2003, and another 12 were approved or pending in 2004. The reference case assumes that all the uprates will be carried out, as well as others expected by the NRC over the next 15 years, leading to an increase of 3.5 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2003 and 2025.

Nuclear units would be retired if their operation were no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original license expiration dates. As of December 2004, license renewals for 30 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 28 additional applicants have announced intentions to pursue license renewals over the next 3 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 71. Levelized electricity costs for new plants, 2015 and 2025 (2003 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 71) [*136*]. The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the risks of siting new units.

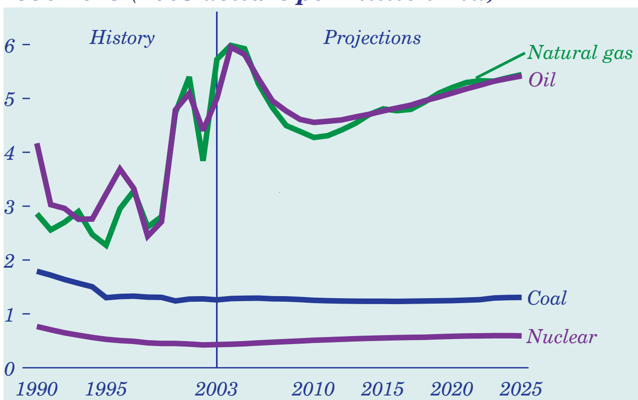
Capital costs are expected to be reduced over time (Table 27), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,333 and 7,200 Btu per kilowatthour, respectively, by 2010.

Table 27. Costs of producing electricity from new plants, 2015 and 2025

Costs	2015 Advanced coal	2015 Advanced combined cycle	2025 Advanced coal	2025 Advanced combined cycle
	2003 mills per kilowatthour			
Capital	31.68	11.63	28.87	11.08
Fixed	4.59	1.36	4.59	1.36
Variable	12.28	34.88	13.98	39.06
Incremental transmission	3.24	2.80	3.41	2.86
Total	**51.79**	**50.67**	**50.85**	**54.36**

Coal and Nuclear Fuel Costs Are Expected To Be Stable

Figure 72. Fuel prices to electricity generators, 1990-2025 (2003 dollars per million Btu)

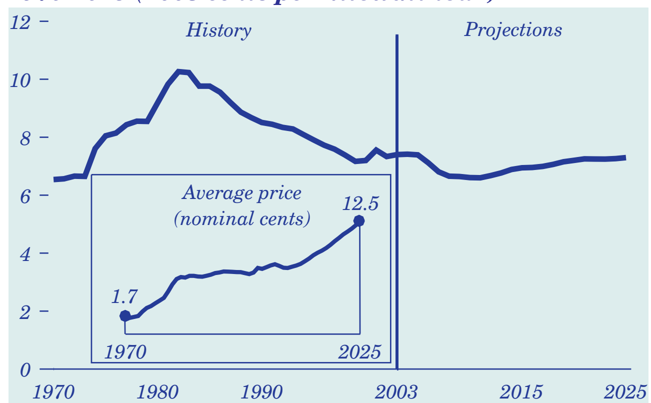


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. For a new coal-fired plant built today, fuel costs would represent about one-half of total operating costs, whereas the share for a new natural-gas-fired plant would be almost 90 percent. For nuclear units, fuel costs typically are a much smaller portion of total production costs, and nonfuel operations and maintenance costs make up a much larger share.

The impact of higher natural gas prices in the projections is offset by increased generation from coal-fired and nuclear power plants and by higher generation efficiencies as new capacity is installed. Although natural gas prices have been volatile in recent years, delivered prices to electricity generators are projected to peak at $6 per million Btu in 2004, then drop by almost 30 percent by 2010 before climbing steadily to almost $5.50 per million Btu in 2025 (Figure 72). Nuclear fuel costs, currently around $0.40 per million Btu (roughly 4 mills per kilowatthour), are projected to rise to about $0.60 per million Btu in 2025. Delivered petroleum prices to electricity generators follow a price path similar to that for natural gas prices, with a sharp drop through 2010 followed by a steady rise through 2025. Despite increasing fuel costs, the natural gas share of total generation is projected to increase from 16 percent in 2003 to 24 percent in 2025 because of the higher efficiency of gas-fired capacity.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Figure 73. Average U.S. retail electricity prices, 1970-2025 (2003 cents per kilowatthour)

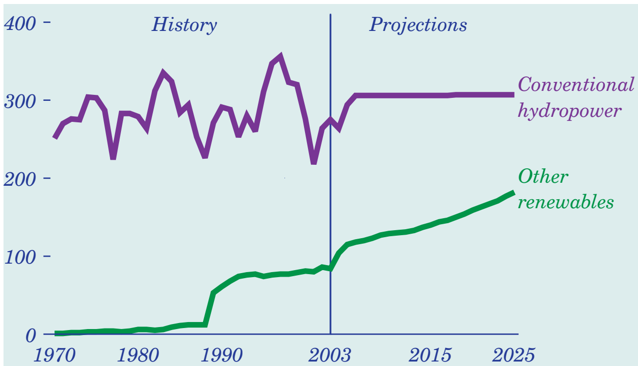


Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11 percent, from 7.4 cents per kilowatthour in 2003 to 6.6 cents in 2011 (Figure 73), then rise to 7.3 cents per kilowatthour in 2025. Prices follow the trend of the generation cost component of price, which makes up 65 percent of the total price of electricity and changes mainly in response to changes in natural gas prices. The distribution component, 28 percent of the total electricity price, is expected to decline from 2003 to 2025 at an average annual rate of 0.7 percent, as the cost of distribution infrastructure is spread over a growing amount of total electricity trade. Transmission prices are expected to increase at an average annual rate of 1.0 percent because of the additional investment needed to meet projected growth in electricity demand. Electricity prices for individual customer classes are projected to follow the average price trend, declining through 2011 and then increasing for the remainder of the forecast. Residential and commercial prices in 2025 are projected to be slightly lower than 2003 prices, and industrial prices are expected to be slightly higher than in 2003.

Competition in retail and wholesale generation markets can strongly influence electricity prices. In 2004, 17 States and the District of Columbia had competitive retail electricity markets in operation. Montana, Nevada, New Mexico, and Oklahoma have delayed opening competitive retail markets; Arkansas has repealed its restructuring legislation; and California's competitive retail market is suspended. Many States have cited a lack of operational wholesale markets and inadequate generation and transmission capacity as reasons for delaying retail competition.

Increases in Nonhydropower Renewable Generation Are Expected

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

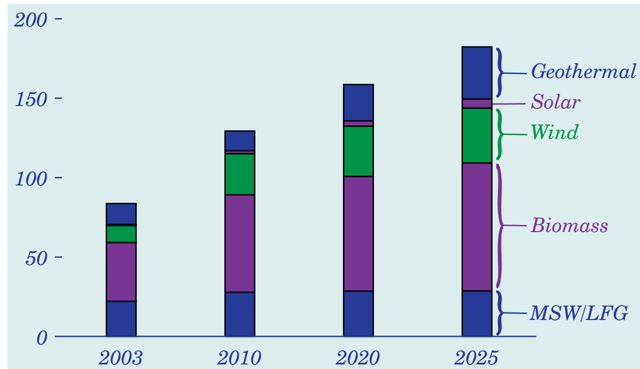


Despite strong growth in renewable electricity generation as a result of technology improvements and expected higher fossil fuel costs, grid-connected generators using renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply. From 359 billion kilowatthours in 2003 (9.3 percent of total generation) renewable generation increases to only 489 billion kilowatthours (8.5 percent) in 2025 (Figure 74).

Conventional hydropower remains the major source of renewable generation in the *AEO2005* reference case. After 4 years of below-normal precipitation, hydroelectric generation is expected to recover in 2005; however, with little new capacity expected, conventional hydropower generation is projected to increase from 275 billion kilowatthours in 2003 (7.1 percent of total generation) to just 307 billion kilowatthours (5.3 percent of the total) in 2025. Other renewables account for 5.3 percent of projected additions to capacity from 2003 to 2025 and 6.4 percent of the projected increase in generation. Generation from nonhydropower renewables increases from 84 billion kilowatthours in 2003 (2.2 percent of generation) to 182 billion kilowatthours in 2025 (3.2 percent). Biomass, including combined heat and power systems and biomass co-firing in coal-fired plants, is the largest source of other renewable generation in the forecast. Electricity from biomass combustion increases from 37 billion kilowatthours in 2003 (1.0 percent) to 81 billion kilowatthours in 2025 (1.4 percent), with 49 percent of the increase coming from dedicated power plants and the rest primarily from combined heat and power.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 75. Nonhydroelectric renewable electricity generation by energy source, 2003-2025 (billion kilowatthours)

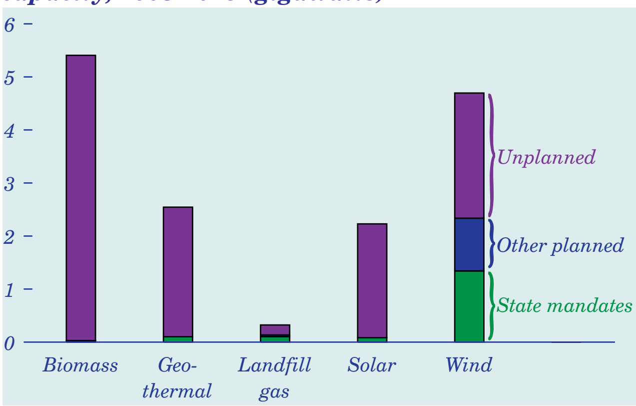


AEO2005 projects significant increases in electricity generation from both geothermal and wind power (Figure 75). In the West, geothermal output increases from 13 billion kilowatthours in 2003 to 33 billion kilowatthours in 2025. Wind-powered generating capacity increases from 6.6 gigawatts in 2003 to 11.3 gigawatts in 2025, and generation from wind capacity increases from less than 11 billion kilowatthours in 2003 to 35 billion in 2025. The mid-term prospects for wind power are uncertain, depending on response to the recent extension of the Federal production tax credit through 2005 and the likelihood of further extensions, as well as responses to State programs, technology improvements, transmission availability, and public interest.

Generation from municipal solid waste and landfill gas (MSW/LFG) is projected to increase by 7 billion kilowatthours, to 29 billion kilowatthours in 2025, but little new municipal solid waste capacity is expected. Solar technologies generally are projected to remain too costly to be competitive in supplying power to the grid. Central-station photovoltaic capacity increases in the forecast from about 40 megawatts in 2003 to 400 megawatts in 2025, and solar thermal capacity increases from about 400 megawatts to more than 500 megawatts. In contrast, individual grid-connected photovoltaic installations grow rapidly, from about 60 megawatts in 2003 to nearly 1,800 megawatts in 2025. Grid-connected photovoltaics and solar thermal, which together provided about 0.7 billion kilowatthours of electricity in 2003, are projected to supply nearly 6 billion kilowatthours in 2025 [*137*].

State Programs Will Continue To Support Renewable Energy Use

Figure 76. Additions of renewable generating capacity, 2003-2025 (gigawatts)



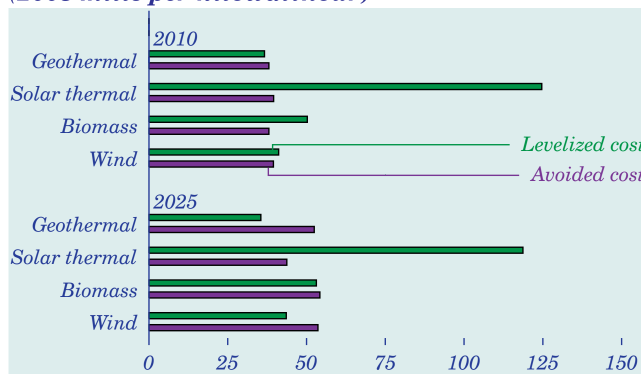
In the *AEO2005* reference case, 14.9 gigawatts of new nonhydroelectric renewable energy capacity is projected to enter service from 2003 through 2025, including 10.6 gigawatts in the electric power sector, 2.6 gigawatts of combined heat and power, and 1.7 gigawatts of end-use applications. In the electric power sector, 1.6 gigawatts is projected as a result of State requirements and goals (wind 1.3 gigawatts, geothermal and landfill gas each 0.1 gigawatt, plus smaller amounts of biomass, waste, and solar capacity) and the rest from commercial projects (Figure 76).

Most new renewables capacity projected in the near term results from specific projects and State programs. After 2010, the projected growth in renewable energy capacity is based on its ability to become competitive in electricity markets. The Federal production tax credit for wind plants was not extended until late in 2004, and so only 213 megawatts of new wind capacity is expected to be completed in 2004. In 2005, however, more than 1 gigawatt of new capacity is expected to enter service before the credit expires on December 31.

Because States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new capacity resulting from State renewable portfolio standards, mandates, and nonmandatory goals are reduced in *AEO2005*, but they are still significant, including 903 megawatts expected in Texas, 146 megawatts each in California and Minnesota, 141 megawatts in Nevada, 80 megawatts in New Mexico, and 65 megawatts in Pennsylvania.

Renewables Are Expected To Become More Competitive Over Time

Figure 77. Levelized and avoided costs for new renewable plants in the Northwest, 2010 and 2025 (2003 mills per kilowatthour)

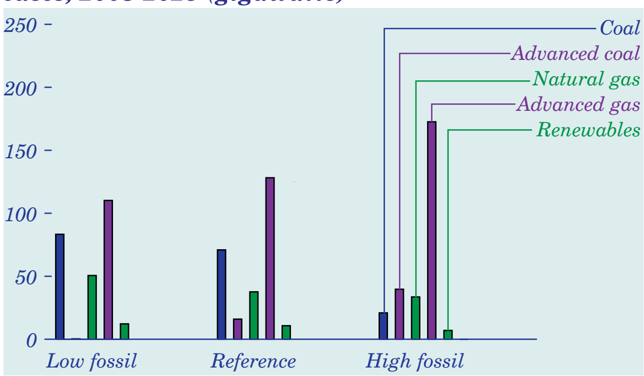


The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the marginal cost of power only during the hours of least demand. Dispatchable geothermal and biomass resources compete directly with new coal and nuclear plants, which to a large extent determine the avoided cost [*138*] for baseload energy (Figure 77). In some regions and years, new geothermal or biomass plants may be competitive with new coal-fired plants, but their development is limited by the availability of geothermal resources or competitive biomass fuels.

Intermittent technologies—specifically, wind and solar—can be used only when resources are available. Because of their relatively low operating costs and limited resource availability, the avoided costs of these technologies are determined largely by the operating costs of the most expensive units operating when their resources are available. Solar generators tend to operate during peak load periods, when gas-fired combustion turbines and combined-cycle units with higher fuel costs tend to determine avoided cost. The levelized cost of solar thermal generation is projected to be significantly higher than its avoided cost through 2025. The availability of wind resources varies among regions, but wind plants generally tend to displace intermediate load generation. Thus, the avoided costs of wind power will be determined largely by the low-to-modest operating costs of combined-cycle and coal-fired plants. In some regions and years, the levelized costs for wind power are projected to be below its avoided costs.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 78. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2003-2025 (gigawatts)

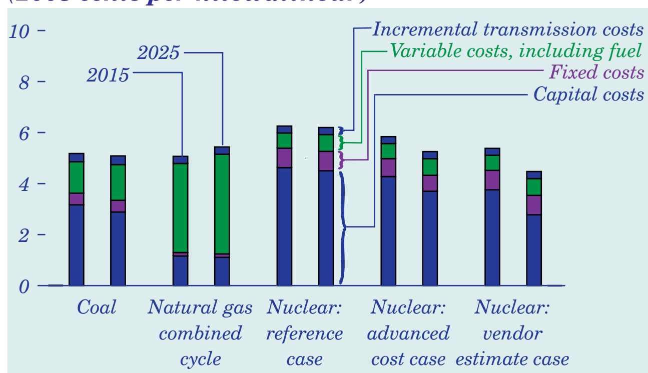


The *AEO2005* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Values for technology characteristics are determined in consultation with industry and government specialists, but uncertainty surrounds the assumptions for new technologies. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect a 10-percent reduction from reference case levels in 2025. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2005 levels.

Natural gas technologies make up the largest share of new capacity additions in all cases, but the mix of current and advanced technologies varies (Figure 78). In the high fossil fuel case, advanced technologies are used for 84 percent (173 gigawatts) of projected gas-fired capacity additions, compared with 69 percent (110 gigawatts) in the low fossil fuel case. The coal share of total capacity additions varies from 22 percent to 33 percent in the cases. In the low fossil fuel case, only a negligible amount of advanced coal-fired generating capacity is added. In the high fossil fuel case, advanced coal technologies are more competitive, making up 65 percent of all coal-fired capacity additions. The projections for average fossil fuel efficiency in the electric power sector in 2025 are 37 percent in the reference case, 38 percent in the high fossil fuel case, and 36 percent in the low fossil fuel case, based on different assumptions about the penetration of advanced technologies in the cases.

Sensitivity Cases Look at Possible Reductions in Nuclear Power Costs

Figure 79. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2025 (2003 cents per kilowatthour)

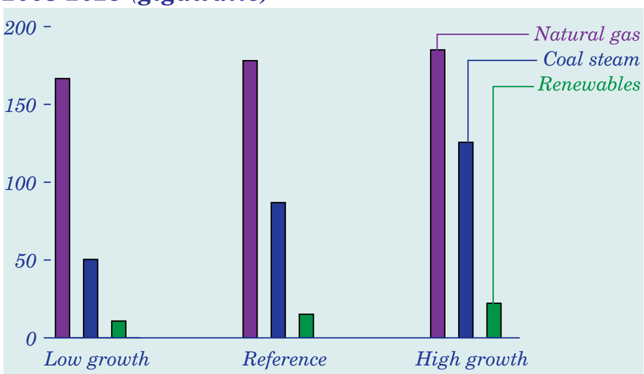


The *AEO2005* reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. Two alternative nuclear cost cases analyze the sensitivity of the projections to lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 20 percent below the reference case in 2025, reflecting a 28-percent reduction in overnight capital costs from 2005 to 2025. (Earlier analysis showed that a 10-percent reduction in capital and operating costs would be insufficient to stimulate new nuclear construction.) The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 38 percent in 2025. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its advanced pressurized-water reactor (AP1000). Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the two alternative nuclear cost cases are competitive with the generating costs projected for new coal- and natural-gas-fired units toward the end of the projection period (Figure 79). In the advanced nuclear case 7 gigawatts of new nuclear capacity is added by 2025, and in the vendor estimate case 25 gigawatts is added by 2025. The additional nuclear capacity displaces primarily projected new coal-fired capacity. The projections in Figure 79 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

Rapid Economic Growth Would Boost New Coal and Renewable Capacity

Figure 80. Cumulative new generating capacity by technology type in three economic growth cases, 2003-2025 (gigawatts)



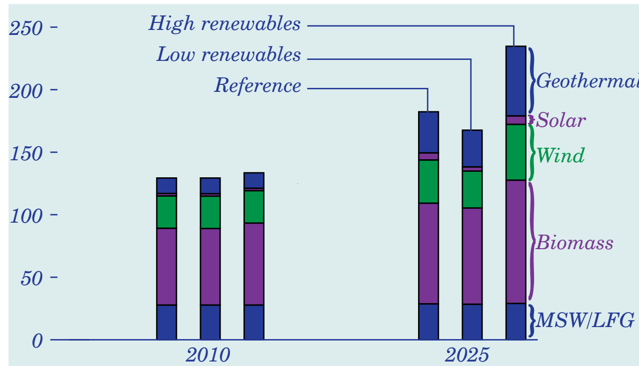
The projected annual average growth rate for GDP from 2003 to 2025 ranges from 3.6 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 4-percent change in projected electricity demand in 2010 and a 12-percent change in 2025, with a corresponding difference of 105 gigawatts in the amount of new capacity projected to be built from 2003 to 2025 in the high and low economic growth cases, including combined heat and power in the end-use sectors.

Most (74 percent) of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new coal-fired plants. The stronger demand growth assumed in the high growth case is also projected to stimulate additions of renewable plants and new natural-gas-fired capacity (Figure 80). In the low economic growth case, total capacity additions are reduced by 53 gigawatts, and 70 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2025 are 5 percent higher in the high economic growth case than in the reference case, due to higher natural gas prices and the costs of building additional generating capacity. Electricity prices in 2025 in the low economic growth case are projected to be 4 percent lower than in the reference case. In the high economic growth case, a 5-percent increase in consumption of fossil fuels results in a 6-percent increase in carbon dioxide emissions from electricity generators in 2025.

Lower Cost Assumptions Increase Biomass and Geothermal Capacity

Figure 81. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2025 (billion kilowatthours)

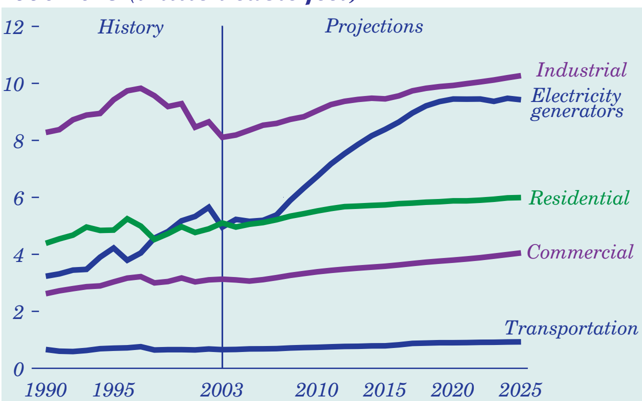


The impacts of key assumptions about the availability and cost of nonhydroelectric renewable energy resources for electricity generation are shown in two alternative technology cases. In the low renewables case, the cost and performance of generators using renewable resources are assumed to remain unchanged throughout the forecast. The high renewables case assumes cost reductions of 10 percent in 2025 on a site-specific basis for hydroelectric, geothermal, biomass, wind, and solar generating capacity (however, no new additions of conventional hydropower are projected in any of the cases, given the lack of suitable new sites for development).

In the low renewables case, construction of new renewable capacity is less than projected in the reference case (Figure 81). In the high renewables case, more additions of biomass, geothermal, and wind capacity are projected through 2025 than in the reference case, with most of the incremental capacity added between 2010 and 2025. In 2025, projected total electricity generation from nonhydropower renewables is 52 billion kilowatthours higher in the high renewables case than in the reference case, with most of the increment coming from geothermal (22.8 billion kilowatthours), biomass (18.0 billion kilowatthours), and wind energy (10.1 billion kilowatthours). Still, nonhydropower renewables are projected to remain relatively small contributors to total generation in the high renewables case, accounting for 134 billion kilowatthours (2.9 percent of the total) in 2010 and 235 billion kilowatthours (4.1 percent) in 2025.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

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

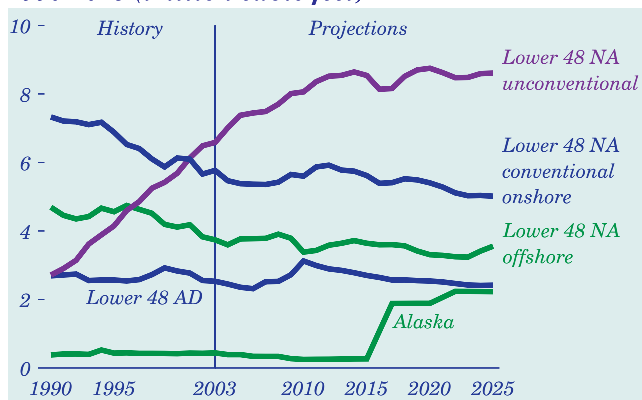


In the *AEO2005* reference case, total natural gas consumption increases from 22.0 trillion cubic feet in 2003 to 30.7 trillion cubic feet in 2025. In the electric power sector, natural gas consumption increases from 5.0 trillion cubic feet in 2003 to 9.4 trillion cubic feet in 2025 (Figure 82), accounting for 31 percent of total demand for natural gas in 2025 as compared with 23 percent in 2003. The increase in natural gas consumption for electricity generation results from both the construction of new gas-fired generating plants and higher capacity utilization at existing plants. Most new electricity generation capacity is expected to be fueled by natural gas, because natural-gas-fired generators are projected to have advantages over coal-fired generators that include lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions. Toward the end of the forecast, however, when natural gas prices rise substantially, coal-fired power plants are expected to be competitive for new capacity additions.

Industrial consumption of natural gas, including lease and plant fuel, is projected to increase from 8.1 trillion cubic feet in 2003 to 10.3 trillion cubic feet in 2025. Although increases are projected for most industrial sectors, decreases are expected in the iron, steel, and aluminum industries. The industrial sectors with the largest projected increases in natural gas consumption growth from 2003 through 2025 include metal-based durables, petroleum refining, bulk chemicals, and food. Natural gas use is also projected to increase in the residential sector by 0.7 percent per year and in the commercial sector 1.2 percent per year on average from 2003 to 2025.

Unconventional Production Becomes the Largest Source of U.S. Gas Supply

Figure 83. Natural gas production by source, 1990-2025 (trillion cubic feet)



As a result of technological improvements and rising natural gas prices, natural gas production from relatively abundant unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production. Lower 48 unconventional gas production grows from 6.6 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025 (Figure 83) and from 35 percent of total lower 48 production in 2003 to 44 percent in 2025.

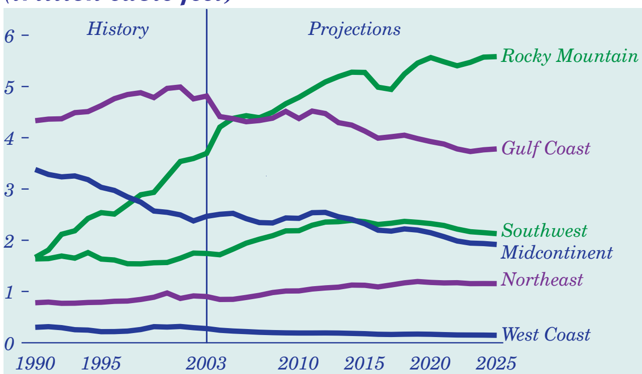
Production of lower 48 nonassociated (NA) conventional natural gas declines from 9.5 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025, as resource depletion causes exploration and development costs to increase. Offshore NA natural gas production is projected to rise slowly to a peak of 3.9 trillion cubic feet in 2008, then decline to 3.6 trillion cubic feet in 2025.

Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves is projected to increase from 2.5 trillion cubic feet in 2003 to 3.1 trillion cubic feet in 2010 due to a projected increase in offshore AD gas production [*139*]. After 2010, both onshore and offshore AD gas production are projected to decline, and total lower 48 AD gas production falls to 2.4 trillion cubic feet in 2025.

The North Slope Alaska natural gas pipeline is projected to begin transporting Alaskan gas to the lower 48 States in 2016. In 2025, total Alaskan gas production is projected to be 2.2 trillion cubic feet in the reference case, compared with 0.4 trillion cubic feet in 2003.

Growing Production Is Expected from the Rocky Mountain Region

Figure 84. Lower 48 onshore natural gas production by supply region, 1990-2025 (trillion cubic feet)



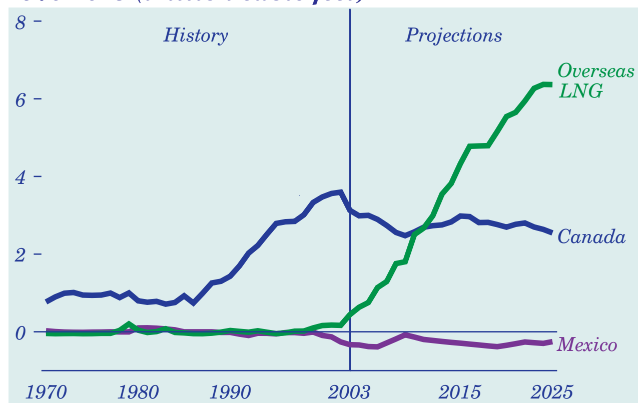
In the reference case, total natural gas supplies are projected to grow by 8.2 trillion cubic feet from 2003 to 2025. Domestic natural gas production is expected to account for 34 percent of the total growth in gas supply, and net imports are projected to account for the remaining 66 percent.

Over the forecast period, the largest increase in lower 48 onshore natural gas production is projected to come from the Rocky Mountain region, primarily from unconventional gas deposits [*140*]. Rocky Mountain natural gas production is projected to increase from 3.7 trillion cubic feet in 2003 to 5.6 trillion cubic feet in 2025 (Figure 84). In 2003, Rocky Mountain production was 27 percent of total lower 48 onshore production. The Rocky Mountain region's share of lower 48 onshore production is projected to increase to 38 percent in 2025. The only other increases in production are expected in the Northeast and Southwest regions. In the Northeast, production rises from 900 billion cubic feet in 2003 to 1.2 trillion cubic feet in 2019 and declines slightly thereafter. In the Southwest, production rises from 1.7 trillion cubic feet in 2003 to 2.4 trillion cubic feet in 2018 and declines to 2.1 trillion cubic feet in 2025.

Natural gas production in the onshore Gulf Coast and Midcontinent regions remains relatively constant through 2011, then declines to 3.8 and 1.9 trillion cubic feet, respectively, in 2025. West Coast production declines throughout the forecast. Regional declines in the projections reflect depletion of the natural gas resource base and increasing costs of gas exploration and development in those regions.

Net Imports of Natural Gas Grow in the Projections

Figure 85. Net U.S. imports of natural gas, 1970-2025 (trillion cubic feet)



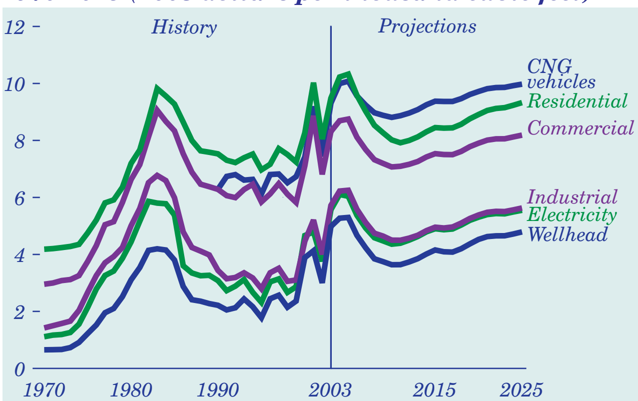
Net imports of natural gas make up the difference between U.S. production and consumption. Imports are expected to be priced competitively with domestic sources. Supplies of natural gas from overseas sources account for most of the projected increase in net imports in the reference case (Figure 85). New LNG terminals are projected to start coming into operation in 2006, and net LNG imports increase to 6.4 trillion cubic feet in 2025.

Net imports of natural gas from Canada are projected to decline from 3.0 trillion cubic feet in 2005 to 2.5 trillion cubic feet in 2009, rise again to 3.0 trillion cubic feet in 2015, and then decline to 2.5 trillion cubic feet in 2025. A steady decline of conventional production in the Western Sedimentary Basin is more than offset by increases in unconventional production in western Canada, conventional production in the MacKenzie Delta and Eastern Canada, and LNG imports. Although a MacKenzie Delta natural gas pipeline is expected to open in 2010, pipeline imports from Canada decline at the end of the forecast, because Canada's gas consumption increases more rapidly than its production.

Mexico has considerable natural gas resources, but the United States historically has been a net exporter of gas to Mexico, where industrial consumers along the border are closer to U.S. supplies than they are to domestic supplies. In the reference case, net U.S. exports to Mexico are projected to increase through 2006, when an LNG import terminal in Baja California, Mexico, begins exporting natural gas from western Mexico to the United States [*141*].

Delivered Prices Follow Projected Trends in Wellhead Prices

Figure 86. Natural gas prices by end-use sector, 1970-2025 (2003 dollars per thousand cubic feet)



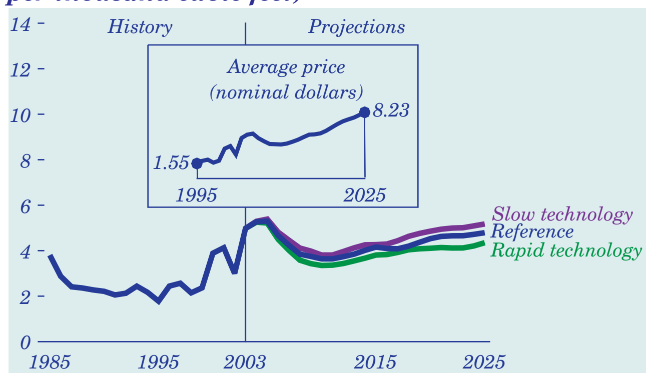
Trends in delivered natural gas prices largely reflect changes in wellhead prices. Wellhead natural gas prices are projected to decline in the early years of the *AEO2005* reference case forecast, as drilling levels increase, new production capacity comes on line, and LNG imports increase in response to current high prices. As a result, end-use delivered prices are projected to fall (Figure 86). After 2011, however, both wellhead and delivered natural gas prices are projected to increase in response to the higher exploration and development costs associated with smaller and deeper gas deposits in the remaining domestic gas resource base.

Transmission and distribution margins in the end-use sectors reflect both the volumes of gas delivered and the infrastructure arrangements of the sectors. The industrial and electricity generation sectors have the lowest end-use prices, because they receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges. In addition, summer-peaking electric generators reduce transmission costs by using interruptible transportation rates during the summer, when there is spare pipeline capacity. As power generators take a larger share of the natural gas market, however, they are expected to rely more on higher cost firm transportation service.

On average, transmission and distribution margins are projected to remain relatively constant in the forecast, because the cost of new facilities largely offset the reduced depreciation expenses of existing facilities. If public opposition prevented the building of new infrastructure, delivered prices could be higher than projected in the reference case.

Technology Advances Could Moderate Future Natural Gas Prices

Figure 87. Lower 48 natural gas wellhead prices in three cases, 1985-2025 (2003 dollars per thousand cubic feet)



In the reference case, average lower 48 wellhead natural gas prices are projected to decline from the 2004 level to $3.64 per thousand cubic feet (2003 dollars) in 2010 and then increase to $4.79 per thousand cubic feet in 2025 (Figure 87). Technically recoverable natural gas resources (Table 28) are expected to be adequate to support projected production increases. As lower 48 conventional natural gas resources are depleted and wellhead prices rise, an increasing proportion of U.S. natural gas supply is projected to come from Alaska, unconventional production, and LNG imports.

In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than those assumed in the reference case, which are based on historical rates. As a result, natural gas development costs are higher, wellhead prices are higher ($5.18 per thousand cubic feet in 2025), natural gas consumption is reduced, and LNG imports increase.

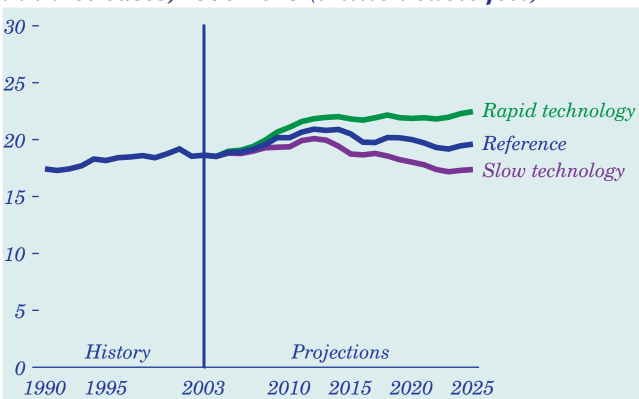
The rapid technology case assumes 50 percent faster technology progress than in the reference case, resulting in lower development costs, lower wellhead prices ($4.35 per thousand cubic feet in 2025), increased consumption of natural gas, and lower LNG imports than are projected in the reference case.

Table 28. Technically recoverable U.S. natural gas resources as of January 1, 2003 (trillion cubic feet)

Proved	Unproved	Total
186.9	1,150.5	1,337.5

Natural Gas Supply Projections Reflect Technological Progress Rates

Figure 88. Lower 48 natural gas production in three cases, 1990-2025 (trillion cubic feet)



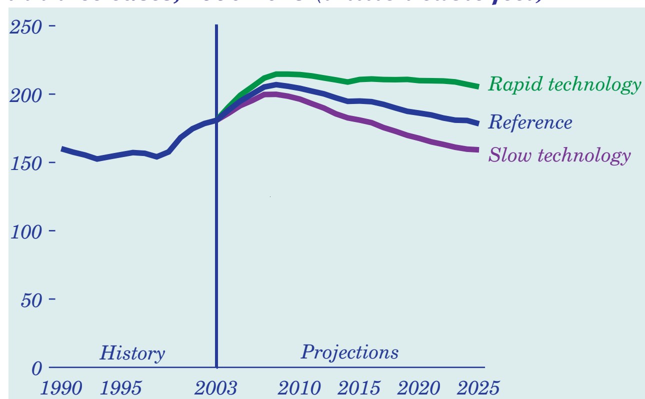
Because the impacts of technological progress are cumulative, the rapid and slow technology cases diverge increasingly from the reference case in the later years of the forecast (Figure 88). In the reference case, lower 48 natural gas production is projected to total 19.6 trillion cubic feet in 2025. The corresponding projections are 22.5 trillion cubic feet in the rapid oil and gas technology case and 17.4 trillion cubic feet in the slow technology case.

The cost-reducing effects of rapid technological progress primarily affect the economic recoverability of the unconventional resource base, because there are more opportunities for technological improvement in the exploration and recovery of unconventional gas than there are for conventional gas. In 2025, unconventional gas production is projected to be 11.0 trillion cubic feet in the rapid technology case and 7.1 trillion cubic feet in the slow technology case, compared with 8.6 trillion cubic feet in the reference case.

The rate of technological progress also affects the contributions of other natural gas supply sources. Because rapid progress is projected to increase the rate of production of lower 48 natural gas resources and reduce wellhead prices, both the Alaska gas pipeline and new LNG terminals are less viable economically in the rapid technology case than in the reference case, and their construction is delayed. In the slow technology case, more LNG terminal capacity is projected to be built, and the Alaska gas pipeline and some LNG terminals are projected to be built earlier. Projected LNG imports in 2025 total 5.7 trillion cubic feet in the rapid technology case and 6.8 trillion cubic feet in the slow technology case.

Rapid Technology Assumptions Raise Natural Gas Reserve Projections

Figure 89. Lower 48 natural gas reserves in three cases, 1990-2025 (trillion cubic feet)



Natural gas wellhead productive capacity directly reflects reserve levels. The *AEO2005* projections for lower 48 natural gas reserves are based on expected levels of natural gas exploration and development drilling resulting from projected cash flows and profitability. In the reference case, lower 48 reserves grow to 207 trillion cubic feet in 2008, then decline slowly to 178 trillion cubic feet in 2025 (Figure 89).

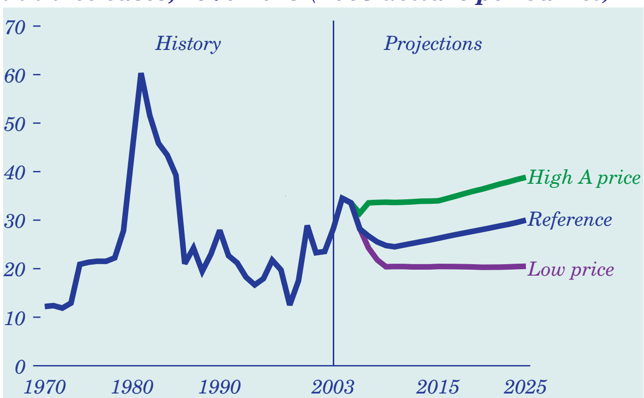
In the rapid technology case, the finding and success rates for gas well drilling are higher than in the reference case, and exploration and development costs are reduced, resulting in more drilling activity and reserve additions. In this case, lower 48 reserves are projected to peak at 215 trillion cubic feet in 2009, then decline to 205 trillion cubic feet in 2025.

In the slow technology case, finding and success rates are lower, exploration and development costs are higher, and drilling activity and reserve additions are lower than projected in the reference case. Lower 48 reserves are projected to peak at 200 trillion cubic feet in 2008, then decline to 159 trillion cubic feet in 2025.

In all three cases, the natural gas resource base is sufficient in the early years of the forecast to support the increases in drilling activity and reserve additions that are stimulated by higher projected prices. As a result, reserve additions early in the forecast generally exceed production. In later years, resource depletion reduces reserve additions per well, and rising costs of gas well development reduce drilling activity. As a result, production generally exceeds reserve additions, causing total reserves to decline toward the end of the forecast.

Oil Prices Are Expected To Decline from Recent Peaks, Then Rise

Figure 90. Lower 48 crude oil wellhead prices in three cases, 1970-2025 (2003 dollars per barrel)



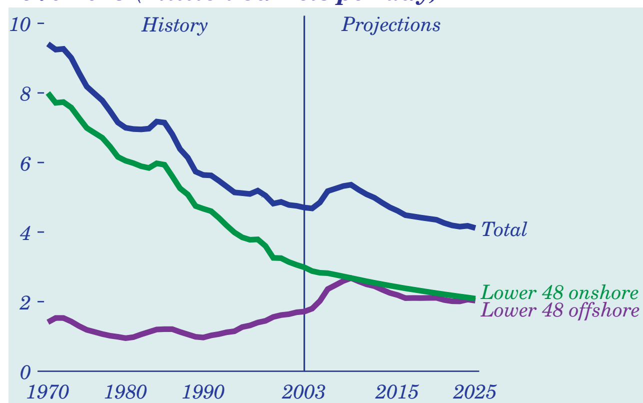
In the *AEO2005* reference case, the average lower 48 crude oil price (as distinct from the world oil price) is projected to decline from current levels to $24.50 per barrel (2003 dollars) in 2010, before increasing to $30.00 per barrel in 2025 (Figure 90). The U.S. price of oil, unlike natural gas, is set in the international marketplace. In the high A world oil price case, the lower 48 crude oil price is projected to be $33.65 per barrel in 2010 and $38.84 per barrel in 2025. In the low world oil price case, the lower 48 price declines to $20.44 per barrel in 2010, then remains relatively stable through 2025.

Between 2003 and 2010, crude oil prices are expected to decline as new deepwater oil fields are brought into production in the Gulf of Mexico and West Africa, new oil sands production is initiated in Canada, and OPEC and Russia expand production capacity. Near-term price expectations are highly uncertain, however, given the potential for political instability in many oil-exporting countries, which could significantly change the world's oil demand and supply picture.

Uncertainty about world oil prices in the longer term is reflected in the low and high A world oil price cases. Crude oil prices are determined largely by the balance between production and consumption and the mix of OPEC and non-OPEC production. In the reference case, oil production and consumption in 2025 are balanced at 120 million barrels per day, with OPEC accounting for 46 percent of total production. The low oil price case projects production of 128 million barrels per day in 2025, with the OPEC share at 51 percent. The high A case projects 114 million barrels per day, with the OPEC share at 37 percent.

Lower 48 Crude Oil Production Is Expected To Decline After 2009

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



In the reference case, total lower 48 crude oil production is projected to increase from 4.7 million barrels per day in 2003 to 5.4 million barrels per day in 2009, then decline to 4.1 million barrels per day in 2025 (Figure 91). In the low oil price case, lower 48 oil production peaks in 2009 at 5.3 million barrels per day, then declines to 3.9 million barrels per day in 2025. In the high A oil price case, lower 48 production peaks in 2009 at 5.4 million barrels per day and declines to 4.5 million barrels per day in 2025. The projected peaks in oil production are attributable to offshore production, particularly in the Gulf of Mexico, where deepwater oil production is projected to total 2.3 million barrels per day in 2009 (Table 29).

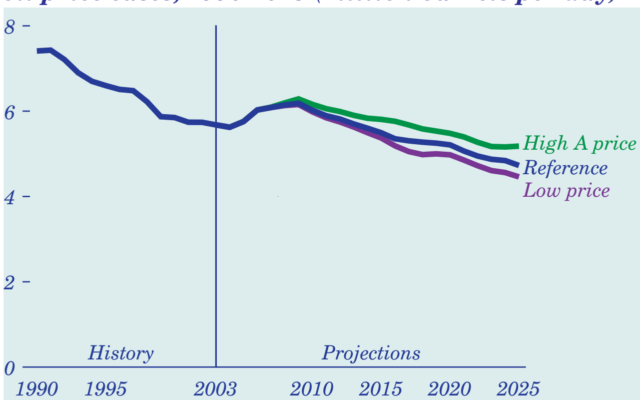
Offshore crude oil production is more sensitive than onshore production to oil prices, because a smaller portion of offshore oil resources has been depleted. In the reference case, total offshore production (including the Gulf of Mexico and offshore California) rises to 2.7 million barrels per day in 2009, then declines to 2.0 million barrels per day in 2025. In the low and high A price cases, the projections for lower 48 offshore production in 2025 are 1.9 million barrels per day and 2.3 million barrels per day, respectively. Onshore lower 48 oil production is projected to decline in all three cases, with 2025 values ranging from 2.0 million barrels per day in the low price case to 2.2 million barrels per day in the high A price case.

Table 29. Crude oil production from Gulf of Mexico offshore, 2003-2025 (million barrels per day)

	2003	2010	2015	2020	2025
Shallow	0.5	0.3	0.3	0.3	0.3
Deep	1.1	2.2	1.8	1.8	1.7
Total	**1.6**	**2.5**	**2.1**	**2.1**	**2.0**

U.S. Oil Production Is Marginally Sensitive to World Oil Prices

Figure 92. Total U.S. crude oil production in three oil price cases, 1990-2025 (million barrels per day)



The different paths projected for total U.S. crude oil production in the three world oil price cases reflect differences both in the numbers of new fields developed and in the volumes of oil recovered from existing fields. Total U.S. oil production is only marginally sensitive to crude oil price projections (Figure 92), both because future production is expected to come largely from developed fields, such as Prudhoe Bay, and because development of much of the remaining oil resource base (Table 30) would be uneconomical even with much higher oil prices. In the high A and low world oil price cases, total U.S. production in 2025 is projected at 5.2 and 4.5 million barrels per day, respectively.

The different price paths in the three cases primarily affect the development and production of lower 48 offshore resources (Table 31). Smaller deepwater fields that are not profitable when prices are low are expected to become profitable at higher price levels.

Table 30. Technically recoverable U.S. oil resources as of January 1, 2003 (billion barrels)

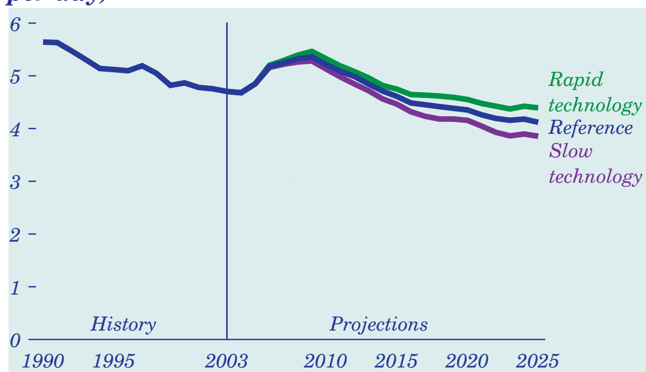
Proved	Unproved	Total
24.0	118.8	142.8

Table 31. Onshore and offshore lower 48 crude oil production in three cases, 2025 (million barrels per day)

	Onshore	Offshore	Total
Low oil price	2.03	1.88	3.91
Reference	2.09	2.03	4.12
High A oil price	2.16	2.30	4.47

More Rapid Technology Advances Could Raise Oil Production

Figure 93. Lower 48 crude oil production in three technology cases, 1990-2025 (million barrels per day)

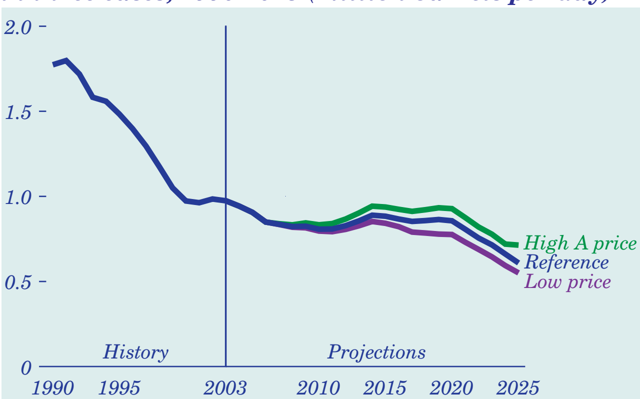


Lower 48 crude oil production is projected to reach 4.4 and 3.9 million barrels per day in 2025 in the rapid and slow technology cases, respectively, compared with 4.1 million barrels per day in the reference case (Figure 93). The technology cases assume the same world oil prices as in the reference case, but the rate of technological progress is assumed to be 50 percent higher (in the rapid technology case) or lower (in the slow technology case) than the historical rate. With domestic oil demand determined largely by oil prices and economic growth rates, consumption is not expected to change significantly in the technology cases. Thus, changes in production resulting from the different rates of technological progress lead to different projected levels of petroleum imports. In 2025, net petroleum imports are projected to range from 18.5 million barrels per day in the rapid technology case to 19.6 million barrels per day in the slow technology case, as compared with 19.1 million barrels per day in the reference case.

In the lower 48 States, offshore crude oil production is more sensitive than onshore production to changes in technology, because there are more opportunities for technological improvement in the less mature areas offshore, particularly in the deepwater Gulf of Mexico. Cumulative offshore production from 2004 through 2025 is projected to be 0.7 billion barrels (4.0 percent) higher in the rapid technology case and 0.8 billion barrels (4.7 percent) lower in the slow technology case than in the reference case. Cumulative onshore production is about 0.4 billion barrels (2.0 percent) higher in the rapid oil and gas technology case and 0.4 billion barrels (1.8 percent) lower in the slow technology case than in the reference case.

Crude Oil Production in Alaska Depends on Oil Prices

Figure 94. Alaskan crude oil production in three cases, 1990-2025 (million barrels per day)



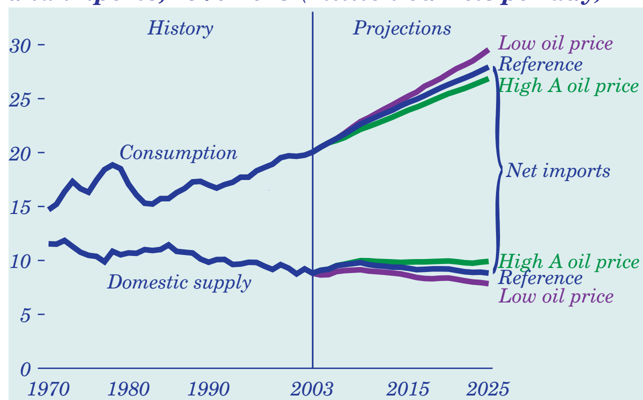
Alaskan crude oil production originates mainly from the North Slope, which includes the National Petroleum Reserve-Alaska (NPR-A) and the State lands surrounding Prudhoe Bay. Because oil and gas producers are prohibited from building permanent roads in NPR-A, exploration and production are expected to be about 30 percent more expensive than is typical for the North Slope of Alaska. Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), *AEO2005* does not project any production from ANWR; however, an EIA analysis [*142*] projects that if drilling were allowed, production would start 10 years later and reach 900,000 barrels per day in 2025 if the area contains the mean level of resources (10.4 billion barrels) estimated by the U.S. Geological Survey.

In the reference case, crude oil production from Alaska is expected to decline to about 810,000 barrels per day in 2010 (Figure 94). After 2010, increased production from NPR-A raises Alaska's total production to about 890,000 barrels per day in 2014. Depletion of the oil resource base in the North Slope, NPR-A, and southern Alaska oil fields is expected to lead to a decline in the State's total production to about 610,000 barrels per day in 2025.

As in the lower 48 States, oil production in Alaska is marginally sensitive to projected changes in oil prices. Higher prices make more of the reservoir oil in-place profitable. In 2025, Alaska's production is projected to be about 100,000 barrels per day above the reference case level in the high A oil price case and 60,000 barrels per day below the reference case level in the low oil price case.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 95. Petroleum supply, consumption, and imports, 1970-2025 (million barrels per day)



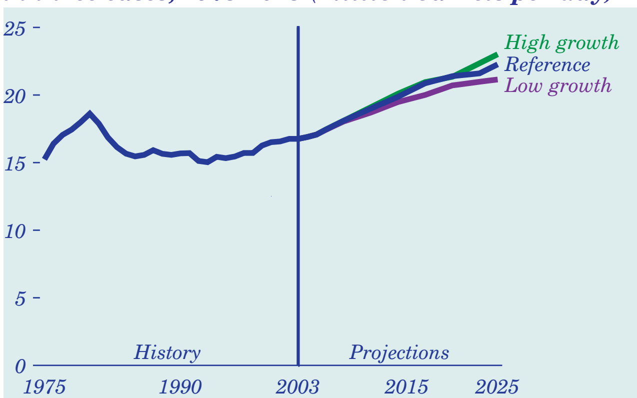
In 2003, net imports of crude oil and refined products accounted for 56 percent of domestic petroleum consumption. Dependence on petroleum imports is projected to reach 68 percent in 2025 in the reference case (Figure 95). The corresponding import shares of total consumption in 2025 are expected to be 63 percent in the high A oil price case and 72 percent in the low oil price case.

The portion of domestic petroleum demand that is supplied by imports depends on the world crude oil price. Because imported products are the most expensive source of petroleum supply, the first effect of assuming crude oil prices above those projected in the reference case is reduced consumption of imported petroleum products. Higher prices also stimulate the production of relatively high-cost domestic crude oil, resulting in lower projected levels of imported crude. Prices below those in the reference case have the opposite effect: U.S. consumption and product imports increase, production of domestic crude oil falls, and the portion of petroleum consumption met by imports rises.

Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More petroleum product imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 21 percent of net petroleum imports in 2025 in the low oil price case and 12 percent in the high A oil price case, compared with 16 percent in the reference case, increasing from a 14-percent share in 2003.

Expansion at Existing Refineries Increases U.S. Refining Capacity

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



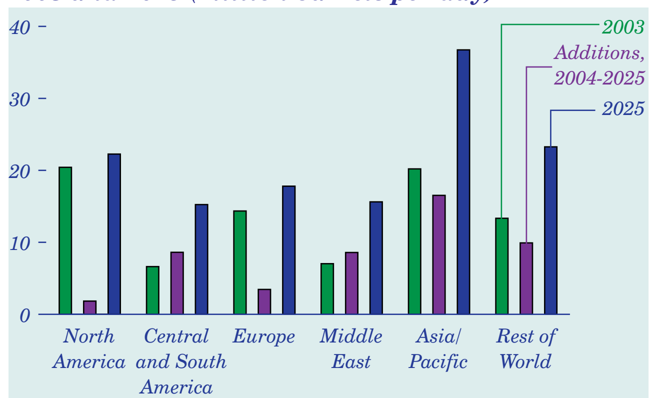
Falling demand for petroleum and deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1996, and 1.4 million barrels per day of distillation capacity was added between 1996 and 2003. Financial and legal considerations 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 *AEO2005* cases (Figure 96).

Distillation capacity is projected to grow from the 2003 year-end level of 16.8 million barrels per day to 22.3 million barrels per day in 2025 in the reference case, 21.4 million in the high A oil price case, and 22.5 million in the low price case, as compared with the 1981 peak of 18.6 million barrels per day. Almost all new capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively (92 to 95 percent of operable capacity) throughout the forecast. The 2003 utilization rate was 93 percent, well above the lows of 69 percent during the 1980s and 88 percent during the early 1990s but consistent with capacity utilization rates since the mid-1990s.

Distillation is only the first step in the refining process. Improved processing of the intermediate streams obtained from crude distillation is expected to reduce yields of residual fuel, which has a shrinking market, and improve yields of the higher value "light products," such as gasoline, distillate, jet fuel, and liquefied petroleum gas. Further process improvements will be required to reduce the sulfur content of gasoline and some types of distillate fuel.

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

Figure 97. Worldwide refining capacity by region, 2003 and 2025 (million barrels per day)



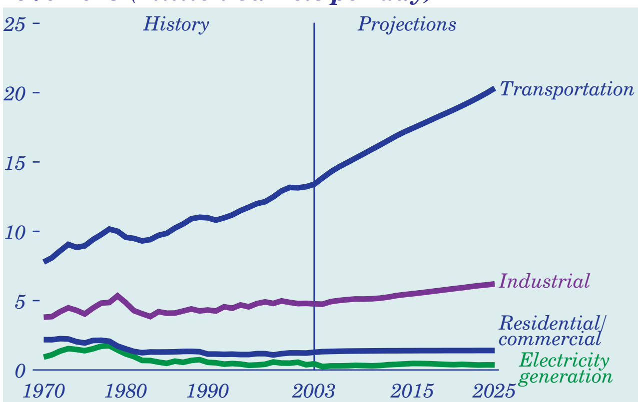
Worldwide crude oil distillation capacity was 82.0 million barrels per day at the end of 2003. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by about 60 percent—to more than 131 million barrels per day—by 2025. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 97).

The Asia/Pacific region has been the fastest growing refining center over the past decade. In the mid-1990s, it surpassed Western Europe as the world's second largest refining center (after North America) in terms of distillation capacity; and in 2003, capacity in the Asia/Pacific region capacity was only 220,000 barrels per day lower than that in North America. 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 lower 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.

Petroleum Use Increases Mainly in the Transportation Sector

Figure 98. Petroleum consumption by sector, 1970-2025 (million barrels per day)



The transportation sector accounted for two-thirds of U.S. petroleum use in 2003 (Figure 98). In the forecast, population growth and economic growth cause miles traveled to increase across all modes of transit. Although improvements in vehicle technology yield reductions in fuel use per mile traveled, the increases in mileage outweigh increases in efficiency, leading to increases in consumption of gasoline, diesel, and jet fuel.

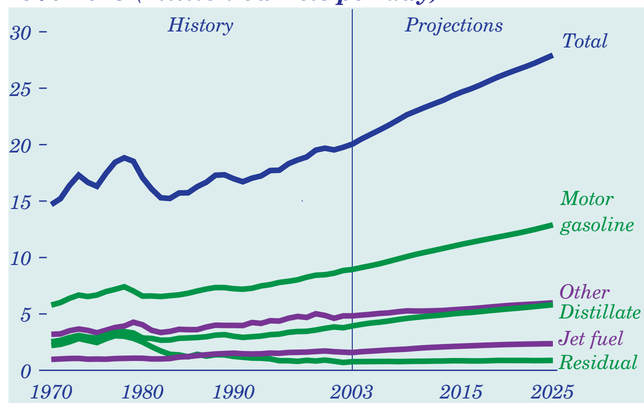
The industrial sector currently accounts for 24 percent of U.S. petroleum demand. In the reference case, industrial consumption is projected to be 1.2 million barrels per day higher in 2025 than it was in 2003, and industrial consumption of liquefied petroleum gas (LPG), largely as a chemical feedstock, increases by about 490,000 barrels per day.

In the residential sector, distillate use is displaced by LPG, natural gas, and electricity for home heating toward the end of the forecast, in systems that require less maintenance than oil furnaces. As a result, residential oil use drops by 88,000 barrels per day from 2003 to 2025. Commercial use of heating oil grows from 246,000 barrels per day in 2003 to 362,000 barrels per day in 2025. The delivered price of distillate to commercial customers is projected to be lower than the price of natural gas throughout the forecast.

Only 3 percent of U.S. electricity is currently generated from refined petroleum, but the electricity sector nearly matches residential petroleum use by the end of the forecast. Consumption of residual and distillate fuel in the electric power sector increase modestly.

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

Figure 99. Consumption of petroleum products, 1970-2025 (million barrels per day)



U.S. petroleum consumption is projected to increase by 7.9 million barrels per day from 2003 to 2025 (Figure 99). About 92 percent of the projected growth in petroleum consumption consists of "light products" (including gasoline, diesel, heating oil, jet fuel, kerosene, LPG, and petrochemical feedstocks), which are more difficult and costly to produce than heavy products.

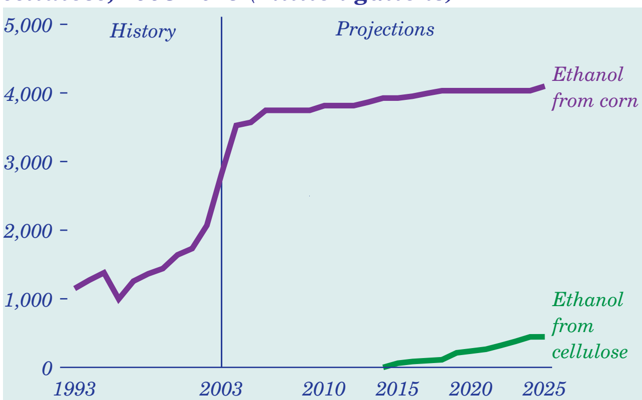
Gasoline continues to make up nearly one-half of all petroleum used in the United States, increasing from 8.9 million barrels per day in 2003 to 12.9 million in 2025, mostly for transportation. Consumption of distillate fuel is also projected to increase, by 1.9 million barrels per day, from 2003 to 2025. Gasoline is used only in spark-ignition engines; distillate is used in furnaces, boilers, diesel engines, and some turbines. Jet fuel consumption is projected to increase by 789,000 barrels per day from 2003 to 2025.

Consumption of "other" petroleum products is projected to increase from 4.8 million barrels per day in 2003 to 6.0 million barrels per day in 2025. LPG used for heating and chemical production is included in the "other" category, along with other chemical feedstocks, still gas used for refinery fuel, and asphalt.

Residual fuel use, constrained by air quality regulations, increases by only 110,000 barrels per day from 2003 to 2025, including an increase of 79,000 barrels per day in residual fuel use for baseload electricity generation. More intensive refinery processing to maximize light product yield and minimize heavy product yield is expected to limit the availability of residual fuel. LPG use also remains about constant.

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

Figure 100. U.S. ethanol production from corn and cellulose, 1993-2025 (million gallons)



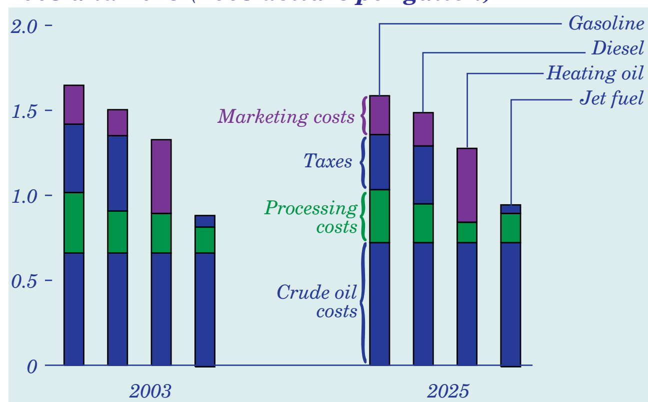
U.S. ethanol production, with corn as the primary feedstock, totaled 2,821 million gallons in 2003 and is projected to increase to 4,544 million gallons in 2025 (Figure 100). About 26 percent of the increase consists of ethanol distilled from cellulosic biomass such as wood and agricultural residues. The high renewables case projects a similar increase in ethanol production, but all the growth is in ethanol from cellulose, based on more rapid improvement in the technology.

Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer and also serves as an oxygenate in areas that are required to use oxygenated fuels (minimum 2.7 percent oxygen content by weight) during the winter months to reduce carbon monoxide emissions. It is also expected to replace MTBE as the oxygenate for RFG in 20 States that have placed limits on MTBE use because of concerns about groundwater contamination. It is assumed that the Federal requirement for 2 percent oxygen in RFG will continue in all States. Some ethanol is also used in E85 fuel, a blend of 70 to 85 percent ethanol and gasoline. E85 consumption is projected to increase from a national total of 11 million gallons in 2003 to 47 million gallons in 2025.

The American Jobs Creation Act of 2004 extended the excise tax exemption for ethanol through 2010, at 51 cents per gallon. It is assumed that the exemption will continue to be extended at that level (in nominal dollars) through the end of the forecast.

Refining Costs for Most Petroleum Products Remain Stable or Decline

Figure 101. Components of refined product costs, 2003 and 2025 (2003 dollars per gallon)

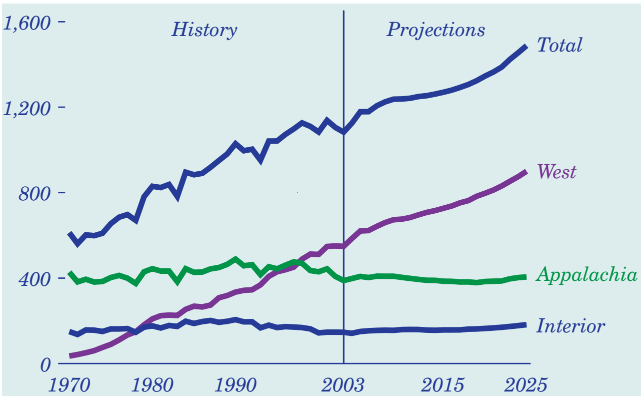


Refined product prices are determined by crude oil costs, refining costs (including profits), marketing costs, and taxes (Figure 101). In the *AEO2005* projection, crude oil continues as the largest part of product prices. Marketing costs remain stable, but the contribution of taxes is projected to change considerably. Refining costs for gasoline and diesel fuel are expected to remain about the same in the forecast, despite rising demand and new Federal requirements for low-sulfur gasoline (2004 to 2007) and ultra-low-sulfur diesel fuel (2006 to 2010). Refining costs for jet fuel are projected to increase as demand increases, by 2 cents per gallon from 2003 to 2025, while refining costs for heating oil are projected to fall by 11 cents per gallon. Most diesel fuel must have no more than 15 parts per million sulfur by 2012, whereas heating oil, which is otherwise very similar to diesel fuel, has no sulfur limit.

Whereas crude oil costs tend to increase refined product prices in the forecast, the assumption that Federal motor fuel taxes remain at nominal 2003 levels tends to reduce prices. Although Federal motor fuel taxes have been raised occasionally in the past, the assumption of constant nominal Federal taxes is consistent with history. The net impact of the assumption is an expected decrease in Federal taxes (in 2003 dollars) from 2003 to 2025—8 cents per gallon for gasoline, 10 cents for diesel fuel, and 2 cents for jet fuel. State motor fuels taxes are assumed to keep up with inflation, as they have generally in the past.

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

Figure 102. Coal production by region, 1970-2025 (million short tons)



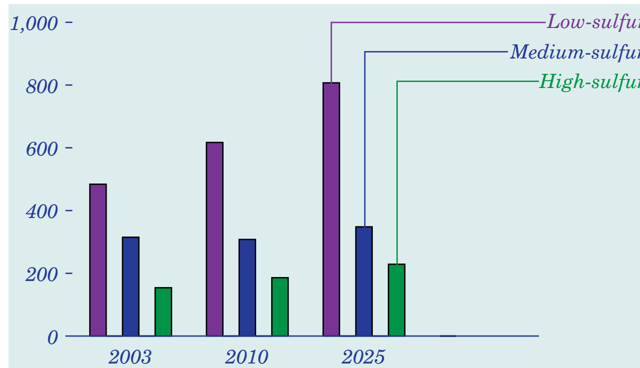
U.S. coal production has remained near 1,100 million tons annually since 1997. In the early years of the *AEO2005* forecast, a projected increase in coal use for electricity generation leads to an increase in production, to 1,238 million tons in 2010. After 2010, coal production increases with projected additions of new, unplanned coal-fired generating capacity, particularly from 2015 to 2025.

Little change is projected for Appalachian coal production (Figure 102). The region has been mined extensively, and increases in demand are likely to be met with coal from other areas. In the Interior region, production is projected to increase by 36 million tons from 2003 to 2025. Western coal production, which has grown steadily since 1970, is projected to continue to increase through 2025, especially in the Powder River Basin, where vast reserves are contained in thick seams accessible to surface mining. Easing of rail transportation bottlenecks will be key for coal producers in the West to take advantage of market opportunities presented by slower growth in Appalachian production, fuel switching at existing power plants, and demand from new power plants expected to be built in the West and Southeast regions.

The use of Western coals can reduce sulfur dioxide emissions by up to 85 percent relative to many types of higher sulfur eastern coals. As coal demand grows over the forecast, however, new coal-fired generating capacity is required to use the best available control technology (scrubbers or advanced coal technologies), which can reduce sulfur emissions by 90 percent or more, providing market opportunities for higher sulfur coal later in the forecast.

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

Figure 103. Distribution of domestic coal to the electricity sector by sulfur content, 2003, 2010, and 2025 (million short tons)



To reduce sulfur dioxide emissions as required under Phase 1 of CAAA90, many generators switched from higher sulfur coals to low-sulfur coal, leading to an excess of sulfur dioxide allowances. The excess allowances generated were banked or sold for use in Phase 2, which took effect on January 1, 2000. Low-sulfur coal will continue to be used in generator compliance strategies and is also expected to be attractive to many generators where it is the least expensive coal available.

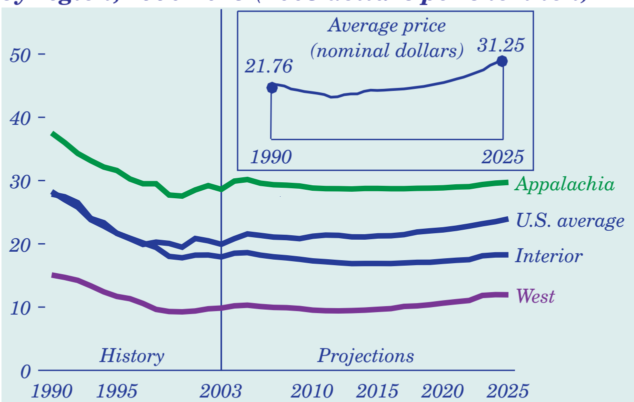
Distribution of low-sulfur coal to the electricity sector is projected to increase on average by 3.1 percent per year between 2003 and 2011 (Figure 103) as most banked allowances are used. After 2017, low-sulfur coal maintains about a 58-percent share of domestic coal use for generation, up from 51 percent in 2003. Most of the low-sulfur coal used in 2025 is projected to come from the West, primarily the Powder River Basin and the Rocky Mountain regions. Projected declines in transportation rates contribute to the expected growth in sales of western low-sulfur coal, for which transportation costs are a relatively large part of delivered costs—typically over 60 percent for coal originating from the Powder River Basin, compared with under 25 percent for Central Appalachian coal.

Despite tighter emissions limits in CAAA90 Phase 2, the market for higher sulfur coals will continue in some regions, with 27 gigawatts of capacity expected to be retrofitted with scrubbers by 2025. Although use of higher sulfur coals at unscrubbed plants is expected to decline, their use at retrofitted or new units is projected to increase from 2003 levels.

Coal Prices and Mine Employment

Average Minemouth Coal Prices Are Not Projected To Rise Significantly

Figure 104. Average minemouth price of coal by region, 1990-2025 (2003 dollars per short ton)



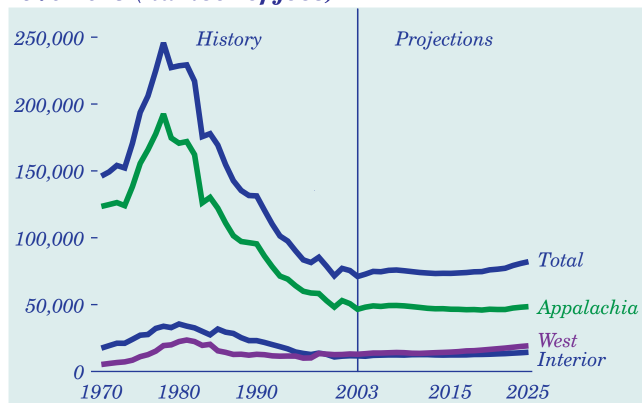
Between 1990 and 1999, the average minemouth price of coal declined by 4.9 percent per year, from $28.26 per ton (2003 dollars) to $18.01 per ton (Figure 104). Increases in U.S. coal mining productivity of 6.3 percent per year during the period helped to reduce mining costs and contributed to the decline in prices. Since 1999, growth in U.S. coal mining productivity has slowed to 1.3 percent per year, and minemouth coal prices have remained virtually unchanged despite some short-term fluctuations. The average in 2003 was $17.93 per ton.

Minemouth coal prices are projected to rise initially in the *AEO2005* reference case, primarily in response to strong growth in the demand for coal in the electric power sector. After 2005, when natural gas prices are in decline, natural-gas-fired generating capacity becomes more competitive, and coal demand grows more slowly. The combination of moderate growth in demand, improvements in mining productivity, and a continuing shift to low-cost coal from Wyoming's Powder River Basin leads to a projected decline in the average minemouth price, from $18.61 per ton in 2005 to around $17.00 per ton shortly after 2010, and it continues at about that level through 2020. After 2020 the price is projected to increase to $18.26 per ton in 2025, as rising natural gas prices and the need for baseload generating capacity result in the construction of new coal-fired generating capacity.

Increases in coal production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, result in projected minemouth price increases of 0.8 and 0.9 percent per year, respectively, in those regions from 2003 to 2025.

Coal Mine Employment Is Expected To Remain Near Current Levels

Figure 105. U.S. coal mine employment by region, 1970-2025 (number of jobs)



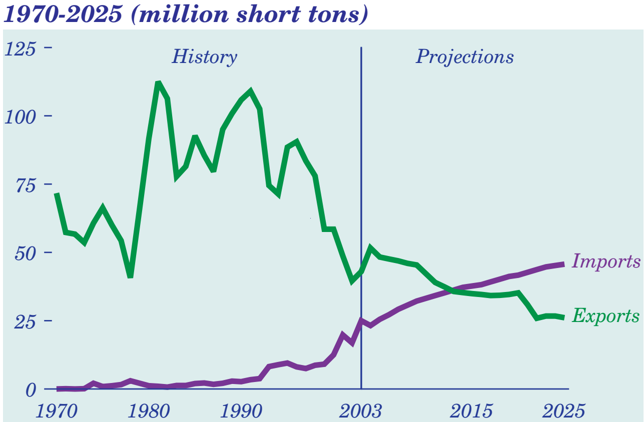
Most jobs in the U.S. coal industry remain east of the Mississippi River, mainly in the Appalachian region (65 percent of total mining jobs in 2003). Most coal production, however, occurs west of the Mississippi River (56 percent in 2003), with the major share from the Powder River Basin. As coal demand increases, pressure to keep prices low will shift more production to mines with higher labor productivity. Large surface mines in the Powder River Basin take advantage of economies of scale, using large earth-moving equipment and combining adjacent mines to increase operating flexibility. Underground mines in northern Appalachia, the Illinois Basin, and the Rocky Mountain region use highly productive and increasingly automated longwall equipment to maximize production while reducing the number of miners required.

Labor productivity is expected to continue to improve in most regions but at a decreasing rate. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

About 11,000 additional jobs are projected to be created in the U.S. coal industry by 2025 (Figure 105). The new mining jobs will be in the most productive surface and underground mines, but jobs will be lost in the less productive mines of Central Appalachia.

Declining U.S. Coal Exports, Rising Imports Are Projected

Figure 106. U.S. coal exports and imports, 1970-2025 (million short tons)



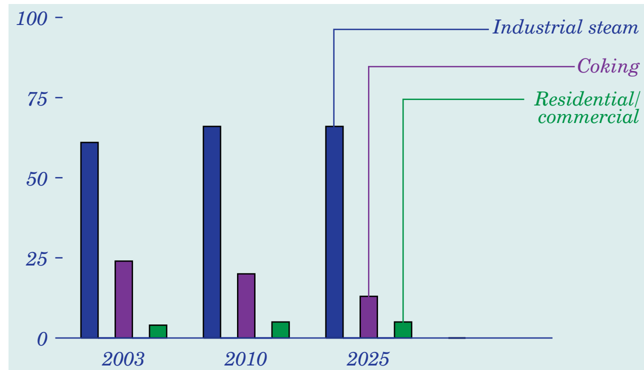
U.S. coal exports declined steadily from 1996 through 2002, from 90 million tons to 40 million tons, despite a substantial increase in world coal trade from 503 million tons in 1996 to 656 million tons in 2002. During the same period, low-cost supplies of coal from China, Colombia, Indonesia, Russia, and Australia satisfied much of the growth in international demand for steam coal, while low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in world markets. Since 2002, U.S. exports have rebounded, however, including increases in exports of steam coal to Canada in 2003 and to overseas customers in 2004.

Although U.S. coal exports are projected to remain above the 2003 level for the next several years, the U.S. share of total world coal trade is ultimately projected to fall from 6 percent in 2003 to 3 percent in 2025, as international competition intensifies and imports of coal to Europe and the Americas grow more slowly or decline. Following a projected rise in 2004, U.S. coal exports decline gradually in the forecast, from 43 million tons in 2003 to 26 million tons in 2025 (Figure 106).

U.S. imports of low-sulfur coal are projected to grow from 25 million tons in 2003 to 46 million tons in 2025. The addition and expansion of existing coal import facilities and the need to meet tighter emission targets are expected to make coal imports an increasingly attractive option for U.S. coal-fired power plants located near the Gulf Coast and the Atlantic seaboard. Much of the additional import tonnage is expected to originate from mines in Colombia, Venezuela, and Indonesia.

U.S. Consumption of Coking Coal Declines in the Forecast

Figure 107. Coal consumption in the industrial and buildings sectors, 2003, 2010, and 2025 (million short tons)



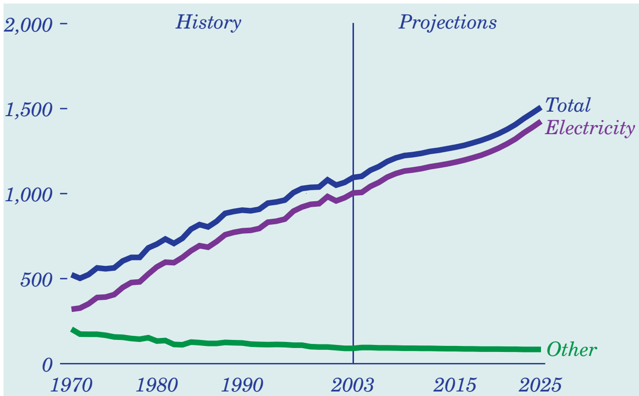
Although most coal is used to generate electricity, 91 million tons (8 percent of consumption) is used annually in the industrial and buildings (residential and commercial) sectors (Figure 107). Steam coal is used in manufacturing paper, chemical, food, and textile products. The key use of coal in these sectors is to produce process steam, which provides heat and mechanical power. Electricity is often produced in conjunction with steam (cogeneration) and is used in the manufacturing process or sold into the electric power grid. Coal is used by the cement industry as an important source of fuel for dry kilns, and the chemical industry also uses coal as a feedstock. Consumption of steam coal in the industrial sector is projected to remain relatively constant in the forecast.

Coal is also used to produce coke, which in turn is used as a source of energy and as a raw material input at blast furnaces to produce iron. Coking coal is the most important source of energy in the iron and steel industry, accounting for 51 percent of the energy consumed in 2003. In the forecast, U.S. consumption of coking coal declines by 2.7 percent per year, from 24 million tons in 2003 to 13 million tons in 2025, as production shifts from coke-based production at integrated steel mills to electric arc furnaces. Coking coal's share of total energy use in the U.S. steel industry is projected to decline to 35 percent in 2025.

Although coal is used to generate much of the electricity consumed in the buildings sectors, its direct consumption accounts for only a minor portion of total energy use in those sectors. Annual coal consumption in the building sectors is projected to remain constant at about 5 million tons.

Coal Consumption for Electricity Continues To Rise in the Forecast

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



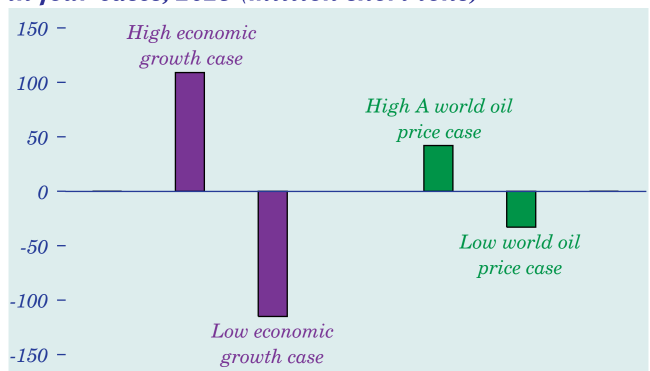
Domestic coal demand is projected to increase by 413 million tons (38 percent) in the reference case forecast, from 1,095 million tons in 2003 to 1,508 million tons in 2025 (Figure 108). Of all the coal consumed in 2003, 92 percent was used for electricity generation, and that share is expected to rise to 94 percent in 2025. Coal use for electricity generation is expected to increase on average, by 1.6 percent per year from 2003 to 2025. Coal accounted for 51 percent of U.S. electricity generation (including combined heat and power) in 2003 and is projected to account for 50 percent in 2025, when more natural gas is expected to be used for generation.

Overall, coal consumption in the electric power sector is expected to grow as existing coal-fired plants are used more intensively and new ones are added after 2011. Nationally, capacity utilization for coal plants (excluding combined heat and power) is expected to rise from 72 percent in 2003 to 83 percent in 2025. Only 3 gigawatts of coal-fired capacity is expected to be retired in the forecast, and 87 gigawatts of new capacity, including 16 gigawatts of integrated gasification combined cycle, is expected to be added—more than half in regions west of the Mississippi River.

New coal-fired generating capacity is expected to result in large increases in coal consumption in the Mountain and East South Central Census Divisions. Western coal will continue to account for the largest share of coal use for electricity generation in the Mountain Census Division, and its share in the East South Central Division is projected to increase from 32 percent in 2003 to 37 percent in 2025.

Higher Economic Growth Stimulates Electricity Generation from Coal

Figure 109. Projected variation from the reference case projection of total U.S. coal demand in four cases, 2025 (million short tons)

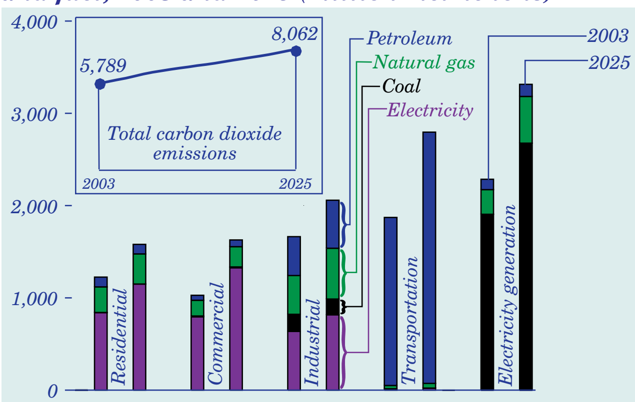


Domestic coal consumption in 2025 is projected to range from 1,393 million tons in the low economic growth cases to 1,617 million tons in the high economic growth case, with coal use for electricity generation making up 219 million tons (98 percent) of the difference. The most significant impact on coal occurs in the later years of the forecast period, when economic conditions influence plans for new electricity generation capacity. Projected additions of coal-fired capacity from 2003 to 2025 are 39 gigawatts higher in the high economic growth case than in the reference case and 37 gigawatts lower in the low economic growth case. Regionally, the Mountain and East South Central Census Divisions show the largest increases in coal consumption in the high economic growth case and the largest declines in the low economic growth case relative to the reference case.

Compared with the economic growth cases, a smaller impact on coal consumption is expected in the world oil price cases (Figure 109). The projection for total U.S. coal demand in 2025 is 33 million tons lower in the low world oil price case than in the reference case and 42 million tons higher in the high A world oil price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels, including coal. For electricity generation, the low oil price case projects 34 million tons less coal use in 2025 than is projected in the reference case. In the high A world oil price case, elevated prices for low-sulfur distillate are projected to stimulate the coal-to-liquids market. In 2025, 48 million tons of coal is projected to be consumed at coal-to-liquids plants, yielding 62 million barrels of fuel liquids and 34 billion kilowatthours of electricity.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 110. Carbon dioxide emissions by sector and fuel, 2003 and 2025 (million metric tons)

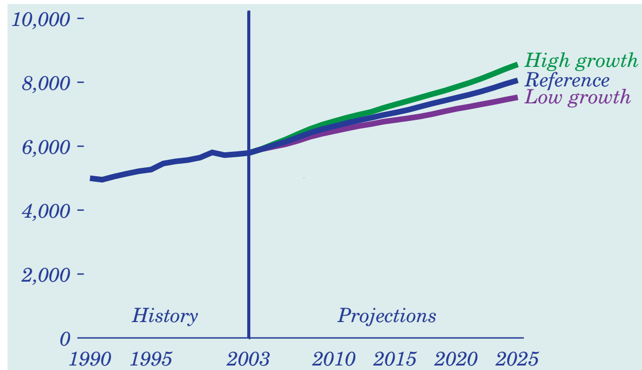


Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2003 to 2025, to 8,062 million metric tons (Figure 110). Emissions per capita are projected to grow by 0.7 percent per year. New carbon dioxide mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.2 percent per year, reflecting increased electrification and penetration of computers, electronics, and appliances in the sector. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector, and carbon dioxide emissions from the sector are projected to increase by 2.1 percent per year from 2003 to 2025. Industrial emissions are projected to grow by 1.0 percent per year, as shifts to less energy-intensive industries and efficiency gains help to moderate the effect of growth in energy use. In the transportation sector, carbon dioxide emissions grow at an annual rate of 1.8 percent. Increases in highway, rail, and air travel are partially offset by efficiency improvements in rail freight and aircraft, but passenger vehicle fuel economy is projected to increase only slightly above 2003 levels. In the electric power sector, continued reliance on coal and growth in natural-gas-fired generation result in a projected average increase in carbon dioxide emissions of 1.7 percent per year and an increase in the sector's share of total emissions to 41 percent in 2025 from 39 percent in 2003.

Emissions Projections Change With Economic Growth Assumptions

Figure 111. Carbon dioxide emissions in three economic growth cases, 1990-2025 (million metric tons)



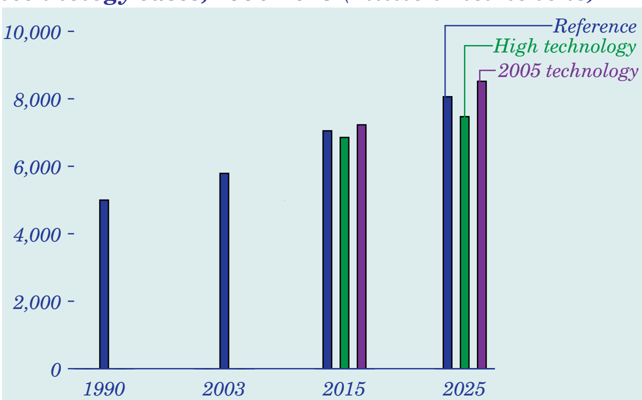
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.6 percent per year from 2003 to 2025, compared with 3.1 percent per year in the reference case. In the low economic growth case, GDP growth averages 2.5 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case, and projected energy consumption in 2025 is 6 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to be 6 percent higher than in the reference case in 2025, at 8,561 million metric tons (Figure 111). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.9 percent per year from 2003 to 2025 in the high growth case, as compared with 1.6 percent per year in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity for turnover in the stock of energy-using technologies, adding new equipment and increasing the overall efficiency of the capital stock.

Projected total energy consumption in 2025 is 6 percent lower in the low economic growth case than in the reference case, and carbon dioxide emissions in 2025 are 7 percent lower, at 7,530 million metric tons. Energy intensity is projected to decline at an average rate of 1.4 percent per year from 2003 to 2025 in the low economic growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 112. Carbon dioxide emissions in three technology cases, 1990-2025 (million metric tons)

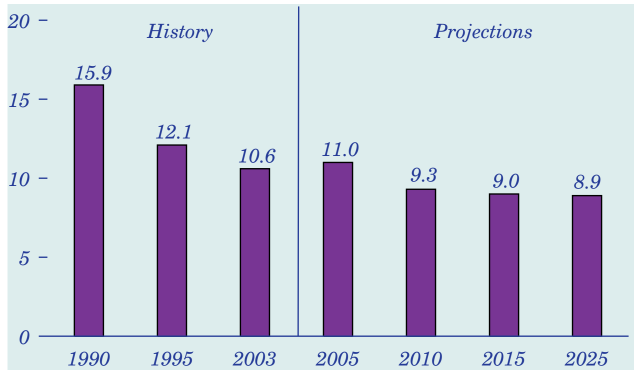


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*143*]. Energy intensity is expected to decline on average by 1.9 percent per year through 2025 in the high technology case, as compared with 1.6 percent in the reference case. As a result, energy consumption is projected to be 5 percent lower than in the reference case in 2025, at 126 quadrillion Btu, and carbon dioxide emissions are projected to be 7 percent lower than in the reference case, at 7,471 million metric tons (Figure 112).

The 2005 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2005; that new building shell and plant efficiencies will remain at their 2005 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2005 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.4 percent per year from 2003 to 2025. Energy consumption reaches 140 quadrillion Btu in 2025 in the 2005 technology case, and carbon dioxide emissions in 2025 are projected to be 6 percent higher than in the reference case, at 8,519 million metric tons.

Sulfur Dioxide Emissions Are Cut in Response to Tightening Regulations

Figure 113. Sulfur dioxide emissions from electricity generation, 1990-2025 (million short tons)



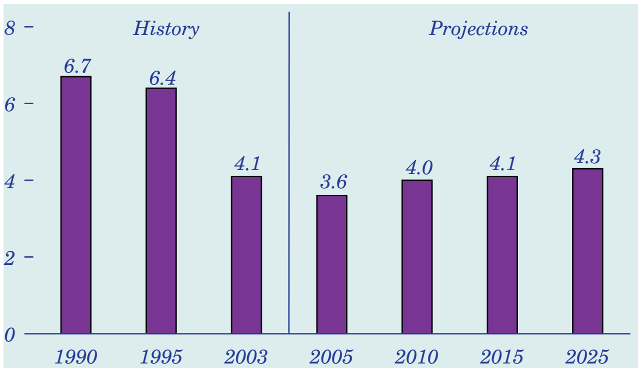
CAAA90 called for annual emissions of SO_2 by electricity generators in the power sector to be reduced to approximately 12 million short tons in 1996, 9.48 million short tons per year from 2000 to 2009, and 8.95 million short tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million short tons per year is not expected to be reached until after 2012. Coal combustion accounts for more than 95 percent of the SO_2 produced by generators.

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

Power companies have announced plans to add scrubbers to 22 gigawatts of capacity in order to comply with State or Federal initiatives. About 6 gigawatts of additional capacity is projected to be retrofitted with scrubbers. SO_2 emissions are projected to drop from 10.6 million short tons in 2003 to 8.9 million tons in 2025 (Figure 113). The SO_2 emission allowance price is projected to rise to near \$275 per ton in 2010 as banked allowances are used and to remain between \$250 and \$325 per ton from 2010 through 2025.

Nitrogen Oxide Emissions Are Projected To Fall in the Near Term

Figure 114. Nitrogen oxide emissions from electricity generation, 1990-2025 (million short tons)



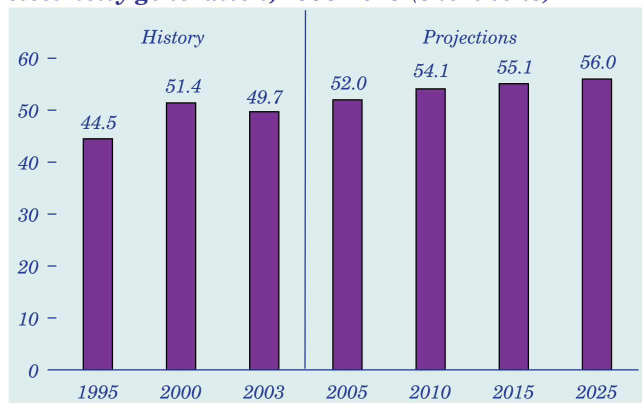
NO_x emissions from electricity generation in the U.S. power sector are projected to fall in the short term as new regulations take effect (Figure 114). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months.

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

The Ozone Transport Rule called for capping NO_x emissions in Midwestern and Eastern States, and limits have been finalized for 19 States. The limits, which apply to NO_x emissions during the 5-month summer season in the 19 States covered, are expected to stimulate additions of emission control equipment to some existing plants. National NO_x emissions are projected to increase from 4.1 million short tons in 2003 to 4.3 million short tons in 2025. Due to the geographical restriction of the cap, coal use and NO_x emissions are expected to increase at plants outside the 19 covered States. Overall, selective catalytic reduction equipment is projected to be added to approximately 74 gigawatts of capacity, and NO_x allowance prices are projected to range from roughly $4,000 to $5,600 per ton between 2005 and 2025.

Mercury Emissions Are Expected To Grow With Increased Coal Use

Figure 115. Mercury emissions from electricity generation, 1995-2025 (short tons)



Mercury is a metallic element that occurs naturally in all types of coal. Its concentration can vary significantly by coal type and origin, even within a single mine. There are no Federal regulations on mercury emissions from power plants, but the EPA is considering mandatory limits. Several States have adopted or are considering mercury control regulations for power plants within their jurisdictions.

Emissions of mercury depend on a variety of site-specific factors, including the amounts of mercury and other compounds (such as chlorine) in the coal, the boiler type and configuration, and the presence of pollution control equipment such as fabric filters, electrostatic precipitators, flue gas desulfurization, and selective catalytic control equipment. Technologies that remove SO_2 and NO_x have shown promise in removing mercury from bituminous coals but have not performed as well with lower ranked coals [*144*]. The U.S. Department of Energy, together with industry partners, is sponsoring research and development programs on advanced technologies to reduce mercury emissions from power plants.

The *AEO2005* reference case assumes no regulation of mercury emissions in the electricity generation sector through 2025, and the average mercury content of coal burned at power plants is assumed to stay relatively constant at about 7.4 pounds per trillion Btu of energy input to coal-fired electricity production. Consequently, with coal use for electricity generation projected to increase, total mercury emissions from power plants are also projected to increase, from 49.7 short tons in 2003 to 56.0 short tons in 2025 (Figure 115).

Forecast Comparisons

Only one other organization—Global Insight, Incorporated (GII)—produces a comprehensive energy projection with a time horizon similar to that of *AEO2005*. Other organizations address one or more aspects of the energy markets. The most recent projection from GII, as well as other forecasts that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2005* projections.

Economic Growth

In *AEO2005* the projected growth in real GDP, based on 2000 chain-weighted dollars, is 3.1 percent per year from 2003 to 2025—slightly higher than the 3.0-percent average annual growth projected in *AEO2004* (Table 32). The *AEO2005* forecast is based on the May 2004 long-range forecast and the August short-term forecast of GII, modified to reflect EIA's view on energy prices, demand, and production.

The average annual GDP growth rate projections for the United States from 2003 through 2009 range from 3.4 to 3.6 percent. The *AEO2005* reference case and GII project the lowest rate at 3.4 percent, and the Office of Management and Budget (OMB) projects the highest rate at 3.6 percent, followed by the Congressional Budget Office (CBO) and Oxford Economic Forecasting (OEF) at 3.5 percent. When the projection period is extended to 2014, the uncertainty in the GDP growth rate is reflected by a widening of the range of GDP growth rate projections (3.1 to 3.5 percent). While *AEO2005* remains in the lower half of the range, the CBO projection reflects a considerable slowing of GDP growth during the 2010 to 2014 period. Because few commercial or private forecast organizations project GDP growth rates for the United States to 2025, comparisons over the entire period from 2003 to 2025 are not readily available. The *AEO2005* reference case projection reflects a slowing of the GDP growth rate after 2015, consistent with an expected slowing of population growth.

World Oil Prices

Comparisons with other oil price forecasts are shown in Table 33. The world oil price measure varies by forecast. In some projections, the measure is the spot price for WTI, Brent, or a basket of crude oils. *AEO2005* uses the annual average U.S. refiner's acquisition cost of imported crude oil, including transportation and fees. There is no simple way to put the forecasts for oil prices on a common basis. The range between the *AEO2005* low and high B world oil price cases spans the range of published forecasts. In fact, the *AEO2005* high B world oil price case is considerably above all the other forecasts for 2025.

Recent variability in crude oil prices demonstrates the uncertainty inherent in forecasting crude oil markets, which generally widens as the time horizon extends into the future. The oil price paths proffered by several organizations (Table 33), including *AEO*, illustrate the uncertainty. For example, for 2010, the price range in the forecasts is from a low of about $22 per barrel projected by Altos Partners (Altos) to a high of almost $35 per barrel projected by Petroleum Industry Research Associates, Inc. (PIRA). The range in the forecasts for 2025 is somewhat narrower but

Table 32. Forecasts of annual average economic growth, 2003-2025

	Average annual percentage growth		
Forecast	2003-2009	2003-2014	2003-2025
AEO2004	3.5	3.2	3.0
AEO2005			
Reference	3.4	3.3	3.1
Low growth	2.9	2.8	2.5
High growth	4.1	3.9	3.6
GII	3.4	3.2	3.1
OMB	3.6	NA	NA
CBO	3.5	3.1	NA
OEF	3.5	3.5	NA

NA = not available.

Table 33. Forecasts of world oil prices, 2010-2025 (2003 dollars per barrel)

Forecast	2010	2015	2020	2025
AEO2004 (reference case)	24.53	25.44	26.41	27.40
AEO2005				
Reference	25.00	26.75	28.50	30.31
High A world oil price	33.99	34.24	36.74	39.24
High B world oil price	37.00	40.67	44.33	48.00
October oil futures	30.99	32.33	33.67	35.00
Low world oil price	20.99	20.99	20.99	20.99
GII	27.08	25.58	26.66	27.12
IEA (reference scenario)	23.25	25.37	27.48	29.07
IEA (high oil price case)	37.00	37.00	37.00	37.00
Altos	21.92	22.67	23.93	24.60
PEL	25.00	27.00	27.00	29.00
PIRA	34.75	39.15	NA	NA
DB	24.00	24.00	24.00	24.00
EEA	26.58	25.55	24.93	NA
SEER	26.13	28.40	28.25	29.00
EVA	28.99	28.39	30.97	34.77

NA = not available.

still substantial, from a low of $24 per barrel projected by Deutsche Bank, A.G. (DB) to a high of nearly $35 per barrel projected by Energy Ventures Analysis, Incorporated (EVA).

Total Energy Consumption

The *AEO2005* forecast of end-use sector energy consumption shows higher growth for petroleum and natural gas than occurred from 1980 to 2003 but lower projected growth in electricity consumption (Table 34). Much of the projected growth in petroleum consumption is driven by increased demand in the industrial sector for petrochemical and manufacturing applications as economic activity expands, and in the transportation sector as improvements in efficiency fail to offset increases in miles traveled. Natural gas consumption is expected to increase in the residential, commercial, and industrial sectors as environmental and economic pressures benefit natural gas at the expense of petroleum and coal consumption. Coal consumption in those end-use sectors is expected to decline slightly as a result of increased fuel switching and growing concern about emissions.

Electricity is expected to remain the fastest growing source of delivered energy. Its growth does not outpace historical rates, however, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. The *AEO2005* projections are generally consistent with the outlook from GII; however, GII projects slower growth in natural gas consumption, electricity consumption, and electricity losses, as well as slightly faster growth in petroleum consumption, resulting from differences in relative prices and projected growth in each sector.

Table 34. Forecasts of average annual growth rates for energy consumption, 2003-2025 (percent)

Energy use	History 1980-2003	Projections AEO2005	Projections GII
Petroleum*	0.8	1.5	1.6
Natural gas*	0.2	1.0	0.7
Coal*	-1.7	-0.6	-0.4
Electricity	2.2	1.9	1.6
Delivered energy	0.7	1.4	1.3
Electricity losses	1.9	1.4	0.9
Primary energy	1.0	1.4	1.2

**Excludes consumption by electricity generators in the electric power sector but includes consumption for end-use combined heat and power generation.*

Electricity

The *AEO2005* projections for the electricity generation sector assume that wholesale electricity markets in most U.S. regions will be restructured, resulting in average wholesale electricity prices that approach long-run marginal costs. The same cannot be said for retail markets at the State level: as of 2003, only 17 States and the District of Columbia had competitive retail markets in operation. Further, a number of States have delayed opening competitive retail markets, Arkansas has repealed retail restructuring, and California has suspended restructuring. The *AEO2005* cases assume that no additional retail markets will be restructured, but that partial restructuring (particularly in wholesale markets) will lead to increased competition in the electric power industry, lower operating and maintenance costs, and early retirement of inefficient generating units.

Comparison of the *AEO2005* reference case, GII, and EVA forecasts shows some variation in projected electricity sales (Table 35). The forecasts for total electricity sales in 2025 range from 4,982 billion kilowatthours (GII) to 5,396 billion kilowatthours (EVA). The rate of demand growth ranges from 1.6 percent (GII) to 2.0 percent (EVA). All price forecasts reflect competition in wholesale markets and slow growth in electricity demand relative to GDP growth, exerting downward pressure on real electricity prices through 2025. Rising natural gas prices balance some of the downward pressure and tend to push electricity prices up in the later years of the forecasts.

The *AEO2005* reference case projects a slight decline in real electricity prices over the full period of the forecast (except for the industrial sector), although average prices increase slightly during the last several years as capacity margins tighten and natural gas prices climb. In contrast, GII projects a decline in electricity prices over the second half of the forecast as lower natural gas prices to generators ($4.23 per million Btu in the GII forecast, compared with $5.44 per million Btu in the *AEO2005* reference case in 2025) contribute to a small decrease in average electricity prices, from 7.2 cents per kilowatthour in 2015 to 7.1 cents per kilowatthour in 2025. The higher natural gas price projected in the *AEO2005* reference case leads to an increase in average electricity price, from 6.9 cents per kilowatthour in 2015 to 7.3 cents per kilowatthour in 2025.

Both the *AEO2005* reference case and GII projections include some planned capacity additions in the near

Table 35. Comparison of electricity forecasts, 2015 and 2025 (billion kilowatthours, except where noted)

Projection	2003	AEO2005 Reference	AEO2005 Low economic growth	AEO2005 High economic growth	Other forecasts GII	Other forecasts EVA	Other forecasts EEA	Other forecasts SEER	Other forecasts PIRA
					2015				
Average end-use price (2003 cents per kilowatthour)	**7.4**	**6.9**	**6.7**	**7.1**	**7.2**	**NA**	**NA**	**NA**	**NA**
Residential	8.7	8.1	7.7	8.3	8.3	8.1	NA	NA	NA
Commercial	7.9	7.3	6.9	7.5	7.7	7.4	NA	NA	NA
Industrial	5.1	5.0	4.7	5.2	4.8	4.7	NA	NA	NA
Net energy for load, including CHP	**3,857**	**4,912**	**4,762**	**5,082**	**4,667**	**5,131**	**4,913**	**4,472**	**4,706**
Coal	1,971	2,306	2,269	2,354	2,325	2,190	2,255	2,230	2,115
Oil	135	150	146	149	45	22	77	97	97
Natural gas [a]	632	1,171	1,077	1,285	1,035	1,523	1,306	815	1,237
Nuclear	764	826	826	826	800	822	813	794	805
Hydroelectric/other [b]	350	438	426	448	446	538	383	356	430
Nonutility sales to grid [c]	28	59	53	67	NA	NA	41	179	NA
Net imports	5	21	18	20	16	36	38	NA	23
Electricity sales	**3,482**	**4,430**	**4,295**	**4,583**	**4,244**	**4,571**	**4,415**	**NA**	**NA**
Residential	1,280	1,584	1,569	1,604	1,569	1,673	1,561	NA	NA
Commercial/other [d]	1,233	1,680	1,657	1,703	1,539	1,699	1,588	NA	NA
Industrial	969	1,166	1,069	1,276	1,136	1,200	1,266	NA	NA
Capability, including CHP (gigawatts) [e]	**948**	**1,002**	**981**	**1,030**	**989**	**1,074**	**1,074**	**NA**	**NA**
Coal	314	320	316	325	347	330	335	NA	NA
Oil and natural gas	415	455	439	476	408	329	500	NA	NA
Nuclear	99	102	102	102	100	102	102	NA	NA
Hydroelectric/other	119	125	123	126	134	312	138	NA	NA
					2025				
Average end-use price (2002 cents per kilowatthour)	**7.4**	**7.3**	**7.0**	**7.6**	**7.1**	**NA**	**NA**	**NA**	**NA**
Residential	8.7	8.3	8.0	8.7	8.2	8.1	NA	NA	NA
Commercial	7.9	7.6	7.3	8.1	7.7	7.3	NA	NA	NA
Industrial	5.1	5.4	5.1	5.7	4.7	4.7	NA	NA	NA
Net energy for load, including CHP	**3,857**	**5,780**	**5,444**	**6,117**	**5,475**	**6,100**	**NA**	**5,309**	**NA**
Coal	1,971	2,890	2,613	3,179	2,932	2,597	NA	2,578	NA
Oil	135	163	158	168	26	19	NA	94	NA
Natural gas [a]	632	1,406	1,371	1,409	1,267	1,831	NA	1,181	NA
Nuclear	764	830	830	830	773	888	NA	816	NA
Hydroelectric/other [b]	350	480	461	519	464	727	NA	398	NA
Nonutility sales to grid [c]	28	91	74	110	NA	NA	NA	242	NA
Net imports	5	11	11	12	13	40	NA	NA	NA
Electricity sales	**3,482**	**5,219**	**4,914**	**5,518**	**4,982**	**5,396**	**NA**	**NA**	**NA**
Residential	1,280	1,810	1,748	1,850	1,851	2,007	NA	NA	NA
Commercial/other [d]	1,233	2,123	2,047	2,196	1,846	2,058	NA	NA	NA
Industrial	969	1,286	1,119	1,472	1,285	1,331	NA	NA	NA
Capability, including CHP (gigawatts) [e]	**948**	**1,190**	**1,129**	**1,248**	**1,140**	**1,246**	**NA**	**NA**	**NA**
Coal	314	398	361	438	435	390	NA	NA	NA
Oil and natural gas	415	555	535	567	466	387	NA	NA	NA
Nuclear	99	103	103	103	100	110	NA	NA	NA
Hydroelectric/other	119	134	130	141	139	358	NA	NA	NA

[a]Includes supplemental gaseous fuels. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, plus a small quantity of petroleum coke. [c]For *AEO2005*, includes only net sales from combined heat and power plants. [d]"Other" includes sales of electricity to government, railways, and street lighting authorities. [e]EIA capacity is net summer capability, including combined heat and power plants. GII capacity is nameplate, excluding cogeneration plants. [f]EVA "other" includes all CHP.

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

Sources: ***AEO2005:*** AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LM2005.D102004A (low economic growth case), and HM2005.D102004A (high economic growth case). **GII:** Global Insight, Inc., *Summer 2004 U.S. Energy Outlook* (August 2004). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2004). **SEER:** Strategic Energy and Economic Research, Inc., *2004 Energy Outlook* (October 2004). PIRA: PIRA Research Group (October 2004).

term, with the *AEO2005* reference case expecting about 28 gigawatts through 2005 and GII expecting about 14 gigawatts. Virtually all the projected capacity additions are natural gas fired. These two forecasts project that prices will fall in the near term as a result of excess total capacity.

All the forecasts except for GII project that demand will grow fastest in the commercial sector, and that more cycling and baseload capability will be built than peaking units. All the forecasts show significant net additions to coal-fired capacity: 84 gigawatts through 2025 in the *AEO2005* reference case and 121 gigawatts through 2025 in the GII forecast. Both GII and the *AEO2005* reference case project no nuclear retirements; however, EVA projects 8 gigawatts of nuclear capacity additions by 2025.

The fuel mix in the EVA forecast differs from that in the *AEO2005* reference case and the other forecasts. All the forecasts, except for EVA, project that coal will provide about one-half and natural gas about one-quarter of the growth in electricity generation over the forecast period. The EVA forecast assumes that legislation similar to the Clear Skies Act—including further restrictions on SO_2, NO_x, and mercury emissions—will be in effect by 2010. The EVA forecast also includes a tax of $5 per ton on carbon dioxide emissions, beginning in 2013. *AEO2005* does not assume either passage of the Clear Skies Act or any carbon tax throughout the forecast horizon. In the EVA forecast, the combination of further environmental restrictions and a tax on carbon dioxide leads to greater growth in hydroelectric generation.

Natural Gas

There are considerable differences among published forecasts of natural gas prices, production, consumption, and imports (Table 36). The differences highlight the uncertainty of future market trends. Because the forecasts depend heavily on the underlying assumptions that shape them, the assumptions made in each forecast should be considered when different projections are compared.

Over the period from 2007 to 2025, the *AEO2005* reference case is within the range of projections for total natural gas consumption in the other forecasts. The lowest projected totals for natural gas consumption in 2005 are from the DB forecast, and the highest are from the EVA forecast. For residential and commercial natural gas consumption, DB projects the strongest growth from 2003 to 2025, and the GII forecast has the lowest projected consumption levels. The *AEO2005* reference case projections for 2025 fall in the high end of the range for residential consumption and in the mid-range for commercial consumption. Natural gas consumption in the industrial and electric power sectors is more difficult to compare, given potential definitional differences. The EVA forecast shows the fastest growth in natural gas consumption from 2003 to 2025 in combined totals for the industrial and electric power sectors, whereas the DB forecast shows much slower growth than the other forecasts.

Natural gas for domestic consumption is supplied by domestic production and net imports. All forecasts show domestic production providing a decreasing share of total natural gas supply. The Altos forecast shows a smaller shift in that direction, with significantly lower net imports and significantly higher domestic production. Three of the forecasts—*AEO2005* reference case, GII, and DB—project that net imports will supply about 30 percent of end-use consumption by 2025. EVA projects that 36 percent of consumption will be supplied by net imports, Strategic Energy & Economic Research, Incorporated (SEER) projects 26 percent, and Altos 18 percent (for Altos, the percentage is calculated as net imports divided by the sum of production and net imports).

The volume of net imports varies significantly among the forecasts, as does the mix of net imports. GII, SEER, and Altos expect a decline in net pipeline imports of more than 50 percent between 2003 and 2025, the *AEO2005* reference case projects a more modest decline of about 20 percent, and EVA anticipates an increase in net pipeline imports of 30 percent (DB is not included in this comparison because of definitional differences). All the forecasts project strong growth in LNG imports, with net LNG imports in 2025 ranging from 4.6 trillion cubic feet in the Altos forecast to 8.3 trillion cubic feet in the EVA forecast (again, DB is excluded from this comparison). The *AEO2005* reference case is more conservative than most of the forecasts for LNG imports: GII, EVA, and SEER all project higher levels of LNG imports in 2025 than are projected in the *AEO2005* reference case.

Wellhead natural gas price projections for 2025 in the *AEO2005* reference case are higher than those in all the other available forecasts, with the exception of Altos. Wellhead natural gas prices in the EEA and PIRA forecasts exceed those in the *AEO2005* reference case in 2015. Of the three forecasts that project

Table 36. Comparison of natural gas forecasts, 2015 and 2025 (trillion cubic feet, except where noted)

Projection	2003	AEO2005 reference case	Other forecasts						
			GII[a]	EEA[b]	EVA	PIRA	DB	SEER	Altos
		2015							
Lower 48 wellhead price (2003 dollars per thousand cubic feet)	**4.98**	**4.16**	**3.84**	**4.69**	**3.71**	**5.14c**	**3.66**	**3.90**	**3.92**
Dry gas production [d]	**19.07**	**20.77**	**19.28**	**21.39 [e]**	**20.22 [f]**	**17.34**	**21.24**	**20.24**	**22.48**
Net imports	**3.30**	**7.02**	**6.94**	**7.97**	**9.82**	**9.77**	**3.76**	**6.98**	**5.78**
Pipeline	2.86	2.69	1.63	2.94	4.64	4.66	2.75 [g]	2.71	1.15
LNG [h]	0.44	4.33	5.31	5.03	5.18	5.11	1.01 i	4.26	4.63
Consumption	**21.97**	**27.96**	**26.29**	**28.87**	**29.72**	**27.22**	**24.99**	**27.21**	**NA**
Residential	5.10	5.74	5.40	5.75	5.52	5.39	5.71	5.57	NA
Commercial	3.14	3.58	3.24	3.56	3.68	3.56	3.65	3.58	NA
Industrial [j]	7.03	8.26	7.67 [k]	7.73 [l]	8.00 [m]	6.30 [n]	7.90	8.09	NA
Electricity generators [o]	4.93	8.39	8.01 [p]	9.59 [q]	10.24	9.88 [r]	5.93	7.81	NA
Other [s]	1.77	1.99	1.96	2.23	2.28 [t]	2.09	1.81	2.17	NA
End-use prices (2003 dollars per thousand cubic feet)									
Residential	9.62	8.45	8.36	8.29	NA	NA	NA	8.89	NA
Commercial	8.32	7.54	7.22	7.50	NA	NA	NA	7.63	NA
Industrial [j]	5.72	4.96	5.15 [u]	5.79	NA	NA	NA	5.25	NA
Electricity generators [o]	5.55	4.90	4.21	5.49	NA	NA	NA	4.77	NA
		2025							
Lower 48 wellhead price (2003 dollars per thousand cubic feet)	**4.98**	**4.79**	**3.96**	**NA**	**3.98**	**NA**	**3.66**	**4.26**	**5.78**
Dry gas production [d]	**19.07**	**21.83**	**20.43**	**NA**	**21.51 [f]**	**NA**	**18.84**	**21.99**	**24.10**
Net imports	**3.30**	**8.66**	**8.49**	**NA**	**12.01**	**NA**	**8.19**	**7.84**	**5.15**
Pipeline	2.86	2.29	0.97	NA	3.72	NA	4.75 [g]	1.31	0.51
LNG [h]	0.44	6.37	7.52	NA	8.29	NA	3.44 [i]	6.53	4.64
Consumption	**21.97**	**30.67**	**29.00**	**NA**	**33.58**	**NA**	**27.03**	**29.83**	**NA**
Residential	5.10	5.99	5.87	NA	5.88	NA	6.30	5.88	NA
Commercial	3.14	4.05	3.52	NA	4.07	NA	4.13	4.04	NA
Industrial [j]	7.03	9.00	8.06 [k]	NA	8.96 [m]	NA	8.72	8.95	NA
Electricity generators [o]	4.93	9.43	9.42 [p]	NA	12.10	NA	6.23	8.60	NA
Other [s]	1.77	2.20	2.13	NA	2.57 [t]	NA	1.64	2.35	NA
End-use prices (2003 dollars per thousand cubic feet)									
Residential	9.62	9.33	8.34	NA	NA	NA	NA	9.48	NA
Commercial	8.32	8.19	7.22	NA	NA	NA	NA	7.99	NA
Industrial [j]	5.72	5.63	5.22 [u]	NA	NA	NA	NA	5.61	NA
Electricity generators [o]	5.55	5.55	4.31	NA	NA	NA	NA	5.13	NA

NA = not available.

[a]Summer 2004 (previously DRI-WEFA). Conversion factors: 1,000 cubic feet = 1.027 million Btu for production, 1.028 million Btu for end-use consumption, 1.019 million Btu for electric power. [b]The EEA projection shows a cyclical price trend; forecast values for an isolated year may be misleading. [c]Henry Hub daily cash natural gas price in 2003 dollars per thousand cubic feet. [d]Does not include supplemental fuels. [e]Includes Alaska production. [f]Wet natural gas production. [g]Includes net pipeline imports from Mexico, Canada, and the Bahamas. [h]Includes LNG imports into Florida via the Bahamas. [i]Includes net LNG imports into the United States only. [j]Includes consumption for combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public; excludes consumption by nonutility generators. [k]Excludes gas used in cogeneration or other nonutility generation. [l]Includes natural gas consumed in cogeneration. [m]Includes transportation fuel consumed in natural gas vehicles. [n]Excludes gas demand for nonutility generation. [o]Includes consumption of energy by electricity-only and CHP plants; includes small power producers and exempt wholesale generators. [p]Includes gas used in cogeneration or other nonutility generation. [q]Includes independent power producers and excludes cogenerators. [r]Equals the sum of gas demand for nonutility generation plus gas demand for utility generation. [s]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [t]Includes lease, plant, and pipeline fuel. [u]On-system sales or system gas (i.e., does not include gas delivered for the account of others).

Sources: **2003 and *AEO2005*:** AEO2005 National Energy Modeling System, run AEO2005.D102004A (reference case). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2004). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **PIRA:** PIRA Energy Group (October 2004). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 11, 2004. **Altos:** Altos North American Regional Gas Model (NARG) Base Case (September 2004).

end-use prices for 2025 (*AEO2005*, GII, and SEER), SEER shows the highest end-use-to-wellhead margins for the electric power sector, and the *AEO2005* reference case shows the lowest end-use-to-wellhead margins for the industrial sector. For the residential and commercial sectors, the projected margins in the *AEO2005* reference case fall between GII on the low end and SEER on the high end of the available forecasts. Industrial sector margins are notably lower in the *AEO2005* reference case than in the other forecasts, and electric power sector margins are notably lower in the GII forecast (where some of the differences may reflect definitional variations) than in the other forecasts.

Petroleum

The *AEO2005* projections for petroleum can be compared with forecasts from DB, GII, EVA, and PIRA. The basis of comparison varies, depending on the coverage of the other forecasts. The *AEO2005* projections for petroleum product demand, domestic production of crude oil and natural gas liquids, and imports of crude oil and petroleum products through 2025 are compared with the DB and GII forecasts in Table 37, which also shows comparisons with the EVA forecast for total U.S. imports of crude oil and petroleum products through 2025 and with the PIRA forecast through 2015.

Consistent with expected economic growth, rising demand for petroleum products is a feature of all the forecasts. DB, GII, and the *AEO2005* reference case expect total product demand in 2025 to be about 40 percent higher than in 2003. DB and GII, however, project a different slate of products. Both expect gasoline and distillate demand in 2025 that is several hundred thousand barrels per day below the *AEO2005* reference case levels. GII's projected distillate demand is 710,000 barrels per day lower in 2025 than the *AEO2005* reference case, and gasoline demand is 410,000 barrels per day lower in 2025 than the *AEO2005* reference case.

GII's forecast assumes that light and heavy vehicles will travel fewer miles in 2025 than assumed in the *AEO2005* reference case. Light vehicles use primarily gasoline, and heavy vehicles use primarily distillate. For air travel, GII assumes stronger growth than *AEO2005,* and the GII projection of jet fuel demand is 460,000 barrels per day higher than the *AEO2005* reference case in 2025. GII projects that "other" petroleum product demand will be about 730,000 barrels per day higher than shown in the *AEO2005* reference case in 2025, due mostly to higher industrial consumption of petroleum. DB's jet fuel projection for 2025 is slightly below the *AEO2005* reference case, but its "other" petroleum product projection is 880,000 barrels per day higher.

PIRA's forecast is the only one that envisions a reversal of gasoline demand growth in the future. In 2015, PIRA projects gasoline demand that is 380,000 barrels per day lower than its projection for 2010. The PIRA projections of gasoline demand and total petroleum product demand in 2015 are the lowest of all the forecasts, at 1.89 and 1.55 million barrels per day below the respective *AEO2005* reference case projections. Diesel displaces gasoline between 2010 and 2015 in PIRA's forecast, which also assumes somewhat less highway travel than does the *AEO2005* reference case. Jet fuel demand in 2015 is slightly higher in the PIRA forecast, and "other" petroleum product demand is 820,000 barrels per day higher than projected in the *AEO2005* reference case.

In all the forecasts, imports are needed to meet more than one-half of U.S. petroleum demand, and the import share of total demand is projected to increase. In 2003, 56 percent of demand was met by imports, and that share is projected to rise to 68 percent in 2025 in *AEO2005*. DB is less optimistic about domestic oil and gas production. In 2025, DB projects that crude oil production will be 710,000 barrels per day lower and natural gas liquids 760,000 barrels per day lower than projected in the *AEO2005* reference case. With DB's total petroleum demand projection about the same as that in the *AEO2005* reference case, the fraction of demand projected to be met by imports in 2025 is more than 6 percentage points above the *AEO2005* reference case projection.

GII is somewhat more optimistic about domestic crude oil and natural gas liquids production in 2025 than the *AEO2005* reference case. In 2025, GII projects that total crude oil production will be 90,000 barrels per day higher and natural gas liquids production 320,000 barrels per day higher than projected in the *AEO2005* reference case. GII is less optimistic than the *AEO2005* reference case, however, about domestic refinery expansion. Crude oil imports are 3.76 million barrels per day lower in 2025 in the GII forecast, but petroleum product imports are 3.84 million barrels per day higher than in the *AEO2005* reference case. Despite somewhat lower total demand and lower crude imports, GII projects an import share that is 0.9 percentage points higher in 2025 than in the

AEO2005 reference case. The reason is that volume gains from domestic processing of imported crude are counted as domestic production. Substitution of product imports for crude imports therefore increases the import share of product supplied.

PIRA expects the lowest level of crude oil and petroleum product imports in 2015 among the forecasts compared, due in part to relatively low projections of product demand. EVA projects the highest level of crude oil and petroleum product imports among all the forecasts, 2.18 million barrels per day above the *AEO2005* reference case in 2025.

Coal

There is a great deal of uncertainty about the possible enactment of environmental regulations that would affect coal demand in the United States. Various programs that would restrict emissions of mercury, fine particulates ($PM_{2.5}$) and greenhouse gases are being discussed and introduced by the U.S. Environmental Protection Agency and the U.S. Congress. The *AEO2005* reference case does not anticipate when and how new environmental requirements may take effect, whereas the other forecasts may include such assumptions. All the coal forecasts included in Table 38 incorporate the current requirements of the Clean Air Act Amendments of 1990 and the NO_x SIP call that affects 19 eastern and midwestern States over the forecast period. EVA assumes that legislation similar to the Clean Air Interstate Rule and the Clean Air Mercury Rule will be enacted and will include further restrictions on emissions of SO_2, NO_x, and mercury. EVA's forecast also includes a $5 per ton fee on carbon dioxide emissions beginning in 2013. The *AEO2005*, Hill, and GII forecasts do not include mandated reductions in mercury or carbon dioxide emissions.

Table 37. Comparison of petroleum forecasts, 2015 and 2025 (million barrels per day, except where noted)

Projection	2003	AEO2005			Other forecasts			
		Reference	Low world oil price	High world oil price	GII	DB	EVA	PIRA
				2015				
Crude oil and NGL production	**7.41**	**7.46**	**7.32**	**7.83**	**7.41**	**6.51**	**NA**	**NA**
Crude oil	5.69	5.49	5.37	5.81	5.17	4.91	NA	5.05
Natural gas liquids	1.72	1.96	1.95	2.02	2.24	1.61	NA	NA
Total net imports	**11.24**	**15.40**	**16.19**	**14.10**	**15.18**	**16.17**	**17.70**	**14.68**
Crude oil	9.65	13.28	13.73	12.74	11.07	NA	NA	NA
Petroleum products	1.58	2.12	2.45	1.36	4.11	NA	NA	NA
Petroleum demand	**20.00**	**24.67**	**25.25**	**23.95**	**24.19**	**24.34**	**NA**	**23.12**
Motor gasoline	8.93	11.17	11.38	10.76	10.98	10.86	NA	9.28
Jet fuel	1.57	2.15	2.16	2.13	2.23	1.96	NA	2.20
Distillate fuel	3.95	5.07	5.25	4.95	4.62	4.79	NA	4.72
Residual fuel	0.77	0.85	0.96	0.79	0.63	0.87	NA	0.68
Other	4.77	5.42	5.50	5.32	3.42	5.85	NA	6.24
Import share of product supplied (percent)	**56.2**	**62.4**	**64.1**	**58.9**	**64.3**	**66.5**	**NA**	**64.0**
				2025				
Crude oil and NGL production	**7.41**	**6.77**	**6.45**	**7.30**	**7.19**	**5.30**	**NA**	**NA**
Crude oil	5.69	4.73	4.46	5.18	4.82	4.02	NA	NA
Natural gas liquids	1.72	2.04	1.99	2.12	2.36	1.28	NA	NA
Total net imports	**11.24**	**19.11**	**21.19**	**16.48**	**19.19**	**20.83**	**21.29**	**NA**
Crude oil	9.65	16.11	16.63	14.83	12.35	NA	NA	NA
Petroleum products	1.58	3.00	4.55	1.65	6.84	NA	NA	NA
Petroleum demand	**20.00**	**27.93**	**29.55**	**26.85**	**27.71**	**27.92**	**NA**	**NA**
Motor gasoline	8.93	12.89	13.37	12.33	12.48	12.30	NA	NA
Jet fuel	1.57	2.36	2.46	2.34	2.82	2.30	NA	NA
Distillate fuel	3.95	5.81	6.68	5.63	5.10	5.51	NA	NA
Residual fuel	0.77	0.88	1.03	0.79	0.60	0.96	NA	NA
Other	4.77	5.98	6.01	5.76	6.71	6.86	NA	NA
Import share of product supplied (percent)	**56.2**	**68.4**	**71.7**	**63.1**	**69.3**	**74.6**	**NA**	**NA**

NA = Not available.

Sources: ***AEO2005:*** AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LW2005.D102004A (low world oil price case), and HW2005.D102004A (high world oil price case). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski, November 11, 2004. **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **PIRA:** PIRA Energy Group (October 2004).

Table 38. Comparison of coal forecasts, 2015, 2020, and 2025 (million short tons, except where noted)

Projection	2003	AEO2005			Other forecasts		
		Reference	Low economic growth	High economic growth	EVA	Hill	GII
		2015					
Production	1,083	1,270	1,249	1,294	1,150	1,239 [a]	1,189
Consumption by sector							
Electricity generation	1,004	1,185	1,166	1,208	1,082	1,173	1,100
Coking plants	24	18	17	18	21	23	20
Industrial/other	62	71	69	72	60	62	68
Total	1,095	1,273	1,252	1,297	1,163	1,258	1,188
Net coal exports	18.0	-2.8	-2.8	-2.8	-20.6	-19.0	-1.6
Exports	43.0	34.9	34.9	34.9	24.7	25.0	29.1
Imports	25.0	37.7	37.7	37.7	45.3	44.0	30.7
Minemouth price							
(2003 dollars per short ton)	17.93	16.89	16.62	17.10	19.35 [b]	17.28 [c,d]	NA
(2003 dollars per million Btu)	0.86	0.84	0.83	0.85	0.94 [b]	0.84 [c,d]	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	24.42	24.07	24.76	27.26 [b]	26.89 [d]	24.62 [e]
(2003 dollars per million Btu)	1.28	1.23	1.22	1.25	1.36 [b]	1.31 [d]	1.19
		2020					
Production	1,083	1,345	1,295	1,397	1,231	1,285 [a]	1,287
Consumption by sector							
Electricity generation	1,004	1,267	1,219	1,317	1,174	1,233	1,204
Coking plants	24	15	15	15	20	22	18
Industrial/other	62	71	69	73	58	59	68
Total	1,095	1,352	1,303	1,405	1,252	1,314	1,290
Net coal exports	18.0	-6.6	-6.6	-7.2	-28.3	-29.0	-6.0
Exports	43.0	35.2	35.2	34.5	26.0	22.0	25.8
Imports	25.0	41.7	41.7	41.7	54.3	51.0	31.8
Minemouth price							
(2003 dollars per short ton)	17.93	17.25	16.79	17.89	19.38 [b]	17.85 [c,d]	NA
(2003 dollars per million Btu)	0.86	0.86	0.83	0.89	0.95 [b]	0.87 [c,d]	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	24.66	24.00	25.41	27.46 [b]	28.14 [d]	23.70 [e]
(2003 dollars per million Btu)	1.28	1.25	1.21	1.28	1.38 [b]	1.37 [d]	1.15
		2025					
Production	1,083	1,488	1,373	1,597	1,328	NA	1,365
Consumption by sector							
Electricity generation	1,004	1,425	1,312	1,531	1,284	NA	1,288
Coking plants	24	13	13	13	18	NA	16
Industrial/other	62	71	68	73	55	NA	68
Total	1,095	1,508	1,393	1,617	1,357	NA	1,372
Net coal exports	18.0	-19.6	-18.8	-19.6	-36.9	NA	-9.2
Exports	43.0	26.1	26.9	26.1	27.4	NA	23.7
Imports	25.0	45.7	45.7	45.7	64.3	NA	32.9
Minemouth price							
(2003 dollars per short ton)	17.93	18.26	17.11	19.78	19.60 [b]	NA	NA
(2003 dollars per million Btu)	0.86	0.91	0.85	0.98	0.97 [b]	NA	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	25.95	24.46	27.76	27.75 [b]	NA	22.85 [e]
(2003 dollars per million Btu)	1.28	1.31	1.24	1.39	1.39 [b]	NA	1.10

[a]Coal production in the Hill & Associates forecast was estimated as total coal consumption minus imports plus exports.
[b]The average coal price is a weighted average of the projected spot market FOB mine price for all domestic coal.
[c]The minemouth price represents an average for domestic steam coal only. Exports and coking coal are not included in the average.
[d]The prices provided by Hill & Associates were converted from 2004 dollars to 2003 dollars in order to be consistent with *AEO2005*.
[e]Estimated by multiplying the delivered price of coal in dollars per million Btu by the average heat content of coal delivered to electricity generators in million Btu per short ton.

Btu = British thermal unit. NA = Not available.

Sources: ***AEO2005*:** AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LM2005.D102004A (low economic growth case), and HM2005.D102004A (high economic growth case). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **Hill:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2022* (August 2004). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **PIRA:** PIRA Energy Group (October 2004).

Given the more restrictive assumptions of the EVA forecast, it is not surprising that the *AEO2005* reference case and Hill forecasts project significantly higher levels of coal consumption than EVA. While GII projects total coal consumption levels that are the most similar to EVA's in 2025, its projection of industrial consumption over the forecast is similar to that in *AEO2005*. The *AEO2005* reference case projects higher coal consumption levels than Hill (by about 3 percent in 2020) and EVA (by about 10 percent in 2025). All four forecasts show significant increases in coal consumption over the forecast period.

Both *AEO2005* and Hill project a decline in real minemouth coal prices from 2003 to 2015 but expect growth in real prices thereafter. EVA forecasts an 8-percent price increase (based on short tons) between 2003 and 2015 and an additional small increase between 2015 and 2025. The EVA forecast includes lower coal consumption and higher minemouth coal prices over all periods than either the *AEO2005* reference case or the Hill forecast.

As western coal production makes further inroads into markets traditionally served by eastern coal, the average heat content of the coals produced and consumed will drop as well, reflecting the lower thermal content per ton of western coals. The *AEO2005* reference case and EVA forecasts indicate similar average heat content (calculated by dividing dollars per ton by dollars per million Btu). The average heat content of coal production in the *AEO2005* reference case, EVA, and Hill forecasts is roughly 20.1 to 20.6 million Btu per ton in 2015, 2020, and 2025, compared with the 2003 base level of 20.9 million Btu per ton. The forecast similarities suggest that comparable shares of western production are included in the three projections.

Gross exports of coal represent a small and declining part of domestic coal production. In the *AEO2005* reference case, the share of total production that is exported is projected to fall from 4 percent in 2003 to roughly 2 percent in 2025. Currently, coal is the only domestic energy resource for which exports still exceed imports. All the forecasts project that the United States eventually will import more coal than it exports. GII projects the lowest level of coal imports, only 8 million tons more in 2025 than in 2003. Both EVA and Hill project a faster rate of increase in net coal imports, with 19 to 21 million tons more coal imported than exported in 2015. EVA projects net coal imports in 2025 equal to almost twice the tonnage projected in the *AEO2005* reference case (37 million and 20 million tons, respectively). Strong price competition from other exporters and the loss of markets as Europe moves away from coal for environmental reasons are among the causes for the long-term decline in U.S. exports. The coal forecasts reflect the uncertainties facing the U.S. coal industry as it simultaneously adapts to pressures arising from increasing regulatory restrictions on coal production, domestic and international environmental regulations, restructuring of the U.S. electricity generation industry, and increasing competition from the relatively undeveloped coalfields of international competitors.

List of Acronyms

AD	Associated-dissolved (natural gas)
AEO2004	*Annual Energy Outlook 2004*
AEO2005	*Annual Energy Outlook 2005*
Altos	Altos Partners
AMT	Alternative Minimum Tax
ANWR	Arctic National Wildlife Refuge
Btu	British thermal unit
CAFE	Corporate average fuel economy
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBECS	Commercial Buildings Energy Consumption Survey (EIA)
CBO	Congressional Budget Office
CCCC	Climate Change Credit Corporation
CH_4	Methane
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DB	Deutsche Bank, A.G.
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
EVA	Energy Ventures Analysis, Incorporated
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FSU	Former Soviet Union
GDP	Gross domestic product
GII	Global Insight, Incorporated
GTL	Gas-to-liquids
HAPs	Hazardous air pollutants
Hill	Hill & Associates
IRAC	U.S. average refiner's acquisition cost of imported crude oil
ITC	Investment Tax Credit
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MACT	Maximum Achievable Control Technology
mpg	Miles per gallon
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
N_2O	Nitrous oxide
NA	Nonassociated (natural gas)
NAAQS	1997 National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NBP	NO_x budget program (Connecticut)
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxides
NPR-A	National Petroleum Reserve-Alaska
NRC	U.S. Nuclear Regulatory Commission
NRLM	Nonroad locomotive and marine diesel fuel
NYMEX	New York Mercantile Exchange
OEF	Oxford Economic Forecasting
OMB	Office of Management and Budget
OPEC	Organization of Petroleum Exporting Countries
pCAIR	Proposed Clean Air Interstate Rule
PECO	Pennsylvania Electric Company
PEL	Petroleum Economics, Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
PTC	Renewable energy production tax credit
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Solar photovoltaics
RFG	Reformulated gasoline
RPS	Renewable portfolio standard
SAGE	System for Analysis of Global Energy Markets (EIA)
SCR	Selective catalytic reduction
SEER	Seasonal energy efficiency ratio
SEER	Strategic Energy & Economic Research, Incorporated
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SUV	Sport utility vehicle
TVA	Tennessee Valley Authority
ULSD	Ultra-low-sulfur diesel fuel
VEETC	Volumetric Ethanol Excise Tax Credit
WTI	West Texas Intermediate crude oil

Notes and Sources

Text Notes

Overview

[*1*] The projections in *AEO2005* are based on Federal and State laws and regulations in effect on October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Legislation and Regulations

[*2*] The SEER is a measure of cooling performance that is used to rate the efficiency of central air conditioners and heat pumps. It is defined as the ratio of cooling output (in Btu) to total electric energy input (in watthours) during normal annual usage.

[*3*] National Resources Defense Council v. Abraham, U.S. Court of Appeals, 2nd District.

[*4*] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters," 40 CFR Part 63 (February 26, 2004), web site www.epa.gov/ttn/atw/boiler/ria-final.pdf.

[*5*] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Industrial Boilers and Process Heaters NESHAP*, EPA-452/R-04-002 (Washington, DC, February 2004), web site www.epa.gov/ttn/atw/boiler/ria-final.pdf.

[*6*] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel: Final Rule," 40 CFR Parts 9, 69, et al. (May 11, 2004).

[*7*] Tier 4 refers to the fourth set of emissions standards applying to nonroad diesel emissions. The standards do not apply to locomotive and marine applications, which are covered by separate EPA regulations.

[*8*] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution From New Locomotive Engines and New Marine Compression Ignition Engines Less Than 30 Liters per Cylinder: Proposed Rule," 40 CFR Parts 92 and 94 (June 29, 2004).

[*9*] U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Summary*, EPA-420-F-04-029 (Washington, DC, May 2004), web site www. epa.gov/otaq/regs/nonroad/equip-hd/2004fr/420f04029.htm.

[*10*] The EPA has designated seven regional Credit Trading Areas (CTAs) in the United States, organized along State lines. See web site www.npradc.org/issues/fuels/pdf/diesel_summary.pdf.

[*11*] Transmix is the mixture in a pipeline at the interface between adjoining batches of petroleum product with dissimilar physical characteristics, which cannot be absorbed into adjoining batches.

[*12*] U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Rule Facts and Figures*, EPA-420-F-04-037 (Washington, DC, May 2004), web site www.epa.gov/nonroad-diesel/2004fr/420f04037.htm.

[*13*] This section describes the bill known as PL 108-357 (H.R. 4520), "American Jobs Creation Act of 2004." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid= f:h4520enr.txt.pdf.

[*14*] Carry-back refers to the practice of using a credit from taxable income for a prior tax period. Carry-forward refers to using a credit in a future taxable period.

[*15*] The reference price for a taxable year is the price in the calendar year preceding the claendar year in which the taxable year begins. This price is determined as: (a) in the case of qualified crude oil production, the Secretary of the Treasury's estimate of the average annual wellhead price per barrel for all domestic crude oil (the price of which is not subject to regulation by the United States), and (b) in the case of qualified natural gas production, the Secretary of the Treasury's estimate of the average annual wellhead price per 1,000 cubic feet for all domestic natural gas.

[*16*] Extension of the in-service date for wind, closed-loop biomass, and poultry litter through 2005 was also part of the Working Families Tax Relief Act of 2004.

[*17*] Transmix is the mixture in a pipeline at the interface between adjoining batches of petroleum product with dissimilar physical characteristics, which cannot be absorbed into adjoining batches.

[*18*] This section describes the bill known as P.L. 108-311 (H.R. 1308), "Working Families Tax Relief Act of 2004." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_public_ laws&docid=f:publ311.108.pdf.

[*19*] This section describes the bill known as P.L. 108-324 (H.R. 4837), "Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_ cong_public_laws&docid=f:publ324.108.pdf.

[*20*] Connecticut Department of Environmental Protection, "Regulations of Connecticut State Agencies (RCSA)," Title 22a, Section 22a-174-1 to 22a-174-200, "Abatement of Air Pollution," web site www.dep.state.ct.us/air2/regs/mainregs.htm.

[*21*] State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), "Comparison of State Multi-Pollutant Strategies for Power Plants" (April 2003).

[*22*] Northeast States for Coordinated Air Use Management, "Mercury Emissions from Coal-Fired Power Plants —The Case for Regulatory Action" (October 2003), web site www.nescaum.org.

[*23*] State of Maine, "An Act to Provide Leadership in Addressing the Threat of Climate Change," Chapter 237, H.P. 622—L.D. 845, Session Laws of the State of Maine, 121st Legislature (Approved May 21, 2003), web site http://janus. state.me.us/legis.

[*24*] Maine Greenhouse Gas Initiative, web site http://maineghg.raabassociates.org.

[*25*] Massachusetts Department of Environmental Protection, "Regulations and Notices," web site www.mass.gov/dep/bwp/daqc/daqcpubs.htm#regs.

[*26*] Massachusetts Department of Environmental Protection, "Emission Control Plans," web site www.mass.gov/dep/bwp/daqc/daqcpubs.htm#ecp.

[*27*] Web site www.mass.gov/ocd/climate.html.

[28] Massachusetts Department of Environmental Protection, web sites www.mass.gov/dep/bwp/hgres.htm and www.mass.gov/dep/bwp/daqc/daqcpubs.htm#regs.

[29] "Air Quality Standards, Definitions, Sampling and Reference Methods and Air Pollution Control Regulations for the Entire State of Missouri," Chapter 6, web site www.sos.mo.gov/ adrules/csr/current/10csr/10csr.asp.

[30] State of New Hampshire, New Hampshire Code of Administrative Rules, "Multiple Pollutant and Annual Budget Trading and Banking Program," Chapter Env-A2900, web site www.des.state.nh.us/rules/air.htm.

[31] B.G. Rabe, "Greenhouse and Statehouse: The Evolving State Government Role in Climate Change" (Pew Center on Global Climate Change, November 2002), web site www.pewclimate.org.

[32] State of New York, Department of Environmental Conservation, "Acid Deposition Reduction Budget Trading Programs," web site www.dec.state.ny.us/website/dar/adopted.html.

[33] State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), "Comparison of State Multi-Pollutant Strategies for Power Plants" (April 2003).

[34] North Carolina Department of Environment and Natural Resources, *Implementation of the "Clean Smokestacks Act"* (May 30, 2003), web site http://daq.state.nc.us/news/leg/.

[35] North Carolina Department of Environment and Natural Resources, *Mercury Clean Smokestacks Act Second Interim Report* (September 2004), web site http://daq.state.nc.us/news/leg/.

[36] North Carolina Department of Environment and Natural Resources, *CO_2 Clean Smokestacks Act, Second Interim Report* (September 2004), web site http://daq.state.nc.us/news/leg/.

[37] North Carolina Department of Environment and Natural Resources, web site http://daq.state.nc.us/news/leg/.

[38] State of Oregon, Oregon Administrative Rules, Chapter 345, Division 24, "Specific Standards for Siting Non-Nuclear Facilities and Related or Supporting Facilities," web site http://arcweb.sos.state.or.us/banners/rules.htm.

[39] Energy Information Administration, "State Electricity Profiles for Oregon, 2002," web site www.eia.doe.gov/emeu/states/main_or.html.

[40] S. Sadler, "Oregon Carbon Dioxide Emission Standards for New Energy Facilities," Oregon Office of Energy, Oregon Energy Facility Siting Council, Rule Division 24, OAR 345-024-0500 (1997), web sites www.energy.state.or.us and www.climatetrust.org.

[41] Assuming a plant heat rate of 10,000 Btu per kilowatthour and a CO_2 emission factor of 25.50 kg carbon per million Btu.

[42] Texas Natural Resource Conservation Commission, web site www.tnrcc.state.tx.us/permitting/airperm/grandfathered.

[43] Web sites http://www1.leg.wa.gov/legislature and www.efsec.wa.gov.

[44] On December 7, 2004, the Alliance of Automobile Manufacturers and several California auto dealerships filed suit in the U.S. District Court in Fresno, California, against A.B. 1493.

[45] Conversion methodology assumes 70.22 kilograms of carbon dioxide per million Btu of gasoline and 125,000 Btu per gallon of gasoline, which equates to 8.78 kilograms of carbon dioxide per gallon of gasoline.

[46] The Clean Air Act allows States to opt out of Federal light-duty vehicle exhaust emissions standard requirements if they choose to adopt California's standards. Connecticut, New Jersey, and Rhode Island have also passed legislation adopting California's light vehicle emissions standards, excluding the new greenhouse gas emission standards. The California Low Emission Vehicle Program (LEVP) requires more stringent criteria emission standards and minimum sales requirements for zero-emission vehicles, which include hybrid, electric, and fuel cell vehicles. Because these States were not expected to adopt the California light vehicle greenhouse gas emission standards, the associated light vehicle fuel economy impact from the sales of zero-emission vehicles due to their opting into the California LEVP are not represented in the *AEO2005* reference case and, therefore, were not included in the A.B. 1493 sensitivity cases.

[47] California Environmental Protection Agency Air Resources Board, *Addendum Presenting And Describing Revisions To: Initial Statement of Reasons For Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (September 10, 2004), p. 1, web site www.arb.ca.gov/regact/grnhsgas/addendum.pdf.

[48] California Environmental Protection Agency Air Resources Board, *Addendum Presenting And Describing Revisions To: Initial Statement of Reasons For Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (September 10, 2004), Table 8.2-1, p. 17, web site www.arb.ca.gov/regact/grnhsgas/addendum.pdf.

[49] Percentages derived from EMFAC model runs (April 23, 2002) provided by Jonathan Taylor, California Air Resources Board (December 20, 2004).

[50] The NEMS model does not capture State-specific sales, stocks, or vehicle miles traveled. The impact of the fuel economy equivalent standards were modeled nationally and applied regionally in subsequent runs based on State-specific distributions of light vehicle energy use and travel.

[51] Analysis of the National Highway Traffic Safety Administration model year 2001 CAFE data indicated that 12.3 percent of new light trucks sold (trucks less than 8,500 pounds gross vehicle weight) have a loaded vehicle weight less than 3,750 pounds.

[52] The EMFAC model was used to develop the baseline CO_2 equivalent emissions in the CARB analysis. Reductions were estimated on the basis of a NESCCAF model and applied to the EMFAC baseline.

[53] Census Division 9 includes the following States: Alaska, California, Hawaii, Oregon, and Washington.

[54] Census Division 1 includes the following States: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Census Division 2 includes the following States: New Jersey, New York, and Pennsylvania.

[55] Energy Information Administration, *Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003*, SR/OIAF/2004-05 (Washington, DC, May 2005),

web site www.eia. doe.gov/oiaf/servicerpt/csa/pdf/sroiaf(2004)05.pdf.

[*56*] U.S. Environmental Protection Agency, "Interstate Air Quality Rule," web site www.epa.gov/interstateairquality.

[*57*]*Federal Register*, Vol. 69, No. 20, 40 CFR parts 51, 72, 75, and 96 (January 30, 2004).

[*58*] *Federal Register*, Vol. 69, No. 112, 40 CFR Parts 51, 72, 73, 74, 77, 78, and 96 (June 10, 2004).

[*59*] U.S. Environmental Protection Agency, "Utility Mercury Reductions Rule," web site www.epa.gov/air/mercuryrule.

[*60*] *Federal Register*, Vol. 69, No. 20, 40 CFR Parts 60 and 63 (January 30, 2004).

[*61*] *Federal Register*, Vol. 69, No. 51, 40 CFR Parts 60, 72, and 75 (March 16, 2004).

[*62*] Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003), Table 8.2a, p. 224.

[*63*] The bill covers emissions of the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (NO_x), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[*64*] This section describes the provisions proposed in S.A. 3546 and H.R. 4067, both titled the Climate Stewardship Act of 2004. For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills& docid=f:h4067ih.txt.pdf.

[*65*]The commercial sector includes government entities.

[*66*] In the definition of a covered entity, the clarification that the 10,000 metric ton threshold applies to emissions "from any single facility owned by the entity" was not present in the original version of the bill (S. 139). Because few commercial facilities would have emissions above the threshold, most entities in the commercial sector would be exempt. Addition of the "single facility" restriction clears up a key uncertainty in the definition of a "covered entity" in S. 139. The most recent bill also requires that all of a covered entity's emissions be subject to allowance requirements—not just the emissions from facilities that exceed the threshold. This interpretation suggests a possible avoidance strategy: an entity might design, organize, and operate its facilities to ensure that no single facility's emissions exceeded the threshold.

[*67*] The bill allows each covered entity to obtain 15 percent of its emission allowances from alternative compliance sources, including purchase of allowances from certified reduction or sequestration programs, both domestically and abroad. As an incentive for early action, entities reducing their emissions below 1990 levels by 2010 may be granted a limit of 20 percent of their target reductions from alternative compliance sources from 2010 to 2016.

[*68*] Covered entities would be required to submit allowances for their covered emissions or, to a limited extent, offsetting emission reduction credits from noncovered entities. Therefore, the covered emissions, less any offset credits, would be subject to the allowance cap.

[*69*] This provision would require the entity to show that a specific capital project is underway to reduce emissions and to return any allowances borrowed, at an effective interest rate of 10 percent per year. In addition, borrowed allowances would count against the limit on alternative compliance offsets. Therefore, in the aggregate, allowance borrowing would likely be minimal.

[*70*] The emissions for 2000 cited in the bill match the levels reported in U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000,* EPA-430-R-02-003 (Washington, DC, April 2002), after adjusting for the residential and agricultural sectors and U.S. territories.

[*71*]Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, SR/OIAF/2003-02 (Washington, DC, June 2003). For the full report, see web site www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf. For a summary, see web site www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf. A followup analysis of the amended (single phase) version of the bill, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, is available at web site www.eia.doe.gov/oiaf/analysispaper/sacsa/index.html.

[*72*] A provision entitled "Dedicated Program for Sequestration in Agricultural Soils" would allow an entity to satisfy up to 1.5 percent of its total allowance submission requirements with registered increases in net carbon sequestration in agricultural soils. Entities would remain subject to an overall limit on offsets of 15 percent, or 20 percent if they met certain early action criteria.

[*73*]Refineries, as industrial entities, would be required to obtain allowance permits for the fuel they burned in refining oil, in addition to allowances for downstream emissions of the transportation fuel they sold. The costs would be passed on to consumers.

Issues in Focus

[*74*] For a description of the SAGE model, see Energy Information Administration, *International Energy Outlook 2004*, DOE/EIA-0484(2004) (Washington, DC, April 2004).

[*75*] For a detailed review of real GDP and oil projections by country and region, see *International Energy Outlook 2004*.

[*76*] A more rigorous determination of income elasticities, which controlled for price changes, was also undertaken. It involved a statistical estimation of the relationship between the projected demand for oil and projected real GDP and world oil prices. The numbers quoted here for income elasticities are similar to those that were statistically estimated.

[*77*] For a recent study and a review of the empirical literature see D. Gately and H.G. Huntington, "The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand," OP50, Energy Modeling Forum (Stanford, CA: Stanford University, August 2001).

[*78*] D. Gately and H.G. Huntington, "The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand," OP50, Energy Modeling Forum (Stanford, CA: Stanford University, August 2001).

[*79*] Cumulative production in a year is obtained by multiplying oil production per day by 365. For oil-producing countries, it is assumed that oil is sold domestically at the same world oil price.

[*80*] G.A. Smook, *Handbook for Pulp and Paper Technologies*, 2nd Edition (Bellingham, WA: Angus Wilde Publications, 1992).

[*81*] American Forest and Paper Association, *Statistics of Paper, Paperboard and Wood Pulp*, 41st Edition (Washington, DC, 2004).

[*82*] American Forest and Paper Association, *Statistics of Paper, Paperboard and Wood Pulp*, 41st Edition (Washington, DC, 2004).

[*83*] Note that the output forecasts were disaggregated into the four components of bulk chemicals in previous *AEO*s. The history and prospects for agricultural chemicals were discussed in *Annual Energy Outlook 2004*.

[*84*] American Chemical Council, *Guide to the Business of Chemistry 2003*, p. 169.

[*85*] For example, PotashCorp, “The PotashCorp Letter” (June 2003).

[*86*] For example, see Celanese AG, “Celanese To Source Methanol from Southern Chemical Company” (press release, July 22, 2003).

[*87*] National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004).

[*88*] National Highway Traffic Safety Administration, *Automotive Fuel Economy Program Annual Update Calendar Year 2002* (Washington, DC, September 2003), Table II-4.

[*89*] U.S. Environmental Protection Agency, *Light-Duty Automotive Technology and Fuel Economy Trends: 1975 Through 2004* (Ann Arbor, MI, April 2004), Table E-3.

[*90*] S.C. Davis and S.W. Diegel, *Transportation Energy Data Book Edition 24*, ORNL-6970 (Oak Ridge, TN: Oak Ridge National Laboratory, October 2003), Table 4.9.

[*91*] “President Announces Clear Skies & Global Climate Change Initiatives” (February 14, 2002), web site www.whitehouse.gov/news/releases/2002/02/20020214-5.html.

[*92*] See the Addendum to the *Global Climate Change Policy Book*, web site www.whitehouse.gov/news/releases/2002/02/climatechange.html. The BAU projections cited in the Addendum are somewhat higher than those in a Policies and Measures case developed by the EPA for the *U.S. Climate Action Report 2002*. EIA has adjusted the Addendum projections to reflect the most recent (2002 and 2003) data on emissions published by EIA, as well as to estimate the intervening years of the projections (the EPA projections were provided for 5-year intervals). In addition, EIA has extrapolated the projections to estimate emissions for 2025.

[*93*] U.S. Department of State, *U.S. Climate Action Report 2002* (Washington, DC, May 2002), Chapter 5, “Projected Greenhouse Gas Emissions,” pp. 70-80, web site http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsUSClimateActionReport.html.

[*94*] U.S. Environmental Protection Agency, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA 30-R-99-013 (Washington, DC, September 1999), web site www.epa.gov/ghginfo/pdfs/07-complete.pdf; and *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* (December 2001), web site www.epa.gov/ghginfo/pdfs/final_addendum2.pdf.

[*95*] U.S. Environmental Protection Agency, *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions,* EPA 000-F-97-000 (Washington, DC, June 2001), web site www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf.

[*96*] U.S. Environmental Protection Agency, *U.S. Adipic Acid and Nitric Acid N_2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (Washington, DC, December 2001), web site www.epa.gov/ghginfo/pdfs/adipic.pdf.

[*97*] A degree-day is defined as the difference between the average daily temperature (in degrees Fahrenheit) and 65. Averages above 65 degrees Fahrenheit count as cooling degree-days, and averages below 65 degrees Fahrenheit count as heating degree-days. For example, if the average temperature on a given day is 40 degrees Fahrenheit, then 25 heating degree-days are counted.

[*98*] The rate was later raised to 15 percent by the Crude Oil Windfall Profits Act of 1980, which extended the credit to December 31, 1985, when it was allowed to lapse for wind.

[*99*] Dollars are expressed in year 2003 values, except as otherwise noted.

[*100*]See IRS Form 8835, “Renewable Electricity Production Credit,” for the year 2003, web site www.irs.gov/pub/irs-pdf/f8835.pdf.

[*101*]Interstate Renewable Energy Council, Database of State Incentives for Renewable Energy, web site www.dsire.org (September 22, 2003). Note: 425 megawatts, the original mandated term in 1994, has been extended to 825 megawatts in 2006 and 1,125 megawatts in 2010.

[*102*]“Tax Relief Extension Act of 1999,” Public Law 106-170.

[*103*]The American Wind Energy Association estimates 1,697 megawatts of installations of all sizes in 2001 (see web site www.awea.org/faq/ instcap.html).

[*104*]“Job Creation and Worker Assistance Act of 2002,” Public Law 107-147.

[*105*]The American Wind Energy Association estimates 1,689 megawatts net capacity growth in 2003 (see web site www.awea.org/faq/instcap.html).

[*106*]Wind power facilities also receive a 5-year accelerated depreciation allowance on Federal income tax.

[*107*]For further discussion of cost and performance improvements, see C. Namovicz, “Modeling Wind and Intermittent Generation in the National Energy Modeling System (NEMS),” in American Wind Energy Association, *WindPower 2003 Conference Proceedings* (2003).

[*108*]Cost includes “busbar” costs plus transmission interconnection charge, but does not include additional grid services that may be required to facilitate integration of wind power. Excellent wind resources refer to sites in wind power Class 6 or better, defined by the Pacific Northwest Laboratory as a site with an annual average wind speed at 50 meter hub height of 8.0 meters per second (17.9 miles per hour) or higher. See D.L. Elliot et al., *Wind Energy Resource Atlas of the United States* (Pacific Northwest Laboratory, March 1987), p. 3.

[*109*]Note that the levelized cost of both natural gas and coal plants depends on expected utilization rates. For comparison purposes, an 85-percent utilization rate is assumed for coal and 87 percent for combined cycle.

Effective utilization rates (capacity factors) for current-technology wind plants range from 33 to 40 percent, depending on quality of the wind resource. The 40-percent capacity factor corresponds to the lowest levelized wind cost.

[*110*]Claiming the PTC precludes these facilities from claiming the 10-percent investment tax credit also available to geothermal and solar plants. Also, the tax credit applies only to generation sold to a non-related party, and thus would not be available to facilities using photovoltaics or other "distributed generation" technology to provide on-site power.

[*111*]For example, leading Danish wind turbine manufacturer Vestas announced in early 2003 plans to build a significant factory in Oregon, but uncertainty over PTC extension was cited as the primary reason for delaying or curtailing the plan. See B. Jacklet, *Portland Tribune* (June 13, 2003), web site www.portlandtribune.com/archview.cgi?id=18698.

[*112*]The distributed generation projections for the residential and commercial sectors currently use an average electricity price in energy savings calculations without specific consideration of the time-of-day or demand-charge rates applicable to some customers. These projections focus only on baseload electricity requirements. However, potential investment decisions involving PV systems do use an "air-conditioning" electricity price in energy savings calculations, since maximum PV generation correlates with the air conditioning season.

[*113*]Distributed generation technologies are assumed to receive the grid's marginal cost of generation—the avoided cost of generation only, without transmission and distribution costs that are included in the retail rate.

[*114*]PV installed costs are per kilowatt of peak capacity and represent grid-connected systems with no battery storage or power backup. Installed costs for all other distributed generation technologies represent grid-connected CHP systems. Installed capital costs for all technologies include costs for equipment, labor and materials, interconnection, project and construction management, engineering and contingency fees.

[*115*]Electrical conversion efficiency for PV is the system efficiency as opposed to solar cell efficiency. For a more detailed description of residential and commercial distributed generation assumptions, including combined electrical and thermal efficiency for CHP systems, see *Assumptions for the Annual Energy Outlook 2005*, web site www.eia.doe.gov/oiaf/aeo/assumption/index.html.

[*116*]For PV and fuel cell technologies, a doubling of cumulative shipments results in an assumed 13-percent reduction in installed capital costs. For microturbines, a doubling results in an assumed 10-percent reduction in costs.

[*117*]ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* (January 2000), p. 17.

[*118*]Absorption chillers use heat instead of an electric motor in the compression phase of the cooling cycle. The waste heat produced during the generation process may be used with an absorption chiller to provide cooling in a CHP system.

[*119*]A discussion of the regulation issues and a database providing basic State-by-State permitting information for distributed generation projects is on the Energy and Environmental Analysis, Inc., web site at www.eea-inc.com/rrdb/DGRegProject/guide.html.

[*120*]The IEEE standard was announced in July 2003. See web site http://standards.ieee.org/announcements/1547idr.html.

[*121*]The types of pollutants responsible for designation as a nonattainment zone vary by region. A list of nonattainment areas is available at web site www.epa.gov/oar/oaqps/greenbk.

[*122*]Distributed generation projections in the buildings sectors are developed at the Census division level to include variation between geographical regions. There are nine Census divisions in the United States. For a map showing the States included in each division, see web site www.eia.doe.gov/geography.html.

[*123*]Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (preliminary).

[*124*]Current tax law includes a 10-percent investment tax credit available to businesses that install a qualifying solar PV system. In addition, commercial PV owners may depreciate their equipment using an accelerated depreciation schedule and a 5-year economic life. The depreciable basis only needs to be reduced by half of the investment tax credit.

[*125*]See Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[*126*]For further information on the California Energy Commission rebate program, see web site www.energy.ca.gov/renewables/emerging_renewables. html. For a discussion of State renewable energy requirements see T. Petersik, "State Renewable Energy Requirements and Goals: Status Through 2003" (July 2004), web site www.eia.doe.gov/oiaf/analysispaper/rps/index.html. For information on renewable energy incentives throughout the United States, see the North Carolina Solar Center's Database of State Incentives for Renewable Energy, web site www.dsireusa.org.

[*127*]The buildings sector technology cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or economic growth.

[*128*]The high technology case assumptions call for PV costs to decline by 17 percent, fuel cell costs to decline by 29 percent, and costs for microturbines to decline by 13 percent with a doubling of cumulative shipments.

Market Trends

[*129*]Energy-intensive industries include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

[*130*]The reference case assumes the Organization of Petroleum Exporting Countries' (OPEC) members will continue to demonstrate a disciplined production approach that reflects a strategy of price defense in which the larger producers are willing to increase or decrease production levels to maintain fairly stable prices (in real dollar terms) to discourage the development of alternative crude oil supplies or energy sources, allow for continued robust worldwide economic growth, and maintain compliance with quotas, particularly for smaller OPEC producers. Under this strategy, prices are assumed to be kept in a range from $27 to $30 per barrel in 2003 dollars, near the high end of the current OPEC price target range. Since OPEC, particularly the Persian Gulf nations, are expected to be the dominant supplier of oil in the international market over the mid-term, the organization's production choices will significantly affect world oil prices. The low oil price scenario could result from a future market where all oil production becomes more competitive. The high A and B price scenarios could result from a more cohesive and market-assertive OPEC with lower production goals and other non-financial (geopolitical) considerations or from the development of a less optimistic oil resource situation than currently expected.

[*131*]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).

[*132*]Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence. Alternative fuels include ethanol, electricity, hydrogen, natural gas, and propane.

[*133*]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.

[*134*]Values for incremental investments and energy expenditure savings are discounted back to 2004 at a 7-percent real discount rate.

[*135*]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco et al., *Technical Options for Improving the Fuel Economy of U.S. Cars and Light Trucks by 2010-2015* (Washington, DC: American Council for an Energy Efficient Economy, April 2001); M.A. Weiss et al., *On the Road in 2020: A Life-Cycle Analysis of New Automotive Technologies* (Cambridge, MA: Massachusetts Institute of Technology, October 2000); A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001); and Energy and Environmental Analysis, Inc., *Documentation of Technologies included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (prepared for Energy Information Administration, September 30, 2002).

[*136*]Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and combined heat and power capacity. The costs reflect the arithmetic average of the regional cost.

[*137*]*AEO2005* does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See *Annual Energy Review 2003*, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[*138*]Avoided cost estimates the incremental cost of fuel and capacity displaced by a unit of the specified resource and more accurately reflects its as-dispatched energy value than comparison to the levelized cost of other individual technologies. It does not reflect system reliability cost nor does it necessarily indicate the lowest cost alternative for meeting system energy and capacity needs.

[*139*]Associated-dissolved natural gas is produced in conjunction with crude oil. Nonassociated gas is produced without crude oil production.

[*140*]Unconventional gas includes tight (low permeability), sandstone gas, shale gas, and coalbed methane.

[*141*]Gas exports from the United States to Mexico continue to exceed imports from Mexico through the end of the projections.

[*142*]Energy Information Administration, *Analysis of Oil and Gas Production in the Arctic National Wildlife Refuge*, SR/OIAF/2004-04 (Washington, DC, March 2004).

[*143*]**Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004). Industrial: EIA, *Industrial Model: Update on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001). **Transportation:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne,

IL: Argonne National Laboratory, 2001). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy. **Renewable generating technologies:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

[*144*]U.S. Environmental Protection Agency, *Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report*, EPA-600/R-01-109, April 2002, Table ES-1, Page ES-10.

Table Notes and Sources

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

Table 1. Total energy supply and disposition in the *AEO2005* reference case: summary, 2002-2025: AEO-2005 National Energy Modeling System, run AEO2005. D102004A. **Notes:** Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Table 2. Impacts of 13 SEER central air conditioner and heat pump standard compared with 12 SEER standard, 2006-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and SEER12.D110204A. **Note:** Future costs and savings (energy bill savings, equipment cost increase, and net present value) are discounted back to 2005 at a 7-percent real discount rate.

Table 3. Final nonroad diesel emissions standards: U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Rule, Exhaust Emission Standards*, EPA-420-F-04-032 (Washington, DC, May 2004), web site www.epa.gov/nonroad-diesel/2004fr/420f04032.htm. **Notes:** For rated engine power 25 to less than 75 horsepower, the 3.5 standard includes both NO_x and nonmethane hydrocarbons. For rated engine power 750 horsepower or more, the 5.0 standard for NO_x applies to generator sets over 1,200 horsepower. For all generator sets, the 0.02 standard for particulate matter applies to generator sets, and the 0.03 standard applies to other engines; the 0.50 standard for NO_x applies to generator sets only.

Table 4. Timeline for implementing nonroad diesel fuel sulfur limits: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** For all standards, the effective date is June 1 of the year indicated. For small refiners in 2014 and after, the NRLM diesel downgrade to 500 ppm is allowed indefinitely; the 15 ppm standard is required at the refinery gate only.

Table 5. Key projections for distillate fuel markets in two cases, 2007-2014: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and AEO2005. NONONROAD.D102704A.

Table 6. Basic features of State renewable energy requirements as of December 31, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** The Minnesota mandate specifies various dates, beginning in 2003. The original requirement for 125 megawatts of biomass capacity has been reduced. For the Minnesota goal, specific characteristics are being determined. See web site www.puc.state.mn.us, Docket 03-869. NS = not specified in the State requirement. NA = not applicable.

Table 7. Estimated capacity contributing to State renewable energy programs through 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** Biomass includes biomass co-firing and cogeneration capacity, but none is known to have been built. In Arizona, a 3-megawatt biomass-fueled plant slated for 2003 entered service in early 2004 and is not shown here. In addition to capacity shown here, the Salt River project added a 4-megawatt landfill gas project under a separate requirement. In California, new capacity that contributes to the State's RPS requirement but was built for other reasons. In Wisconsin, 20 kilowatts of solar capacity was also built. The RPS also spurred biomass co-firing in varying proportions at 79 megawatts of existing fossil-fueled capacity, as well as refurbishment and operation of 7.2 megawatts of existing hydroelectric capacity. Pennsylvania's program has resulted in 10 megawatts of new renewables capacity. In addition, 118 megawatts of new wind capacity in Pennsylvania and 66 megawatts in West Virginia were supported by separate sustainable development funds. Fewer than one-half of the States accept mass-burn municipal solid waste, and specific requirements vary by State. Totals shown in the table may not equal the sum of their components, due to independent rounding.

Table 8. Existing State air emissions legislation with potential impacts on the electricity generation sector: Sources cited in the text.

Table 9. CARB CO_2 equivalent emission standards for light-duty vehicles, model years 2009-2016: California Air Resources Board, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (Sacramento, CA, August 6, 2004).

Table 10. CARB fuel economy equivalent standards for light-duty vehicles, model years 2009-2016: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 11. Comparison of key factors in the CARB and EIA analyses, 2020: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 12. Emissions targets in multi-pollutant legislation: Energy Information Administration, *Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003*, SR/OIAF/2004-05 (Washington, DC, May 2005), web site www.eia.doe.gov/oiaf/servicerpt/csa/pdf/sroiaf(2004)05.pdf. **Notes:** The limits on NO_x emissions under S. 1844 are split between two regions: 1.47 million tons in Zone 1 (the East) in 2008 to 2017 and 0.72 million tons in Zone 2 (the West) from 2008 through 2017; and 1.07 million tons in Zone 1 and 0.72 million tons in Zone 2 in 2018. The 2009 limit on SO_2 emissions under S. 366 is split between

two regions: 0.275 million tons in the West and 1.975 million tons in the other regions. Under S. 366, minimum facility-specific reductions of mercury emissions without trading are required in 2008. Under S. 843, minimum facility-specific reductions of mercury emissions between 50 percent (2009 to 2012) and 70 percent (after 2012) are required. Under S. 366, the 2009 limit on CO_2 emissions from the electricity sector is the estimated 1990 emissions level. Under S. 843, the 2009 to 2012 limit on CO_2 emissions is based on EIA's *AEO2004* projection of 2006 emissions, and the limit for 2013 and subsequent years is based on the estimated 2001 emissions level.

Table 13. Key projections from EIA's 2004 analysis of proposed multi-pollutant control bills, 2025: Energy Information Administration, AEO2004 National Energy Modeling System, runs AEO2004.D101703E, INBASE. D040904A, INCS3PWS.D040904A, INCA4P.D040904A, INCA4PLO.D040904A, and INJF4P.D041604A. **Note:** mercury emissions in 2003 are NEMS estimates, not actual amounts.

Table 14. Historical emissions and proposed future caps for the combination of affected pCAIR States: 2002: U.S. Environmental Protection Agency, web site http://cfpub.epa.gov/gdm. **Future emissions caps:** U.S. Environmental Protection Agency, web site www.epa.gov/interstateair quality/rule.html.

Table 15. Key electricity sector projections from EIA's analysis of proposed pCAIR regulations, 2015 and 2025: 2003 SO_2 allowance price: U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/auctions/2003/03summary.html. **Other 2003 values and projections:** Energy Information Administration, AEO-2005 National Energy Modeling System, runs AEO2005. D102004A and CAIR2005.D010505A. **Note:** Coal-fired capacity retrofits include currently planned and unplanned (projected) FGD and SCR installations.

Table 16. Projected growth in world gross domestic product, oil consumption, and oil intensity in the *AEO2005* reference case, 2003-2025: United States: AEO2005 National Energy Modeling System, run AEO2005.D102004A. **Other countries:** Energy Information Administration, *International Energy Outlook 2004*, DOE/EIA-0484(2004) (Washington, DC, April 2004).

Table 17. Key projections in the reference case, 2003-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 18. Key projections in the high A world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run HW2005.D102004A.

Table 19. Key projections in the high B world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run VHW2005.D010705A.

Table 20. Key projections in the low world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run LW2005.D102004A.

Table 21. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 22. Levelized costs of new conventional and renewable generation in two cases, 2010: AEO2005 National Energy Modeling System, runs AEO2005. D102004A and PTCEXT05.D102904A. **Notes:** Cost "at the busbar," does not include transmission investment or additional costs to accommodate intermittent renewable resources. Costs reflect national averages for best available regional resources; comparative costs within specific regions may differ significantly. Fuel costs are slightly reduced with the PTC, reflecting reduced demand from the electric power sector. It is assumed that PV will continue to take advantage of the higher-value investment tax credit (ITC) rather than the PTC. Avoided costs represent estimates of the incremental cost of fuel and capacity displaced by a unit of the specified resource and more accurately reflect their as-dispatched energy value. They do not reflect system reliability costs, nor do they necessarily indicate the lowest cost alternative for meeting system energy and capacity needs.

Table 23. Renewable electricity capacity and generation in two cases, 2005, 2015, and 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and PTCEXT05.D102904A.

Table 24. Projected installed costs and electrical conversion efficiencies for distributed generation technologies by year and technology, 2004, 2010, 2020, 2025: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2005*, DOE/EIA-0554 (2005) (Washington, DC, February 2005), web site www.eia.doe.gov/oiaf/aeo/assumption/index.html.

Table 25. Buildings sector distributed electricity generation in alternative cases: difference from the reference case in 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, BLDFRZN. D102104A, BLDHIGH.D110404A, LW2005.D102004A, and HW2005.D102004A.

Table 26. New car and light truck horsepower ratings and market shares, 1990-2025: History: U.S. Environmental Protection Agency, Office of Transportation and Air Quality, *Light-Duty Automotive Technology And Fuel Economy Trends: 1975-2003*, EPA-420-S-03-004, April 2003. **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 27. Costs of producing electricity from new plants, 2015 and 2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 28. Technically recoverable U.S. natural gas resources as of January 1, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 29. Crude oil production from Gulf of Mexico offshore, 2003-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 30. Technically recoverable U.S. oil resources as of January 1, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 31. Onshore and offshore lower 48 crude oil production in three cases, 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LW2005. D102004A, and HW2005.D102004A.

Figure Notes and Sources

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

Figure 1. Energy prices, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **compared:** ***AEO2004*** **projections:** Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington, DC, January 2004). ***AEO2005*** **projections:** Table A1.

Figure 2. Delivered energy consumption by sector, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **projections:** Table A2.

Figure 3. Energy consumption by fuel, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **projections:** Tables A1 and A18.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **projections:** Table A20.

Figure 5. Electricity generation by fuel, 1970-2025: History: Energy Information Administration (EIA), Form EIA-860B, "Annual Electric Generator Report—Nonutility", EIA, *Annual Energy Review 2003*, DOE/EIA-0384 (2003) (Washington, DC, September 2004), and Edison Electric Institute. ***AEO2004*** **and** ***AEO2005*** **projections:** Table A8.

Figure 6. Total energy production and consumption, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **projections:** Table A1.

Figure 7. Energy production by fuel, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). ***AEO2004*** **and** ***AEO2005*** **projections:** Tables A1 and A18.

Figure 8. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** Table A19.

Figure 9. Projected electricity prices under proposed multi-pollutant control bills, 2010, 2020, and 2025: Energy Information Administration, AEO2004 National Energy Modeling System, runs AEO2004.D101703E, INBASE.D040904A, INCS3PWS.D040904A, INCA4P.D040904A, INCA4PLO.D040904A, and INJF4P.D041604A.

Figure 10. Projected electricity generation by fuel in two cases, 2025: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A and CAIR2005.D010505A.

Figure 11. Projected coal production by region in two cases, 2025: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A and CAIR2005.D010505A.

Figure 12. World oil prices in the reference, October oil futures, high A, high B, and low oil price cases, 1990-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LW2005.D102004A, HW2005.D102004A, VHW2005.D120304A, and CF2005.D111104A.

Figure 13. OPEC oil production in four world oil price cases, 1990-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LW2005.D102004A, HW2005.D102004A, and VHW2005.D120304A.

Figure 14. Non-OPEC oil production in four world oil price cases, 1990-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LW2005.D102004A, HW2005.D102004A, and VHW2005.D120304A.

Figure 15. Projected growth in output for energy-intensive industries in ***AEO2004*** **and** ***AEO2005*****, 2003-2025:** AEO2004 National Energy Modeling System, run AEO2004.D101703E, and AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 16. Projected growth in energy consumption for the pulp and paper industry in ***AEO2004*** **and** ***AEO2005*****, 2003-2025:** AEO2004 National Energy Modeling System, run AEO2004.D101703E, and AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 17. Projected output growth for components of the bulk chemicals industry in ***AEO2004*** **and** ***AEO2005*****, 2003-2025:** AEO2004 National Energy Modeling System, run AEO2004.D101703E, and AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 18. Projected growth in energy consumption for the bulk chemicals industry by energy source in ***AEO2004*** **and** ***AEO2005*****, 2003-2025:** AEO2004 National Energy Modeling System, run AEO2004.D101703E, and AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 19. Average fuel economy for new light-duty vehicles, 1980-2004: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 20. Projected improvement in U.S. greenhouse gas intensity in three cases, 2002-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LTRKITEN.D111504A, and HTRKITEN.D111604A.

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Figure 51. Efficiency indicators for selected commercial equipment, 2003 and 2025: Navigant Consulting, Inc., "EIA-Technology Forecast Updates—Residential and Commercial Building Technologies—Reference Case," Reference No. 117943 (September 2004), and AEO2005 National Energy Modeling System, run AEO2005.D102004A.

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Figure 57. Transportation stock fuel efficiency by mode, 2003-2025: History: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book Edition 22*, ORNL-6967, Table 12.1 (Oak Ridge, TN, September 2002). For aircraft, Energy Information Administration analysis of Bureau of Transportation Statistics, Office of Airline Information, Schedule T-2 (2003). **Projections:** Table A7.

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Figure 97. Worldwide refining capacity by region, 2003 and 2025: History: *Oil and Gas Journal*, Energy Database (January 2004). **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A; and World Oil, Refining, Logistics, and Demand (WORLD) Model, run AEO05B.

Figure 98. Petroleum consumption by sector, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** Table A11.

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Figure 104. Average minemouth price of coal by region, 1990-2025: 1990-2000: Energy Information Administration (EIA), *Coal Industry Annual*, DOE/EIA- 0584; **2001-2003:** EIA, *Annual Coal Report 2003,* DOE/EIA-0584(2003) (Washington, DC, September 2004), and previous issues. **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 105. U.S. coal mine employment by region, 1970-2025: History: 1970-1976: U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbooks*; **1977-1978:** Energy Information Administration (EIA), *Energy Data Report, Coal-Bituminous and Lignite*, DOE/EIA-0118, and EIA, *Energy Data Report, Coal-Pennsylvania Anthracite*, DOE/EIA-0119; **1979-1992:** EIA, *Coal Production*, DOE/EIA-0118; **1993-2000:** EIA, *Coal Industry Annual*, DOE/EIA-0584; **2001-2002:** EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004) and previous issues. **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Figure 106. U.S. coal exports and imports, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2003,* DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A.

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Figure 108. Electricity and other coal consumption, 1970-2025: History: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and EIA, *Short-Term Energy Outlook October 2004*. **Projections:** Table A16.

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Figure 110. Carbon dioxide emissions by sector and fuel, 2003 and 2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** Table A19.

Figure 111. Carbon dioxide emissions in three economic growth cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** Table B19.

Figure 112. Carbon dioxide emissions in three technology cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** Table E4.

Figure 113. Sulfur dioxide emissions from electricity generation, 1990-2025: History: 1990 and 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA- 454/R-00-002 (Washington, DC, March 2000). **2003:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2003,* web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** Table A8.

Figure 114. Nitrogen oxide emissions from electricity generation, 1990-2025: History: 1990 and 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA- 454/R-00-002 (Washington, DC, March 2000). **2003:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2003*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** Table A8.

Figure 115. Mercury emissions from electricity generation, 1995-2025: History: 1995, 2000, and 2003: Energy Information Administration, Office of Integrated Analysis and Forecasts. **Projections:** Table A8.

Appendixes

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production							
Crude Oil and Lease Condensate	12.15	12.03	12.75	11.63	11.03	10.01	-0.8%
Natural Gas Plant Liquids	2.56	2.34	2.66	2.67	2.80	2.81	0.8%
Dry Natural Gas	19.48	19.58	20.97	21.33	22.48	22.42	0.6%
Coal	22.70	22.66	25.10	25.56	27.04	29.90	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[1]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other[2]	1.12	0.93	0.97	0.78	0.77	0.82	-0.5%
Total	**71.94**	**71.42**	**77.79**	**77.73**	**80.35**	**82.73**	**0.7%**
Imports							
Crude Oil[3]	19.93	21.08	24.69	28.98	32.29	35.16	2.4%
Petroleum Products[4]	4.75	5.16	6.06	6.32	6.83	8.27	2.2%
Natural Gas	4.11	4.02	5.71	8.00	8.95	9.70	4.1%
Other Imports[5]	0.56	0.69	0.92	1.07	1.15	1.23	2.6%
Total	**29.35**	**30.95**	**37.38**	**44.37**	**49.22**	**54.36**	**2.6%**
Exports							
Petroleum[6]	2.05	2.13	2.14	2.21	2.26	2.32	0.4%
Natural Gas	0.52	0.70	0.65	0.81	0.86	0.83	0.8%
Coal	1.03	1.12	1.06	0.88	0.89	0.65	-2.5%
Total	**3.60**	**3.95**	**3.86**	**3.90**	**4.01**	**3.80**	**-0.2%**
Discrepancy[7]	**-0.30**	**0.18**	**0.05**	**-0.09**	**-0.05**	**0.10**	**N/A**
Consumption							
Petroleum Products[8]	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural Gas	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Coal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[1]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other[9]	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Net Imports - Petroleum	**22.64**	**24.10**	**28.61**	**33.10**	**36.87**	**41.11**	**2.5%**
Prices (2003 dollars per unit)							
World Oil Price (dollars per barrel)[10]	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Coal Minemouth Price (dollars per ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
Average Electricity Price (cents per kilowatthour)	7.4	7.4	6.6	6.9	7.2	7.3	-0.1%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 natural gas wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 coal minemouth prices: EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004). 2003 petroleum supply values and 2002 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 and 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004).
Projections: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Energy Consumption							
Residential							
Distillate Fuel	0.92	0.96	0.90	0.88	0.83	0.77	-1.0%
Kerosene	0.06	0.07	0.09	0.09	0.09	0.09	0.8%
Liquefied Petroleum Gas	0.57	0.54	0.57	0.61	0.64	0.67	0.9%
Petroleum Subtotal	1.54	1.58	1.56	1.58	1.56	1.53	-0.1%
Natural Gas	5.04	5.25	5.68	5.90	6.05	6.17	0.7%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Renewable Energy[1]	0.39	0.40	0.40	0.39	0.39	0.38	-0.3%
Electricity	4.32	4.37	5.02	5.40	5.79	6.18	1.6%
Delivered Energy	**11.30**	**11.61**	**12.67**	**13.29**	**13.80**	**14.26**	**0.9%**
Electricity Related Losses	9.62	9.71	10.80	11.29	11.77	12.35	1.1%
Total	**20.92**	**21.31**	**23.47**	**24.58**	**25.56**	**26.62**	**1.0%**
Commercial							
Distillate Fuel	0.50	0.52	0.62	0.66	0.71	0.77	1.8%
Residual Fuel	0.08	0.07	0.07	0.07	0.08	0.08	0.2%
Kerosene	0.02	0.02	0.03	0.03	0.03	0.03	0.5%
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.11	0.5%
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.2%
Petroleum Subtotal	0.74	0.75	0.86	0.91	0.96	1.02	1.4%
Natural Gas	3.20	3.22	3.49	3.69	3.91	4.17	1.2%
Coal	0.09	0.10	0.10	0.10	0.10	0.10	-0.1%
Renewable Energy[3]	0.08	0.09	0.09	0.09	0.09	0.09	0.0%
Electricity	4.12	4.13	5.00	5.63	6.33	7.12	2.5%
Delivered Energy	**8.23**	**8.29**	**9.53**	**10.41**	**11.38**	**12.49**	**1.9%**
Electricity Related Losses	9.18	9.18	10.76	11.77	12.86	14.25	2.0%
Total	**17.40**	**17.46**	**20.29**	**22.18**	**24.24**	**26.74**	**2.0%**
Industrial[4]							
Distillate Fuel	0.99	1.03	1.04	1.08	1.14	1.19	0.7%
Liquefied Petroleum Gas	2.17	2.09	2.30	2.44	2.59	2.74	1.2%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.21	0.28	0.34	0.38	0.38	0.38	1.4%
Motor Gasoline[2]	0.30	0.31	0.31	0.33	0.35	0.37	0.9%
Other Petroleum[5]	4.26	4.30	4.69	4.69	5.02	5.23	0.9%
Petroleum Subtotal	9.15	9.31	10.17	10.43	11.03	11.47	1.0%
Natural Gas	7.75	7.19	8.10	8.50	8.89	9.26	1.2%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Natural Gas Subtotal	8.90	8.34	9.31	9.73	10.21	10.57	1.1%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	1.37	1.39	1.42	1.42	1.42	1.42	0.1%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	2.08	2.11	2.03	1.95	1.89	1.83	-0.6%
Renewable Energy[7]	1.78	1.79	2.07	2.19	2.34	2.50	1.5%
Electricity	3.32	3.31	3.78	3.98	4.19	4.39	1.3%
Delivered Energy	**25.23**	**24.86**	**27.35**	**28.27**	**29.66**	**30.76**	**1.0%**
Electricity Related Losses	7.38	7.35	8.13	8.31	8.52	8.78	0.8%
Total	**32.61**	**32.21**	**35.47**	**36.58**	**38.19**	**39.53**	**0.9%**

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

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Transportation							
Distillate Fuel[8]	5.42	5.54	6.95	7.67	8.35	9.05	2.3%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Motor Gasoline[2]	16.48	16.64	19.14	20.81	22.31	24.04	1.7%
Residual Fuel	0.65	0.62	0.56	0.57	0.58	0.58	-0.3%
Liquefied Petroleum Gas	0.02	0.02	0.06	0.07	0.08	0.09	6.0%
Other Petroleum[10]	0.20	0.24	0.26	0.27	0.29	0.31	1.2%
Petroleum Subtotal	26.10	26.31	31.00	33.84	36.35	38.97	1.8%
Pipeline Fuel Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Compressed Natural Gas	0.01	0.02	0.06	0.08	0.10	0.11	7.6%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	6.7%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.08	0.08	0.09	0.10	0.11	0.12	2.0%
Delivered Energy	**26.88**	**27.07**	**31.85**	**34.75**	**37.39**	**40.04**	**1.8%**
Electricity Related Losses	0.17	0.17	0.19	0.21	0.22	0.24	1.5%
Total	**27.05**	**27.24**	**32.04**	**34.96**	**37.61**	**40.28**	**1.8%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.83	8.04	9.51	10.28	11.03	11.78	1.8%
Kerosene	0.09	0.11	0.14	0.14	0.14	0.13	0.6%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Liquefied Petroleum Gas	2.86	2.75	3.03	3.22	3.42	3.60	1.2%
Motor Gasoline[2]	16.82	16.98	19.49	21.18	22.70	24.45	1.7%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.93	0.97	0.97	1.02	1.03	1.03	0.3%
Other Petroleum[12]	4.45	4.52	4.93	4.94	5.30	5.53	0.9%
Petroleum Subtotal	37.53	37.96	43.58	46.75	49.90	52.98	1.5%
Natural Gas	16.00	15.68	17.33	18.17	18.94	19.70	1.0%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Pipeline Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Natural Gas Subtotal	17.83	17.48	19.23	20.13	21.09	21.85	1.0%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	1.47	1.50	1.53	1.52	1.52	1.52	0.1%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	2.18	2.22	2.14	2.06	2.00	1.94	-0.6%
Renewable Energy[13]	2.25	2.28	2.55	2.67	2.82	2.97	1.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.84	11.88	13.89	15.11	16.41	17.81	1.9%
Delivered Energy	**71.63**	**71.82**	**81.39**	**86.73**	**92.23**	**97.56**	**1.4%**
Electricity Related Losses	26.35	26.40	29.88	31.57	33.37	35.62	1.4%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Electric Power[14]							
Distillate Fuel	0.20	0.33	0.39	0.40	0.42	0.45	1.4%
Residual Fuel	0.68	0.80	0.87	0.92	0.98	0.98	0.9%
Petroleum Subtotal	0.88	1.13	1.26	1.32	1.40	1.43	1.1%
Natural Gas	5.76	5.06	6.87	8.56	9.64	9.61	3.0%
Steam Coal	19.80	20.49	22.81	23.65	25.28	28.54	1.5%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[15]	3.54	3.62	4.30	4.46	4.75	5.14	1.6%
Electricity Imports	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**38.19**	**38.28**	**43.77**	**46.68**	**49.79**	**53.43**	**1.5%**

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

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Total Energy Consumption							
Distillate Fuel	8.03	8.37	9.90	10.68	11.45	12.23	1.7%
Kerosene	0.09	0.11	0.14	0.14	0.14	0.13	0.6%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Liquefied Petroleum Gas	2.86	2.75	3.03	3.22	3.42	3.60	1.2%
Motor Gasoline[2]	16.82	16.98	19.49	21.18	22.70	24.45	1.7%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	1.61	1.77	1.84	1.94	2.01	2.02	0.6%
Other Petroleum[12]	4.45	4.52	4.93	4.94	5.30	5.53	0.9%
Petroleum Subtotal	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural Gas	21.76	20.74	24.21	26.73	28.59	29.32	1.6%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Pipeline Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Natural Gas Subtotal	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	21.27	21.99	24.34	25.17	26.80	30.07	1.4%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[16]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Energy Use and Related Statistics							
Delivered Energy Use	71.63	71.82	81.39	86.73	92.23	97.56	1.4%
Total Energy Use	97.99	98.22	111.27	118.29	125.60	133.18	1.4%
Population (millions)	288.60	291.39	310.12	323.55	336.99	350.64	0.8%
Gross Domestic Product (billion 1996 dollars)	10075	10381	13084	15216	17634	20292	3.1%
Carbon Dioxide Emissions (million metric tons)	5750.5	5788.7	6626.8	7052.4	7519.6	8062.3	1.5%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2002 and 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2002 and 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Residential	**15.02**	**15.81**	**14.33**	**14.98**	**15.64**	**16.13**	**0.1%**
Primary Energy[1]	8.33	9.68	8.35	8.74	9.21	9.62	-0.0%
Petroleum Products[2]	10.04	11.27	10.44	10.76	11.36	11.93	0.3%
Distillate Fuel	8.37	9.57	8.29	8.49	8.85	9.12	-0.2%
Liquefied Petroleum Gas	12.98	14.58	14.25	14.45	15.06	15.65	0.3%
Natural Gas	7.82	9.22	7.79	8.21	8.66	9.07	-0.1%
Electricity	25.22	25.42	22.96	23.63	24.12	24.24	-0.2%
Commercial	**15.06**	**15.63**	**13.76**	**14.87**	**15.70**	**16.20**	**0.2%**
Primary Energy[1]	6.57	7.92	6.81	7.20	7.54	7.82	-0.1%
Petroleum Products[2]	6.95	8.03	7.13	7.28	7.55	7.84	-0.1%
Distillate Fuel	6.15	7.03	6.30	6.49	6.76	7.06	0.0%
Residual Fuel	4.27	4.96	4.26	4.52	4.81	5.08	0.1%
Natural Gas	6.62	8.08	6.87	7.33	7.68	7.96	-0.1%
Electricity	23.35	23.24	19.93	21.25	22.10	22.40	-0.2%
Industrial[3]	**6.39**	**7.78**	**6.85**	**7.24**	**7.75**	**8.13**	**0.2%**
Primary Energy	4.93	6.49	5.55	5.83	6.27	6.64	0.1%
Petroleum Products[2]	6.53	8.29	7.24	7.42	7.88	8.36	0.0%
Distillate Fuel	6.33	7.24	6.78	7.19	7.37	7.73	0.3%
Liquefied Petroleum Gas	8.48	12.57	10.02	10.22	10.74	11.35	-0.5%
Residual Fuel	3.94	4.59	3.87	4.10	4.34	4.62	0.0%
Natural Gas[4]	3.89	5.56	4.37	4.82	5.23	5.47	-0.1%
Metallurgical Coal	1.88	1.85	1.82	1.76	1.75	1.68	-0.4%
Steam Coal	1.60	1.55	1.56	1.55	1.56	1.60	0.1%
Electricity	14.73	15.03	13.84	14.62	15.47	15.75	0.2%
Transportation	**10.07**	**11.46**	**10.95**	**10.95**	**11.16**	**11.46**	**0.0%**
Primary Energy	10.04	11.43	10.93	10.92	11.13	11.44	0.0%
Petroleum Products[2]	10.04	11.43	10.93	10.93	11.13	11.44	0.0%
Distillate Fuel[5]	9.55	10.92	10.76	10.71	10.66	10.85	-0.0%
Jet Fuel[6]	6.05	6.46	6.25	6.29	6.58	6.93	0.3%
Motor Gasoline[7]	11.32	12.93	12.32	12.26	12.52	12.81	-0.0%
Residual Fuel	3.83	4.49	3.74	4.01	4.28	4.56	0.1%
Liquefied Petroleum Gas[8]	15.15	16.65	15.24	15.28	15.66	16.24	-0.1%
Natural Gas[9]	7.23	9.04	8.56	9.11	9.45	9.69	0.3%
Ethanol (E85)[10]	14.65	16.23	17.11	17.37	17.22	18.13	0.5%
Electricity	20.03	20.64	18.81	19.59	19.99	19.96	-0.2%
Average End-Use Energy	**10.26**	**11.50**	**10.56**	**10.95**	**11.42**	**11.83**	**0.1%**
Primary Energy	7.85	9.32	8.61	8.83	9.18	9.55	0.1%
Electricity	21.60	21.74	19.36	20.35	21.11	21.38	-0.1%
Electric Power[11]							
Fossil Fuel Average	1.90	2.24	2.06	2.28	2.45	2.46	0.4%
Petroleum Products	4.37	5.28	4.55	4.77	5.10	5.42	0.1%
Distillate Fuel	5.69	6.48	5.36	5.53	6.01	6.33	-0.1%
Residual Fuel	3.99	4.79	4.19	4.44	4.71	5.00	0.2%
Natural Gas	3.69	5.46	4.27	4.81	5.20	5.44	-0.0%
Steam Coal	1.27	1.28	1.25	1.23	1.25	1.31	0.1%

Table A3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Average Price to All Users[12]							
Petroleum Products[2]	9.09	10.51	9.91	10.00	10.29	10.66	0.1%
Distillate Fuel	8.71	9.90	9.53	9.72	9.79	10.03	0.1%
Jet Fuel	6.05	6.46	6.25	6.29	6.58	6.93	0.3%
Liquefied Petroleum Gas	9.52	13.04	10.99	11.21	11.74	12.34	-0.3%
Motor Gasoline[7]	11.32	12.93	12.31	12.25	12.51	12.80	-0.0%
Residual Fuel	3.93	4.66	3.99	4.25	4.52	4.81	0.1%
Natural Gas	5.15	6.86	5.52	5.92	6.30	6.59	-0.2%
Coal	1.29	1.30	1.27	1.25	1.27	1.32	0.1%
Ethanol (E85)[10]	14.65	16.23	17.11	17.37	17.22	18.13	0.5%
Electricity	21.60	21.74	19.36	20.35	21.11	21.38	-0.1%
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)							
Residential	163.90	177.17	175.88	193.21	209.76	223.86	1.1%
Commercial	122.69	128.15	129.92	153.52	177.28	200.93	2.1%
Industrial	124.40	147.11	139.57	152.35	169.93	184.96	1.0%
Transportation	263.73	302.59	341.13	372.46	407.83	449.31	1.8%
Total Non-Renewable Expenditures	674.72	755.02	786.50	871.55	964.80	1059.05	1.5%
Transportation Renewable Expenditures	0.01	0.02	0.03	0.05	0.07	0.08	7.2%
Total Expenditures	**674.73**	**755.04**	**786.54**	**871.60**	**964.87**	**1059.13**	**1.6%**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2002 and 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 transportation sector natural gas delivered prices are based on EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and estimated state and federal taxes. 2003 transportation sector natural gas delivered prices are model results. 2002 and 2003 coal prices based on: EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2002 and 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Households (millions)							
Single-Family	74.87	76.15	84.29	89.62	94.55	99.50	1.2%
Multifamily	29.22	29.51	31.12	32.34	33.69	35.08	0.8%
Mobile Homes	6.38	6.35	6.63	7.15	7.55	7.90	1.0%
Total	**110.47**	**112.01**	**122.03**	**129.11**	**135.78**	**142.48**	**1.1%**
Average House Square Footage	**1730**	**1742**	**1823**	**1871**	**1912**	**1950**	**0.5%**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.3	103.6	103.8	102.9	101.6	100.1	-0.2%
Total Energy Consumption	189.4	190.3	192.4	190.4	188.3	186.8	-0.1%
(thousand Btu per square foot)							
Delivered Energy Consumption	59.1	59.5	57.0	55.0	53.1	51.3	-0.7%
Total Energy Consumption	109.5	109.2	105.5	101.8	98.5	95.8	-0.6%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.40	0.44	0.45	0.46	0.47	0.7%
Space Cooling	0.71	0.65	0.71	0.73	0.76	0.80	0.9%
Water Heating	0.37	0.37	0.38	0.38	0.38	0.37	0.1%
Refrigeration	0.41	0.40	0.36	0.35	0.35	0.36	-0.5%
Cooking	0.10	0.10	0.11	0.12	0.13	0.13	1.1%
Clothes Dryers	0.24	0.24	0.26	0.26	0.27	0.29	0.8%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	-0.1%
Lighting	0.76	0.78	0.92	0.99	1.06	1.13	1.7%
Clothes Washers[1]	0.03	0.03	0.04	0.05	0.06	0.06	3.3%
Dishwashers[1]	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.12	0.13	0.19	0.23	0.27	0.28	3.5%
Personal Computers	0.07	0.07	0.10	0.12	0.13	0.15	3.5%
Furnace Fans	0.08	0.08	0.10	0.10	0.11	0.12	1.5%
Other Uses[2]	0.88	0.95	1.26	1.46	1.65	1.85	3.1%
Delivered Energy	**4.32**	**4.37**	**5.02**	**5.40**	**5.79**	**6.18**	**1.6%**
Natural Gas							
Space Heating	3.52	3.70	4.00	4.17	4.28	4.36	0.8%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	12.9%
Water Heating	1.14	1.17	1.27	1.29	1.30	1.32	0.6%
Cooking	0.21	0.21	0.23	0.25	0.26	0.27	1.2%
Clothes Dryers	0.07	0.07	0.09	0.10	0.11	0.12	2.3%
Other Uses[3]	0.10	0.10	0.10	0.10	0.10	0.09	-0.3%
Delivered Energy	**5.04**	**5.25**	**5.68**	**5.90**	**6.05**	**6.17**	**0.7%**
Distillate							
Space Heating	0.79	0.84	0.78	0.77	0.73	0.68	-1.0%
Water Heating	0.13	0.12	0.12	0.11	0.10	0.10	-1.0%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.92**	**0.96**	**0.90**	**0.88**	**0.83**	**0.77**	**-1.0%**
Liquefied Petroleum Gas							
Space Heating	0.31	0.30	0.29	0.30	0.31	0.30	0.1%
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	0.1%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.6%
Other Uses[3]	0.18	0.17	0.20	0.23	0.26	0.28	2.4%
Delivered Energy	**0.57**	**0.54**	**0.57**	**0.61**	**0.64**	**0.67**	**0.9%**
Marketed Renewables (wood)[5]	0.39	0.40	0.40	0.39	0.39	0.38	-0.3%
Other Fuels[6]	0.07	0.08	0.10	0.10	0.10	0.10	0.6%

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

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Delivered Energy Consumption by End-Use							
Space Heating	5.46	5.72	6.00	6.19	6.26	6.29	0.4%
Space Cooling	0.71	0.65	0.71	0.73	0.76	0.80	0.9%
Water Heating	1.69	1.71	1.82	1.83	1.84	1.85	0.3%
Refrigeration	0.41	0.40	0.36	0.35	0.35	0.36	-0.5%
Cooking	0.34	0.34	0.37	0.39	0.42	0.44	1.1%
Clothes Dryers	0.31	0.31	0.35	0.37	0.38	0.40	1.2%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	-0.1%
Lighting	0.76	0.78	0.92	0.99	1.06	1.13	1.7%
Clothes Washers	0.03	0.03	0.04	0.05	0.06	0.06	3.3%
Dishwashers	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.12	0.13	0.19	0.23	0.27	0.28	3.5%
Personal Computers	0.07	0.07	0.10	0.12	0.13	0.15	3.5%
Furnace Fans	0.08	0.08	0.10	0.10	0.11	0.12	1.5%
Other Uses[7]	1.16	1.22	1.56	1.79	2.00	2.23	2.8%
Delivered Energy	**11.30**	**11.61**	**12.67**	**13.29**	**13.80**	**14.26**	**0.9%**
Electricity Related Losses	**9.62**	**9.71**	**10.80**	**11.29**	**11.77**	**12.35**	**1.1%**
Total Energy Consumption by End-Use							
Space Heating	6.32	6.61	6.94	7.13	7.21	7.22	0.4%
Space Cooling	2.29	2.11	2.24	2.27	2.32	2.41	0.6%
Water Heating	2.51	2.53	2.64	2.63	2.61	2.60	0.1%
Refrigeration	1.33	1.30	1.15	1.08	1.07	1.08	-0.8%
Cooking	0.56	0.57	0.61	0.64	0.67	0.70	0.9%
Clothes Dryers	0.84	0.85	0.91	0.92	0.94	0.97	0.6%
Freezers	0.43	0.42	0.37	0.37	0.37	0.38	-0.4%
Lighting	2.45	2.51	2.91	3.07	3.21	3.39	1.4%
Clothes Washers	0.10	0.10	0.13	0.15	0.18	0.19	2.9%
Dishwashers	0.08	0.08	0.08	0.09	0.09	0.09	0.8%
Color Televisions	0.40	0.43	0.60	0.70	0.81	0.85	3.2%
Personal Computers	0.22	0.23	0.32	0.37	0.41	0.45	3.2%
Furnace Fans	0.26	0.27	0.31	0.32	0.33	0.35	1.2%
Other Uses[7]	3.13	3.32	4.28	4.83	5.35	5.93	2.7%
Total	**20.92**	**21.31**	**23.47**	**24.58**	**25.56**	**26.62**	**1.0%**
Non-Marketed Renewables							
Geothermal[8]	0.00	0.00	0.00	0.01	0.01	0.01	7.6%
Solar[9]	0.02	0.02	0.03	0.03	0.04	0.04	2.7%
Total	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**3.3%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and spa heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	68.8	70.1	79.0	85.9	93.6	101.8	1.7%
New Additions	2.1	2.1	2.3	2.5	2.6	3.0	1.6%
Total	**70.9**	**72.1**	**81.2**	**88.4**	**96.2**	**104.8**	**1.7%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	116.0	114.8	117.3	117.7	118.3	119.2	0.2%
Electricity Related Losses	129.4	127.2	132.5	133.1	133.7	136.0	0.3%
Total Energy Consumption	245.4	242.0	249.7	250.8	252.0	255.2	0.2%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.16	0.16	0.16	0.16	0.4%
Space Cooling[1]	0.46	0.42	0.45	0.48	0.51	0.54	1.2%
Water Heating[1]	0.14	0.14	0.15	0.15	0.16	0.16	0.7%
Ventilation	0.16	0.16	0.17	0.18	0.19	0.20	0.9%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Lighting	1.09	1.10	1.28	1.37	1.44	1.52	1.5%
Refrigeration	0.20	0.20	0.23	0.24	0.26	0.28	1.6%
Office Equipment (PC)	0.13	0.14	0.24	0.29	0.33	0.36	4.5%
Office Equipment (non-PC)	0.31	0.31	0.45	0.57	0.70	0.87	4.8%
Other Uses[2]	1.47	1.48	1.84	2.17	2.56	3.00	3.3%
Delivered Energy	**4.12**	**4.13**	**5.00**	**5.63**	**6.33**	**7.12**	**2.5%**
Natural Gas							
Space Heating[1]	1.32	1.36	1.43	1.47	1.51	1.56	0.7%
Space Cooling[1]	0.01	0.01	0.02	0.02	0.02	0.03	4.0%
Water Heating[1]	0.57	0.57	0.66	0.72	0.78	0.85	1.8%
Cooking	0.26	0.26	0.31	0.34	0.37	0.40	2.0%
Other Uses[3]	1.03	1.02	1.08	1.15	1.23	1.33	1.2%
Delivered Energy	**3.20**	**3.22**	**3.49**	**3.69**	**3.91**	**4.17**	**1.2%**
Distillate							
Space Heating[1]	0.20	0.22	0.32	0.37	0.42	0.47	3.5%
Water Heating[1]	0.07	0.07	0.07	0.07	0.08	0.08	0.4%
Other Uses[4]	0.23	0.23	0.22	0.22	0.21	0.21	-0.3%
Delivered Energy	**0.50**	**0.52**	**0.62**	**0.66**	**0.71**	**0.77**	**1.8%**
Marketed Renewables (biomass)	0.08	0.09	0.09	0.09	0.09	0.09	0.0%
Other Fuels[5]	0.33	0.33	0.34	0.34	0.34	0.35	0.2%
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.66	1.73	1.90	2.00	2.09	2.20	1.1%
Space Cooling[1]	0.47	0.43	0.47	0.49	0.53	0.57	1.3%
Water Heating[1]	0.77	0.78	0.88	0.94	1.01	1.09	1.5%
Ventilation	0.16	0.16	0.17	0.18	0.19	0.20	0.9%
Cooking	0.29	0.29	0.34	0.37	0.40	0.43	1.8%
Lighting	1.09	1.10	1.28	1.37	1.44	1.52	1.5%
Refrigeration	0.20	0.20	0.23	0.24	0.26	0.28	1.6%
Office Equipment (PC)	0.13	0.14	0.24	0.29	0.33	0.36	4.5%
Office Equipment (non-PC)	0.31	0.31	0.45	0.57	0.70	0.87	4.8%
Other Uses[6]	3.14	3.15	3.56	3.96	4.43	4.98	2.1%
Delivered Energy	**8.23**	**8.29**	**9.53**	**10.41**	**11.38**	**12.49**	**1.9%**

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

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electricity Related Losses	**9.18**	**9.18**	**10.76**	**11.77**	**12.86**	**14.25**	**2.0%**
Total Energy Consumption by End-Use							
Space Heating[1]	1.98	2.06	2.24	2.32	2.41	2.52	0.9%
Space Cooling[1]	1.48	1.37	1.44	1.49	1.56	1.66	0.9%
Water Heating[1]	1.08	1.08	1.20	1.26	1.33	1.41	1.2%
Ventilation	0.52	0.52	0.55	0.55	0.56	0.59	0.6%
Cooking	0.36	0.36	0.41	0.43	0.46	0.49	1.4%
Lighting	3.51	3.55	4.04	4.23	4.36	4.56	1.1%
Refrigeration	0.64	0.65	0.71	0.75	0.80	0.85	1.2%
Office Equipment (PC)	0.43	0.44	0.76	0.90	1.01	1.08	4.2%
Office Equipment (non-PC)	0.99	1.00	1.41	1.75	2.13	2.61	4.5%
Other Uses[6]	6.41	6.44	7.52	8.49	9.63	10.98	2.5%
Total	**17.40**	**17.46**	**20.29**	**22.18**	**24.24**	**26.74**	**2.0%**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.02	0.03	0.03	0.03	0.04	2.1%

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	3826	3851	4836	5392	6046	6733	2.6%
Nonmanufacturing	1240	1254	1329	1458	1587	1736	1.5%
Total	**5067**	**5105**	**6165**	**6850**	**7633**	**8469**	**2.3%**
Energy Prices (2003 dollars per million Btu)							
Distillate Oil	6.33	7.24	6.78	7.19	7.37	7.73	0.3%
Liquefied Petroleum Gas	8.48	12.57	10.02	10.22	10.74	11.35	-0.5%
Residual Oil	3.94	4.59	3.87	4.10	4.34	4.62	0.0%
Motor Gasoline	11.22	12.79	11.68	11.62	11.90	12.21	-0.2%
Natural Gas	3.89	5.56	4.37	4.82	5.23	5.47	-0.1%
Metallurgical Coal	1.88	1.85	1.82	1.76	1.75	1.68	-0.4%
Steam Coal	1.60	1.55	1.56	1.55	1.56	1.60	0.1%
Electricity	14.73	15.03	13.84	14.62	15.47	15.75	0.2%
Energy Consumption (quadrillion Btu)[1]							
Distillate	0.99	1.03	1.04	1.08	1.14	1.19	0.7%
Liquefied Petroleum Gas	2.17	2.09	2.30	2.44	2.59	2.74	1.2%
Petrochemical Feedstocks	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.21	0.28	0.34	0.38	0.38	0.38	1.4%
Motor Gasoline	0.30	0.31	0.31	0.33	0.35	0.37	0.9%
Petroleum Coke	1.02	1.00	1.07	1.17	1.30	1.38	1.5%
Still Gas	1.40	1.48	1.77	1.57	1.65	1.68	0.6%
Asphalt and Road Oil	1.24	1.22	1.16	1.21	1.30	1.43	0.7%
Miscellaneous Petroleum[2]	0.60	0.61	0.69	0.73	0.77	0.75	1.0%
Petroleum Subtotal	9.15	9.31	10.17	10.43	11.03	11.47	1.0%
Natural Gas	7.75	7.19	8.10	8.50	8.89	9.26	1.2%
Lease and Plant Fuel[3]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Natural Gas Subtotal	8.90	8.34	9.31	9.73	10.21	10.57	1.1%
Metallurgical Coal and Coke[4]	0.71	0.72	0.61	0.53	0.47	0.42	-2.4%
Steam Coal	1.37	1.39	1.42	1.42	1.42	1.42	0.1%
Coal Subtotal	2.08	2.11	2.03	1.95	1.89	1.83	-0.6%
Renewables[5]	1.78	1.79	2.07	2.19	2.34	2.50	1.5%
Purchased Electricity	3.32	3.31	3.78	3.98	4.19	4.39	1.3%
Delivered Energy	**25.23**	**24.86**	**27.35**	**28.27**	**29.66**	**30.76**	**1.0%**
Electricity Related Losses	7.38	7.35	8.13	8.31	8.52	8.78	0.8%
Total	**32.61**	**32.21**	**35.47**	**36.58**	**38.19**	**39.53**	**0.9%**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)							
Distillate	0.19	0.20	0.17	0.16	0.15	0.14	-1.6%
Liquefied Petroleum Gas	0.43	0.41	0.37	0.36	0.34	0.32	-1.1%
Petrochemical Feedstocks	0.24	0.26	0.24	0.22	0.20	0.19	-1.5%
Residual Fuel	0.04	0.05	0.05	0.06	0.05	0.04	-0.9%
Motor Gasoline	0.06	0.06	0.05	0.05	0.05	0.04	-1.4%
Petroleum Coke	0.20	0.20	0.17	0.17	0.17	0.16	-0.8%
Still Gas	0.28	0.29	0.29	0.23	0.22	0.20	-1.7%
Asphalt and Road Oil	0.24	0.24	0.19	0.18	0.17	0.17	-1.6%
Miscellaneous Petroleum[2]	0.12	0.12	0.11	0.11	0.10	0.09	-1.3%
Petroleum Subtotal	1.81	1.82	1.65	1.52	1.44	1.35	-1.3%
Natural Gas	1.53	1.41	1.31	1.24	1.16	1.09	-1.1%
Lease and Plant Fuel[3]	0.23	0.23	0.20	0.18	0.17	0.15	-1.7%
Natural Gas Subtotal	1.76	1.63	1.51	1.42	1.34	1.25	-1.2%
Metallurgical Coal and Coke[4]	0.14	0.14	0.10	0.08	0.06	0.05	-4.7%
Steam Coal	0.27	0.27	0.23	0.21	0.19	0.17	-2.2%
Coal Subtotal	0.41	0.41	0.33	0.28	0.25	0.22	-2.9%
Renewables[5]	0.35	0.35	0.34	0.32	0.31	0.29	-0.8%
Purchased Electricity	0.65	0.65	0.61	0.58	0.55	0.52	-1.0%
Delivered Energy	**4.98**	**4.87**	**4.44**	**4.13**	**3.89**	**3.63**	**-1.3%**
Electricity Related Losses	1.46	1.44	1.32	1.21	1.12	1.04	-1.5%
Total	**6.44**	**6.31**	**5.75**	**5.34**	**5.00**	**4.67**	**-1.4%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Industrial Combined Heat and Power							
Capacity (gigawatts)	24.95	24.87	29.50	32.23	36.03	40.09	2.2%
Generation (billion kilowatthours)	147.19	139.59	171.71	192.47	220.64	250.10	2.7%

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2002 and 2003 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 and 2003 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2002 and 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 consumption values based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 shipments: Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Level of Travel							
(billion vehicle miles traveled)							
Light-Duty Vehicles less than 8,500 pounds	2557	2602	3017	3354	3680	4053	2.0%
Commercial Light Trucks[1]	64	65	78	87	96	107	2.3%
Freight Trucks greater than 10,000 pounds	210	214	268	300	336	373	2.6%
(billion seat miles available)							
Air	908	932	1152	1327	1455	1520	2.2%
(billion ton miles traveled)							
Rail	1328	1352	1576	1690	1833	2001	1.8%
Domestic Shipping	606	592	649	669	706	733	1.0%
Energy Efficiency Indicators							
(miles per gallon)							
New Light-Duty Vehicle[2]	24.6	25.1	25.7	26.1	26.5	26.9	0.3%
New Car[2]	28.9	29.5	29.7	30.3	30.6	31.0	0.2%
New Light Truck[2]	21.3	21.8	22.9	23.4	24.1	24.6	0.6%
Light-Duty Stock[3]	20.0	20.0	20.1	20.4	20.7	21.0	0.2%
New Commercial Light Truck[1]	14.1	14.6	15.2	15.6	16.0	16.4	0.5%
Stock Commercial Light Truck[1]	13.8	14.0	14.7	15.1	15.5	15.9	0.6%
Freight Truck	6.0	6.0	6.0	6.2	6.4	6.6	0.4%
(seat miles per gallon)							
Aircraft	55.2	55.3	59.2	62.1	65.2	68.5	1.0%
(ton miles per thousand Btu)							
Rail	2.9	2.9	3.1	3.3	3.4	3.6	1.0%
Domestic Shipping	2.3	2.3	2.3	2.4	2.4	2.4	0.2%
Energy Use by Mode							
(quadrillion Btu)							
Light-Duty Vehicles	15.58	15.78	18.45	20.24	21.85	23.69	1.9%
Commercial Light Trucks[1]	0.58	0.58	0.67	0.72	0.78	0.84	1.7%
Bus Transportation	0.24	0.25	0.26	0.27	0.27	0.27	0.3%
Freight Trucks	4.39	4.46	5.56	6.11	6.60	7.10	2.1%
Rail, Passenger	0.11	0.12	0.13	0.15	0.16	0.17	1.7%
Rail, Freight	0.47	0.47	0.51	0.52	0.54	0.56	0.8%
Shipping, Domestic	0.26	0.26	0.28	0.29	0.30	0.31	0.8%
Shipping, International	0.59	0.56	0.51	0.52	0.52	0.52	-0.3%
Recreational Boats	0.31	0.31	0.33	0.35	0.37	0.39	1.0%
Air	2.87	2.74	3.43	3.83	4.11	4.25	2.0%
Military Use	0.64	0.69	0.80	0.81	0.82	0.83	0.9%
Lubricants	0.20	0.20	0.21	0.23	0.25	0.27	1.4%
Pipeline Fuel	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Total	**26.92**	**27.07**	**31.85**	**34.75**	**37.39**	**40.04**	**1.8%**
(million barrels per day oil equivalent)							
Light-Duty Vehicles	8.19	8.29	9.72	10.65	11.49	12.45	1.9%
Commercial Light Trucks[1]	0.30	0.30	0.35	0.38	0.41	0.44	1.7%
Bus Transportation	0.12	0.12	0.13	0.13	0.13	0.13	0.3%
Freight Trucks	2.09	2.13	2.66	2.92	3.16	3.40	2.2%
Rail, Passenger	0.05	0.06	0.06	0.07	0.07	0.08	1.7%
Rail, Freight	0.22	0.22	0.24	0.25	0.25	0.26	0.8%
Shipping, Domestic	0.12	0.12	0.13	0.13	0.14	0.14	0.8%
Shipping, International	0.26	0.25	0.22	0.23	0.23	0.23	-0.3%
Recreational Boats	0.16	0.16	0.18	0.19	0.19	0.20	1.0%
Air	1.39	1.33	1.66	1.85	1.99	2.06	2.0%
Military Use	0.31	0.33	0.39	0.39	0.40	0.40	0.9%
Lubricants	0.09	0.09	0.10	0.11	0.12	0.13	1.4%
Pipeline Fuel	0.35	0.33	0.35	0.37	0.42	0.43	1.2%
Total	**13.65**	**13.73**	**16.19**	**17.67**	**19.00**	**20.36**	**1.8%**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2002 and 2003: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004); Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2003/2002* (Washington, DC, 2003); EIA, *Fuel Oil and Kerosene Sales 2002*, DOE/EIA-0535(2002) (Washington, DC, November 2003); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1881	1916	2169	2251	2440	2836	1.8%
Petroleum	83	106	112	118	124	128	0.9%
Natural Gas[3]	457	407	634	854	1038	1048	4.4%
Nuclear Power	780	764	813	826	830	830	0.4%
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	0.1%
Renewable Sources[4]	311	318	389	398	412	430	1.4%
Distributed Generation (Natural Gas)	0	0	0	0	1	3	N/A
Total	**3503**	**3501**	**4109**	**4438**	**4836**	**5267**	**1.9%**
Combined Heat and Power[5]							
Coal	31	34	33	34	34	33	-0.1%
Petroleum	7	7	6	7	7	7	0.1%
Natural Gas	151	149	188	200	196	186	1.0%
Renewable Sources	6	6	4	4	4	4	-1.7%
Total	**197**	**197**	**230**	**244**	**240**	**230**	**0.7%**
Total Net Generation	**3700**	**3699**	**4339**	**4683**	**5076**	**5497**	**1.8%**
Less Direct Use	50	50	66	65	65	65	1.2%
Net Available to the Grid	**3650**	**3649**	**4273**	**4617**	**5011**	**5432**	**1.8%**
Commercial and Industrial Generation[6]							
Coal	21	21	21	21	21	21	N/A
Petroleum	5	6	9	10	12	13	3.8%
Natural Gas	83	76	100	117	141	169	3.7%
Other Gaseous Fuels[7]	6	6	4	5	5	5	-0.4%
Renewable Sources[4]	34	35	43	45	50	55	2.0%
Other[8]	9	10	10	10	10	10	-0.0%
Total	**159**	**153**	**187**	**208**	**238**	**273**	**2.7%**
Less Direct Use	131	126	139	149	164	182	1.7%
Total Sales to the Grid	**28**	**28**	**48**	**59**	**74**	**91**	**5.5%**
Total Electricity Generation	**3860**	**3852**	**4526**	**4890**	**5314**	**5770**	**1.9%**
Total Net Generation to the Grid	**3678**	**3677**	**4322**	**4676**	**5085**	**5522**	**1.9%**
Net Imports	**22**	**5**	**9**	**21**	**15**	**11**	**4.1%**
Electricity Sales by Sector							
Residential	1267	1280	1471	1584	1696	1810	1.6%
Commercial	1208	1210	1466	1651	1854	2088	2.5%
Industrial	972	969	1107	1166	1229	1286	1.3%
Transportation	22	23	26	29	32	35	2.0%
Total	**3469**	**3481**	**4070**	**4430**	**4811**	**5220**	**1.9%**
Direct Use	182	175	204	214	229	248	1.6%
Total Electricity Use	**3651**	**3657**	**4274**	**4644**	**5040**	**5467**	**1.8%**
End-Use Prices[9]							
(2003 cents per kilowatthour)							
Residential	8.6	8.7	7.8	8.1	8.2	8.3	-0.2%
Commercial	8.0	7.9	6.8	7.3	7.5	7.6	-0.2%
Industrial	5.0	5.1	4.7	5.0	5.3	5.4	0.2%
Transportation	6.8	7.0	6.4	6.7	6.8	6.8	-0.2%
All Sectors Average	**7.4**	**7.4**	**6.6**	**6.9**	**7.2**	**7.3**	**-0.1%**
Prices by Service Category[9]							
(2003 cents per kilowatthour)							
Generation	4.7	4.8	4.1	4.5	4.7	4.9	0.1%
Transmission	0.6	0.5	0.6	0.6	0.7	0.7	1.0%
Distribution	2.1	2.1	2.0	1.9	1.8	1.8	-0.7%

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector Emissions[1]							
Sulfur Dioxide (million tons)	10.19	10.59	9.29	8.97	8.95	8.95	-0.8%
Nitrogen Oxide (million tons)	4.37	4.12	3.99	4.09	4.18	4.29	0.2%
Mercury (tons)	50.08	49.70	54.08	55.12	55.45	55.97	0.5%

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and supporting databases. 2002 and 2003 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 and 2003 prices: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. **Projections**: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.8	305.2	304.6	310.6	334.6	389.2	1.1%
Other Fossil Steam[4]	131.5	128.6	119.4	101.1	100.0	99.4	-1.2%
Combined Cycle	70.3	106.9	136.4	147.9	176.8	189.4	2.6%
Combustion Turbine/Diesel	118.6	124.8	132.7	141.8	168.0	188.6	1.9%
Nuclear Power[5]	98.9	99.2	100.6	102.2	102.7	102.7	0.2%
Pumped Storage	20.7	20.8	20.9	20.9	20.9	20.9	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	90.2	92.0	95.0	96.3	99.0	102.9	0.5%
Distributed Generation[7]	0.0	0.0	0.4	1.1	3.1	6.9	N/A
Total	**836.1**	**877.5**	**909.9**	**921.9**	**1005.0**	**1100.0**	**1.0%**
Combined Heat and Power[8]							
Coal Steam	5.1	5.1	5.1	5.0	5.0	5.0	0.0%
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	N/A
Combined Cycle	29.1	31.3	33.5	33.5	33.5	33.5	0.3%
Combustion Turbine/Diesel	5.1	5.1	5.1	5.1	5.1	5.1	0.0%
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	N/A
Total	**40.6**	**42.8**	**45.1**	**45.0**	**45.0**	**45.0**	**0.2%**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.0	1.8	1.8	1.8	1.8	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	28.3	28.3	28.3	28.3	N/A
Combustion Turbine/Diesel	0.0	0.0	3.9	3.9	3.9	3.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	2.7	2.8	2.9	3.0	N/A
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**36.7**	**36.8**	**36.9**	**37.0**	**N/A**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	0.0	6.5	30.6	85.1	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	3.5	15.3	44.2	56.8	N/A
Combustion Turbine/Diesel	0.0	0.0	5.9	19.7	47.4	69.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.2	1.3	4.0	7.7	N/A
Distributed Generation[7]	0.0	0.0	0.4	1.1	3.1	6.9	N/A
Total	**0.0**	**0.0**	**9.9**	**44.0**	**129.1**	**226.4**	**N/A**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**46.6**	**80.8**	**166.0**	**263.4**	**N/A**
Cumulative Retirements[10]							
Coal Steam	0.0	0.0	2.4	3.0	3.0	3.0	N/A
Other Fossil Steam[4]	0.0	0.0	9.3	27.5	28.6	29.2	N/A
Combined Cycle	0.0	0.0	0.1	0.4	0.4	0.4	N/A
Combustion Turbine/Diesel	0.0	0.0	1.9	6.6	8.1	9.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**13.8**	**37.6**	**40.1**	**42.6**	**N/A**
Total Electric Power Sector Capacity	**876.7**	**920.3**	**954.9**	**966.9**	**1050.0**	**1145.0**	**1.0%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Commercial and Industrial Generators[11]							
Coal	4.2	4.1	4.1	4.1	4.1	4.1	-0.0%
Petroleum	1.0	0.7	1.5	1.5	1.7	1.7	4.2%
Natural Gas	14.2	14.4	17.4	19.7	22.8	26.7	2.9%
Other Gaseous Fuels	1.8	1.8	1.5	1.6	1.6	1.7	-0.3%
Renewable Sources[6]	5.4	5.4	6.8	7.3	8.3	9.9	2.7%
Other	0.7	0.7	0.7	0.7	0.7	0.7	N/A
Total	**27.2**	**27.1**	**32.1**	**34.9**	**39.2**	**44.8**	**2.3%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**5.0**	**7.8**	**12.1**	**17.7**	**N/A**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.5 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2003.
[10]Cumulative retirements after December 31, 2003.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Electricity Trade	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	138.9	136.7	105.5	82.4	50.6	37.9	-5.7%
Gross Domestic Economy Trade	173.9	198.5	206.9	178.8	133.2	101.6	-3.0%
Gross Domestic Trade	**312.8**	**335.2**	**312.3**	**261.2**	**183.8**	**139.5**	**-3.9%**
Gross Domestic Firm Power Sales (million 2003 dollars)	7037.4	6926.5	5344.6	4176.6	2564.5	1919.7	-5.7%
Gross Domestic Economy Sales (million 2003 dollars)	5357.4	7959.8	7280.2	7408.5	5938.8	4682.6	-2.4%
Gross Domestic Sales (million 2003 dollars)	**12394.7**	**14886.3**	**12624.9**	**11585.1**	**8503.3**	**6602.3**	**-3.6%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	9.5	11.3	2.2	1.5	0.5	0.0	-23.4%
Economy Imports From Canada and Mexico	26.8	18.2	29.3	38.7	31.0	25.1	1.5%
Gross Imports From Canada and Mexico	**36.3**	**29.5**	**31.4**	**40.2**	**31.5**	**25.2**	**-0.7%**
Firm Power Exports To Canada and Mexico	5.6	5.5	1.0	0.7	0.2	0.0	N/A
Economy Exports To Canada and Mexico	8.7	19.5	21.3	18.3	15.9	14.0	-1.5%
Gross Exports To Canada and Mexico	**14.3**	**24.9**	**22.3**	**18.9**	**16.1**	**14.0**	**-2.6%**

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2002 and 2003 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1999. 2002 and 2003 Mexican electricity trade data: DOE Form FE-718R, “Annual Report of International Electrical Export/Import Data.” 2002 Canadian international electricity trade data: National Energy Board, *Annual Report 2001*. 2003 Canadian electricity trade data: National Energy Board, *Annual Report 2002*. **Projections:** Energy Information Administration, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Crude Oil							
Domestic Crude Production[1]	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Alaska	0.98	0.97	0.81	0.88	0.86	0.61	-2.1%
Lower 48 States	4.75	4.71	5.22	4.61	4.35	4.12	-0.6%
Net Imports	9.13	9.65	11.31	13.28	14.80	16.11	2.4%
Gross Imports	9.14	9.66	11.32	13.29	14.81	16.12	2.4%
Exports	0.01	0.01	0.01	0.01	0.01	0.01	-0.9%
Other Crude Supply[2]	0.07	-0.03	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**14.94**	**15.31**	**17.33**	**18.77**	**20.01**	**20.84**	**1.4%**
Other Petroleum Supply							
Natural Gas Plant Liquids	1.88	1.72	1.96	1.96	2.04	2.04	0.8%
Net Product Imports	1.41	1.58	2.06	2.12	2.31	3.00	2.9%
Gross Refined Product Imports[3]	1.61	1.85	1.99	1.87	1.90	2.47	1.3%
Unfinished Oil Imports	0.41	0.34	0.59	0.76	0.91	1.02	5.2%
Blending Components	0.37	0.41	0.48	0.52	0.55	0.60	1.7%
Exports	0.97	1.01	0.99	1.03	1.05	1.08	0.3%
Refinery Processing Gain[4]	0.98	1.00	1.11	1.36	1.50	1.56	2.0%
Other Inputs[5]	0.67	0.69	0.53	0.46	0.46	0.50	-1.5%
Total Primary Supply[6]	**19.89**	**20.30**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	8.85	8.93	10.28	11.17	11.97	12.89	1.7%
Jet Fuel[8]	1.61	1.57	1.95	2.15	2.29	2.36	1.9%
Distillate Fuel[9]	3.79	3.95	4.70	5.07	5.44	5.81	1.8%
Residual Fuel	0.70	0.77	0.80	0.85	0.88	0.88	0.6%
Other[10]	4.75	4.77	5.25	5.42	5.74	5.98	1.0%
Total	**19.71**	**20.00**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.26	1.28	1.33	1.38	1.41	1.42	0.5%
Industrial[11]	4.82	4.87	5.33	5.49	5.81	6.05	1.0%
Transportation	13.24	13.35	15.76	17.21	18.48	19.82	1.8%
Electric Power[12]	0.39	0.50	0.56	0.59	0.62	0.64	1.1%
Total	**19.71**	**20.00**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Discrepancy[13]	**0.18**	**0.29**	**-0.00**	**0.00**	**0.00**	**-0.00**	**N/A**
World Oil Price (2003 dollars per barrel)[14]	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Import Share of Product Supplied	0.54	0.56	0.58	0.62	0.65	0.68	0.9%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	91.94	113.78	125.14	153.97	180.07	215.89	3.0%
Domestic Refinery Distillation Capacity[15]	16.8	16.8	18.7	20.2	21.4	22.3	1.3%
Capacity Utilization Rate (percent)	91.0	93.0	94.0	94.2	94.8	94.9	0.1%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[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 for combined heat and power, which produces electricity and other useful thermal energy.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2002 data: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2003 data: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A12. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
World Oil Price (2003 dollars per barrel)	**24.10**	**27.73**	**25.00**	**26.75**	**28.50**	**30.31**	**0.4%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	116.1	132.7	114.9	117.7	122.7	126.4	-0.2%
Liquefied Petroleum Gas	111.6	125.4	122.6	124.2	129.5	134.6	0.3%
Commercial							
Distillate Fuel	85.1	97.3	86.9	89.5	93.2	97.3	0.0%
Residual Fuel	63.9	74.3	63.7	67.7	71.9	76.0	0.1%
Residual Fuel (2003 dollars per barrel)	26.84	31.21	26.77	28.44	30.21	31.92	0.1%
Industrial[1]							
Distillate Fuel	87.7	100.2	93.3	98.8	101.2	106.2	0.3%
Liquefied Petroleum Gas	73.0	108.1	86.1	87.9	92.3	97.6	-0.5%
Residual Fuel	59.0	68.7	57.9	61.4	64.9	69.1	0.0%
Residual Fuel (2003 dollars per barrel)	24.76	28.84	24.33	25.77	27.27	29.02	0.0%
Transportation							
Diesel Fuel (distillate)[2]	131.6	150.4	147.5	146.8	146.1	148.6	-0.1%
Jet Fuel[3]	81.7	87.2	84.3	85.0	88.8	93.5	0.3%
Motor Gasoline[4]	140.4	160.3	152.4	151.6	154.9	158.5	-0.1%
Liquid Petroleum Gas	130.3	143.2	131.1	131.4	134.7	139.7	-0.1%
Residual Fuel	57.4	67.3	56.0	60.0	64.1	68.3	0.1%
Residual Fuel (2003 dollars per barrel)	24.09	28.25	23.50	25.21	26.92	28.68	0.1%
Ethanol (E85)[5]	137.6	152.4	160.5	163.0	161.6	170.1	0.5%
Electric Power[6]							
Distillate Fuel	79.0	89.8	74.4	76.7	83.3	87.8	-0.1%
Residual Fuel	59.7	71.7	62.7	66.5	70.5	74.9	0.2%
Residual Fuel (2003 dollars per barrel)	25.05	30.12	26.32	27.91	29.63	31.45	0.2%
Refined Petroleum Product Prices[7]							
Distillate Fuel	120.3	136.7	131.0	133.4	134.4	137.7	0.0%
Jet Fuel[3]	81.7	87.2	84.3	85.0	88.8	93.5	0.3%
Liquefied Petroleum Gas	81.8	112.1	94.5	96.4	101.0	106.1	-0.3%
Motor Gasoline[4]	140.4	160.3	152.2	151.5	154.8	158.4	-0.1%
Residual Fuel	58.8	69.8	59.8	63.6	67.7	72.0	0.1%
Residual Fuel (2003 dollars per barrel)	24.71	29.32	25.11	26.72	28.43	30.22	0.1%
Average	**118.2**	**136.6**	**128.3**	**129.1**	**132.4**	**136.8**	**0.0%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Includes only kerosene type.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 and 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2002 and 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 and 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2002 and 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

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

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production							
Dry Gas Production[1]	18.96	19.07	20.42	20.77	21.89	21.83	0.6%
Supplemental Natural Gas[2]	0.07	0.06	0.08	0.08	0.08	0.08	0.7%
Net Imports	**3.50**	**3.24**	**4.94**	**7.02**	**7.89**	**8.66**	**4.6%**
Canada	3.60	3.13	2.57	2.98	2.69	2.55	-0.9%
Mexico	-0.26	-0.33	-0.14	-0.29	-0.35	-0.25	-1.2%
Liquefied Natural Gas[3]	0.17	0.44	2.50	4.33	5.54	6.37	12.9%
Total Supply	**22.53**	**22.37**	**25.44**	**27.86**	**29.85**	**30.56**	**1.4%**
Consumption by Sector							
Residential	4.89	5.10	5.52	5.74	5.88	5.99	0.7%
Commercial	3.11	3.13	3.39	3.58	3.80	4.05	1.2%
Industrial[4]	7.53	6.99	7.87	8.26	8.64	9.00	1.2%
Electric Power[5]	5.65	4.96	6.74	8.39	9.45	9.43	3.0%
Transportation[6]	0.01	0.02	0.06	0.08	0.10	0.11	7.8%
Pipeline Fuel	0.67	0.64	0.68	0.71	0.80	0.82	1.2%
Lease and Plant Fuel[7]	1.11	1.12	1.17	1.20	1.29	1.27	0.6%
Total	**22.98**	**21.95**	**25.44**	**27.96**	**29.95**	**30.67**	**1.5%**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[8]	**-0.45**	**0.42**	**-0.00**	**-0.09**	**-0.10**	**-0.11**	**N/A**
Natural Gas Prices (2003 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[9]	**3.06**	**4.98**	**3.64**	**4.16**	**4.53**	**4.79**	**-0.2%**
Delivered Prices							
Residential	8.04	9.49	8.02	8.45	8.91	9.33	-0.1%
Commercial	6.81	8.31	7.07	7.54	7.90	8.19	-0.1%
Industrial[4]	4.00	5.72	4.50	4.96	5.38	5.63	-0.1%
Electric Power[5]	3.76	5.57	4.36	4.90	5.31	5.55	-0.0%
Transportation[10]	7.44	9.31	8.81	9.38	9.72	9.98	0.3%
Average[11]	**5.29**	**7.04**	**5.67**	**6.08**	**6.47**	**6.77**	**-0.2%**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 and 2001 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). Other 2002 and 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 residential and commercial delivered prices: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 electric power sector prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004. 2002 and 2003 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and estimated state and federal taxes. 2003 transportation sector delivered prices are model results. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Crude Oil							
Lower 48 Average Wellhead Price[1] (2003 dollars per barrel)	**24.91**	**28.60**	**24.50**	**26.27**	**28.06**	**30.00**	**0.2%**
Production (million barrels per day)[2]							
U.S. Total	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Lower 48 Onshore	3.06	2.99	2.63	2.42	2.24	2.09	-1.6%
Lower 48 Offshore	1.69	1.72	2.58	2.19	2.11	2.03	0.8%
Alaska	0.98	0.97	0.81	0.88	0.86	0.61	-2.1%
Lower 48 End of Year Reserves (billion barrels)[2]	**19.34**	**18.94**	**21.23**	**18.89**	**17.79**	**16.47**	**-0.6%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2003 dollars per thousand cubic feet)	**3.06**	**4.98**	**3.64**	**4.16**	**4.53**	**4.79**	**-0.2%**
Dry Production (trillion cubic feet)[3]							
U.S. Total	18.96	19.07	20.42	20.77	21.89	21.83	0.6%
Lower 48 Onshore	13.69	13.89	14.98	15.38	15.30	14.71	0.3%
Associated-Dissolved[4]	1.54	1.54	1.32	1.22	1.15	1.08	-1.6%
Non-Associated	12.15	12.36	13.66	14.16	14.16	13.63	0.4%
Conventional	5.66	5.77	5.60	5.62	5.40	5.02	-0.6%
Unconventional	6.49	6.59	8.06	8.54	8.75	8.61	1.2%
Lower 48 Offshore	4.85	4.73	5.19	5.12	4.70	4.89	0.1%
Associated-Dissolved[4]	1.02	0.99	1.81	1.48	1.39	1.34	1.4%
Non-Associated	3.83	3.74	3.38	3.64	3.31	3.56	-0.2%
Alaska	0.43	0.44	0.25	0.27	1.89	2.23	7.6%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**178.48**	**180.77**	**204.21**	**194.93**	**186.10**	**178.29**	**-0.1%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.07**	**0.06**	**0.08**	**0.08**	**0.08**	**0.08**	**0.7%**
Total Lower 48 Wells Drilled (thousands)	**25.45**	**30.08**	**27.67**	**29.33**	**29.59**	**26.96**	**-0.5%**

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

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2002 and 2003 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). 2002 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2002) (Washington, DC, December 2003). 2002 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 natural gas lower 48 average wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 crude oil lower 48 average wellhead price: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). Other 2002 and 2003 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production[1]							
Appalachia	408	388	403	385	384	406	0.2%
Interior	147	146	159	157	164	182	1.0%
West	550	549	676	727	797	900	2.3%
East of the Mississippi	504	481	510	493	499	538	0.5%
West of the Mississippi	601	603	729	777	846	950	2.1%
Total	**1105**	**1083**	**1238**	**1270**	**1345**	**1488**	**1.5%**
Net Imports							
Imports	17	25	33	38	42	46	2.8%
Exports	40	43	42	35	35	26	-2.2%
Total	**-23**	**-18**	**-9**	**3**	**7**	**20**	**N/A**
Total Supply[2]	**1083**	**1065**	**1229**	**1273**	**1352**	**1507**	**1.6%**
Consumption by Sector							
Residential and Commercial	4	4	5	5	5	5	0.4%
Industrial[3]	63	62	66	66	66	66	0.3%
Coke Plants	22	24	20	18	15	13	-2.7%
Electric Power[4]	976	1004	1139	1185	1267	1425	1.6%
Total Sectoral Consumption	**1066**	**1095**	**1229**	**1273**	**1352**	**1508**	**1.5%**
Coal to Liquids							
Heat and Power (included in Industrial)	0	0	0	0	0	0	N/A
Liquids Production	0	0	0	0	0	0	N/A
Total Coal Use	**1066**	**1095**	**1229**	**1273**	**1352**	**1508**	**1.5%**
Discrepancy and Stock Change[5]	**17**	**-29**	**0**	**-0**	**-1**	**-1**	**N/A**
Average Minemouth Price							
(2003 dollars per short ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
(2003 dollars per million Btu)	0.89	0.86	0.85	0.84	0.86	0.91	0.2%
Delivered Prices (2003 dollars per short ton)[6]							
Industrial	36.08	34.74	33.80	33.44	33.77	34.60	-0.0%
Coke Plants	51.60	50.63	49.87	48.38	48.03	46.14	-0.4%
Electric Power							
(2003 dollars per short ton)	26.26	25.86	24.89	24.42	24.66	25.95	0.0%
(2003 dollars per million Btu)	1.27	1.28	1.25	1.23	1.25	1.31	0.1%
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average	**27.38**	**26.91**	**25.78**	**25.22**	**25.37**	**26.51**	**-0.1%**
Exports[7]	41.18	39.80	39.29	37.40	37.20	36.06	-0.4%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002 and 11.6 million tons in 2003.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential and commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002: Energy Information Administration (EIA), *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). 2003 data based on: EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004); EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004); and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	77.80	77.93	78.18	78.18	78.18	78.18	0.0%
Geothermal[2]	2.17	2.18	2.21	2.66	3.45	4.62	3.5%
Municipal Solid Waste[3]	3.26	3.34	3.57	3.63	3.66	3.67	0.4%
Wood and Other Biomass[4,5]	1.77	1.77	1.83	2.06	2.75	4.50	4.3%
Solar Thermal	0.39	0.39	0.45	0.47	0.49	0.51	1.3%
Solar Photovoltaic[6]	0.03	0.04	0.15	0.23	0.32	0.40	10.9%
Wind	5.01	6.56	8.88	9.29	10.45	11.25	2.5%
Total	**90.42**	**92.21**	**95.27**	**96.50**	**99.29**	**103.13**	**0.5%**
Generation (billion kilowatthours)							
Conventional Hydropower	260.67	269.29	300.39	300.55	300.81	301.09	0.5%
Geothermal[2]	14.49	13.15	12.33	16.09	22.83	32.78	4.2%
Municipal Solid Waste[3]	20.46	20.28	25.58	26.07	26.36	26.49	1.2%
Wood and Other Biomass[5]	9.74	9.40	27.61	30.01	32.35	37.35	6.5%
Dedicated Plants	7.06	5.73	10.32	11.67	16.21	27.29	7.4%
Cofiring	2.68	3.66	17.29	18.34	16.13	10.06	4.7%
Solar Thermal	0.55	0.53	0.80	0.86	0.92	0.99	2.9%
Solar Photovoltaic[6]	0.00	0.00	0.32	0.52	0.74	0.96	30.0%
Wind	10.35	10.73	25.89	27.34	31.61	34.52	5.5%
Total	**316.27**	**323.38**	**392.90**	**401.44**	**415.61**	**434.19**	**1.3%**
End-Use Sector[7]							
Net Summer Capacity							
Conventional Hydropower[8]	1.02	1.03	1.03	1.03	1.03	1.03	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.22	0.26	0.26	0.26	0.26	0.26	0.0%
Biomass	4.08	4.08	5.14	5.55	6.18	6.75	2.3%
Solar Photovoltaic[6]	0.04	0.06	0.39	0.44	0.80	1.80	17.0%
Total	**5.37**	**5.43**	**6.82**	**7.30**	**8.27**	**9.85**	**2.7%**
Generation (billion kilowatthours)							
Conventional Hydropower[8]	3.67	5.82	5.82	5.82	5.82	5.82	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	1.65	1.86	2.24	2.24	2.24	2.24	0.8%
Biomass	29.04	27.59	33.76	36.19	39.86	43.21	2.1%
Solar Photovoltaic[6]	0.09	0.12	0.83	0.95	1.68	3.74	16.9%
Total	**34.45**	**35.39**	**42.64**	**45.20**	**49.60**	**55.00**	**2.0%**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Annual Energy Review 2003, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2002 and 2003 generation: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Marketed Renewable Energy[2]							
Residential (wood)	**0.39**	**0.40**	**0.40**	**0.39**	**0.39**	**0.38**	**-0.3%**
Commercial (biomass)	**0.08**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.0%**
Industrial[3]	**1.78**	**1.79**	**2.07**	**2.19**	**2.34**	**2.50**	**1.5%**
Conventional Hydroelectric	0.04	0.06	0.06	0.06	0.06	0.06	0.0%
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Biomass	1.73	1.72	1.99	2.12	2.27	2.42	1.6%
Transportation	**0.17**	**0.24**	**0.32**	**0.33**	**0.36**	**0.38**	**2.2%**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Ethanol used in Gasoline Blending	0.17	0.24	0.32	0.33	0.35	0.38	2.2%
Electric Power[5]	**3.54**	**3.62**	**4.30**	**4.46**	**4.75**	**5.14**	**1.6%**
Conventional Hydroelectric	2.64	2.72	3.08	3.08	3.08	3.08	0.6%
Geothermal	0.30	0.28	0.27	0.39	0.61	0.92	5.6%
Municipal Solid Waste[6]	0.31	0.32	0.34	0.35	0.35	0.35	0.4%
Biomass	0.17	0.18	0.32	0.35	0.36	0.40	3.6%
Dedicated Plants	0.11	0.09	0.10	0.12	0.17	0.28	5.4%
Cofiring	0.06	0.09	0.22	0.23	0.19	0.11	0.9%
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	6.2%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.10	0.11	0.27	0.28	0.33	0.36	5.5%
Total Marketed Renewable Energy	**5.96**	**6.13**	**7.17**	**7.46**	**7.93**	**8.48**	**1.5%**
Sources of Ethanol							
From Corn	0.17	0.24	0.32	0.33	0.34	0.34	1.7%
From Cellulose	0.00	0.00	0.00	0.01	0.02	0.04	N/A
Total	**0.17**	**0.24**	**0.32**	**0.33**	**0.36**	**0.38**	**2.2%**
Non-Marketed Renewable Energy[7] Selected Consumption							
Residential	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**3.3%**
Solar Hot Water Heating	0.02	0.02	0.03	0.03	0.03	0.04	2.4%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	7.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	17.5%
Commercial	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**2.1%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.7%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	16.7%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2002 and 2003 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Residential							
Petroleum	104.1	106.2	107.4	108.4	107.0	104.1	-0.1%
Natural Gas	265.9	277.3	300.2	311.7	319.4	325.6	0.7%
Coal	1.0	1.1	1.1	1.0	1.0	0.9	-1.0%
Electricity	823.7	840.3	946.5	998.0	1060.3	1149.4	1.4%
Total	**1194.7**	**1225.0**	**1355.2**	**1419.1**	**1487.6**	**1580.0**	**1.2%**
Commercial							
Petroleum	52.6	53.8	61.3	64.9	68.7	72.8	1.4%
Natural Gas	168.7	170.6	184.0	194.7	206.4	220.1	1.2%
Coal	8.6	9.4	9.2	9.2	9.1	9.1	-0.1%
Electricity	785.4	794.3	943.0	1040.3	1159.3	1325.8	2.4%
Total	**1015.4**	**1028.1**	**1197.6**	**1309.1**	**1443.5**	**1627.9**	**2.1%**
Industrial[1]							
Petroleum	412.5	421.8	466.7	476.1	503.6	520.7	1.0%
Natural Gas[2]	449.9	419.8	483.8	506.0	531.6	550.2	1.2%
Coal	183.9	186.1	189.5	181.9	176.2	171.1	-0.4%
Electricity	632.0	636.1	712.2	734.6	768.2	816.6	1.1%
Total	**1678.4**	**1663.8**	**1852.3**	**1898.7**	**1979.6**	**2058.6**	**1.0%**
Transportation							
Petroleum[3]	1810.6	1821.6	2165.0	2364.4	2540.2	2723.1	1.8%
Natural Gas[4]	37.1	35.4	40.0	42.9	48.7	50.4	1.6%
Electricity	14.4	14.9	16.9	18.2	19.9	22.3	1.8%
Total	**1862.1**	**1871.9**	**2221.8**	**2425.5**	**2608.9**	**2795.8**	**1.8%**
Electric Power[5]							
Petroleum	76.9	95.8	96.3	100.7	106.9	109.2	0.6%
Natural Gas	305.6	266.6	362.1	450.8	508.0	506.5	3.0%
Coal	1855.8	1906.0	2139.8	2218.8	2371.5	2676.8	1.6%
Other	17.3	17.3	20.4	20.9	21.2	21.5	1.0%
Total	**2255.6**	**2285.7**	**2618.6**	**2791.1**	**3007.6**	**3314.1**	**1.7%**
Total Carbon Dioxide Emissions by Primary Fuel[6]							
Petroleum[3]	2456.7	2499.2	2896.7	3114.5	3326.5	3530.0	1.6%
Natural Gas	1227.1	1169.7	1370.2	1506.1	1614.0	1652.9	1.6%
Coal	2049.4	2102.5	2339.5	2410.9	2557.9	2857.9	1.4%
Other	17.3	17.3	20.4	20.9	21.2	21.5	1.0%
Total	**5750.5**	**5788.7**	**6626.8**	**7052.4**	**7519.6**	**8062.3**	**1.5%**
Carbon Dioxide Emissions (ton per person)	**19.9**	**19.9**	**21.4**	**21.8**	**22.3**	**23.0**	**0.7%**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2002, international bunker fuels accounted for 82 to 100 million metric tons of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[6]Emissions from the electric power sector are distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A19. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Real Gross Domestic Product	**10075**	**10381**	**13084**	**15216**	**17634**	**20292**	**3.1%**
Real Potential Gross Domestic Product	**10396**	**10736**	**13464**	**15188**	**17491**	**20462**	**3.0%**
Real Disposable Personal Income	**7560**	**7734**	**9594**	**11192**	**12783**	**14990**	**3.1%**
Components of Real Gross Domestic Product							
Real Consumption	7123	7356	9031	10389	11826	13352	2.7%
Real Investment	1561	1629	2324	2977	3805	4868	5.1%
Real Government Spending	1858	1909	2135	2302	2486	2647	1.5%
Real Exports	1012	1032	1917	2640	3633	4956	7.4%
Real Imports	1484	1550	2287	2991	3883	5094	5.6%
Energy Intensity (thousand Btu per 2000 dollar of GDP)							
Delivered Energy	7.11	6.92	6.23	5.70	5.23	4.81	-1.6%
Total Energy	9.73	9.47	8.51	7.78	7.13	6.57	-1.6%
Price Indices							
GDP Chain-Type Price Index (2000=1.000)	1.041	1.060	1.218	1.373	1.563	1.814	2.5%
Consumer Price Index (1982-4=1)	1.80	1.84	2.12	2.41	2.78	3.26	2.6%
Wholesale Price Index (1982=1.00)							
All Commodities	1.31	1.38	1.50	1.61	1.74	1.91	1.5%
Fuel and Power	0.93	1.13	1.13	1.35	1.61	1.93	2.5%
Interest Rates (percent, nominal)							
Federal Funds Rate	1.67	1.13	5.51	5.56	5.52	5.91	N/A
10-Year Treasury Note	4.61	4.01	6.61	6.47	6.43	6.57	N/A
AA Utility Bond Rate	7.19	6.39	7.66	8.07	8.34	8.59	N/A
Unemployment Rate (percent)	**5.78**	**5.99**	**5.57**	**4.89**	**4.48**	**4.55**	**N/A**
Housing Starts (millions)	**1.88**	**1.98**	**1.89**	**1.89**	**1.88**	**1.89**	**-0.2%**
Commercial Floorspace, Total (billion square feet)	**70.9**	**72.1**	**81.2**	**88.4**	**96.2**	**104.8**	**1.7%**
Unit Sales of Light-Duty Vehicles (millions)	**16.78**	**16.63**	**18.06**	**18.49**	**19.66**	**21.11**	**1.1%**
Value of Shipments (billion 1996 dollars)							
Total Industrial	5067	5105	6165	6850	7633	8469	2.3%
Non-manufacturing	1240	1254	1329	1458	1587	1736	1.5%
Manufacturing	3826	3851	4836	5392	6046	6733	2.6%
Energy-Intensive	1057	1048	1219	1298	1384	1462	1.5%
Non-Energy Intensive	2769	2803	3617	4094	4662	5271	2.9%
Population and Employment (millions)							
Population, with Armed Forces Overseas	288.6	291.4	310.1	323.5	337.0	350.6	0.8%
Population, aged 16 and over	223.9	226.5	244.1	254.5	265.3	276.5	0.9%
Employment, Nonfarm	130.3	129.9	140.7	148.8	159.7	169.1	1.2%
Employment, Manufacturing	15.3	14.5	14.0	13.3	13.0	12.7	-0.6%
Labor Force	145.1	146.5	159.3	163.4	169.8	176.8	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 2002 and 2003: Global Insight macroeconomic model CTL0804, modified by Energy Information Administration (EIA); and Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
World Oil Price (2003 dollars per barrel)[1]	**24.10**	**27.73**	**25.00**	**26.75**	**28.50**	**30.31**	**0.4%**
Production (Conventional)[2]							
Industrialized Countries							
U.S. (50 states)	9.27	9.09	9.61	9.27	9.21	8.82	-0.1%
Canada	2.14	2.25	1.83	1.64	1.60	1.57	-1.6%
Mexico	3.61	3.80	4.21	4.55	4.62	4.85	1.1%
Western Europe[3]	6.87	6.69	6.35	5.89	5.51	5.00	-1.3%
Japan	0.20	0.13	0.08	0.07	0.06	0.06	-3.3%
Australia and New Zealand	0.75	0.66	0.96	0.91	0.89	0.86	1.2%
Total Industrialized	**22.85**	**22.62**	**23.05**	**22.33**	**21.89**	**21.16**	**-0.3%**
Eurasia							
Former Soviet Union							
Russia	7.67	8.34	9.98	10.62	10.90	11.11	1.3%
Caspian Area[4]	1.66	1.87	3.14	4.46	5.23	6.22	5.6%
Eastern Europe[5]	0.17	0.22	0.33	0.38	0.41	0.45	3.2%
Total Eurasia	**9.50**	**10.44**	**13.46**	**15.46**	**16.54**	**17.78**	**2.5%**
Developing Countries							
OPEC[6]							
Asia	1.39	1.38	1.47	1.47	1.51	1.56	0.6%
Middle East	20.90	20.95	24.45	26.87	32.37	38.47	2.8%
North Africa	3.03	2.99	3.44	3.71	4.44	4.78	2.2%
West Africa	2.01	1.98	2.36	2.64	3.13	3.74	2.9%
South America	2.91	2.85	3.34	3.81	4.44	5.20	2.8%
Non-OPEC							
China	2.99	3.10	3.64	3.50	3.49	3.41	0.4%
Other Asia	2.38	2.59	2.65	2.76	2.71	2.64	0.1%
Middle East[7]	1.91	1.81	2.24	2.47	2.57	2.78	2.0%
Africa	2.89	2.94	3.75	4.75	5.44	6.56	3.7%
South and Central America	3.79	3.93	4.53	5.38	5.91	6.42	2.3%
Total Developing Countries	**44.20**	**44.52**	**51.87**	**57.35**	**66.02**	**75.57**	**2.4%**
Total Production (Conventional)	**76.55**	**77.58**	**88.38**	**95.14**	**104.45**	**114.51**	**1.8%**
Production (Nonconventional)[8]							
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Other North America	0.81	0.93	1.73	3.09	3.33	3.46	6.2%
Western Europe	0.04	0.04	0.04	0.05	0.05	0.05	1.8%
Asia	0.03	0.03	0.04	0.04	0.05	0.07	4.4%
Middle East[7]	0.01	0.03	0.12	0.16	0.21	0.25	10.8%
Africa.	0.20	0.21	0.23	0.25	0.28	0.32	2.0%
South and Central America	0.54	0.57	0.82	1.36	1.48	1.50	4.5%
Total Production (Nonconventional)	**1.63**	**1.79**	**2.98**	**4.94**	**5.40**	**5.65**	**5.4%**
Total Production	**78.18**	**79.37**	**91.35**	**100.08**	**109.85**	**120.17**	**1.9%**

Table A20. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Consumption[9]							
Industrialized Countries							
U.S. (50 states)	19.71	20.00	22.98	24.67	26.32	27.93	1.5%
U.S. Territories	0.32	0.36	0.38	0.40	0.43	0.47	1.2%
Canada	2.09	2.17	2.30	2.46	2.62	2.80	1.2%
Mexico	1.98	2.02	2.36	2.63	2.88	3.48	2.5%
Western Europe[3]	13.81	14.22	14.72	15.08	15.45	15.71	0.5%
Japan	5.30	5.58	5.70	5.72	5.69	5.84	0.2%
Australia and New Zealand	1.01	1.04	1.27	1.40	1.54	1.69	2.2%
Total Industrialized	**44.23**	**45.38**	**49.72**	**52.36**	**54.93**	**57.92**	**1.1%**
Eurasia							
Former Soviet Union	4.11	4.18	4.39	5.02	5.74	6.45	2.0%
Eastern Europe[5]	1.41	1.42	1.56	1.68	1.89	2.09	1.8%
Total Eurasia	**5.52**	**5.59**	**5.95**	**6.70**	**7.63**	**8.54**	**1.9%**
Developing Countries							
China	5.16	5.54	7.63	9.20	11.06	12.79	3.9%
India	2.18	2.19	2.79	3.48	4.37	5.29	4.1%
South Korea	2.18	2.17	2.51	2.65	2.75	2.93	1.4%
Other Asia	5.59	5.74	7.28	8.36	9.47	10.66	2.9%
Middle East[7]	5.68	5.58	6.83	7.53	8.34	9.08	2.2%
Africa	2.67	2.72	3.13	3.57	4.13	4.66	2.5%
South and Central America	4.88	4.69	5.81	6.53	7.48	8.61	2.8%
Total Developing Countries	**28.35**	**28.64**	**35.98**	**41.31**	**47.59**	**54.01**	**2.9%**
Total Consumption	**78.10**	**79.60**	**91.65**	**100.38**	**110.14**	**120.47**	**1.9%**
OPEC Production[10]	30.65	30.60	35.79	39.67	47.21	55.13	2.7%
Non-OPEC Production[10]	47.52	48.77	55.56	60.41	62.64	65.04	1.3%
Net Eurasia Exports	3.99	4.84	7.51	8.75	8.92	9.25	3.0%
OPEC Market Share	0.39	0.39	0.39	0.40	0.43	0.46	0.8%

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2002 data derived from: Energy Information Administration (EIA), *International Energy Annual 2002*, DOE/EIA-0219(2002) (Washington, DC, March 2004). **2003 and projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	12.03	12.74	12.75	12.78	10.99	11.03	11.07	9.96	10.01	10.19
Natural Gas Plant Liquids	2.34	2.66	2.66	2.70	2.69	2.80	2.86	2.75	2.81	2.83
Dry Natural Gas	19.58	20.90	20.97	21.39	21.34	22.48	23.11	21.94	22.42	22.65
Coal	22.66	24.73	25.10	25.43	26.05	27.04	28.15	27.51	29.90	32.20
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.84
Other[2]	0.93	0.92	0.97	1.09	0.71	0.77	0.95	0.78	0.82	0.98
Total	**71.42**	**77.18**	**77.79**	**78.84**	**77.71**	**80.35**	**82.82**	**79.29**	**82.73**	**86.35**
Imports										
Crude Oil[3]	21.08	24.02	24.69	24.97	30.89	32.29	32.16	32.85	35.16	36.52
Petroleum Products[4]	5.16	5.25	6.06	7.19	5.44	6.83	9.75	6.65	8.27	10.69
Natural Gas	4.02	5.08	5.71	6.14	8.57	8.95	9.52	8.86	9.70	10.44
Other Imports[5]	0.69	0.90	0.92	0.96	1.12	1.15	1.17	1.21	1.23	1.25
Total	**30.95**	**35.25**	**37.38**	**39.27**	**46.02**	**49.22**	**52.60**	**49.58**	**54.36**	**58.90**
Exports										
Petroleum[6]	2.13	2.10	2.14	2.19	2.19	2.26	2.34	2.22	2.32	2.42
Natural Gas	0.70	0.67	0.65	0.64	0.91	0.86	0.81	0.91	0.83	0.73
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.88	0.67	0.65	0.65
Total	**3.95**	**3.83**	**3.86**	**3.89**	**3.99**	**4.01**	**4.02**	**3.80**	**3.80**	**3.80**
Discrepancy[7]	**0.18**	**0.03**	**0.05**	**0.03**	**0.02**	**-0.05**	**-0.09**	**0.14**	**0.10**	**0.10**
Consumption										
Petroleum Products[8]	39.09	43.37	44.84	46.42	48.29	51.30	54.31	50.43	54.42	58.44
Natural Gas	22.54	25.39	26.11	26.97	29.17	30.73	32.00	30.06	31.47	32.55
Coal	22.71	24.58	24.95	25.30	26.27	27.27	28.42	28.05	30.48	32.81
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.85
Other[9]	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Net Imports - Petroleum	**24.10**	**27.17**	**28.61**	**29.98**	**34.14**	**36.87**	**39.57**	**37.28**	**41.11**	**44.79**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.73	24.45	25.00	25.61	27.40	28.50	29.71	28.75	30.31	31.99
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.48	3.64	3.89	4.19	4.53	4.88	4.53	4.79	5.16
Coal Minemouth Price (dollars per ton)	17.93	17.17	17.30	17.70	16.79	17.25	17.89	17.11	18.26	19.78
Average Electricity Price (cents per kilowatthour)	7.4	6.4	6.6	6.9	6.9	7.2	7.5	7.0	7.3	7.6

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

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

Sector and Source	2003	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2025 Low Economic Growth	2025 Reference	2025 High Economic Growth
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.90	0.90	0.90	0.83	0.83	0.83	0.77	0.77	0.77
Kerosene	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08
Liquefied Petroleum Gas	0.54	0.57	0.57	0.57	0.63	0.64	0.65	0.65	0.67	0.67
Petroleum Subtotal	1.58	1.56	1.56	1.56	1.55	1.56	1.57	1.51	1.53	1.53
Natural Gas	5.25	5.68	5.68	5.69	5.90	6.05	6.13	5.96	6.17	6.28
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.38	0.39	0.39	0.37	0.38	0.39
Electricity	4.37	5.01	5.02	5.03	5.66	5.79	5.88	5.96	6.18	6.31
Delivered Energy	**11.61**	**12.67**	**12.67**	**12.69**	**13.51**	**13.80**	**13.98**	**13.81**	**14.26**	**14.52**
Electricity Related Losses	9.71	10.83	10.80	10.77	11.71	11.77	11.80	12.12	12.35	12.42
Total	**21.31**	**23.49**	**23.47**	**23.47**	**25.22**	**25.56**	**25.79**	**25.93**	**26.62**	**26.94**
Commercial										
Distillate Fuel	0.52	0.61	0.62	0.62	0.70	0.71	0.72	0.74	0.77	0.78
Residual Fuel	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.85	0.86	0.86	0.95	0.96	0.97	0.99	1.02	1.04
Natural Gas	3.22	3.47	3.49	3.49	3.80	3.91	4.01	4.01	4.17	4.32
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	4.97	5.00	5.02	6.17	6.33	6.48	6.87	7.12	7.37
Delivered Energy	**8.29**	**9.47**	**9.53**	**9.55**	**11.09**	**11.38**	**11.64**	**12.05**	**12.49**	**12.91**
Electricity Related Losses	9.18	10.73	10.76	10.73	12.75	12.86	13.00	13.97	14.25	14.50
Total	**17.46**	**20.20**	**20.29**	**20.28**	**23.84**	**24.24**	**24.64**	**26.02**	**26.74**	**27.41**
Industrial[4]										
Distillate Fuel	1.03	0.97	1.04	1.12	1.02	1.14	1.26	1.05	1.19	1.34
Liquefied Petroleum Gas	2.09	2.14	2.30	2.48	2.27	2.59	2.94	2.31	2.74	3.22
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	0.28	0.32	0.34	0.37	0.37	0.38	0.40	0.37	0.38	0.44
Motor Gasoline[2]	0.31	0.29	0.31	0.34	0.30	0.35	0.39	0.32	0.37	0.43
Other Petroleum[5]	4.30	4.41	4.69	4.97	4.51	5.02	5.36	4.62	5.23	5.63
Petroleum Subtotal	9.31	9.51	10.17	10.87	9.85	11.03	12.11	10.00	11.47	12.92
Natural Gas	7.19	7.79	8.10	8.50	8.24	8.89	9.68	8.33	9.26	10.31
Lease and Plant Fuel[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Natural Gas Subtotal	8.34	8.99	9.31	9.72	9.51	10.21	11.04	9.61	10.57	11.63
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	1.39	1.40	1.42	1.46	1.38	1.42	1.46	1.36	1.42	1.47
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	2.11	1.99	2.03	2.08	1.83	1.89	1.95	1.76	1.83	1.91
Renewable Energy[7]	1.79	1.97	2.07	2.17	2.13	2.34	2.60	2.21	2.50	2.84
Electricity	3.31	3.54	3.78	4.04	3.77	4.19	4.64	3.82	4.39	5.02
Delivered Energy	**24.86**	**26.00**	**27.35**	**28.88**	**27.10**	**29.66**	**32.34**	**27.40**	**30.76**	**34.32**
Electricity Related Losses	7.35	7.65	8.13	8.65	7.79	8.52	9.31	7.76	8.78	9.88
Total	**32.21**	**33.65**	**35.47**	**37.54**	**34.89**	**38.19**	**41.65**	**35.16**	**39.53**	**44.20**

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

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuel[8]	5.54	6.54	6.95	7.38	7.55	8.35	9.14	8.04	9.05	10.19
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Motor Gasoline[2]	16.64	18.85	19.14	19.47	21.36	22.31	23.26	22.69	24.04	25.32
Residual Fuel	0.62	0.56	0.56	0.57	0.57	0.58	0.58	0.57	0.58	0.59
Liquefied Petroleum Gas	0.02	0.05	0.06	0.06	0.07	0.08	0.08	0.08	0.09	0.09
Other Petroleum[10]	0.24	0.24	0.26	0.27	0.27	0.29	0.32	0.28	0.31	0.35
Petroleum Subtotal	26.31	30.21	31.00	31.84	34.55	36.35	38.11	36.53	38.97	41.46
Pipeline Fuel Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.10	0.11	0.10	0.11	0.12
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.05**	**31.85**	**32.71**	**35.54**	**37.39**	**39.18**	**37.58**	**40.04**	**42.56**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**27.24**	**31.24**	**32.04**	**32.90**	**35.77**	**37.61**	**39.40**	**37.82**	**40.28**	**42.80**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.03	9.51	10.01	10.11	11.03	11.95	10.61	11.78	13.09
Kerosene	0.11	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Liquefied Petroleum Gas	2.75	2.87	3.03	3.21	3.08	3.42	3.78	3.15	3.60	4.09
Motor Gasoline[2]	16.98	19.18	19.49	19.86	21.71	22.70	23.70	23.04	24.45	25.79
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	0.97	0.95	0.97	1.02	1.01	1.03	1.06	1.02	1.03	1.11
Other Petroleum[12]	4.52	4.63	4.93	5.22	4.76	5.30	5.66	4.88	5.53	5.97
Petroleum Subtotal	37.96	42.14	43.58	45.12	46.91	49.90	52.76	49.03	52.98	56.94
Natural Gas	15.68	16.99	17.33	17.75	18.03	18.94	19.93	18.39	19.70	21.03
Lease and Plant Fuel Plant[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Pipeline Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Natural Gas Subtotal	17.48	18.88	19.23	19.69	20.09	21.09	22.14	20.50	21.85	23.20
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	1.50	1.50	1.53	1.56	1.48	1.52	1.57	1.47	1.52	1.58
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	2.22	2.10	2.14	2.19	1.94	2.00	2.06	1.86	1.94	2.02
Renewable Energy[13]	2.28	2.46	2.55	2.66	2.61	2.82	3.08	2.67	2.97	3.32
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.62	13.89	14.18	15.70	16.41	17.10	16.77	17.81	18.83
Delivered Energy	**71.82**	**79.19**	**81.39**	**83.83**	**87.24**	**92.23**	**97.14**	**90.84**	**97.56**	**104.31**
Electricity Related Losses	26.40	29.39	29.88	30.35	32.47	33.37	34.34	34.09	35.62	37.05
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Electric Power[14]										
Distillate Fuel	0.33	0.38	0.39	0.40	0.49	0.42	0.53	0.43	0.45	0.51
Residual Fuel	0.80	0.85	0.87	0.90	0.89	0.98	1.02	0.97	0.98	1.00
Petroleum Subtotal	1.13	1.23	1.26	1.30	1.39	1.40	1.55	1.40	1.43	1.51
Natural Gas	5.06	6.51	6.87	7.28	9.08	9.64	9.86	9.56	9.61	9.34
Steam Coal	20.49	22.48	22.81	23.11	24.34	25.28	26.36	26.19	28.54	30.79
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.27	4.30	4.30	4.67	4.75	4.94	5.01	5.14	5.53
Electricity Imports	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.01**	**43.77**	**44.54**	**48.17**	**49.79**	**51.44**	**50.86**	**53.43**	**55.87**

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

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Distillate Fuel	8.37	9.41	9.90	10.42	10.60	11.45	12.48	11.04	12.23	13.60
Kerosene	0.11	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Liquefied Petroleum Gas	2.75	2.87	3.03	3.21	3.08	3.42	3.78	3.15	3.60	4.09
Motor Gasoline[2]	16.98	19.18	19.49	19.86	21.71	22.70	23.70	23.04	24.45	25.79
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	1.77	1.80	1.84	1.91	1.90	2.01	2.08	1.99	2.02	2.11
Other Petroleum[12]	4.52	4.63	4.93	5.22	4.76	5.30	5.66	4.88	5.53	5.97
Petroleum Subtotal	39.09	43.37	44.84	46.42	48.29	51.30	54.31	50.43	54.42	58.44
Natural Gas	20.74	23.50	24.21	25.03	27.11	28.59	29.79	27.96	29.32	30.38
Lease and Plant Fuel[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Pipeline Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Natural Gas Subtotal	22.54	25.39	26.11	26.97	29.17	30.73	32.00	30.06	31.47	32.55
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	21.99	23.98	24.34	24.68	25.82	26.80	27.93	27.66	30.07	32.37
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	22.71	24.58	24.95	25.30	26.27	27.27	28.42	28.05	30.48	32.81
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.85
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	79.19	81.39	83.83	87.24	92.23	97.14	90.84	97.56	104.31
Total Energy Use	98.22	108.58	111.27	114.19	119.71	125.60	131.48	124.93	133.18	141.35
Population (millions)	291.39	305.62	310.12	314.61	325.13	336.99	348.84	334.92	350.64	366.35
Gross Domestic Product (billion 2000 dollars)	10381	12640	13084	13740	16163	17634	19089	17957	20292	22570
Carbon Dioxide Emissions										
Carbon Dioxide Emissions (million metric tons)	5788.7	6472.5	6626.8	6782.8	7170.9	7519.6	7856.1	7529.7	8062.3	8560.8

[1]Includes wood used for residential heating. See Table B4 and/or Table B17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Table B3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**15.81**	**13.88**	**14.33**	**14.89**	**14.98**	**15.64**	**16.37**	**15.51**	**16.13**	**16.93**
Primary Energy[1]	9.68	8.15	8.35	8.63	8.84	9.21	9.62	9.28	9.62	10.08
Petroleum Products[2]	11.27	10.15	10.44	10.71	10.90	11.36	11.84	11.44	11.93	12.41
Distillate Fuel	9.57	8.05	8.29	8.43	8.44	8.85	9.17	8.82	9.12	9.43
Liquefied Petroleum Gas	14.58	13.88	14.25	14.73	14.61	15.06	15.71	14.98	15.65	16.25
Natural Gas	9.22	7.61	7.79	8.07	8.31	8.66	9.06	8.75	9.07	9.53
Electricity	25.42	22.18	22.96	23.93	23.09	24.12	25.22	23.31	24.24	25.42
Commercial	**15.63**	**13.28**	**13.76**	**14.45**	**14.95**	**15.70**	**16.52**	**15.52**	**16.20**	**17.08**
Primary Energy[1]	7.92	6.63	6.81	7.07	7.21	7.54	7.89	7.53	7.82	8.22
Petroleum Products[2]	8.03	6.89	7.13	7.43	7.15	7.55	7.90	7.52	7.84	8.15
Distillate Fuel	7.03	6.06	6.30	6.59	6.34	6.76	7.09	6.77	7.06	7.35
Residual Fuel	4.96	4.17	4.26	4.35	4.62	4.81	4.99	4.85	5.08	5.33
Natural Gas	8.08	6.70	6.87	7.13	7.36	7.68	8.04	7.67	7.96	8.37
Electricity	23.24	19.19	19.93	21.00	21.03	22.10	23.28	21.44	22.40	23.65
Industrial[3]	**7.78**	**6.54**	**6.85**	**7.23**	**7.25**	**7.75**	**8.27**	**7.55**	**8.13**	**8.67**
Primary Energy	6.49	5.31	5.55	5.84	5.86	6.27	6.68	6.14	6.64	7.07
Petroleum Products[2]	8.29	6.98	7.24	7.54	7.44	7.88	8.34	7.75	8.36	8.77
Distillate Fuel	7.24	6.56	6.78	7.11	6.95	7.37	7.67	7.47	7.73	7.99
Liquefied Petroleum Gas	12.57	9.64	10.02	10.51	10.18	10.74	11.38	10.47	11.35	11.98
Residual Fuel	4.59	3.80	3.87	3.93	4.16	4.34	4.53	4.37	4.62	4.87
Natural Gas[4]	5.56	4.19	4.37	4.65	4.91	5.23	5.60	5.15	5.47	5.89
Metallurgical Coal	1.85	1.80	1.82	1.84	1.73	1.75	1.77	1.67	1.68	1.70
Steam Coal	1.55	1.54	1.56	1.59	1.53	1.56	1.60	1.54	1.60	1.69
Electricity	15.03	13.27	13.84	14.62	14.60	15.47	16.39	14.98	15.75	16.69
Transportation	**11.46**	**10.56**	**10.95**	**11.31**	**10.73**	**11.16**	**11.59**	**11.04**	**11.46**	**11.93**
Primary Energy	11.43	10.54	10.93	11.28	10.71	11.13	11.56	11.01	11.44	11.90
Petroleum Products[2]	11.43	10.54	10.93	11.29	10.71	11.13	11.57	11.02	11.44	11.91
Distillate Fuel[5]	10.92	10.43	10.76	11.28	10.12	10.66	11.08	10.48	10.85	11.27
Jet Fuel[6]	6.46	5.98	6.25	6.47	6.19	6.58	7.00	6.51	6.93	7.22
Motor Gasoline[7]	12.93	11.86	12.32	12.66	12.16	12.52	12.93	12.41	12.81	13.30
Residual Fuel	4.49	3.65	3.74	3.83	4.11	4.28	4.47	4.32	4.56	4.83
Liquefied Petroleum Gas[8]	16.65	14.86	15.24	15.75	15.11	15.66	16.39	15.31	16.24	17.00
Natural Gas[9]	9.04	8.31	8.56	8.88	9.07	9.45	9.89	9.35	9.69	10.20
Ethanol (E85)[10]	16.23	16.70	17.11	17.28	17.48	17.22	17.65	18.00	18.13	18.13
Electricity	20.64	18.13	18.81	19.68	19.07	19.99	20.94	19.20	19.96	20.93
Average End-Use Energy	**11.50**	**10.22**	**10.56**	**10.93**	**10.97**	**11.42**	**11.89**	**11.39**	**11.83**	**12.32**
Primary Energy	9.32	8.33	8.61	8.91	8.80	9.18	9.57	9.16	9.55	9.96
Electricity	21.74	18.74	19.36	20.21	20.21	21.11	22.06	20.62	21.38	22.37
Electric Power[11]										
Fossil Fuel Average	2.24	1.98	2.06	2.17	2.31	2.45	2.56	2.39	2.46	2.54
Petroleum Products	5.28	4.43	4.55	4.68	4.89	5.10	5.40	5.12	5.42	5.73
Distillate Fuel	6.48	5.14	5.36	5.57	5.55	6.01	6.34	5.99	6.33	6.63
Residual Fuel	4.79	4.11	4.19	4.27	4.52	4.71	4.90	4.75	5.00	5.27
Natural Gas	5.46	4.08	4.27	4.55	4.87	5.20	5.55	5.15	5.44	5.82
Steam Coal	1.28	1.23	1.25	1.28	1.21	1.25	1.28	1.24	1.31	1.39

Table B3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.58	9.91	10.22	9.89	10.29	10.69	10.23	10.66	11.07
Distillate Fuel	9.90	9.21	9.53	9.98	9.22	9.79	10.17	9.65	10.03	10.45
Jet Fuel	6.46	5.98	6.25	6.47	6.19	6.58	7.00	6.51	6.93	7.22
Liquefied Petroleum Gas	13.04	10.66	10.99	11.43	11.29	11.74	12.30	11.61	12.34	12.86
Motor Gasoline[7]	12.93	11.85	12.31	12.64	12.15	12.51	12.92	12.40	12.80	13.29
Residual Fuel	4.66	3.92	3.99	4.08	4.33	4.52	4.71	4.56	4.81	5.06
Natural Gas	6.86	5.37	5.52	5.75	5.99	6.30	6.64	6.29	6.59	6.99
Coal	1.30	1.25	1.27	1.30	1.23	1.27	1.30	1.25	1.32	1.41
Ethanol (E85)[10]	16.23	16.70	17.11	17.28	17.48	17.22	17.65	18.00	18.13	18.13
Electricity	21.74	18.74	19.36	20.21	20.21	21.11	22.06	20.62	21.38	22.37
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	170.34	175.88	183.12	196.72	209.76	222.43	208.36	223.86	239.28
Commercial	128.15	124.66	129.92	136.76	164.55	177.28	190.81	185.66	200.93	219.13
Industrial	147.11	125.25	139.57	157.62	143.07	169.93	201.82	150.46	184.96	225.20
Transportation	302.59	320.52	341.13	361.71	372.99	407.83	444.15	405.66	449.31	497.43
Total Non-Renewable Expenditures	755.02	740.77	786.50	839.21	877.32	964.80	1059.21	950.14	1059.05	1181.04
Transportation Renewable Expenditures	0.02	0.03	0.03	0.04	0.06	0.07	0.07	0.07	0.08	0.09
Total Expenditures	**755.04**	**740.80**	**786.54**	**839.25**	**877.38**	**964.87**	**1059.28**	**950.21**	**1059.13**	**1181.14**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	**10381**	**12640**	**13084**	**13740**	**16163**	**17634**	**19089**	**17957**	**20292**	**22570**
Real Potential Gross Domestic Product	**10736**	**13176**	**13464**	**13858**	**16343**	**17491**	**18909**	**18530**	**20462**	**22637**
Real Disposable Personal Income	**7734**	**9314**	**9594**	**9946**	**11938**	**12783**	**13627**	**13698**	**14990**	**16237**
Components of Real Gross Domestic Product										
Real Consumption	7356	8774	9031	9379	10894	11826	12531	11899	13352	14485
Real Investment	1629	2162	2324	2561	3268	3805	4257	3861	4868	5685
Real Government Spending	1909	2055	2135	2180	2285	2486	2613	2379	2647	2832
Real Exports	1032	1874	1917	1976	3336	3633	3947	4361	4956	5555
Real Imports	1550	2140	2287	2454	3550	3883	4365	4657	5094	5834
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.92	6.27	6.23	6.11	5.40	5.23	5.09	5.06	4.81	4.63
Total Energy	9.47	8.60	8.51	8.31	7.41	7.13	6.89	6.96	6.57	6.27
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.060	1.295	1.218	1.142	1.736	1.563	1.394	2.077	1.814	1.556
Consumer Price Index (1982-4=1)	1.84	2.20	2.12	1.99	3.16	2.78	2.47	3.87	3.26	2.78
Wholesale Price Index (1982=1.00)										
All Commodities	1.38	1.57	1.50	1.41	2.01	1.74	1.54	2.33	1.91	1.62
Fuel and Power	1.13	1.16	1.13	1.11	1.70	1.61	1.51	2.12	1.93	1.75
Interest Rates (percent, nominal)										
Federal Funds Rate	1.13	5.88	5.51	5.15	5.99	5.52	5.01	6.57	5.91	5.28
10-Year Treasury Note	4.01	6.86	6.61	6.35	6.92	6.43	5.93	7.29	6.57	5.88
AA Utility Bond Rate	6.39	7.96	7.66	7.35	9.07	8.34	7.61	9.66	8.59	7.57
Unemployment Rate (percent)	**5.99**	**6.17**	**5.57**	**4.97**	**5.13**	**4.48**	**3.86**	**5.27**	**4.55**	**3.84**
Housing Starts (millions)	**1.98**	**1.70**	**1.89**	**2.17**	**1.55**	**1.88**	**2.08**	**1.47**	**1.89**	**2.16**
Commercial Floorspace, Total (billion square feet)	**72.1**	**80.2**	**81.2**	**82.2**	**92.7**	**96.2**	**99.7**	**99.8**	**104.8**	**109.8**
Unit Sales of Light-Duty Vehicles (millions)	**16.63**	**17.02**	**18.06**	**19.37**	**17.98**	**19.66**	**21.47**	**18.54**	**21.11**	**23.78**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5105	5659	6165	6749	6626	7633	8692	7103	8469	9925
Non-manufacturing	1254	1163	1329	1528	1305	1587	1864	1414	1736	2077
Manufacturing	3851	4496	4836	5220	5322	6046	6827	5689	6733	7847
Energy-Intensive	1048	1164	1219	1273	1276	1384	1501	1313	1462	1627
Non-Energy Intensive	2803	3332	3617	3948	4046	4662	5326	4375	5271	6220
Population and Employment (millions)										
Population with Armed Forces Overseas	291.4	305.6	310.1	314.6	325.1	337.0	348.8	334.9	350.6	366.4
Population (aged 16 and over)	226.5	240.8	244.1	247.5	256.7	265.3	273.8	264.9	276.5	288.1
Employment,Non-Agriculture	129.9	134.3	140.7	147.5	148.4	159.7	169.9	155.6	169.1	183.6
Employment, Manufacturing	14.5	13.4	14.0	14.6	12.3	13.0	13.6	11.8	12.7	13.6
Labor Force	146.5	156.7	159.3	162.6	163.1	169.8	176.8	167.5	176.8	186.4

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2003: Global Insight macroeconomic model CTL0804, modified by Energy Information Administration (EIA); and Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Low and High A Oil Price Case Comparisons

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

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Production										
Crude Oil and Lease Condensate	12.03	12.67	12.75	13.04	10.54	11.03	11.60	9.44	10.01	10.97
Natural Gas Plant Liquids	2.34	2.67	2.66	2.69	2.76	2.80	2.91	2.73	2.81	2.92
Dry Natural Gas	19.58	21.05	20.97	21.23	22.11	22.48	23.59	21.73	22.42	23.42
Coal	22.66	25.10	25.10	25.09	26.68	27.04	27.37	29.20	29.90	30.60
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.14	8.10	8.13
Other[2]	0.93	0.96	0.97	1.18	0.83	0.77	0.96	0.86	0.82	1.04
Total	**71.42**	**77.80**	**77.79**	**78.61**	**79.13**	**80.35**	**82.69**	**80.78**	**82.73**	**85.75**
Imports										
Crude Oil[3]	21.08	25.07	24.69	23.98	33.27	32.29	31.42	36.30	35.16	32.36
Petroleum Products[4]	5.16	6.34	6.06	4.93	8.74	6.83	4.41	11.56	8.27	6.51
Natural Gas	4.02	5.55	5.71	5.62	8.77	8.95	8.70	9.28	9.70	9.43
Other Imports[5]	0.69	0.92	0.92	0.92	1.15	1.15	1.15	1.23	1.23	1.24
Total	**30.95**	**37.88**	**37.38**	**35.45**	**51.93**	**49.22**	**45.68**	**58.37**	**54.36**	**49.53**
Exports										
Petroleum[6]	2.13	2.16	2.14	2.09	2.46	2.26	2.20	2.68	2.32	2.25
Natural Gas	0.70	0.65	0.65	0.65	0.88	0.86	0.86	0.86	0.83	0.82
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.89	0.65	0.65	0.65
Total	**3.95**	**3.88**	**3.86**	**3.81**	**4.23**	**4.01**	**3.95**	**4.19**	**3.80**	**3.71**
Discrepancy[7]	**0.18**	**0.12**	**0.05**	**-0.05**	**0.10**	**-0.05**	**-0.13**	**0.33**	**0.10**	**-0.15**
Consumption										
Petroleum Products[8]	39.09	45.34	44.84	43.74	53.36	51.30	49.64	57.67	54.42	52.34
Natural Gas	22.54	26.02	26.11	26.22	30.19	30.73	31.11	30.33	31.47	31.71
Coal	22.71	24.95	24.95	24.94	26.92	27.27	27.49	29.79	30.48	30.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.15	8.10	8.13
Other[9]	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Net Imports - Petroleum	**24.10**	**29.25**	**28.61**	**26.82**	**39.55**	**36.87**	**33.63**	**45.18**	**41.11**	**36.62**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10] World Oil	27.73	20.99	25.00	33.99	20.99	28.50	36.74	20.99	30.31	39.24
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.61	3.64	3.67	4.32	4.53	4.55	4.68	4.79	4.84
Coal Minemouth Price (dollars per ton)	17.93	17.27	17.30	17.57	17.13	17.25	17.87	18.16	18.26	18.56
Average Electricity Price (cents per kilowatthour)	7.4	6.6	6.6	6.7	7.1	7.2	7.3	7.1	7.3	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.91	0.90	0.83	0.86	0.83	0.75	0.81	0.77	0.66
Kerosene	0.07	0.09	0.09	0.08	0.10	0.09	0.08	0.09	0.09	0.07
Liquefied Petroleum Gas	0.54	0.58	0.57	0.54	0.66	0.64	0.60	0.70	0.67	0.61
Petroleum Subtotal	1.58	1.58	1.56	1.45	1.62	1.56	1.43	1.60	1.53	1.34
Natural Gas	5.25	5.69	5.68	5.68	6.07	6.05	6.07	6.17	6.17	6.17
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.39	0.39	0.39	0.38	0.38	0.38
Electricity	4.37	5.03	5.02	5.01	5.81	5.79	5.78	6.20	6.18	6.16
Delivered Energy	**11.61**	**12.71**	**12.67**	**12.55**	**13.90**	**13.80**	**13.67**	**14.36**	**14.26**	**14.06**
Electricity Related Losses	9.71	10.81	10.80	10.79	11.81	11.77	11.75	12.40	12.35	12.27
Total	**21.31**	**23.52**	**23.47**	**23.34**	**25.71**	**25.56**	**25.42**	**26.76**	**26.62**	**26.33**
Commercial										
Distillate Fuel	0.52	0.63	0.62	0.56	0.75	0.71	0.63	0.82	0.77	0.65
Residual Fuel	0.07	0.07	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.11	0.11	0.10
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.87	0.86	0.80	1.00	0.96	0.87	1.08	1.02	0.90
Natural Gas	3.22	3.49	3.49	3.50	3.92	3.91	3.96	4.17	4.17	4.23
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.01	5.00	4.99	6.36	6.33	6.31	7.17	7.12	7.10
Delivered Energy	**8.29**	**9.55**	**9.53**	**9.47**	**11.47**	**11.38**	**11.32**	**12.59**	**12.49**	**12.40**
Electricity Related Losses	9.18	10.78	10.76	10.75	12.94	12.86	12.82	14.33	14.25	14.13
Total	**17.46**	**20.33**	**20.29**	**20.23**	**24.41**	**24.24**	**24.15**	**26.92**	**26.74**	**26.53**
Industrial[4]										
Distillate Fuel	1.03	1.05	1.04	1.02	1.16	1.14	1.09	1.22	1.19	1.13
Liquefied Petroleum Gas	2.09	2.32	2.30	2.26	2.64	2.59	2.53	2.84	2.74	2.63
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	0.28	0.34	0.34	0.34	0.43	0.38	0.39	0.45	0.38	0.36
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.35	0.35	0.35	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.74	4.69	4.60	4.98	5.02	4.89	5.04	5.23	5.06
Petroleum Subtotal	9.31	10.26	10.17	9.99	11.13	11.03	10.79	11.50	11.47	11.10
Natural Gas	7.19	8.08	8.10	8.17	8.83	8.89	9.02	9.21	9.26	9.38
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Natural Gas Subtotal	8.34	9.28	9.31	9.39	10.13	10.21	10.41	10.48	10.57	10.75
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.39	1.43	1.42	1.42	1.42	1.42	1.54	1.42	1.42	1.77
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	2.11	2.03	2.03	2.03	1.90	1.89	2.01	1.84	1.83	2.18
Renewable Energy[7]	1.79	2.07	2.07	2.06	2.35	2.34	2.35	2.50	2.50	2.50
Electricity	3.31	3.79	3.78	3.76	4.21	4.19	4.21	4.40	4.39	4.41
Delivered Energy	**24.86**	**27.43**	**27.35**	**27.23**	**29.71**	**29.66**	**29.76**	**30.72**	**30.76**	**30.95**
Electricity Related Losses	7.35	8.15	8.13	8.11	8.56	8.52	8.56	8.80	8.78	8.78
Total	**32.21**	**35.58**	**35.47**	**35.34**	**38.27**	**38.19**	**38.32**	**39.52**	**39.53**	**39.73**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Transportation										
Distillate Fuel[8]	5.54	6.97	6.95	6.90	8.37	8.35	8.28	9.13	9.05	9.01
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Motor Gasoline[2]	16.64	19.32	19.14	18.59	22.94	22.31	21.48	24.94	24.04	22.98
Residual Fuel	0.62	0.56	0.56	0.56	0.58	0.58	0.58	0.58	0.58	0.58
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.25	0.29	0.29	0.29	0.32	0.31	0.31
Petroleum Subtotal	26.31	31.21	31.00	30.35	37.11	36.35	35.40	40.14	38.97	37.81
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**32.06**	**31.85**	**31.21**	**38.13**	**37.39**	**36.45**	**41.19**	**40.04**	**38.90**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**27.24**	**32.26**	**32.04**	**31.40**	**38.35**	**37.61**	**36.67**	**41.43**	**40.28**	**39.13**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.57	9.51	9.32	11.14	11.03	10.75	11.98	11.78	11.45
Kerosene	0.11	0.14	0.14	0.12	0.14	0.14	0.12	0.14	0.13	0.11
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Liquefied Petroleum Gas	2.75	3.05	3.03	2.95	3.50	3.42	3.31	3.73	3.60	3.43
Motor Gasoline[2]	16.98	19.67	19.49	18.94	23.33	22.70	21.87	25.35	24.45	23.39
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	0.97	0.97	0.97	0.97	1.08	1.03	1.04	1.11	1.03	1.02
Other Petroleum[12]	4.52	4.98	4.93	4.83	5.25	5.30	5.17	5.34	5.53	5.36
Petroleum Subtotal	37.96	43.93	43.58	42.60	50.86	49.90	48.48	54.32	52.98	51.14
Natural Gas	15.68	17.32	17.33	17.41	18.92	18.94	19.15	19.65	19.70	19.89
Lease and Plant Fuel Plant[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Pipeline Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Natural Gas Subtotal	17.48	19.22	19.23	19.34	21.03	21.09	21.38	21.74	21.85	22.12
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.53	1.53	1.52	1.64	1.53	1.52	1.87
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	2.22	2.14	2.14	2.13	2.00	2.00	2.11	1.95	1.94	2.29
Renewable Energy[13]	2.28	2.55	2.55	2.55	2.83	2.82	2.83	2.97	2.97	2.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.91	13.89	13.85	16.49	16.41	16.40	17.89	17.81	17.79
Delivered Energy	**71.82**	**81.76**	**81.39**	**80.46**	**93.21**	**92.23**	**91.20**	**98.87**	**97.56**	**96.31**
Electricity Related Losses	26.40	29.93	29.88	29.85	33.53	33.37	33.35	35.76	35.62	35.41
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Electric Power[14]										
Distillate Fuel	0.33	0.40	0.39	0.37	1.29	0.42	0.38	2.09	0.45	0.40
Residual Fuel	0.80	1.01	0.87	0.77	1.21	0.98	0.78	1.26	0.98	0.79
Petroleum Subtotal	1.13	1.42	1.26	1.14	2.50	1.40	1.16	3.35	1.43	1.20
Natural Gas	5.06	6.80	6.87	6.89	9.16	9.64	9.72	8.58	9.61	9.59
Steam Coal	20.49	22.81	22.81	22.81	24.92	25.28	25.38	27.84	28.54	28.55
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.30	4.30	4.34	4.73	4.75	4.76	5.18	5.14	5.16
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.84**	**43.77**	**43.70**	**50.02**	**49.79**	**49.75**	**53.65**	**53.43**	**53.20**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Total Energy Consumption										
Distillate Fuel	8.37	9.97	9.90	9.69	12.43	11.45	11.12	14.07	12.23	11.85
Kerosene	0.11	0.14	0.14	0.12	0.14	0.14	0.12	0.14	0.13	0.11
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Liquefied Petroleum Gas	2.75	3.05	3.03	2.95	3.50	3.42	3.31	3.73	3.60	3.43
Motor Gasoline[2]	16.98	19.67	19.49	18.94	23.33	22.70	21.87	25.35	24.45	23.39
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	1.77	1.99	1.84	1.74	2.30	2.01	1.82	2.36	2.02	1.82
Other Petroleum[12]	4.52	4.98	4.93	4.83	5.25	5.30	5.17	5.34	5.53	5.36
Petroleum Subtotal	39.09	45.34	44.84	43.74	53.36	51.30	49.64	57.67	54.42	52.34
Natural Gas	20.74	24.12	24.21	24.30	28.08	28.59	28.87	28.24	29.32	29.48
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Pipeline Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Natural Gas Subtotal	22.54	26.02	26.11	26.22	30.19	30.73	31.11	30.33	31.47	31.71
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	21.99	24.34	24.34	24.34	26.45	26.80	27.02	29.37	30.07	30.42
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	22.71	24.95	24.95	24.94	26.92	27.27	27.49	29.79	30.48	30.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.15	8.10	8.13
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	81.76	81.39	80.46	93.21	92.23	91.20	98.87	97.56	96.31
Total Energy Use	98.22	111.69	111.27	110.31	126.74	125.60	124.55	134.63	133.18	131.72
Population (millions)	291.39	310.12	310.12	310.12	336.99	336.99	336.99	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13108	13084	13032	17679	17634	17623	20341	20292	20263
Carbon Dioxide Emissions										
Carbon Dioxide Emissions (million metric tons)	5788.7	6657.2	6626.8	6545.6	7604.8	7519.6	7432.4	8171.6	8062.3	7949.6

[1]Includes wood used for residential heating. See Table C4 and/or Table C17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Residential	**15.81**	**14.20**	**14.33**	**14.66**	**15.23**	**15.64**	**15.90**	**15.74**	**16.13**	**16.47**
Primary Energy[1]	9.68	8.22	8.35	8.72	8.83	9.21	9.46	9.27	9.62	9.98
Petroleum Products[2]	11.27	9.91	10.44	12.26	10.23	11.36	12.87	10.53	11.93	13.94
Distillate Fuel	9.57	7.77	8.29	9.83	7.94	8.85	10.08	8.03	9.12	10.65
Liquefied Petroleum Gas	14.58	13.71	14.25	16.45	13.63	15.06	16.78	13.85	15.65	17.91
Natural Gas	9.22	7.76	7.79	7.83	8.47	8.66	8.67	8.96	9.07	9.13
Electricity	25.42	22.86	22.96	23.12	23.72	24.12	24.27	23.85	24.24	24.40
Commercial	**15.63**	**13.61**	**13.76**	**14.05**	**15.24**	**15.70**	**15.95**	**15.73**	**16.20**	**16.53**
Primary Energy[1]	7.92	6.68	6.81	7.15	7.19	7.54	7.79	7.49	7.82	8.18
Petroleum Products[2]	8.03	6.57	7.13	8.89	6.53	7.55	8.89	6.62	7.84	9.65
Distillate Fuel	7.03	5.75	6.30	7.97	5.84	6.76	7.96	5.99	7.06	8.75
Residual Fuel	4.96	3.66	4.26	5.65	3.65	4.81	6.06	3.64	5.08	6.44
Natural Gas	8.08	6.84	6.87	6.90	7.50	7.68	7.69	7.85	7.96	8.01
Electricity	23.24	19.79	19.93	20.13	21.59	22.10	22.32	21.87	22.40	22.68
Industrial[3]	**7.78**	**6.62**	**6.85**	**7.58**	**7.17**	**7.75**	**8.25**	**7.43**	**8.13**	**8.76**
Primary Energy	6.49	5.29	5.55	6.40	5.63	6.27	6.83	5.87	6.64	7.37
Petroleum Products[2]	8.29	6.73	7.24	8.96	6.76	7.88	9.09	6.94	8.36	10.06
Distillate Fuel	7.24	6.23	6.78	8.45	6.44	7.37	8.55	6.68	7.73	9.39
Liquefied Petroleum Gas	12.57	9.49	10.02	12.21	9.35	10.74	12.26	9.56	11.35	13.37
Residual Fuel	4.59	3.26	3.87	5.17	3.18	4.34	5.60	3.18	4.62	5.99
Natural Gas[4]	5.56	4.35	4.37	4.41	5.05	5.23	5.26	5.35	5.47	5.53
Metallurgical Coal	1.85	1.82	1.82	1.82	1.74	1.75	1.75	1.68	1.68	1.69
Steam Coal	1.55	1.56	1.56	1.58	1.56	1.56	1.53	1.60	1.60	1.45
Electricity	15.03	13.79	13.84	13.92	15.14	15.47	15.58	15.41	15.75	15.89
Transportation	**11.46**	**10.39**	**10.95**	**12.65**	**10.08**	**11.16**	**12.41**	**10.15**	**11.46**	**13.18**
Primary Energy	11.43	10.37	10.93	12.63	10.05	11.13	12.38	10.13	11.44	13.16
Petroleum Products[2]	11.43	10.37	10.93	12.64	10.05	11.13	12.39	10.13	11.44	13.17
Distillate Fuel[5]	10.92	10.19	10.76	12.51	9.72	10.66	11.84	9.81	10.85	12.50
Jet Fuel[6]	6.46	5.68	6.25	7.86	5.66	6.58	7.89	5.75	6.93	8.75
Motor Gasoline[7]	12.93	11.76	12.32	14.08	11.34	12.52	13.84	11.36	12.81	14.61
Residual Fuel	4.49	3.10	3.74	5.17	3.09	4.28	5.59	3.08	4.56	5.98
Liquefied Petroleum Gas[8]	16.65	14.72	15.24	17.25	14.29	15.66	17.26	14.40	16.24	18.15
Natural Gas[9]	9.04	8.48	8.56	8.61	9.11	9.45	9.53	9.35	9.69	9.78
Ethanol (E85)[10]	16.23	16.67	17.11	19.09	17.06	17.22	18.70	17.47	18.13	19.69
Electricity	20.64	18.71	18.81	18.96	19.60	19.99	20.15	19.58	19.96	20.15
Average End-Use Energy	**11.50**	**10.22**	**10.56**	**11.55**	**10.68**	**11.42**	**12.15**	**10.95**	**11.83**	**12.82**
Primary Energy	9.32	8.23	8.61	9.77	8.38	9.18	10.01	8.59	9.55	10.69
Electricity	21.74	19.26	19.36	19.52	20.68	21.11	21.26	20.95	21.38	21.58
Electric Power[11]										
Fossil Fuel Average	2.24	2.03	2.06	2.12	2.39	2.45	2.50	2.43	2.46	2.52
Petroleum Products	5.28	3.91	4.55	6.04	4.26	5.10	6.42	4.50	5.42	6.98
Distillate Fuel	6.48	4.83	5.36	6.95	4.98	6.01	7.21	5.10	6.33	8.06
Residual Fuel	4.79	3.54	4.19	5.61	3.50	4.71	6.04	3.50	5.00	6.44
Natural Gas	5.46	4.24	4.27	4.31	5.00	5.20	5.23	5.30	5.44	5.50
Steam Coal	1.28	1.25	1.25	1.26	1.24	1.25	1.28	1.29	1.31	1.33

Table C3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.34	9.91	11.63	9.11	10.29	11.57	9.18	10.66	12.41
Distillate Fuel	9.90	8.97	9.53	11.27	8.57	9.79	11.02	8.51	10.03	11.74
Jet Fuel	6.46	5.68	6.25	7.86	5.66	6.58	7.89	5.75	6.93	8.75
Liquefied Petroleum Gas	13.04	10.46	10.99	13.16	10.35	11.74	13.28	10.54	12.34	14.38
Motor Gasoline[7]	12.93	11.74	12.31	14.07	11.33	12.51	13.82	11.35	12.80	14.59
Residual Fuel	4.66	3.37	3.99	5.39	3.34	4.52	5.80	3.34	4.81	6.20
Natural Gas	6.86	5.49	5.52	5.55	6.13	6.30	6.32	6.51	6.59	6.65
Coal	1.30	1.27	1.27	1.28	1.26	1.27	1.30	1.31	1.32	1.37
Ethanol (E85)[10]	16.23	16.67	17.11	19.09	17.06	17.22	18.70	17.47	18.13	19.69
Electricity	21.74	19.26	19.36	19.52	20.68	21.11	21.26	20.95	21.38	21.58
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	174.78	175.88	178.08	205.81	209.76	211.21	220.02	223.86	225.37
Commercial	128.15	128.89	129.92	131.91	173.53	177.28	179.18	196.75	200.93	203.65
Industrial	147.11	135.96	139.57	151.95	159.31	169.93	179.57	171.50	184.96	198.26
Transportation	302.59	325.97	341.13	385.90	376.13	407.83	441.71	409.89	449.31	501.32
Total Non-Renewable Expenditures	755.02	765.59	786.50	847.84	914.77	964.80	1011.67	998.16	1059.05	1128.59
Transportation Renewable Expenditures	0.02	0.03	0.03	0.04	0.06	0.07	0.07	0.07	0.08	0.09
Total Expenditures	**755.04**	**765.63**	**786.54**	**847.88**	**914.83**	**964.87**	**1011.74**	**998.23**	**1059.13**	**1128.69**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C4. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.68	5.98	6.02	6.16	4.98	5.21	5.48	4.46	4.73	5.18
Alaska	0.97	0.80	0.81	0.83	0.78	0.86	0.93	0.55	0.61	0.71
Lower 48 States	4.71	5.19	5.22	5.33	4.20	4.35	4.55	3.91	4.12	4.47
Net Imports	9.65	11.48	11.31	10.98	15.25	14.80	14.40	16.63	16.11	14.83
Gross Imports	9.66	11.50	11.32	11.00	15.26	14.81	14.41	16.64	16.12	14.84
Exports	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Crude Supply[2]	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.31**	**17.47**	**17.33**	**17.14**	**20.22**	**20.01**	**19.88**	**21.09**	**20.84**	**20.01**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.96	1.96	1.98	2.01	2.04	2.12	1.99	2.04	2.12
Net Product Imports	1.58	2.20	2.06	1.47	3.24	2.31	1.11	4.55	3.00	2.12
Gross Refined Product Imports[3]	1.85	2.09	1.99	1.38	2.85	1.90	0.76	4.11	2.47	1.65
Unfinished Oil Imports	0.34	0.64	0.59	0.59	0.97	0.91	0.85	1.08	1.02	0.95
Blending Components	0.41	0.48	0.48	0.46	0.57	0.55	0.53	0.62	0.60	0.57
Exports	1.01	1.00	0.99	0.97	1.15	1.05	1.02	1.26	1.08	1.05
Refinery Processing Gain[4]	1.00	1.07	1.11	1.14	1.38	1.50	1.55	1.40	1.56	1.62
Other Supply[5]	0.69	0.52	0.53	0.69	0.49	0.46	0.80	0.52	0.50	0.99
Total Primary Supply[6]	**20.30**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.46**	**29.55**	**27.93**	**26.86**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	8.93	10.38	10.28	9.99	12.30	11.97	11.53	13.37	12.89	12.33
Jet Fuel[8]	1.57	1.96	1.95	1.93	2.34	2.29	2.27	2.46	2.36	2.34
Distillate Fuel[9]	3.95	4.73	4.70	4.60	5.90	5.44	5.29	6.68	5.81	5.63
Residual Fuel	0.77	0.87	0.80	0.76	1.00	0.88	0.79	1.03	0.88	0.79
Other[10]	4.77	5.30	5.25	5.14	5.80	5.74	5.59	6.01	5.98	5.76
Total	**20.00**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.47**	**29.55**	**27.93**	**26.85**
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.35	1.33	1.24	1.46	1.41	1.29	1.49	1.42	1.26
Industrial[11]	4.87	5.38	5.33	5.24	5.87	5.81	5.68	6.10	6.05	5.85
Transportation	13.35	15.87	15.76	15.42	18.87	18.48	17.98	20.43	19.82	19.21
Electric Power[12]	0.50	0.63	0.56	0.51	1.13	0.62	0.52	1.53	0.64	0.53
Total	**20.00**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.47**	**29.55**	**27.93**	**26.85**
Discrepancy[13]	**0.29**	**-0.00**	**-0.00**	**-0.00**	**0.00**	**0.00**	**-0.01**	**-0.00**	**-0.00**	**0.00**
World Oil Price (2003 dollars per barrel)[14]	27.73	20.99	25.00	33.99	20.99	28.50	36.74	20.99	30.31	39.24
Import Share of Product Supplied	0.56	0.59	0.58	0.56	0.68	0.65	0.61	0.72	0.68	0.63
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	113.78	108.97	125.14	157.10	147.68	180.07	207.96	172.41	215.89	245.02
Domestic Refinery Distillation Capacity[15]	16.8	18.8	18.7	18.6	21.6	21.4	21.3	22.5	22.3	21.4
Capacity Utilization Rate (percent)	93.0	94.4	94.0	93.6	94.9	94.8	94.8	94.9	94.9	94.8

[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 other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[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 energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C5. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
World Oil Price (2003 dollars per barrel)	**27.73**	**20.99**	**25.00**	**33.99**	**20.99**	**28.50**	**36.74**	**20.99**	**30.31**	**39.24**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	132.7	107.8	114.9	136.3	110.1	122.7	139.8	111.3	126.4	147.7
Liquefied Petroleum Gas	125.4	117.9	122.6	141.5	117.2	129.5	144.3	119.1	134.6	154.0
Commercial										
Distillate Fuel	97.3	79.3	86.9	109.9	80.6	93.2	109.7	82.6	97.3	120.7
Residual Fuel	74.3	54.8	63.7	84.6	54.6	71.9	90.7	54.4	76.0	96.4
Residual Fuel (2003 dollars per barrel)	31.21	23.01	26.77	35.51	22.93	30.21	38.09	22.86	31.92	40.50
Industrial[1]										
Distillate Fuel	100.2	85.7	93.3	116.2	88.4	101.2	117.4	91.6	106.2	128.9
Liquefied Petroleum Gas	108.1	81.6	86.1	105.0	80.4	92.3	105.4	82.2	97.6	115.0
Residual Fuel	68.7	48.7	57.9	77.4	47.7	64.9	83.8	47.6	69.1	89.7
Residual Fuel (2003 dollars per barrel)	28.84	20.46	24.33	32.51	20.01	27.27	35.18	19.97	29.02	37.66
Transportation										
Diesel Fuel (distillate)[2]	150.4	139.7	147.5	171.5	133.2	146.1	162.2	134.5	148.6	171.2
Jet Fuel[3]	87.2	76.7	84.3	106.1	76.3	88.8	106.5	77.6	93.5	118.1
Motor Gasoline[4]	160.3	145.4	152.4	174.1	140.3	154.9	171.2	140.5	158.5	180.7
Liquid Petroleum Gas	143.2	126.6	131.1	148.3	122.9	134.7	148.5	123.8	139.7	156.1
Residual Fuel	67.3	46.4	56.0	77.4	46.3	64.1	83.7	46.1	68.3	89.6
Residual Fuel (2003 dollars per barrel)	28.25	19.51	23.50	32.49	19.43	26.92	35.16	19.38	28.68	37.61
Ethanol (E85)[5]	152.4	156.4	160.5	179.1	160.1	161.6	175.5	163.9	170.1	184.8
Electric Power[6]										
Distillate Fuel	89.8	67.0	74.4	96.3	69.0	83.3	100.0	70.8	87.8	111.8
Residual Fuel	71.7	53.0	62.7	84.0	52.4	70.5	90.3	52.4	74.9	96.3
Residual Fuel (2003 dollars per barrel)	30.12	22.28	26.32	35.29	22.01	29.63	37.94	22.00	31.45	40.46
Refined Petroleum Product Prices[7]										
Distillate Fuel	136.7	123.3	131.0	154.9	117.8	134.4	151.3	117.0	137.7	161.2
Jet Fuel[3]	87.2	76.7	84.3	106.1	76.3	88.8	106.5	77.6	93.5	118.1
Liquefied Petroleum Gas	112.1	90.0	94.5	113.2	89.0	101.0	114.2	90.7	106.1	123.6
Motor Gasoline[4]	160.3	145.2	152.2	174.0	140.1	154.8	171.1	140.4	158.4	180.6
Residual Fuel	69.8	50.5	59.8	80.6	50.0	67.7	86.9	50.0	72.0	92.8
Residual Fuel (2003 dollars per barrel)	29.32	21.21	25.11	33.86	21.02	28.43	36.48	21.00	30.22	38.99
Average	**136.6**	**121.1**	**128.3**	**150.0**	**117.6**	**132.4**	**148.6**	**118.3**	**136.8**	**158.8**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C6. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
World Oil Price (2003 dollars per barrel)[1]	**27.73**	**20.99**	**25.00**	**33.99**	**20.99**	**28.50**	**36.74**	**20.99**	**30.31**	**39.24**
Production (Conventional)[2]										
Industrialized Countries										
U.S. (50 states)	9.09	9.55	9.61	9.95	8.86	9.21	9.76	8.36	8.82	9.60
Canada	2.25	1.82	1.83	1.91	1.58	1.60	1.70	1.54	1.57	1.68
Mexico	3.80	4.17	4.21	4.45	4.50	4.62	4.97	4.69	4.85	5.25
Western Europe[3]	6.69	6.32	6.35	6.65	5.44	5.51	5.85	4.92	5.00	5.35
Japan	0.13	0.08	0.08	0.09	0.06	0.06	0.09	0.05	0.06	0.09
Australia and New Zealand	0.66	0.95	0.96	1.01	0.86	0.89	0.95	0.83	0.86	0.93
Total Industrialized	**22.62**	**22.89**	**23.05**	**24.06**	**21.30**	**21.89**	**23.32**	**20.40**	**21.16**	**22.90**
Eurasia										
Former Soviet Union										
Russia	8.34	9.89	9.98	10.64	10.63	10.90	11.87	10.76	11.11	12.20
Caspian Area[4]	1.87	3.11	3.14	3.35	5.10	5.23	5.70	6.03	6.22	6.83
Eastern Europe[5]	0.22	0.33	0.33	0.35	0.40	0.41	0.44	0.44	0.45	0.48
Total Eurasia	**10.44**	**13.33**	**13.46**	**14.34**	**16.13**	**16.54**	**18.01**	**17.23**	**17.78**	**19.52**
Developing Countries										
OPEC[6]										
Asia	1.38	1.57	1.47	1.19	1.78	1.51	1.14	1.88	1.56	1.16
Middle East	20.95	26.08	24.45	19.84	38.02	32.37	24.44	46.42	38.47	28.62
North Africa	2.99	3.67	3.44	2.79	5.21	4.44	3.35	5.77	4.78	3.56
West Africa	1.98	2.51	2.36	1.91	3.67	3.13	2.36	4.52	3.74	2.78
South America	2.85	3.56	3.34	2.71	5.21	4.44	3.35	6.27	5.20	3.87
Non-OPEC										
China	3.10	3.60	3.64	3.84	3.40	3.49	3.76	3.30	3.41	3.69
Other Asia	2.59	2.62	2.65	2.80	2.64	2.71	2.92	2.56	2.64	2.86
Middle East[7]	1.81	2.22	2.24	2.37	2.51	2.57	2.77	2.69	2.78	3.01
Africa	2.94	3.72	3.75	4.04	5.31	5.44	6.00	6.36	6.56	7.31
South and Central America	3.93	4.48	4.53	4.83	5.77	5.91	6.44	6.22	6.42	7.05
Total Developing Countries	**44.52**	**54.05**	**51.87**	**46.31**	**73.52**	**66.02**	**56.52**	**86.00**	**75.57**	**63.93**
Total Production (Conventional)	**77.58**	**90.26**	**88.38**	**84.72**	**110.95**	**104.45**	**97.85**	**123.63**	**114.51**	**106.34**
Production[6] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.01	0.00	0.00	0.19	0.00	0.00	0.31
Other North America	0.93	1.63	1.73	1.95	2.81	3.33	3.78	2.94	3.46	4.14
Western Europe	0.04	0.04	0.04	0.05	0.03	0.05	0.06	0.03	0.05	0.06
Asia	0.03	0.03	0.04	0.05	0.02	0.05	0.08	0.02	0.07	0.10
Middle East[7]	0.03	0.03	0.12	0.12	0.03	0.21	0.28	0.04	0.25	0.35
Africa	0.21	0.16	0.23	0.26	0.18	0.28	0.41	0.19	0.32	0.47
South and Central America	0.57	0.82	0.82	1.23	1.27	1.48	2.43	1.18	1.50	2.79
Total Production (Nonconventional)	**1.79**	**2.70**	**2.98**	**3.68**	**4.34**	**5.40**	**7.23**	**4.40**	**5.65**	**8.22**
Total Production	**79.37**	**92.97**	**91.35**	**88.39**	**115.30**	**109.85**	**105.08**	**128.04**	**120.17**	**114.56**

Table C6. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	20.00	23.23	22.98	22.41	27.34	26.32	25.47	29.55	27.93	26.85
U.S. Territories	0.36	0.40	0.38	0.35	0.48	0.43	0.39	0.54	0.47	0.42
Canada	2.17	2.39	2.30	2.15	2.88	2.62	2.39	3.16	2.80	2.55
Mexico	2.02	2.43	2.36	2.25	3.24	2.88	2.51	4.13	3.48	2.93
Western Europe[3]	14.22	15.00	14.72	14.22	16.15	15.45	14.82	16.60	15.71	15.06
Japan	5.58	5.91	5.70	5.34	6.46	5.69	4.95	6.93	5.84	4.99
Australia and New Zealand	1.04	1.29	1.27	1.23	1.60	1.54	1.49	1.77	1.69	1.63
Total Industrialized	**45.38**	**50.66**	**49.72**	**47.95**	**58.15**	**54.93**	**52.01**	**62.68**	**57.92**	**54.44**
Eurasia										
Former Soviet Union	4.18	4.46	4.39	4.26	5.94	5.74	5.55	6.73	6.45	6.24
Eastern Europe[5]	1.42	1.58	1.56	1.53	1.93	1.89	1.85	2.15	2.09	2.05
Total Eurasia	**5.59**	**6.04**	**5.95**	**5.79**	**7.88**	**7.63**	**7.41**	**8.88**	**8.54**	**8.28**
Developing Countries										
China	5.54	7.84	7.63	7.27	11.75	11.06	10.45	13.79	12.79	12.08
India	2.19	2.85	2.79	2.69	4.65	4.37	4.09	5.75	5.29	4.92
South Korea	2.17	2.57	2.51	2.39	2.96	2.75	2.56	3.21	2.93	2.72
Other Asia	5.74	7.37	7.28	7.11	9.76	9.47	9.20	11.07	10.66	10.35
Middle East[7]	5.58	6.90	6.83	6.73	8.49	8.34	8.21	9.28	9.08	8.93
Africa	2.72	3.16	3.13	3.07	4.26	4.13	3.99	4.85	4.66	4.49
South and Central America	4.69	5.89	5.81	5.69	7.68	7.48	7.30	8.89	8.61	8.40
Total Developing Countries	**28.64**	**36.57**	**35.98**	**34.94**	**49.55**	**47.59**	**45.80**	**56.83**	**54.01**	**51.90**
Total Consumption	**79.60**	**93.27**	**91.65**	**88.68**	**115.57**	**110.14**	**105.22**	**128.39**	**120.47**	**114.62**
OPEC Production[10]	30.60	38.04	35.79	29.48	54.88	47.21	36.75	65.79	55.13	42.44
Non-OPEC Production[10]	48.77	54.93	55.56	58.91	60.42	62.64	68.33	62.25	65.04	72.13
Net Eurasia Exports	4.84	7.29	7.51	8.55	8.26	8.92	10.60	8.35	9.25	11.23
OPEC Market Share	0.39	0.41	0.39	0.33	0.48	0.43	0.35	0.51	0.46	0.37

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates, natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

October Futures and High B Oil Price Case Comparisons

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Production										
Crude Oil and Lease Condensate	12.03	12.75	13.04	13.18	11.03	11.35	12.21	10.01	10.54	11.22
Natural Gas Plant Liquids	2.34	2.66	2.70	2.78	2.80	2.86	3.01	2.81	2.84	3.00
Dry Natural Gas	19.58	20.97	21.34	22.09	22.48	23.09	24.51	22.42	22.72	24.18
Coal	22.66	25.10	25.05	25.23	27.04	27.07	29.73	29.90	29.91	35.26
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.57	7.60	7.76	8.10	8.26	8.32
Other[2]	0.93	0.97	1.16	1.16	0.77	0.90	1.01	0.82	0.97	1.13
Total	**71.42**	**77.79**	**78.64**	**79.81**	**80.35**	**81.54**	**86.89**	**82.73**	**83.91**	**91.77**
Imports										
Crude Oil[3]	21.08	24.69	24.30	23.87	32.29	31.90	29.23	35.16	34.55	31.20
Petroleum Products[4]	5.16	6.06	4.95	4.19	6.83	5.41	3.45	8.27	6.69	4.06
Natural Gas	4.02	5.71	5.49	5.03	8.95	8.81	7.20	9.70	9.63	6.61
Other Imports[5]	0.69	0.92	0.92	0.92	1.15	1.15	1.15	1.23	1.23	1.23
Total	**30.95**	**37.38**	**35.66**	**34.00**	**49.22**	**47.28**	**41.03**	**54.36**	**52.10**	**43.09**
Exports										
Petroleum[6]	2.13	2.14	2.11	2.08	2.26	2.22	2.17	2.32	2.28	2.22
Natural Gas	0.70	0.65	0.64	0.64	0.86	0.86	0.81	0.83	0.82	0.75
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.81	0.65	0.65	0.64
Total	**3.95**	**3.86**	**3.81**	**3.78**	**4.01**	**3.97**	**3.80**	**3.80**	**3.75**	**3.61**
Discrepancy[7]	**0.18**	**0.05**	**-0.06**	**-0.03**	**-0.05**	**-0.22**	**-0.22**	**0.10**	**-0.13**	**-0.21**
Consumption										
Petroleum Products[8]	39.09	44.84	43.98	43.37	51.30	50.22	48.66	54.42	53.21	51.13
Natural Gas	22.54	26.11	26.29	26.26	30.73	31.21	30.31	31.47	31.71	29.48
Coal	22.71	24.95	24.91	25.02	27.27	27.31	28.89	30.48	30.50	33.83
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.57	7.61	7.76	8.10	8.27	8.32
Other[9]	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Net Imports - Petroleum	**24.10**	**28.61**	**27.15**	**25.98**	**36.87**	**35.09**	**30.51**	**41.11**	**38.96**	**33.04**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.73	25.00	30.99	37.00	28.50	33.67	44.33	30.31	35.00	48.00
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.64	3.63	3.74	4.53	4.45	4.60	4.79	4.83	5.32
Coal Minemouth Price (dollars per ton)	17.93	17.30	17.45	17.69	17.25	17.54	18.39	18.26	18.52	20.41
Average Electricity Price (cents per kilowatthour)	7.4	6.6	6.6	6.7	7.2	7.2	7.3	7.3	7.3	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.

[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3]Includes imports of crude oil for the Strategic Petroleum Reserve.

[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5]Includes coal, coal coke (net), and electricity (net).

[6]Includes crude oil and petroleum products.

[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9]Includes net electricity imports, methanol, and liquid hydrogen.

[10]Average refiner acquisition cost for imported crude oil.

[11]Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.90	0.80	0.76	0.83	0.76	0.64	0.77	0.70	0.56
Kerosene	0.07	0.09	0.06	0.05	0.09	0.06	0.05	0.09	0.06	0.05
Liquefied Petroleum Gas	0.54	0.57	0.54	0.52	0.64	0.61	0.57	0.67	0.63	0.58
Petroleum Subtotal	1.58	1.56	1.40	1.33	1.56	1.43	1.26	1.53	1.39	1.18
Natural Gas	5.25	5.68	5.64	5.63	6.05	6.07	6.03	6.17	6.16	6.07
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.39	0.39	0.39	0.39	0.39	0.38	0.38	0.38
Electricity	4.37	5.02	5.01	5.00	5.79	5.78	5.77	6.18	6.17	6.15
Delivered Energy	**11.61**	**12.67**	**12.46**	**12.37**	**13.80**	**13.68**	**13.46**	**14.26**	**14.11**	**13.80**
Electricity Related Losses	9.71	10.80	10.78	10.77	11.77	11.76	11.63	12.35	12.33	12.09
Total	**21.31**	**23.47**	**23.25**	**23.15**	**25.56**	**25.44**	**25.09**	**26.62**	**26.44**	**25.88**
Commercial										
Distillate Fuel	0.52	0.62	0.57	0.54	0.71	0.63	0.58	0.77	0.66	0.60
Residual Fuel	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.08	0.08	0.07
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.11	0.11	0.10
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.81	0.78	0.96	0.88	0.82	1.02	0.91	0.84
Natural Gas	3.22	3.49	3.49	3.49	3.91	3.97	3.96	4.17	4.23	4.19
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.00	5.00	4.99	6.33	6.32	6.29	7.12	7.11	7.06
Delivered Energy	**8.29**	**9.53**	**9.48**	**9.44**	**11.38**	**11.34**	**11.25**	**12.49**	**12.43**	**12.28**
Electricity Related Losses	9.18	10.76	10.75	10.74	12.86	12.83	12.67	14.25	14.21	13.87
Total	**17.46**	**20.29**	**20.23**	**20.19**	**24.24**	**24.18**	**23.92**	**26.74**	**26.65**	**26.15**
Industrial[4]										
Distillate Fuel	1.03	1.04	1.03	1.02	1.14	1.10	1.09	1.19	1.14	1.14
Liquefied Petroleum Gas	2.09	2.30	2.28	2.26	2.59	2.54	2.50	2.74	2.65	2.57
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	0.28	0.34	0.32	0.29	0.38	0.40	0.34	0.38	0.41	0.35
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.35	0.35	0.35	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.69	4.65	4.61	5.02	4.98	4.78	5.23	5.18	4.94
Petroleum Subtotal	9.31	10.17	10.08	9.97	11.03	10.92	10.58	11.47	11.32	10.88
Natural Gas	7.19	8.10	8.18	8.22	8.89	9.06	9.03	9.26	9.39	9.28
Lease and Plant Fuel[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Natural Gas Subtotal	8.34	9.31	9.40	9.48	10.21	10.42	10.49	10.57	10.71	10.69
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.39	1.42	1.42	1.49	1.42	1.42	2.59	1.42	1.41	3.47
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	2.11	2.03	2.03	2.09	1.89	1.89	3.06	1.83	1.83	3.88
Renewable Energy[7]	1.79	2.07	2.07	2.06	2.34	2.35	2.35	2.50	2.50	2.51
Electricity	3.31	3.78	3.79	3.78	4.19	4.22	4.22	4.39	4.43	4.43
Delivered Energy	**24.86**	**27.35**	**27.35**	**27.38**	**29.66**	**29.81**	**30.69**	**30.76**	**30.80**	**32.40**
Electricity Related Losses	7.35	8.13	8.14	8.14	8.52	8.58	8.51	8.78	8.85	8.71
Total	**32.21**	**35.47**	**35.50**	**35.52**	**38.19**	**38.39**	**39.20**	**39.53**	**39.65**	**41.11**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Transportation										
Distillate Fuel[8]	5.54	6.95	6.94	6.91	8.35	8.30	8.30	9.05	9.03	8.98
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Motor Gasoline[2]	16.64	19.14	18.73	18.39	22.31	21.83	20.94	24.04	23.46	22.25
Residual Fuel	0.62	0.56	0.56	0.56	0.58	0.58	0.58	0.58	0.58	0.59
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.25	0.29	0.29	0.29	0.31	0.32	0.31
Petroleum Subtotal	26.31	31.00	30.54	30.15	36.35	35.78	34.86	38.97	38.33	37.03
Pipeline Fuel Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.85**	**31.40**	**31.01**	**37.39**	**36.84**	**35.91**	**40.04**	**39.42**	**38.09**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.23
Total	**27.24**	**32.04**	**31.59**	**31.20**	**37.61**	**37.06**	**36.13**	**40.28**	**39.65**	**38.32**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.51	9.34	9.23	11.03	10.79	10.61	11.78	11.53	11.27
Kerosene	0.11	0.14	0.10	0.09	0.14	0.10	0.10	0.13	0.10	0.09
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Liquefied Petroleum Gas	2.75	3.03	2.98	2.94	3.42	3.34	3.25	3.60	3.48	3.34
Motor Gasoline[2]	16.98	19.49	19.08	18.74	22.70	22.22	21.33	24.45	23.87	22.66
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	0.97	0.97	0.96	0.93	1.03	1.05	1.00	1.03	1.06	1.01
Other Petroleum[12]	4.52	4.93	4.89	4.85	5.30	5.25	5.05	5.53	5.48	5.24
Petroleum Subtotal	37.96	43.58	42.82	42.23	49.90	49.01	47.52	52.98	51.95	49.94
Natural Gas	15.68	17.33	17.37	17.40	18.94	19.20	19.12	19.70	19.90	19.65
Lease and Plant Fuel Plant[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Pipeline Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Natural Gas Subtotal	17.48	19.23	19.30	19.37	21.09	21.41	21.42	21.85	22.08	21.89
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.60	1.52	1.52	2.70	1.52	1.52	3.58
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	2.22	2.14	2.14	2.20	2.00	2.00	3.17	1.94	1.94	3.99
Renewable Energy[13]	2.28	2.55	2.55	2.55	2.82	2.83	2.83	2.97	2.98	2.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.89	13.88	13.86	16.41	16.43	16.38	17.81	17.82	17.76
Delivered Energy	**71.82**	**81.39**	**80.69**	**80.21**	**92.23**	**91.68**	**91.31**	**97.56**	**96.76**	**96.56**
Electricity Related Losses	26.40	29.88	29.86	29.84	33.37	33.39	33.03	35.62	35.64	34.91
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Electric Power[14]										
Distillate Fuel	0.33	0.39	0.38	0.37	0.42	0.39	0.37	0.45	0.41	0.41
Residual Fuel	0.80	0.87	0.78	0.77	0.98	0.82	0.77	0.98	0.86	0.78
Petroleum Subtotal	1.13	1.26	1.16	1.14	1.40	1.21	1.14	1.43	1.27	1.19
Natural Gas	5.06	6.87	6.99	6.89	9.64	9.80	8.89	9.61	9.63	7.58
Steam Coal	20.49	22.81	22.77	22.82	25.28	25.32	25.72	28.54	28.56	29.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.30	4.30	4.33	4.75	4.78	4.93	5.14	5.29	5.35
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.77**	**43.74**	**43.70**	**49.79**	**49.82**	**49.41**	**53.43**	**53.46**	**52.66**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Total Energy Consumption										
Distillate Fuel	8.37	9.90	9.71	9.60	11.45	11.18	10.98	12.23	11.94	11.68
Kerosene	0.11	0.14	0.10	0.09	0.14	0.10	0.10	0.13	0.10	0.09
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Liquefied Petroleum Gas	2.75	3.03	2.98	2.94	3.42	3.34	3.25	3.60	3.48	3.34
Motor Gasoline[2]	16.98	19.49	19.08	18.74	22.70	22.22	21.33	24.45	23.87	22.66
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	1.77	1.84	1.74	1.70	2.01	1.87	1.76	2.02	1.92	1.79
Other Petroleum[12]	4.52	4.93	4.89	4.85	5.30	5.25	5.05	5.53	5.48	5.24
Petroleum Subtotal	39.09	44.84	43.98	43.37	51.30	50.22	48.66	54.42	53.21	51.13
Natural Gas	20.74	24.21	24.36	24.29	28.59	29.00	28.02	29.32	29.54	27.24
Lease and Plant Fuel[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Pipeline Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Natural Gas Subtotal	22.54	26.11	26.29	26.26	30.73	31.21	30.31	31.47	31.71	29.48
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	21.99	24.34	24.30	24.42	26.80	26.84	28.42	30.07	30.08	33.42
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	22.71	24.95	24.91	25.02	27.27	27.31	28.89	30.48	30.50	33.83
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.89	6.85	6.85	6.88	7.57	7.61	7.76	8.10	8.27	8.32
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	81.39	80.69	80.21	92.23	91.68	91.31	97.56	96.76	96.56
Total Energy Use	98.22	111.27	110.55	110.05	125.60	125.07	124.34	133.18	132.40	131.46
Population (millions)	291.39	310.12	310.12	310.12	336.99	336.99	336.99	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13084	13063	13031	17634	17641	17619	20292	20293	20260
Carbon Dioxide Emissions (million metric tons)	5788.7	6626.8	6561.1	6527.8	7519.6	7460.6	7448.5	8062.3	7981.1	8028.7

[1]Includes wood used for residential heating. See Table C4 and/or Table C17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Residential	**15.81**	**14.33**	**14.58**	**14.85**	**15.64**	**15.78**	**16.13**	**16.13**	**16.36**	**16.98**
Primary Energy[1]	9.68	8.35	8.61	8.89	9.21	9.32	9.72	9.62	9.86	10.62
Petroleum Products[2]	11.27	10.44	11.81	13.00	11.36	12.57	14.49	11.93	13.13	15.68
Distillate Fuel	9.57	8.29	9.35	10.39	8.85	9.79	11.48	9.12	10.13	12.07
Liquefied Petroleum Gas	14.58	14.25	15.73	17.07	15.06	16.34	18.17	15.65	16.77	19.49
Natural Gas	9.22	7.79	7.83	7.93	8.66	8.57	8.74	9.07	9.14	9.65
Electricity	25.42	22.96	22.99	23.16	24.12	24.16	24.25	24.24	24.32	24.50
Commercial	**15.63**	**13.76**	**13.92**	**14.17**	**15.70**	**15.81**	**16.14**	**16.20**	**16.39**	**17.09**
Primary Energy[1]	7.92	6.81	7.04	7.32	7.54	7.65	8.05	7.82	8.05	8.77
Petroleum Products[2]	8.03	7.13	8.27	9.40	7.55	8.57	10.23	7.84	8.92	10.99
Distillate Fuel	7.03	6.30	7.38	8.45	6.76	7.70	9.26	7.06	8.10	9.98
Residual Fuel	4.96	4.26	5.00	5.93	4.81	5.40	7.06	5.08	5.60	7.62
Natural Gas	8.08	6.87	6.90	7.01	7.68	7.59	7.76	7.96	8.01	8.48
Electricity	23.24	19.93	19.97	20.17	22.10	22.19	22.42	22.40	22.55	23.13
Industrial[3]	**7.78**	**6.85**	**7.31**	**7.78**	**7.75**	**8.10**	**8.51**	**8.13**	**8.49**	**8.99**
Primary Energy	6.49	5.55	6.08	6.63	6.27	6.67	7.18	6.64	7.04	7.68
Petroleum Products[2]	8.29	7.24	8.34	9.42	7.88	8.75	10.37	8.36	9.17	11.29
Distillate Fuel	7.24	6.78	7.85	8.90	7.37	8.31	9.80	7.73	8.77	10.61
Liquefied Petroleum Gas	12.57	10.02	11.46	12.72	10.74	11.97	13.72	11.35	12.45	14.91
Residual Fuel	4.59	3.87	4.64	5.59	4.34	5.00	6.66	4.62	5.19	7.22
Natural Gas[4]	5.56	4.37	4.37	4.48	5.23	5.18	5.34	5.47	5.50	5.97
Metallurgical Coal	1.85	1.82	1.82	1.82	1.75	1.75	1.76	1.68	1.68	1.69
Steam Coal	1.55	1.56	1.57	1.55	1.56	1.58	1.45	1.60	1.61	1.56
Electricity	15.03	13.84	13.84	13.95	15.47	15.51	15.63	15.75	15.83	16.07
Transportation	**11.46**	**10.95**	**11.99**	**13.20**	**11.16**	**12.05**	**13.73**	**11.46**	**12.44**	**14.63**
Primary Energy	11.43	10.93	11.97	13.18	11.13	12.03	13.71	11.44	12.42	14.61
Petroleum Products[2]	11.43	10.93	11.97	13.19	11.13	12.04	13.73	11.44	12.43	14.62
Distillate Fuel[5]	10.92	10.76	11.86	12.95	10.66	11.61	13.08	10.85	11.91	13.78
Jet Fuel[6]	6.46	6.25	7.35	8.41	6.58	7.57	9.24	6.93	7.98	10.03
Motor Gasoline[7]	12.93	12.32	13.35	14.69	12.52	13.42	15.24	12.81	13.80	16.23
Residual Fuel	4.49	3.74	4.40	5.36	4.28	4.82	6.51	4.56	5.02	7.09
Liquefied Petroleum Gas[8]	16.65	15.24	16.62	17.87	15.66	16.86	18.24	16.24	17.10	19.55
Natural Gas[9]	9.04	8.56	8.57	8.67	9.45	9.42	9.58	9.69	9.79	10.23
Ethanol (E85)[10]	16.23	17.11	18.05	19.92	17.22	18.31	20.56	18.13	18.74	21.85
Electricity	20.64	18.81	18.85	19.01	19.99	20.02	20.14	19.96	20.07	20.31
Average End-Use Energy	**11.50**	**10.56**	**11.16**	**11.86**	**11.42**	**11.92**	**12.78**	**11.83**	**12.40**	**13.55**
Primary Energy	9.32	8.61	9.33	10.14	9.18	9.76	10.78	9.55	10.21	11.55
Electricity	21.74	19.36	19.38	19.55	21.11	21.15	21.30	21.38	21.47	21.82
Electric Power[11]										
Fossil Fuel Average	2.24	2.06	2.08	2.14	2.45	2.46	2.49	2.46	2.48	2.50
Petroleum Products	5.28	4.55	5.40	6.37	5.10	5.83	7.47	5.42	6.10	8.09
Distillate Fuel	6.48	5.36	6.39	7.42	6.01	6.94	8.48	6.33	7.33	9.13
Residual Fuel	4.79	4.19	4.93	5.87	4.71	5.31	6.98	5.00	5.51	7.55
Natural Gas	5.46	4.27	4.22	4.33	5.20	5.15	5.27	5.44	5.48	5.84
Steam Coal	1.28	1.25	1.26	1.27	1.25	1.25	1.30	1.31	1.31	1.43

Table D3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.91	10.98	12.16	10.29	11.21	12.89	10.66	11.62	13.81
Distillate Fuel	9.90	9.53	10.66	11.75	9.79	10.78	12.32	10.03	11.14	13.03
Jet Fuel	6.46	6.25	7.35	8.41	6.58	7.57	9.24	6.93	7.98	10.03
Liquefied Petroleum Gas	13.04	10.99	12.41	13.67	11.74	12.96	14.69	12.34	13.43	15.91
Motor Gasoline[7]	12.93	12.31	13.34	14.68	12.51	13.41	15.23	12.80	13.79	16.22
Residual Fuel	4.66	3.99	4.71	5.66	4.52	5.09	6.77	4.81	5.30	7.34
Natural Gas	6.86	5.52	5.50	5.61	6.30	6.23	6.41	6.59	6.63	7.16
Coal	1.30	1.27	1.28	1.30	1.27	1.27	1.44	1.32	1.33	1.64
Ethanol (E85)[10]	16.23	17.11	18.05	19.92	17.22	18.31	20.56	18.13	18.74	21.85
Electricity	21.74	19.36	19.38	19.55	21.11	21.15	21.30	21.38	21.47	21.82
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	175.88	175.96	177.88	209.76	209.74	210.86	223.86	224.55	227.83
Commercial	128.15	129.92	130.76	132.61	177.28	177.97	180.17	200.93	202.43	208.29
Industrial	147.11	139.57	147.77	156.12	169.93	177.24	189.83	184.96	192.09	211.34
Transportation	302.59	341.13	367.80	399.87	407.83	433.81	481.55	449.31	479.81	544.99
Total Non-Renewable Expenditures	755.02	786.50	822.30	866.47	964.80	998.76	1062.42	1059.05	1098.88	1192.45
Transportation Renewable Expenditures	0.02	0.03	0.04	0.04	0.07	0.07	0.08	0.08	0.09	0.10
Total Expenditures	**755.04**	**786.54**	**822.34**	**866.51**	**964.87**	**998.83**	**1062.49**	**1059.13**	**1098.96**	**1192.55**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D4. Transportation Sector Key Indicators and Delivered Energy Consumption

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Key Indicators										
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500 pounds	2602	3017	2953	2907	3680	3623	3526	4053	3991	3864
Commercial Light Trucks[1]	65	78	78	77	96	96	95	107	107	106
Freight Trucks greater than 10,000 pounds	214	268	268	267	336	338	337	373	375	374
(billion seat miles available)										
Air	932	1152	1143	1138	1455	1455	1455	1520	1520	1520
(billion ton miles traveled)										
Rail	1352	1576	1575	1576	1833	1836	1905	2001	2002	2147
Domestic Shipping	592	649	657	662	706	718	742	733	744	772
Energy Efficiency Indicators										
(miles per gallon)										
New Light-Duty Vehicle[2]	25.1	25.7	25.9	26.2	26.5	26.9	27.5	26.9	27.3	28.2
New Car[2]	29.5	29.7	30.3	30.5	30.6	31.2	31.7	31.0	31.6	32.3
New Light Truck[2]	21.8	22.9	22.8	23.0	24.1	24.2	24.7	24.6	24.9	25.5
Light-Duty Stock[3]	20.0	20.1	20.2	20.3	20.7	20.9	21.2	21.0	21.3	21.7
New Commercial Light Truck[1]	14.6	15.2	15.2	15.3	16.0	16.1	16.4	16.4	16.5	16.9
Stock Commercial Light Truck[1]	14.0	14.7	14.6	14.7	15.5	15.5	15.7	15.9	16.0	16.2
Freight Truck	6.0	6.0	6.0	6.0	6.4	6.4	6.5	6.6	6.6	6.7
(seat miles per gallon)										
Aircraft	55.3	59.2	59.3	59.4	65.2	65.7	66.1	68.5	69.1	69.4
(ton miles per thousand Btu)										
Rail	2.9	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode										
(quadrillion Btu)										
Light-Duty Vehicles	15.78	18.45	18.04	17.71	21.85	21.36	20.51	23.69	23.11	21.94
Commercial Light Trucks[1]	0.58	0.67	0.66	0.66	0.78	0.78	0.76	0.84	0.84	0.82
Bus Transportation	0.25	0.26	0.26	0.26	0.27	0.26	0.26	0.27	0.26	0.26
Freight Trucks	4.46	5.56	5.55	5.53	6.60	6.56	6.51	7.10	7.08	6.97
Rail, Passenger	0.12	0.13	0.13	0.13	0.16	0.16	0.16	0.17	0.17	0.17
Rail, Freight	0.47	0.51	0.51	0.51	0.54	0.54	0.56	0.56	0.56	0.60
Shipping, Domestic	0.26	0.28	0.28	0.29	0.30	0.30	0.31	0.31	0.31	0.32
Shipping, International	0.56	0.51	0.51	0.51	0.52	0.52	0.52	0.52	0.52	0.52
Recreational Boats	0.31	0.33	0.33	0.33	0.37	0.37	0.37	0.39	0.39	0.39
Air	2.74	3.43	3.39	3.36	4.11	4.08	4.03	4.25	4.22	4.18
Military Use	0.69	0.80	0.80	0.80	0.82	0.82	0.82	0.83	0.83	0.83
Lubricants	0.20	0.21	0.21	0.21	0.25	0.25	0.25	0.27	0.27	0.27
Pipeline Fuel	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Total	**27.07**	**31.85**	**31.40**	**31.01**	**37.39**	**36.84**	**35.91**	**40.04**	**39.42**	**38.09**
(million barrels per day oil equivalent)										
Light-Duty Vehicles	8.29	9.72	9.50	9.32	11.49	11.23	10.78	12.45	12.15	11.53
Commercial Light Trucks[1]	0.30	0.35	0.35	0.35	0.41	0.41	0.40	0.44	0.44	0.43
Bus Transportation	0.12	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13	0.12
Freight Trucks	2.13	2.66	2.66	2.65	3.16	3.14	3.12	3.40	3.39	3.34
Rail, Passenger	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Rail, Freight	0.22	0.24	0.24	0.24	0.25	0.26	0.27	0.26	0.26	0.28
Shipping, Domestic	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.14	0.15	0.15
Shipping, International	0.25	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.23
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Air	1.33	1.66	1.64	1.62	1.99	1.97	1.95	2.06	2.04	2.02
Military Use	0.33	0.39	0.39	0.39	0.40	0.40	0.40	0.40	0.40	0.40
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.33	0.35	0.36	0.36	0.42	0.43	0.43	0.43	0.43	0.42
Total	**13.73**	**16.19**	**15.95**	**15.75**	**19.00**	**18.72**	**18.23**	**20.36**	**20.03**	**19.33**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for #Y!# and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004); Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2003/2002* (Washington, DC, 2003); EIA, *Fuel Oil and Kerosene Sales 2002*, DOE/EIA-0535(2002) (Washington, DC, November 2003); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D5. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.68	6.02	6.16	6.23	5.21	5.36	5.77	4.73	4.98	5.30
Alaska	0.97	0.81	0.82	0.84	0.86	0.90	0.96	0.61	0.64	0.72
Lower 48 States	4.71	5.22	5.34	5.38	4.35	4.46	4.80	4.12	4.34	4.58
Net Imports	9.65	11.31	11.13	10.93	14.80	14.62	13.39	16.11	15.83	14.30
Gross Imports	9.66	11.32	11.14	10.94	14.81	14.63	13.41	16.12	15.84	14.31
Exports	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Crude Supply[2]	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.31**	**17.33**	**17.29**	**17.16**	**20.01**	**19.98**	**19.16**	**20.84**	**20.81**	**19.60**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.96	1.99	2.04	2.04	2.08	2.18	2.04	2.07	2.17
Net Product Imports	1.58	2.06	1.48	1.11	2.31	1.59	0.66	3.00	2.19	0.94
Gross Refined Product Imports[3]	1.85	1.99	1.38	1.02	1.90	1.15	0.38	2.47	1.63	0.56
Unfinished Oil Imports	0.34	0.59	0.61	0.59	0.91	0.93	0.77	1.02	1.04	0.87
Blending Components	0.41	0.48	0.47	0.46	0.55	0.54	0.52	0.60	0.58	0.55
Exports	1.01	0.99	0.98	0.96	1.05	1.03	1.01	1.08	1.06	1.04
Refinery Processing Gain[4]	1.00	1.11	1.12	1.14	1.50	1.53	1.51	1.56	1.61	1.57
Other Supply[5]	0.69	0.53	0.67	0.78	0.46	0.57	1.43	0.50	0.62	1.93
Total Primary Supply[6]	**20.30**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.95**	**27.93**	**27.30**	**26.22**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	8.93	10.28	10.06	9.89	11.97	11.71	11.25	12.89	12.59	11.94
Jet Fuel[8]	1.57	1.95	1.93	1.92	2.29	2.27	2.25	2.36	2.34	2.32
Distillate Fuel[9]	3.95	4.70	4.61	4.56	5.44	5.31	5.22	5.81	5.67	5.55
Residual Fuel	0.77	0.80	0.76	0.74	0.88	0.82	0.77	0.88	0.84	0.78
Other[10]	4.77	5.25	5.18	5.12	5.74	5.65	5.47	5.98	5.86	5.62
Total	**20.00**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.96**	**27.93**	**27.30**	**26.22**
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.33	1.23	1.17	1.41	1.29	1.18	1.42	1.30	1.15
Industrial[11]	4.87	5.33	5.28	5.23	5.81	5.75	5.58	6.05	5.96	5.74
Transportation	13.35	15.76	15.52	15.31	18.48	18.18	17.69	19.82	19.48	18.80
Electric Power[12]	0.50	0.56	0.52	0.51	0.62	0.54	0.51	0.64	0.57	0.53
Total	**20.00**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.96**	**27.93**	**27.30**	**26.22**
Discrepancy[13]	**0.29**	**-0.00**	**0.00**	**-0.00**	**0.00**	**-0.01**	**-0.01**	**-0.00**	**0.00**	**-0.00**
World Oil Price (2003 dollars per barrel)[14]	27.73	25.00	30.99	37.00	28.50	33.67	44.33	30.31	35.00	48.00
Import Share of Product Supplied	0.56	0.58	0.56	0.54	0.65	0.63	0.56	0.68	0.66	0.58
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	113.78	125.14	145.87	165.06	180.07	200.57	226.90	215.89	233.46	267.39
Domestic Refinery Distillation Capacity[15]	16.8	18.7	18.7	18.6	21.4	21.4	20.6	22.3	22.2	21.0
Capacity Utilization Rate (percent)	93.0	94.0	93.8	93.4	94.8	94.8	94.5	94.9	94.9	94.8

[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 other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[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 energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D6. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
World Oil Price (2003 dollars per barrel)	**27.73**	**25.00**	**30.99**	**37.00**	**28.50**	**33.67**	**44.33**	**30.31**	**35.00**	**48.00**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	132.7	114.9	129.7	144.1	122.7	135.8	159.2	126.4	140.5	167.4
Liquefied Petroleum Gas	125.4	122.6	135.3	146.8	129.5	140.6	156.3	134.6	144.2	167.7
Commercial										
Distillate Fuel	97.3	86.9	101.8	116.5	93.2	106.2	127.7	97.3	111.7	137.6
Residual Fuel	74.3	63.7	74.8	88.8	71.9	80.8	105.6	76.0	83.9	114.1
Residual Fuel (2003 dollars per barrel)	31.21	26.77	31.42	37.30	30.21	33.93	44.36	31.92	35.22	47.91
Industrial[1]										
Distillate Fuel	100.2	93.3	107.9	122.5	101.2	114.1	134.5	106.2	120.4	145.7
Liquefied Petroleum Gas	108.1	86.1	98.5	109.4	92.3	102.9	118.0	97.6	107.1	128.3
Residual Fuel	68.7	57.9	69.5	83.7	64.9	74.8	99.7	69.1	77.7	108.0
Residual Fuel (2003 dollars per barrel)	28.84	24.33	29.20	35.14	27.27	31.41	41.85	29.02	32.64	45.37
Transportation										
Diesel Fuel (distillate)[2]	150.4	147.5	162.6	177.5	146.1	159.1	179.2	148.6	163.2	188.8
Jet Fuel[3]	87.2	84.3	99.3	113.5	88.8	102.2	124.8	93.5	107.7	135.4
Motor Gasoline[4]	160.3	152.4	165.2	181.7	154.9	166.1	188.6	158.5	170.7	200.8
Liquid Petroleum Gas	143.2	131.1	142.9	153.7	134.7	145.0	156.8	139.7	147.0	168.1
Residual Fuel	67.3	56.0	65.9	80.2	64.1	72.1	97.5	68.3	75.2	106.1
Residual Fuel (2003 dollars per barrel)	28.25	23.50	27.69	33.70	26.92	30.28	40.93	28.68	31.58	44.58
Ethanol (E85)[5]	152.4	160.5	169.4	186.9	161.6	171.9	192.9	170.1	175.9	205.0
Electric Power[6]										
Distillate Fuel	89.8	74.4	88.6	102.9	83.3	96.3	117.5	87.8	101.7	126.7
Residual Fuel	71.7	62.7	73.7	87.9	70.5	79.4	104.5	74.9	82.5	112.9
Residual Fuel (2003 dollars per barrel)	30.12	26.32	30.97	36.92	29.63	33.36	43.88	31.45	34.64	47.44
Refined Petroleum Product Prices[7]										
Distillate Fuel	136.7	131.0	146.5	161.5	134.4	147.9	169.1	137.7	152.9	178.8
Jet Fuel[3]	87.2	84.3	99.3	113.5	88.8	102.2	124.8	93.5	107.7	135.4
Liquefied Petroleum Gas	112.1	94.5	106.7	117.6	101.0	111.5	126.4	106.1	115.5	136.8
Motor Gasoline[4]	160.3	152.2	165.0	181.5	154.8	165.9	188.5	158.4	170.6	200.7
Residual Fuel	69.8	59.8	70.5	84.7	67.7	76.2	101.3	72.0	79.3	109.8
Residual Fuel (2003 dollars per barrel)	29.32	25.11	29.60	35.56	28.43	32.02	42.54	30.22	33.31	46.12
Average	**136.6**	**128.3**	**141.8**	**156.8**	**132.4**	**144.2**	**165.3**	**136.8**	**149.3**	**176.9**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D7. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
World Oil Price (2003 dollars per barrel)[1]	**27.73**	**25.00**	**30.99**	**37.00**	**28.50**	**33.67**	**44.33**	**30.31**	**35.00**	**48.00**
Production (Conventional)[2]										
Industrialized Countries										
U.S. (50 states)	9.09	9.61	9.93	10.07	9.21	9.55	10.12	8.82	9.28	9.79
Canada	2.25	1.83	1.85	1.90	1.60	1.62	1.71	1.57	1.59	1.69
Mexico	3.80	4.21	4.28	4.47	4.62	4.70	5.05	4.85	4.92	5.35
Western Europe[3]	6.69	6.35	6.41	6.66	5.51	5.56	5.90	5.00	5.04	5.40
Japan	0.13	0.08	0.09	0.10	0.06	0.07	0.09	0.06	0.07	0.09
Australia and New Zealand	0.66	0.96	0.97	1.01	0.89	0.90	0.95	0.86	0.87	0.93
Total Industrialized	**22.62**	**23.05**	**23.54**	**24.20**	**21.89**	**22.40**	**23.83**	**21.16**	**21.77**	**23.26**
Eurasia										
Former Soviet Union										
Russia	8.34	9.98	10.16	10.66	10.90	11.09	12.02	11.11	11.29	12.38
Caspian Area[4]	1.87	3.14	3.20	3.37	5.23	5.33	5.82	6.22	6.32	7.00
Eastern Europe[5]	0.22	0.33	0.34	0.35	0.41	0.42	0.44	0.45	0.46	0.49
Total Eurasia	**10.44**	**13.46**	**13.70**	**14.38**	**16.54**	**16.84**	**18.28**	**17.78**	**18.07**	**19.86**
Developing Countries										
OPEC[6]										
Asia	1.38	1.47	1.31	1.11	1.51	1.35	0.98	1.56	1.41	0.98
Middle East	20.95	24.45	21.74	18.46	32.37	28.88	20.87	38.47	34.76	24.21
North Africa	2.99	3.44	3.06	2.60	4.44	3.96	2.86	4.78	4.32	3.01
West Africa	1.98	2.36	2.10	1.78	3.13	2.79	2.02	3.74	3.38	2.36
South America	2.85	3.34	2.97	2.52	4.44	3.96	2.86	5.20	4.70	3.27
Non-OPEC										
China	3.10	3.64	3.70	3.82	3.49	3.55	3.76	3.41	3.47	3.70
Other Asia	2.59	2.65	2.70	2.80	2.71	2.76	2.94	2.64	2.69	2.89
Middle East[7]	1.81	2.24	2.28	2.35	2.57	2.62	2.77	2.78	2.83	3.02
Africa	2.94	3.75	3.82	4.05	5.44	5.54	6.10	6.56	6.67	7.45
South and Central America	3.93	4.53	4.61	4.86	5.91	6.02	6.57	6.42	6.52	7.22
Total Developing Countries	**44.52**	**51.87**	**48.28**	**44.36**	**66.02**	**61.44**	**51.72**	**75.57**	**70.74**	**58.10**
Total Production (Conventional)	**77.58**	**88.38**	**85.51**	**82.95**	**104.45**	**100.68**	**93.83**	**114.51**	**110.58**	**101.22**
Production[6] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.12	0.00	0.00	0.77	0.00	0.00	1.19
Other North America	0.93	1.73	1.74	2.12	3.33	3.34	4.20	3.46	3.47	4.69
Western Europe	0.04	0.04	0.05	0.05	0.05	0.06	0.07	0.05	0.07	0.08
Asia	0.03	0.04	0.04	0.08	0.05	0.07	0.16	0.07	0.09	0.20
Middle East[7]	0.03	0.12	0.13	0.19	0.21	0.25	0.44	0.25	0.30	0.56
Africa	0.21	0.23	0.23	0.33	0.28	0.29	0.57	0.32	0.33	0.68
South and Central America	0.57	0.82	0.84	1.38	1.48	1.51	2.53	1.50	1.54	2.99
Total Production (Nonconventional)	**1.79**	**2.98**	**3.03**	**4.28**	**5.40**	**5.52**	**8.75**	**5.65**	**5.80**	**10.39**
Total Production	**79.37**	**91.35**	**88.54**	**87.23**	**109.85**	**106.20**	**102.59**	**120.17**	**116.39**	**111.62**

Table D7. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	20.00	22.98	22.54	22.22	26.32	25.76	24.96	27.93	27.30	26.22
U.S. Territories	0.36	0.38	0.35	0.34	0.43	0.40	0.36	0.47	0.44	0.39
Canada	2.17	2.30	2.15	2.08	2.62	2.45	2.24	2.80	2.64	2.37
Mexico	2.02	2.36	2.23	2.18	2.88	2.57	2.31	3.48	3.05	2.62
Western Europe[3]	14.22	14.72	14.25	14.01	15.45	15.00	14.40	15.71	15.31	14.59
Japan	5.58	5.70	5.29	5.14	5.69	5.10	4.54	5.84	5.23	4.48
Australia and New Zealand	1.04	1.27	1.23	1.22	1.54	1.50	1.45	1.69	1.65	1.58
Total Industrialized	**45.38**	**49.72**	**48.05**	**47.18**	**54.93**	**52.78**	**50.26**	**57.92**	**55.63**	**52.26**
Eurasia										
Former Soviet Union	4.18	4.39	4.27	4.21	5.74	5.61	5.43	6.45	6.32	6.08
Eastern Europe[5]	1.42	1.56	1.53	1.52	1.89	1.86	1.83	2.09	2.06	2.01
Total Eurasia	**5.59**	**5.95**	**5.81**	**5.73**	**7.63**	**7.47**	**7.25**	**8.54**	**8.38**	**8.10**
Developing Countries										
China	5.54	7.63	7.29	7.12	11.06	10.63	10.05	12.79	12.35	11.56
India	2.19	2.79	2.68	2.64	4.37	4.15	3.92	5.29	5.04	4.68
South Korea	2.17	2.51	2.39	2.34	2.75	2.61	2.44	2.93	2.79	2.57
Other Asia	5.74	7.28	7.12	7.04	9.47	9.28	9.02	10.66	10.47	10.13
Middle East[7]	5.58	6.83	6.74	6.69	8.34	8.25	8.12	9.08	8.99	8.82
Africa	2.72	3.13	3.06	3.04	4.13	4.03	3.91	4.66	4.55	4.38
South and Central America	4.69	5.81	5.70	5.64	7.48	7.36	7.18	8.61	8.48	8.25
Total Developing Countries	**28.64**	**35.98**	**34.99**	**34.50**	**47.59**	**46.30**	**44.64**	**54.01**	**52.68**	**50.40**
Total Consumption	**79.60**	**91.65**	**88.84**	**87.41**	**110.14**	**106.54**	**102.15**	**120.47**	**116.69**	**110.76**
OPEC Production[10]	30.60	35.79	31.93	27.70	47.21	42.33	31.92	55.13	50.03	36.63
Non-OPEC Production[10]	48.77	55.56	56.61	59.53	62.64	63.87	70.67	65.04	66.36	74.98
Net Eurasia Exports	4.84	7.51	7.89	8.65	8.92	9.37	11.03	9.25	9.68	11.77
OPEC Market Share	0.39	0.39	0.36	0.32	0.43	0.40	0.31	0.46	0.43	0.33

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates, natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Results from Side Cases

Table E1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2003	2010				2015			
		2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.96	0.91	0.90	0.89	0.87	0.89	0.88	0.87	0.82
Kerosene	0.07	0.10	0.09	0.09	0.09	0.10	0.09	0.09	0.08
Liquefied Petroleum Gas	0.54	0.58	0.57	0.57	0.54	0.62	0.61	0.60	0.55
Petroleum Subtotal	1.58	1.58	1.56	1.55	1.50	1.60	1.58	1.55	1.45
Natural Gas	5.25	5.76	5.69	5.66	5.30	6.03	5.90	5.75	4.92
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy	0.40	0.41	0.40	0.39	0.39	0.41	0.39	0.38	0.38
Electricity	4.37	5.06	5.02	4.96	4.70	5.49	5.40	5.27	4.74
Delivered Energy	**11.61**	**12.82**	**12.67**	**12.57**	**11.89**	**13.55**	**13.29**	**12.97**	**11.49**
Electricity Related Losses	9.71	10.88	10.80	10.67	10.11	11.48	11.29	11.01	9.89
Total	**21.31**	**23.70**	**23.47**	**23.24**	**22.00**	**25.03**	**24.58**	**23.97**	**21.38**
Delivered Energy Intensity (million Btu per household)	**103.6**	**105.0**	**103.8**	**103.0**	**97.4**	**105.0**	**102.9**	**100.4**	**89.0**
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.04**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.52	0.62	0.62	0.61	0.62	0.70	0.66	0.65	0.69
Residual Fuel	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.86	0.85	0.86	0.95	0.91	0.90	0.93
Natural Gas	3.22	3.49	3.49	3.48	3.42	3.67	3.69	3.68	3.54
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.04	5.00	4.94	4.59	5.75	5.63	5.49	4.90
Delivered Energy	**8.29**	**9.57**	**9.53**	**9.46**	**9.05**	**10.54**	**10.41**	**10.25**	**9.56**
Electricity Related Losses	9.18	10.85	10.76	10.64	9.87	12.00	11.77	11.47	10.24
Total	**17.46**	**20.42**	**20.29**	**20.10**	**18.91**	**22.54**	**22.18**	**21.72**	**19.80**
Delivered Energy Intensity (thousand Btu per square foot)	**114.8**	**117.8**	**117.3**	**116.5**	**111.3**	**119.2**	**117.8**	**115.9**	**108.1**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	660	673	677	677	677	698	722	722	722
Solar Photovoltaic	48	258	258	258	268	284	304	358	618
Electricity Generation (billion kilowatthours)									
Natural Gas	4.75	4.85	4.87	4.87	4.87	5.02	5.20	5.20	5.20
Solar Photovoltaic	0.10	0.55	0.55	0.55	0.57	0.60	0.64	0.76	1.31
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2005 National Energy Modeling System, runs BLDFRZN.D102104A, BLDDEF.D102104A, BLDHIGH.D110404A, and BLDBEST.D102104A.

2020				2025				Annual Growth 2003-2025 (percent)			
2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
0.86	0.83	0.81	0.75	0.82	0.77	0.74	0.67	-0.7%	-1.0%	-1.2%	-1.6%
0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.07	1.0%	0.8%	0.7%	-0.4%
0.66	0.64	0.62	0.56	0.69	0.67	0.63	0.57	1.1%	0.9%	0.7%	0.2%
1.61	1.56	1.52	1.38	1.61	1.53	1.46	1.30	0.1%	-0.1%	-0.3%	-0.9%
6.25	6.05	5.78	4.71	6.44	6.17	5.78	4.60	0.9%	0.7%	0.4%	-0.6%
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%	-1.0%	-1.1%	-1.3%
0.42	0.39	0.37	0.36	0.42	0.38	0.36	0.35	0.2%	-0.3%	-0.5%	-0.6%
5.92	5.79	5.59	4.83	6.39	6.18	5.96	5.09	1.7%	1.6%	1.4%	0.7%
14.21	**13.80**	**13.28**	**11.29**	**14.86**	**14.26**	**13.57**	**11.35**	**1.1%**	**0.9%**	**0.7%**	**-0.1%**
12.03	11.77	11.36	9.82	12.77	12.35	11.92	10.18	1.3%	1.1%	0.9%	0.2%
26.24	**25.56**	**24.64**	**21.10**	**27.63**	**26.62**	**25.50**	**21.53**	**1.2%**	**1.0%**	**0.8%**	**0.0%**
104.6	**101.6**	**97.8**	**83.1**	**104.3**	**100.1**	**95.3**	**79.7**	**0.0%**	**-0.2%**	**-0.4%**	**-1.2%**
0.04	**0.04**	**0.07**	**0.06**	**0.05**	**0.05**	**0.09**	**0.09**	**3.3%**	**3.3%**	**6.4%**	**5.9%**
0.78	0.71	0.70	0.76	0.88	0.77	0.74	0.84	2.4%	1.8%	1.6%	2.2%
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.2%	0.2%	0.2%	0.2%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.5%	0.5%	0.5%	0.5%
0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.5%	0.5%	0.5%	0.5%
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.2%	0.2%	0.2%	0.2%
1.03	0.96	0.94	1.01	1.13	1.02	0.99	1.09	1.8%	1.4%	1.3%	1.7%
3.86	3.91	3.89	3.70	4.08	4.17	4.14	3.92	1.1%	1.2%	1.2%	0.9%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	-0.1%	-0.1%	-0.1%	-0.1%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%	0.0%	0.0%	0.0%
6.54	6.33	6.09	5.34	7.45	7.13	6.77	5.88	2.7%	2.5%	2.3%	1.6%
11.61	**11.38**	**11.11**	**10.23**	**12.84**	**12.49**	**12.09**	**11.07**	**2.0%**	**1.9%**	**1.7%**	**1.3%**
13.29	12.87	12.38	10.85	14.91	14.25	13.54	11.75	2.2%	2.0%	1.8%	1.1%
24.90	**24.24**	**23.49**	**21.08**	**27.76**	**26.74**	**25.63**	**22.83**	**2.1%**	**2.0%**	**1.8%**	**1.2%**
120.7	**118.3**	**115.5**	**106.3**	**122.6**	**119.2**	**115.4**	**105.7**	**0.3%**	**0.2%**	**0.0%**	**-0.4%**
737	909	909	931	782	1359	1418	1812	0.8%	3.3%	3.5%	4.7%
341	639	766	1672	497	1468	1786	3161	11.2%	16.8%	17.9%	21.0%
5.30	6.57	6.57	6.72	5.63	9.84	10.26	13.13	0.8%	3.4%	3.6%	4.7%
0.72	1.34	1.62	3.44	1.04	3.05	3.69	6.45	11.1%	16.7%	17.7%	20.8%
0.03	**0.03**	**0.03**	**0.04**	**0.03**	**0.04**	**0.04**	**0.05**	**1.1%**	**2.1%**	**2.3%**	**3.3%**

Table E2. Key Results for Industrial Sector Technology Cases

Consumption	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Value of Shipments (billion 1996 dollars)										
Manufacturing	3851	4836	4836	4836	6046	6046	6046	6733	6733	6733
Nonmanufacturing	1254	1329	1329	1329	1587	1587	1587	1736	1736	1736
Total	**5105**	**6165**	**6165**	**6165**	**7633**	**7633**	**7633**	8469	8469	8469
Energy Consumption (quadrillion Btu)[1]										
Distillate Fuel	1.03	1.09	1.04	1.01	1.24	1.14	1.04	1.32	1.19	1.07
Liquefied Petroleum Gas	2.09	2.37	2.30	2.25	2.74	2.59	2.45	2.90	2.74	2.58
Petrochemical Feedstocks	1.32	1.53	1.48	1.45	1.65	1.55	1.46	1.68	1.57	1.48
Residual Fuel	0.28	0.35	0.34	0.33	0.41	0.38	0.35	0.41	0.38	0.34
Motor Gasoline	0.31	0.32	0.31	0.31	0.37	0.35	0.33	0.39	0.37	0.35
Petroleum Coke	1.00	1.10	1.07	1.04	1.37	1.30	1.24	1.45	1.38	1.31
Still Gas	1.48	1.77	1.77	1.77	1.65	1.65	1.65	1.67	1.68	1.67
Asphalt and Road Oil	1.22	1.25	1.16	1.09	1.52	1.30	1.11	1.69	1.43	1.20
Miscellaneous Petroleum[2]	0.61	0.72	0.69	0.67	0.83	0.77	0.70	0.82	0.75	0.67
Petroleum Subtotal	9.31	10.50	10.17	9.92	11.77	11.03	10.32	12.34	11.47	10.67
Natural Gas	7.19	8.42	8.10	7.89	9.52	8.89	8.20	9.96	9.26	8.38
Lease and Plant Fuel[3]	1.15	1.20	1.20	1.20	1.32	1.32	1.32	1.31	1.31	1.31
Natural Gas Subtotal	8.34	9.63	9.31	9.10	10.85	10.21	9.52	11.27	10.57	9.69
Metallurgical Coal and Coke[4]	0.72	0.67	0.61	0.51	0.60	0.47	0.30	0.57	0.42	0.24
Steam Coal	1.39	1.45	1.42	1.40	1.48	1.42	1.35	1.49	1.42	1.34
Coal Subtotal	2.11	2.12	2.03	1.91	2.08	1.89	1.65	2.06	1.83	1.57
Renewable Energy[5]	1.79	2.06	2.07	2.16	2.32	2.34	2.65	2.46	2.50	2.94
Purchased Electricity	3.31	3.86	3.78	3.67	4.43	4.19	3.95	4.71	4.39	4.08
Delivered Energy	**24.86**	**28.17**	**27.35**	**26.76**	**31.45**	**29.66**	**28.09**	**32.84**	**30.76**	**28.95**
Electricity Related Losses	7.35	8.30	8.13	7.90	9.01	8.52	8.03	9.42	8.78	8.16
Total	**32.21**	**36.47**	**35.47**	**34.67**	**40.46**	**38.19**	**36.12**	**42.26**	**39.53**	**37.11**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 1996 dollar)	**4.87**	**4.57**	**4.44**	**4.34**	**4.12**	**3.89**	**3.68**	**3.88**	**3.63**	**3.42**
Industrial Combined Heat and Power										
Capacity (gigawatts)	24.87	29.59	29.50	30.85	35.70	36.03	39.04	38.94	40.09	43.44
Generation (billion kilowatthours)	139.59	172.52	171.71	180.51	219.14	220.64	238.77	243.22	250.10	268.85

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs INDFRZN.D102304A, AEO2005.D102004A, and INDHIGH.D102304A.

Table E3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2601	3015	3016	3020	3661	3680	3704	4017	4052	4092
Commercial Light Trucks[1]	64	78	78	78	96	96	96	106	107	107
Freight Trucks greater than 10,000	214	268	268	269	337	337	337	374	374	374
(billion seat miles available)										
Air	932	1152	1152	1152	1455	1455	1455	1520	1520	1520
(billion ton miles traveled)										
Rail	1354	1579	1579	1579	1836	1836	1837	2005	2005	2006
Domestic Shipping	592	650	650	650	707	707	707	734	734	734
Energy Efficiency Indicators										
(miles per gallon)										
New Light-Duty Vehicle[2]	25.1	25.2	25.7	26.5	25.0	26.5	28.2	24.9	26.9	28.8
New Car[2]	29.5	29.1	29.7	31.3	29.1	30.6	32.8	29.0	31.0	33.4
New Light Truck[2]	21.8	22.5	22.9	23.3	22.6	24.1	25.5	22.7	24.6	26.3
Light-Duty Stock[3]	19.9	20.1	20.1	20.3	20.1	20.7	21.5	20.1	21.0	22.1
New Commercial Light Truck[1]	14.6	15.0	15.2	15.5	14.9	16.0	17.0	14.8	16.4	17.6
Stock Commercial Light Truck[1]	14.0	14.6	14.7	14.7	14.9	15.5	16.1	14.9	15.9	16.8
Freight Truck	6.0	6.0	6.0	6.1	6.1	6.4	6.4	6.1	6.6	6.6
(seat miles per gallon)										
Aircraft	55.3	58.7	59.2	60.7	59.8	65.2	73.7	59.7	68.5	82.4
(ton miles per thousand Btu)										
Rail	2.9	2.9	3.1	3.2	2.9	3.4	3.8	2.9	3.6	4.1
Domestic Shipping	2.3	2.3	2.3	2.4	2.3	2.4	2.5	2.3	2.4	2.6
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.77	18.48	18.42	18.28	22.35	21.81	21.14	24.59	23.65	22.67
Commercial Light Trucks[1]	0.58	0.67	0.66	0.66	0.81	0.78	0.75	0.90	0.84	0.80
Bus Transportation	0.25	0.26	0.26	0.26	0.28	0.27	0.27	0.29	0.27	0.27
Freight Trucks	4.47	5.56	5.56	5.53	6.95	6.61	6.54	7.69	7.11	7.04
Rail, Passenger	0.12	0.13	0.13	0.14	0.14	0.16	0.17	0.14	0.17	0.20
Rail, Freight	0.47	0.54	0.51	0.49	0.62	0.54	0.49	0.68	0.56	0.49
Shipping, Domestic	0.26	0.28	0.28	0.28	0.31	0.30	0.29	0.32	0.31	0.29
Shipping, International	0.56	0.51	0.51	0.51	0.52	0.52	0.52	0.53	0.52	0.52
Recreational Boats	0.31	0.33	0.33	0.33	0.37	0.37	0.37	0.39	0.39	0.39
Air	2.74	3.45	3.43	3.34	4.48	4.11	3.64	4.88	4.25	3.54
Military Use	0.69	0.80	0.80	0.80	0.82	0.82	0.82	0.83	0.83	0.83
Lubricants	0.20	0.21	0.21	0.21	0.25	0.25	0.25	0.27	0.27	0.27
Pipeline Fuel	0.65	0.70	0.70	0.70	0.82	0.82	0.82	0.84	0.84	0.84
Total	**27.07**	**31.93**	**31.82**	**31.54**	**38.72**	**37.35**	**36.07**	**42.36**	**40.01**	**38.15**
Energy Use by Fuel (quadrillion Btu)										
Distillate Fuel[4]	5.54	6.98	6.95	6.89	8.78	8.36	8.19	9.77	9.06	8.85
Jet Fuel[5]	3.26	4.06	4.04	3.95	5.11	4.74	4.27	5.52	4.89	4.18
Motor Gasoline[6]	16.64	19.17	19.12	18.98	22.86	22.27	21.63	25.02	24.00	23.07
Residual Fuel	0.62	0.57	0.56	0.56	0.58	0.58	0.57	0.59	0.58	0.57
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.08
Other Petroleum[7]	0.24	0.26	0.26	0.26	0.29	0.29	0.29	0.31	0.31	0.31
Petroleum Subtotal	26.31	31.09	30.98	30.69	37.70	36.32	35.03	41.30	38.93	37.06
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.70	0.82	0.82	0.82	0.84	0.84	0.84
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.09	0.11	0.11	0.10
Renewable Energy (E85)[8]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.09	0.11	0.12	0.10	0.12	0.14
Delivered Energy	**27.07**	**31.93**	**31.82**	**31.54**	**38.72**	**37.35**	**36.07**	**42.36**	**40.01**	**38.15**
Electricity Related Losses	0.17	0.18	0.19	0.20	0.19	0.22	0.24	0.20	0.24	0.27
Total	**27.24**	**32.12**	**32.02**	**31.74**	**38.92**	**37.57**	**36.31**	**42.55**	**40.25**	**38.42**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
[4]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[5]Includes only kerosene type.
[6]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[7]Includes aviation gasoline and lubricants.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LT.D110904A, BASE.D110904A, and HT.D110904A.

Table E4. Key Results for Integrated Technology Cases

Consumption and Emissions	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	21.3	23.6	23.5	23.3	26.1	25.6	24.7	27.5	26.6	25.4
Commercial	17.5	20.3	20.3	20.2	24.7	24.2	23.6	27.5	26.7	25.6
Industrial	32.2	36.4	35.5	34.7	40.4	38.2	36.0	42.3	39.5	36.8
Transportation	27.2	32.1	32.0	31.8	38.9	37.6	36.3	42.6	40.3	38.5
Total	**98.2**	**112.4**	**111.3**	**109.9**	**130.2**	**125.6**	**120.6**	**139.8**	**133.2**	**126.2**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	39.1	45.3	44.8	44.3	53.9	51.3	49.1	58.2	54.4	51.4
Natural Gas	22.5	26.6	26.1	25.6	31.8	30.7	29.2	32.6	31.5	30.5
Coal	22.7	25.1	25.0	24.6	28.1	27.3	25.7	32.2	30.5	26.7
Nuclear Power	8.0	8.5	8.5	8.5	8.7	8.7	8.7	8.7	8.7	8.7
Renewable Energy	5.9	6.9	6.8	6.9	7.7	7.6	7.9	8.2	8.1	8.8
Other	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.0
Total	**98.2**	**112.4**	**111.3**	**109.9**	**130.2**	**125.6**	**120.6**	**139.8**	**133.2**	**126.2**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**9.5**	**8.6**	**8.5**	**8.4**	**7.4**	**7.1**	**6.8**	**6.9**	**6.6**	**6.2**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	1225.0	1361.6	1355.2	1342.1	1524.0	1487.6	1420.8	1645.4	1580.0	1457.9
Commercial	1028.1	1199.5	1197.6	1186.8	1482.0	1443.5	1385.1	1697.3	1627.9	1499.8
Industrial	1663.8	1900.8	1852.3	1800.3	2105.5	1979.6	1830.1	2219.3	2058.6	1847.0
Transportation	1871.9	2226.1	2221.8	2203.8	2703.4	2608.9	2520.1	2957.0	2795.8	2666.6
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons)										
Petroleum	2403.4	2820.4	2800.4	2770.3	3350.7	3219.6	3096.8	3631.1	3420.8	3245.5
Natural Gas	903.1	1024.9	1008.1	999.5	1143.1	1106.1	1052.2	1185.9	1146.3	1078.6
Coal	196.6	207.9	199.8	189.0	203.4	186.3	165.7	201.4	181.1	158.4
Electricity	2285.7	2634.8	2618.6	2574.2	3117.7	3007.6	2841.5	3500.6	3314.1	2988.9
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)										
Petroleum	95.8	98.6	96.3	93.8	136.4	106.9	94.8	135.9	109.2	100.1
Natural Gas	266.6	370.8	362.1	344.9	527.1	508.0	479.1	525.7	506.5	523.4
Coal	1906.0	2145.0	2139.8	2115.6	2432.7	2371.5	2246.7	2816.6	2676.8	2343.9
Other	17.3	20.4	20.4	19.9	21.5	21.2	21.0	22.5	21.5	21.5
Total	**2285.7**	**2634.8**	**2618.6**	**2574.2**	**3117.7**	**3007.6**	**2841.5**	**3500.6**	**3314.1**	**2988.9**
Carbon Dioxide Emissions by Primary Fuel (million metric tons)										
Petroleum	2499.2	2919.0	2896.7	2864.1	3487.0	3326.5	3191.6	3767.0	3530.0	3345.6
Natural Gas	1169.7	1395.8	1370.2	1344.4	1670.1	1614.0	1531.2	1711.6	1652.9	1602.0
Coal	2102.5	2352.9	2339.5	2304.6	2636.1	2557.9	2412.3	3017.9	2857.9	2502.2
Other	17.3	20.4	20.4	19.9	21.5	21.2	21.0	22.5	21.5	21.5
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LTRKITEN.D111504A, AEO2005.D102004A, and HTRKITEN.D111604A.

Table E5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2003	2010			2020			2025		
		Reference	Vendor Estimates	Advanced Nuclear Cost	Reference	Vendor Estimates	Advanced Nuclear Cost	Reference	Vendor Estimates	Advanced Nuclear Cost
Capacity										
Coal Steam	310.3	309.7	310.2	310.2	339.7	337.0	339.2	394.3	379.8	388.4
Other Fossil Steam	129.7	120.5	120.5	120.5	101.1	100.3	100.3	100.5	99.6	99.6
Combined Cycle	138.2	169.9	169.9	169.9	210.3	207.4	210.8	222.9	219.2	224.3
Combustion Turbine/Diesel	129.9	137.7	137.7	137.7	173.0	173.6	173.3	193.7	191.3	192.8
Nuclear Power	99.2	100.6	100.6	100.6	102.7	108.9	102.7	102.7	127.8	110.1
Pumped Storage	20.8	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	92.2	95.3	95.3	95.3	99.3	98.5	99.0	103.1	101.3	102.8
Distributed Generation (Natural Gas)	0.0	0.4	0.4	0.4	3.1	3.0	2.9	6.9	6.5	6.6
Combined Heat and Power[1]	27.1	32.1	32.1	32.1	39.2	39.3	39.3	44.8	44.8	44.8
Total	**947.4**	**987.0**	**987.5**	**987.5**	**1089.3**	**1088.7**	**1088.4**	**1189.7**	**1191.1**	**1190.4**
Cumulative Additions										
Coal Steam	0.0	1.8	1.8	1.8	32.4	29.1	31.4	86.9	71.9	80.6
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	31.8	31.8	31.8	72.5	69.4	72.8	85.1	81.2	86.3
Combustion Turbine/Diesel	0.0	9.7	9.7	9.7	51.2	51.2	51.3	73.8	70.2	72.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	6.2	0.0	0.0	25.1	7.4
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	0.0	2.9	2.9	2.9	6.9	6.1	6.7	10.7	8.9	10.4
Distributed Generation	0.0	0.4	0.4	0.4	3.1	3.0	2.9	6.9	6.5	6.6
Combined Heat and Power[1]	0.0	5.0	5.0	5.0	12.1	12.2	12.2	17.7	17.7	17.7
Total	**0.0**	**51.5**	**51.6**	**51.6**	**178.1**	**177.2**	**177.3**	**281.1**	**281.6**	**281.2**
Cumulative Retirements	**0.0**	**13.8**	**13.3**	**13.3**	**40.1**	**39.8**	**40.1**	**42.6**	**41.7**	**42.1**
Generation by Fuel (billion kilowatthours)										
Coal	1950	2203	2205	2205	2473	2450	2471	2869	2753	2824
Petroleum	113	117	117	117	131	129	131	135	130	132
Natural Gas	556	822	820	820	1234	1220	1240	1234	1183	1226
Nuclear Power	764	813	813	813	830	877	830	830	1017	886
Pumped Storage	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources	323	393	393	393	416	412	415	434	427	434
Distributed Generation	0	0	0	0	1	1	1	3	3	3
Combined Heat and Power[1]	153	187	187	187	238	238	238	273	273	273
Total	**3850**	**4526**	**4526**	**4526**	**5314**	**5318**	**5317**	**5770**	**5777**	**5769**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	95.8	96.3	96.2	96.2	106.9	104.9	106.7	109.2	105.0	106.5
Natural Gas	266.6	362.1	361.1	361.0	508.0	504.5	510.5	506.5	487.7	502.6
Coal	1906.0	2139.8	2141.8	2141.8	2371.5	2353.8	2371.0	2676.8	2582.2	2639.6
Other	17.3	20.4	20.4	20.4	21.2	21.2	21.2	21.5	21.5	21.6
Total	**2285.7**	**2618.6**	**2619.5**	**2619.4**	**3007.6**	**2984.4**	**3009.3**	**3314.1**	**3196.4**	**3270.2**
Prices to the Electric Power Sector[2] (2003 dollars per million Btu)										
Petroleum	5.28	4.55	4.55	4.55	5.10	5.10	5.10	5.42	5.41	5.42
Natural Gas	5.46	4.27	4.27	4.27	5.20	5.12	5.17	5.44	5.29	5.41
Coal	1.28	1.25	1.25	1.25	1.25	1.24	1.25	1.31	1.28	1.30

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A, ADVNUC5A.D110804A, and ADVNUC20.D102104A.

Table E6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2003	2010			2020			2025		
		Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil
Capacity										
Pulverized Coal	309.8	309.3	309.2	309.2	336.8	336.6	319.1	390.2	377.7	327.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	0.8	3.1	12.4	0.8	16.5	40.2
Conventional Natural Gas Combined-Cycle	138.2	166.6	166.6	166.5	171.1	167.2	166.4	173.1	167.8	166.4
Advanced Natural Gas Combined-Cycle	0.0	2.7	3.3	3.6	22.4	43.1	88.0	26.3	55.1	131.3
Conventional Combustion Turbine	129.9	132.6	132.1	132.0	135.5	128.4	125.8	137.4	127.6	125.2
Advanced Combustion Turbine	0.0	5.6	5.6	5.8	50.8	44.6	21.8	71.1	66.1	37.6
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	99.2	100.6	100.6	100.6	102.7	102.7	102.7	102.7	102.7	102.7
Oil and Gas Steam	129.7	120.5	120.5	120.5	101.4	101.1	96.8	100.7	100.5	92.2
Renewable Sources/Pumped Storage	113.0	116.1	116.1	116.1	121.0	120.2	118.4	125.4	124.0	120.2
Distributed Generation	0.0	0.4	0.4	0.4	5.6	3.1	2.1	12.8	6.9	3.7
Combined Heat and Power[1]	27.1	32.1	32.1	32.1	39.5	39.2	38.6	45.6	44.8	43.3
Total	**947.4**	**987.0**	**987.0**	**987.1**	**1087.6**	**1089.3**	**1092.2**	**1186.1**	**1189.7**	**1190.4**
Cumulative Additions										
Pulverized Coal	0.0	1.9	1.8	1.8	30.0	29.8	12.3	83.3	70.9	20.9
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	0.3	2.6	11.9	0.3	16.0	39.7
Conventional Natural Gas Combined-Cycle	0.0	28.5	28.5	28.4	33.2	29.4	28.4	35.2	29.9	28.4
Advanced Natural Gas Combined-Cycle	0.0	2.7	3.3	3.6	22.4	43.1	88.0	26.3	55.1	131.3
Conventional Combustion Turbine	0.0	4.6	4.1	4.0	12.5	6.6	4.8	15.4	7.7	5.2
Advanced Combustion Turbine	0.0	5.6	5.6	5.8	50.8	44.6	21.8	71.1	66.1	37.6
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	2.9	2.9	2.8	7.7	6.9	5.1	12.2	10.7	7.0
Distributed Generation	0.0	0.4	0.4	0.4	5.6	3.1	2.1	12.8	6.9	3.7
Combined Heat and Power[1]	0.0	5.0	5.0	5.0	12.4	12.1	11.5	18.5	17.7	16.2
Total	**0.0**	**51.6**	**51.5**	**51.6**	**174.9**	**178.1**	**186.0**	**275.2**	**281.1**	**289.9**
Cumulative Retirements	**0.0**	**13.8**	**13.8**	**13.8**	**38.6**	**40.1**	**45.1**	**40.3**	**42.6**	**50.8**
Generation by Fuel (billion kilowatthours)										
Coal	1949.7	2204.1	2202.6	2202.6	2460.1	2473.2	2418.7	2843.2	2869.4	2688.1
Petroleum	112.6	117.5	117.3	117.0	143.5	131.1	126.9	142.0	135.3	157.2
Natural Gas	555.9	820.3	821.7	822.5	1214.2	1233.7	1333.1	1208.6	1233.9	1434.7
Nuclear Power	763.7	813.3	813.3	813.3	830.2	830.2	830.2	830.2	830.2	830.2
Renewable Sources/Pumped Storage	314.7	383.8	384.1	383.9	412.8	406.8	398.9	438.8	425.4	410.4
Distributed Generation	0.0	0.2	0.2	0.2	2.4	1.3	0.9	5.6	3.0	1.6
Combined Heat and Power[1]	153.3	186.6	186.6	186.6	239.9	238.1	233.6	278.6	272.8	262.4
Total	**3849.9**	**4525.7**	**4525.8**	**4526.0**	**5303.1**	**5314.4**	**5342.3**	**5747.1**	**5770.0**	**5784.6**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.49	22.83	22.81	22.81	25.20	25.28	24.66	28.48	28.54	26.56
Petroleum	1.13	1.26	1.26	1.26	1.48	1.40	1.35	1.50	1.43	1.56
Natural Gas	5.06	6.87	6.87	6.86	9.81	9.64	9.62	9.80	9.61	9.99
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Sources	3.62	4.29	4.30	4.30	4.91	4.75	4.65	5.42	5.14	4.90
Total	**38.27**	**43.75**	**43.74**	**43.72**	**50.07**	**49.74**	**48.96**	**53.87**	**53.39**	**51.68**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1906.0	2141.1	2139.8	2139.6	2364.3	2371.5	2314.1	2671.1	2676.8	2490.7
Petroleum	95.8	96.4	96.3	96.1	113.2	106.9	103.5	114.2	109.2	118.5
Natural Gas	266.6	362.0	362.1	361.4	517.1	508.0	507.0	516.4	506.5	526.2
Other	17.3	20.4	20.4	20.4	21.6	21.2	20.8	22.0	21.5	21.1
Total	**2285.7**	**2620.0**	**2618.6**	**2617.6**	**3016.2**	**3007.6**	**2945.4**	**3323.7**	**3314.1**	**3156.5**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LFOSS05.D102104A, AEO2005.D102004A, and HFOSS05.D102104A.

Table E7. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2003	2010			2020			2025		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	77.93	78.18	78.18	78.18	78.18	78.18	78.18	78.18	78.18	78.18
Geothermal[2]	2.18	2.23	2.21	2.21	3.43	3.45	5.63	4.21	4.62	7.30
Municipal Solid Waste[3]	3.34	3.57	3.57	3.57	3.63	3.66	3.70	3.64	3.67	3.71
Wood and Other Biomass[4]	1.77	1.83	1.83	1.78	2.40	2.75	2.62	3.77	4.50	5.18
Solar Thermal	0.39	0.45	0.45	0.45	0.49	0.49	0.49	0.51	0.51	0.51
Solar Photovoltaic	0.04	0.15	0.15	0.15	0.32	0.32	0.32	0.40	0.40	0.40
Wind	6.56	8.88	8.88	8.88	9.52	10.45	11.63	9.91	11.25	13.97
Total	**92.21**	**95.29**	**95.27**	**95.22**	**97.97**	**99.29**	**102.57**	**100.62**	**103.13**	**109.27**
Commercial and Industrial Sector										
Conventional Hydropower	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Wood and Other Biomass	4.08	5.10	5.14	5.51	6.04	6.18	7.52	6.56	6.75	8.69
Solar Photovoltaic	0.06	0.39	0.39	0.39	0.50	0.80	0.99	0.68	1.80	2.32
Total	**5.43**	**6.78**	**6.82**	**7.20**	**7.84**	**8.27**	**9.80**	**8.53**	**9.85**	**12.30**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1950	2202	2203	2200	2474	2473	2468	2872	2869	2847
Petroleum	113	117	117	117	132	131	131	136	135	133
Natural Gas	556	822	822	820	1238	1234	1211	1245	1234	1213
Total Fossil	**2618**	**3141**	**3142**	**3137**	**3843**	**3838**	**3810**	**4252**	**4239**	**4193**
Conventional Hydropower	269.29	300.39	300.39	300.39	300.81	300.81	300.81	301.10	301.09	301.09
Geothermal	13.15	12.53	12.33	12.33	22.71	22.83	41.33	29.36	32.78	55.65
Municipal Solid Waste[3]	20.28	25.58	25.58	25.58	26.12	26.36	26.72	26.24	26.49	26.87
Wood and Other Biomass[4]	9.40	27.66	27.61	29.58	31.70	32.35	33.63	34.86	37.35	44.08
Dedicated Plants	5.73	10.30	10.32	10.08	14.04	16.21	14.86	22.35	27.29	31.66
Cofiring	3.66	17.37	17.29	19.50	17.66	16.13	18.77	12.51	10.06	12.42
Solar Thermal	0.53	0.80	0.80	0.80	0.92	0.92	0.92	0.99	0.99	0.99
Solar Photovoltaic	0.00	0.32	0.32	0.32	0.74	0.74	0.74	0.96	0.96	0.96
Wind	10.73	25.89	25.89	25.89	28.14	31.61	36.15	29.48	34.52	44.60
Total Renewable	**323.38**	**393.16**	**392.90**	**394.88**	**411.14**	**415.61**	**440.31**	**423.00**	**434.19**	**474.25**
Commercial and Industrial Sector[5]										
Total Fossil	102	130	130	130	174	173	173	202	202	202
Conventional Hydropower[6]	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	1.86	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
Wood and Other Biomass	27.59	33.52	33.76	35.96	39.06	39.86	47.65	42.07	43.21	54.50
Solar Photovoltaic	0.12	0.83	0.83	0.83	1.06	1.68	2.08	1.42	3.74	4.78
Total Renewables	**35.39**	**42.41**	**42.64**	**44.84**	**48.17**	**49.60**	**57.78**	**51.55**	**55.00**	**67.33**
Sources of Ethanol										
From Corn	0.24	0.32	0.32	0.32	0.34	0.34	0.34	0.34	0.34	0.34
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.04	0.04	0.04
Total	**0.24**	**0.32**	**0.32**	**0.32**	**0.35**	**0.36**	**0.35**	**0.38**	**0.38**	**0.38**
Carbon Dioxide Emissions by the Power Sector (million metric tons)[1]										
Coal	1906.0	2139.6	2139.8	2136.9	2371.7	2371.5	2367.3	2678.0	2676.8	2659.0
Petroleum	95.8	96.2	96.3	96.4	107.3	106.9	106.8	109.5	109.2	107.6
Natural Gas	266.6	361.9	362.1	361.3	509.6	508.0	500.5	509.8	506.5	498.5
Other	17.3	20.4	20.4	20.4	21.0	21.2	22.0	21.3	21.5	22.4
Total	**2285.7**	**2618.1**	**2618.6**	**2615.0**	**3009.6**	**3007.6**	**2996.7**	**3318.6**	**3314.1**	**3287.6**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LOREN05.D111504A, AEO2005.D102004A, and HIREN05.D111604A.

Table E8. Total Energy Supply and Disposition, Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Production										
Crude Oil and Lease Condensate	12.03	12.56	12.75	12.99	10.56	11.03	11.46	9.43	10.01	10.83
Natural Gas Plant Liquids	2.34	2.59	2.66	2.75	2.65	2.80	2.98	2.58	2.81	3.08
Dry Natural Gas	19.58	20.15	20.97	21.91	20.81	22.48	24.39	20.12	22.42	25.37
Coal	22.66	25.13	25.10	25.03	27.88	27.04	26.08	31.21	29.90	27.96
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.86	7.61	7.57	7.52	8.24	8.10	8.08
Other[2]	0.93	0.96	0.97	0.98	0.75	0.77	0.77	0.82	0.82	0.83
Total	**71.42**	**76.73**	**77.79**	**79.01**	**78.92**	**80.35**	**81.87**	**81.07**	**82.73**	**84.82**
Imports										
Crude Oil[3]	21.08	24.92	24.69	24.37	32.88	32.29	31.91	35.84	35.16	34.34
Petroleum Products[4]	5.16	6.09	6.06	6.01	7.13	6.83	6.49	8.55	8.27	7.87
Natural Gas	4.02	6.20	5.71	5.26	9.07	8.95	8.62	9.80	9.70	9.34
Other Imports[5]	0.69	0.92	0.92	0.92	1.14	1.15	1.15	1.22	1.23	1.24
Total	**30.95**	**38.13**	**37.38**	**36.56**	**50.22**	**49.22**	**48.17**	**55.42**	**54.36**	**52.80**
Exports										
Petroleum[6]	2.13	2.14	2.14	2.14	2.28	2.26	2.25	2.34	2.32	2.31
Natural Gas	0.70	0.64	0.65	0.67	0.80	0.86	0.94	0.73	0.83	0.97
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.88	0.65	0.65	0.67
Total	**3.95**	**3.84**	**3.86**	**3.87**	**3.97**	**4.01**	**4.07**	**3.71**	**3.80**	**3.95**
Consumption										
Petroleum Products[7]	39.09	44.81	44.84	44.85	51.49	51.30	51.24	54.51	54.42	54.39
Natural Gas	22.54	25.78	26.11	26.57	29.26	30.73	32.23	29.39	31.47	33.92
Coal	22.71	24.98	24.95	24.88	28.11	27.27	26.34	31.79	30.48	28.54
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.86	7.61	7.57	7.52	8.24	8.10	8.08
Other[8]	0.02	0.04	0.03	0.03	0.05	0.05	0.05	0.04	0.04	0.04
Total	**98.22**	**110.96**	**111.27**	**111.68**	**125.19**	**125.60**	**126.05**	**132.63**	**133.18**	**133.63**
Net Imports - Petroleum	**24.10**	**28.86**	**28.61**	**28.24**	**37.73**	**36.87**	**36.15**	**42.06**	**41.11**	**39.90**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[9]	27.73	25.00	25.00	25.00	28.50	28.50	28.50	30.31	30.31	30.31
Natural Gas Wellhead Price (dollars per thousand cubic feet)[10]	4.98	3.81	3.64	3.35	4.86	4.53	4.11	5.18	4.79	4.35
Coal Minemouth Price (dollars per ton)	17.93	17.33	17.30	17.24	18.06	17.25	16.91	19.11	18.26	17.41
Average Electricity Price (cents per kilowatthour)	7.4	6.7	6.6	6.5	7.3	7.2	7.0	7.4	7.3	7.1
Carbon Dioxide Emissions (million metric tons)	**5788.7**	**6611.2**	**6626.8**	**6642.7**	**7535.0**	**7519.6**	**7505.1**	**8082.7**	**8062.3**	**8003.9**

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). 2003 carbon dioxide emission values: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E9. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Lower 48 Average Wellhead Price (2003 dollars per thousand cubic feet)	**4.98**	**3.81**	**3.64**	**3.35**	**4.86**	**4.53**	**4.11**	**5.18**	**4.79**	**4.35**
Dry Gas Production[1]	**19.07**	**19.62**	**20.42**	**21.34**	**20.27**	**21.89**	**23.75**	**19.60**	**21.83**	**24.71**
Lower 48 Onshore	13.89	14.40	14.98	15.64	13.72	15.30	16.81	13.07	14.71	17.21
Associated-Dissolved	1.54	1.31	1.32	1.32	1.13	1.15	1.17	1.06	1.08	1.11
Non-Associated	12.36	13.09	13.66	14.32	12.59	14.16	15.64	12.02	13.63	16.10
Conventional	5.77	5.54	5.60	5.66	5.27	5.40	5.37	4.90	5.02	5.08
Unconventional	6.59	7.55	8.06	8.65	7.32	8.75	10.28	7.12	8.61	11.03
Lower 48 Offshore	4.73	4.97	5.19	5.45	4.31	4.70	5.06	4.29	4.89	5.25
Associated-Dissolved	0.99	1.77	1.81	1.86	1.31	1.39	1.48	1.20	1.34	1.43
Non-Associated	3.74	3.20	3.38	3.59	3.00	3.31	3.58	3.09	3.56	3.82
Alaska	0.44	0.25	0.25	0.25	2.24	1.89	1.89	2.23	2.23	2.24
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	**3.24**	**5.43**	**4.94**	**4.47**	**8.07**	**7.89**	**7.49**	**8.86**	**8.66**	**8.17**
Canada	3.13	2.41	2.57	2.60	2.44	2.69	2.80	2.10	2.55	2.90
Mexico	-0.33	-0.12	-0.14	-0.16	-0.28	-0.35	-0.42	-0.03	-0.25	-0.45
Liquefied Natural Gas	0.44	3.14	2.50	2.03	5.92	5.54	5.11	6.78	6.37	5.72
Total Supply	**22.37**	**25.12**	**25.44**	**25.88**	**28.41**	**29.85**	**31.32**	**28.53**	**30.56**	**32.96**
Consumption by Sector										
Residential	5.10	5.47	5.52	5.59	5.81	5.88	5.95	5.91	5.99	6.09
Commercial	3.13	3.36	3.39	3.43	3.74	3.80	3.86	3.98	4.05	4.15
Industrial[3]	6.99	7.81	7.87	7.98	8.53	8.64	8.77	8.80	9.00	9.22
Electric Power[4]	4.96	6.62	6.74	6.91	8.35	9.45	10.52	7.90	9.43	11.17
Transportation[5]	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.64	0.67	0.68	0.70	0.77	0.80	0.85	0.76	0.82	0.90
Lease and Plant Fuel[6]	1.12	1.13	1.17	1.21	1.22	1.29	1.37	1.17	1.27	1.41
Total	**21.95**	**25.12**	**25.44**	**25.88**	**28.51**	**29.95**	**31.42**	**28.64**	**30.67**	**33.06**
Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.42**	**-0.00**	**-0.00**	**-0.00**	**-0.10**	**-0.10**	**-0.10**	**-0.11**	**-0.11**	**-0.11**
Lower 48 End of Year Reserves	**180.77**	**196.29**	**204.21**	**214.24**	**167.58**	**186.10**	**209.87**	**159.19**	**178.29**	**205.34**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E10. Petroleum Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
World Oil Price										
(2003 dollars per barrel)	**27.73**	**25.00**	**25.00**	**25.00**	**28.50**	**28.50**	**28.50**	**30.31**	**30.31**	**30.31**
Crude Oil Supply										
Domestic Crude Oil Production[1]	5.68	5.93	6.02	6.13	4.99	5.21	5.42	4.45	4.73	5.11
Lower 48 Onshore	2.99	2.61	2.63	2.66	2.18	2.24	2.32	2.00	2.09	2.19
Lower 48 Offshore	1.72	2.52	2.58	2.67	1.98	2.11	2.23	1.86	2.03	2.20
Alaska	0.97	0.80	0.81	0.81	0.83	0.86	0.86	0.60	0.61	0.72
Net Crude Oil Imports	9.65	11.41	11.31	11.16	15.07	14.80	14.62	16.43	16.11	15.73
Other Crude Oil Supply	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.31**	**17.35**	**17.33**	**17.30**	**20.05**	**20.01**	**20.04**	**20.88**	**20.84**	**20.85**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.90	1.96	2.02	1.93	2.04	2.17	1.88	2.04	2.24
Net Petroleum Product Imports[2]	1.58	2.08	2.06	2.03	2.46	2.31	2.13	3.14	3.00	2.79
Refinery Processing Gain[3]	1.00	1.11	1.11	1.10	1.51	1.50	1.49	1.58	1.56	1.54
Other Supply[4]	0.69	0.52	0.53	0.54	0.45	0.46	0.47	0.49	0.50	0.50
Total Primary Supply[5]	**20.30**	**22.97**	**22.98**	**22.99**	**26.41**	**26.32**	**26.29**	**27.97**	**27.93**	**27.92**
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.33	1.33	1.33	1.41	1.41	1.40	1.43	1.42	1.41
Industrial[6]	4.87	5.32	5.33	5.33	5.80	5.81	5.81	6.04	6.05	6.08
Transportation	13.35	15.74	15.76	15.78	18.46	18.48	18.50	19.79	19.82	19.85
Electric Power[7]	0.50	0.57	0.56	0.54	0.74	0.62	0.58	0.71	0.64	0.58
Total	**20.00**	**22.97**	**22.98**	**22.99**	**26.41**	**26.32**	**26.29**	**27.97**	**27.93**	**27.92**
Discrepancy[8]	**0.29**	**0.00**	**-0.00**	**-0.00**	**-0.00**	**0.00**	**-0.00**	**-0.00**	**-0.00**	**-0.00**
Lower 48 End of Year Reserves										
(billion barrels)[1]	**18.94**	**20.93**	**21.23**	**21.64**	**17.08**	**17.79**	**18.22**	**15.79**	**16.47**	**16.65**

[1]Includes lease condensate.
[2]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[3]Represents volumetric gain in refinery distillation and cracking processes.
[4]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[5]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[6]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[7]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E11. Natural Gas Prices, Supply, and Disposition, Restricted Supply Case
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010		2015		2020		2025	
		Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply
Natural Gas Prices									
(2003 dollars per thousand cubic feet)									
Lower 48 Average Wellhead Price	4.98	3.64	4.23	4.16	5.13	4.53	5.88	4.79	6.29
Average Delivered Natural Gas Price	7.04	5.67	6.28	6.08	7.11	6.47	7.96	6.77	8.52
Natural Gas Supply									
Dry Natural Gas Production[1]	19.07	20.42	20.26	20.77	20.44	21.89	19.81	21.83	19.07
Lower 48 Onshore	13.89	14.98	14.91	15.38	15.18	15.30	15.03	14.71	14.19
Associated-Dissolved	1.54	1.32	1.31	1.22	1.21	1.15	1.13	1.08	1.05
Non-Associated	12.36	13.66	13.60	14.16	13.97	14.16	13.90	13.63	13.14
Conventional	5.77	5.60	5.76	5.62	5.77	5.40	5.49	5.02	5.04
Unconventional	6.59	8.06	7.84	8.54	8.20	8.75	8.41	8.61	8.10
Lower 48 Offshore	4.73	5.19	5.10	5.12	4.99	4.70	4.52	4.89	4.62
Associated-Dissolved	0.99	1.81	1.77	1.48	1.42	1.39	1.34	1.34	1.28
Non-Associated	3.74	3.38	3.33	3.64	3.58	3.31	3.18	3.56	3.34
Alaska	0.44	0.25	0.25	0.27	0.27	1.89	0.27	2.23	0.26
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	3.24	4.94	4.40	7.02	5.33	7.89	5.59	8.66	5.21
Canada	3.13	2.57	2.62	2.98	3.18	2.69	3.06	2.55	2.31
Mexico	-0.33	-0.14	-0.11	-0.29	-0.20	-0.35	0.04	-0.25	0.40
Liquefied Natural Gas	0.44	2.50	1.88	4.33	2.35	5.54	2.49	6.37	2.49
Total Supply	**22.37**	**25.44**	**24.74**	**27.86**	**25.84**	**29.85**	**25.48**	**30.56**	**24.35**
Natural Gas Consumption by Sector									
Residential	5.10	5.52	5.42	5.74	5.57	5.88	5.55	5.99	5.44
Commercial	3.13	3.39	3.32	3.58	3.46	3.80	3.61	4.05	3.81
Industrial[3]	6.99	7.87	7.72	8.26	7.99	8.64	8.06	9.00	8.26
Electric Power[4]	4.96	6.74	6.38	8.39	7.00	9.45	6.46	9.43	5.14
Transportation[5]	0.02	0.06	0.06	0.08	0.08	0.10	0.09	0.11	0.10
End Use Subtotal	**20.19**	**23.58**	**22.91**	**26.05**	**24.09**	**27.86**	**23.78**	**28.58**	**22.76**
Pipeline Fuel	0.64	0.68	0.66	0.71	0.66	0.80	0.64	0.82	0.62
Lease and Plant Fuel[6]	1.12	1.17	1.16	1.20	1.18	1.29	1.15	1.27	1.09
Total Consumption	**21.95**	**25.44**	**24.74**	**27.96**	**25.94**	**29.95**	**25.57**	**30.67**	**24.46**
Discrepancy[7]	**0.42**	**-0.00**	**0.00**	**-0.09**	**-0.10**	**-0.10**	**-0.10**	**-0.11**	**-0.11**
Total U.S. Electricity Consumption (billion kilowatthours)	3,657	4,274	4,256	4,644	4,600	5,040	4,972	5,467	5,420
Average Delivered Electricity Price (2003 cents per kilowatthour)	7.4	6.6	6.8	6.9	7.3	7.2	7.6	7.3	7.5
Real Gross Domestic Product (billion 2000 dollars)	10,381	13,084	13,068	15,216	15,191	17,634	17,596	20,292	20,264
Delivered Natural Gas Expenditures (billion 2003 dollars)	142.2	133.7	143.8	158.4	171.3	180.2	189.3	193.4	193.9
Natural Gas Expenditures per Dollar Gross Domestic Product (percent)	1.37%	1.02%	1.10%	1.04%	1.13%	1.02%	1.08%	0.95%	0.96%
Natural Gas Expenditures per Capita (dollars per person)	487.96	430.97	463.57	489.70	529.52	534.73	561.60	551.44	552.89

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, and RESSUP.D102704A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2005* (*AEO2005*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years into the future. In order to represent the regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of October 31, 2004, such as the Clean Air Act Amendments (CAAA), and the costs of compliance with regulations, such as the new boiler limits established by the U.S. Environmental Protection Agency (EPA) under the CAAA on February 26, 2004; and the 13 SEER standard for new central air conditioners and heat pumps that was reestablished by the U.S. Court of Appeals, Second Circuit, after originally being set in January 2001.

In general, the historical data used for the *AEO2005* projections were based on EIA's *Annual Energy Review 2003*, published in September 2004 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2003. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2003*, published in December 2004 [*2*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2005* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2005* projections for 2004 and 2005 incorporate short-term projections from EIA's October 2004 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*3*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), industrial output, interest rates, disposable income, prices, and employment. This module uses the following Global Insight models: Macroeconomic Model of the U.S. Economy, national Industry Model, and national Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to forecast regional economic drivers and a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census divisions. For *AEO2005*, bulk chemicals are disaggregated into organic and inorganic chemicals, resins, and agricultural chemicals. In addition, the accounting framework for industrial output has changed from the Standard Industrial Classification (SIC) system to the North American Industry Classification System (NAICS), which has reclassified the components of gross industrial output and moved some manufacturing activities into services.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. Fourteen international petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM. A world oil supply/demand balance is created, including estimates for 16 oil consumption regions and 18 oil production regions. The oil production estimates include both conventional and nonconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, based on delivered energy prices, the menu of equipment available, the 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, based on 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. The commercial module incorporates combined heat and power (CHP) technology. The modules also include forecasts of distributed generation. Both modules incorporate changes to “normal” heating and cooling degree-days by Census division, based on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures is increasing, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the macroeconomic module, the value of shipments is now based on NAICS rather than SIC. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/ assembly use of energy. Bulk chemicals have been further disaggregated to organic, inorganic, resins, and other petroleum products. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles. The air transportation module explicitly represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from the passenger to cargo markets as aircraft age [*4*]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module (EMM) represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled 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 specifically identified CAAA compliance options that have been promulgated by the EPA are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated are not incorporated (e.g., fine particulate proposal). Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2005*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in the Energy Policy Act of 1992 [*5*]. They provide a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power. The credits have no expiration date.

Production tax credits for wind and some types of biomass-fueled plants are also represented. They provide a tax credit of 1.8 cents per kilowatthour for electricity produced in the first 10 years of plant operation. New plants that come on line before January 1, 2006, are eligible to receive the credit. For a description of significant changes made for *AEO2005* in the representation of biomass resource supply, conventional hydroelectricity, wind resources, cost and performance characteristics for wind technologies, and accounting of new renewable energy capacity from State renewable portfolio standards, mandates, and goals, see the "Renewable Fuels Module" chapter of *Assumptions for the Annual Energy Outlook 2005*.

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 among the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of 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 to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities. International LNG supply sources and options for regional expansions of domestic regasification capacity are represented, based on the projected regional costs associated with gas supply, liquefaction, transportation, regasification, and natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module (NGTDM) 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. Peak and off-peak periods are represented for natural gas transmission, and core and non-core markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities in the five PADDs. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2005* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New York, Ohio, South Dakota, Washington, and Wisconsin.

The Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas is assumed to remain intact. The nationwide phase-in of gasoline with an annual average sulfur content of 30 ppm between 2005 and 2007, and the diesel regulations that limit the sulfur content to 15 ppm in highway diesel starting mid-2006 and in all nonroad and locomotive/marine diesel fuel by mid-2012, are represented in *AEO2005*. Growth in demand and the costs of the regulations lead to capacity expansion for refinery-processing units, assuming a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment at about 10 percent [6]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs and State and Federal taxes [7]. Refinery capacity expansion at existing sites may occur in all five refining regions modeled.

Fuel ethanol and biodiesel are included in PMM because they are commonly blended into petroleum products. The PMM allows ethanol blending into gasoline at 10 percent by volume or less and also allows limited quantities of E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and it is expected to be produced from cellulosic material in other regions in the future. Biodiesel is produced from soybean oil or yellow grease, which is primarily recycled cooking oil. Soybean oil biodiesel is assumed to be blended into highway diesel, and yellow grease biodiesel is assumed to be blended into non-highway diesel.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM using 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined in the CMM through the use of a linear programming algorithm that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur allowance costs. Over the forecast horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the user cost of rail transportation equipment.

The CMM produces projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The CMM's linear programming algorithm determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional world coal import demands, subject to constraints on export capacities by country and coal type and trade flows.

U.S. coal production and distribution are computed for 14 supply and 14 demand regions. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Projections of annual U.S. coal imports, specified by demand region and sector, are developed exogenously based primarily on the capability and plans of existing coal-fired power plants to import coal and announced plans to expand coal import infrastructure.

Annual Energy Outlook 2005 Cases

Table F1 provides a summary of the cases used to derive the *AEO2005* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

The following section describes cases listed in Table F1. The reference case assumptions for each sector are described at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

Macroeconomic Growth Cases

In addition to the *AEO2005* reference case, the *low economic growth* and *high economic growth cases* were developed to reflect the uncertainty in forecasts of economic growth. The alternative cases are intended to show the projected effects of alternative growth assumptions on energy markets. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.8 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the *low economic growth case*, economic output is projected to increase by 2.5 percent per year from 2003 through 2025, and growth in GDP per capita is projected to average only 1.9 percent per year.
- The *high economic growth case* assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.6 percent per year), and productivity (2.7 percent per year). With higher productivity gains and employment growth, inflation and interest rates are projected to be lower than in the reference case, and consequently economic output is projected to grow at a higher rate (3.6 percent per year) than in the reference case (3.1 percent). GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case.

World Oil Market Cases

The world oil price in *AEO2005* is the annual average U.S. refiner's acquisition cost of imported crude oil (IRAC). Five distinct world oil price scenarios are represented in *AEO2005*, with prices reaching approximately $21, $30, $35, $39, and $48 per barrel in 2025, respectively, in the low world oil price, reference, October oil futures, high A world oil price, and high B world oil price cases in 2003 dollars. Because these oil price cases are not directly integrated with a world economic model, the impacts of world oil prices on international economies is not directly accounted for in this analysis.

- The *reference case* represents EIA's current judgment regarding the expected behavior of the Organization of Petroleum Exporting Countries (OPEC) in the mid-term, where production is adjusted to keep world oil prices in the $25 to $31

Table F1. Summary of the *AEO2005* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Reference	Baseline economic growth (3.1 percent per annum), world oil price falling to about $25 per barrel by 2010 and rising to $30.31 per barrel, and technology assumptions.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent from 2003 through 2025, compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated	p. 73	p. 215
High Economic Growth	Gross domestic product grows at an average annual rate of 3.6 percent from 2003 through 2025, compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated	p. 73	p. 215
Low World Oil Price	Reference case assumptions except that the world oil prices are $20.99 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
October Oil Futures	World oil prices continue to rise in near term and are $35.00 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 44	p. 218
High A World Oil Price	Reference case assumptions except that the world oil prices are $39.24 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
High B World Oil Price	World oil prices remain high and are $48.00 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
Residential: 2005 Technology	Future equipment purchases based on equipment available in 2005. Existing building shell efficiencies fixed at 2005 levels.	With commercial	p. 84	p. 218
Residential: High Technology	Relative to the reference case, earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 21 percent from 2002 values by 2025.	With commercial	p. 84	p. 218
Residential: Best Available Technology	Relative to the reference case, future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 25 percent from 2002 values by 2025.	With commercial	p. 84	p. 218
Commercial: 2005 Technology	Relative to the reference case, future equipment purchases are based on equipment available in 2005. Building shell efficiencies are fixed at 2005 levels.	With residential	p. 85	p. 219
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025.	With residential	p. 85	p. 219
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Heating shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025.	With residential	p. 85	p. 219
Residential and Commercial: SEER 12	Replaces the recently enacted SEER 13 standard with the previously set level of SEER 12.	Fully integrated	p. 13	p. 218
Residential and Commercial: Warmer temperatures	Summer and winter temperatures trend to the average of the 5 warmest of the past 30 years by 2025.	Fully integrated	p. 55	p. 219

Table F1. Summary of the *AEO2005* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Residential and Commercial: Colder temperatures	Summer and winter temperatures trend to the average of the 5 coldest of the past 30 years by 2025.	Fully integrated	p. 55	p. 219
Industrial: 2005 Technology	Efficiency of plant and equipment fixed at 2005 levels.	Standalone	p. 85	p. 219
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 85	p. 219
Transportation: 2005 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2005 levels.	Standalone	p. 86	p. 220
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 86	p. 220
Transportation: A.B.1493 California Only	Accounts for adoption of vehicle carbon dioxide emissions standards in California.	Fully integrated	p. 27	p. 220
Transportation: A.B.1493 Extended	Accounts for adoption of vehicle carbon dioxide emissions standards in California, New York, Maine, Massachusetts, and Vermont.	Fully integrated	p. 27	p. 220
Integrated 2005 Technology	Baseline macroeconomic drivers, combining the residential, commercial, industrial, and transportation 2005 technology assumptions with electricity low fossil technology and low renewable technology assumptions.	Fully integrated	p. 110	—
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 110	—
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have 20 percent lower capital and operating costs in 2025 than in the reference case.	Fully integrated	p. 93	p. 220
Electricity: Nuclear Vendor Estimate	New nuclear capacity is assumed to have lower capital costs based on vendor goals.	Fully integrated	p. 93	p. 221
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2025 from reference case values.	Fully integrated	p. 93	p. 221
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2005.	Fully integrated	p. 93	p. 221
Electricity: Proposed Clean Air Interstate Rule (pCAIR)	Limits on NO_x and SO_2 emissions.	Fully integrated	p.31	p. 221
Renewables: Low Renewables	New renewable generating technologies are assumed not to improve over time after 2005.	Fully Integrated	p. 94	p. 221
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2025 from reference case values.	Fully Integrated	p. 94	p. 221
Renewables: PTC Extension	The production tax credit (PTC) for wind expires in 2005. *AEO2005* does not assume its extension consistent with the approach generally taken toward public policy in the forecast. This scenario assumes the extension of the PTC through 2015.	Fully integrated	p. 58	p. 222
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate technology parameters adjusted for 50 percent more rapid improvement than in the reference case.	Fully integrated	p. 97	p. 222

Table F1. Summary of the *AEO2005* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Oil and Gas: Slow Technology	Cost, finding rate, and success rate technology parameters adjusted for 50 percent slower improvement than in the reference case.	Fully integrated	p. 97	p. 222
Oil and Gas: Restricted Natural Gas Supply	The slow oil and gas technology case with no Alaskan pipeline and no new U.S. LNG regasification terminals except those already under construction. Proposed expansions of existing U.S. LNG terminals are permitted to go into operation as currently scheduled.	Fully integrated	p. 66	p. 222
Oil and Gas: No Nonroad Diesel Rule	No new nonroad diesel rules.	Fully integrated	p. 14	p. 222

per barrel range and in keeping with their noted goal of keeping potential competitors from taking their market share. Since OPEC, particularly the Persian Gulf nations, is expected to be the dominant supplier of oil in the international market over the midterm, the organization's production choices will significantly affect world oil prices.

- The *low world oil price case* could result from a future market where all oil production becomes more competitive and plentiful.
- The world crude oil price in the *October oil futures case* was developed by extrapolating the U.S. refiner's acquisition cost of imported crude oil based loosely on the rate of growth of futures prices for West Texas Intermediate crude oil on the New York Mercantile Exchange. The prices in the *October oil futures case* continue to rise through 2005, reaching $44 per barrel, before gradually declining to $31 per barrel in 2010, $6 higher then the reference case projection. After 2010, prices rise to $35 per barrel in 2025, about $5 per barrel higher than in the reference case. Prices are above those in the reference case over the entire projection, but below those in the *high A world oil price case* and the *high B world oil price case*.
- The *high A world oil price case* could result from a more cohesive and market-assertive OPEC with lower production goals and other nonfinancial (geopolitical) considerations, including possibly a change in the target price band.
- The *high B world oil price case* could result from a number of possible events. For example, a very high world oil price could result from robust growth in worldwide oil demand, especially in the developing economies, coupled with the inability or unwillingness of OPEC producers to sufficiently expand their oil production capacity.

Buildings Sector Cases

In addition to the *AEO2005* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies, and an integrated cooling efficiency standard case was developed to analyze the effect of the recently implemented 13 SEER standard for central air conditioners and heat pumps.

For the residential sector, the four technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Existing building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*8*]. Heating shell efficiency in 2025 is projected to be 21 percent higher than the 2002 level.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 25 percent over 2002 levels by 2025.
- A *cooling efficiency standard case* for residential and commercial technologies is an integrated case designed to analyze the effects of the recently

enacted central air conditioner and heat pump standard on buildings-related energy use (residential and commercial). This case replaces the 13 SEER standard, which is used in the *AEO2005* reference case, with the previously enacted 12 SEER standard, effective in 2006.

For the commercial sector, the four technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*9*]. Heating shell efficiencies for new and existing buildings are assumed to increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025—a 25-percent improvement relative to the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the *high technology case*, regardless of cost. Heating shell efficiencies for new and existing buildings are assumed to increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025—a 50-percent improvement relative to the reference case.
- A *cooling efficiency standard case* is as described for the residential sector above.

Two additional integrated cases were developed, in combination with assumptions for electricity generation from renewable fuels, to analyze the sensitivity of the projections to changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies.
- The *low renewables case* assumes that costs and performance levels for residential and commercial photovoltaic systems remain constant at 2005 levels through 2025.

To illustrate the potential impacts of warmer and colder weather on buildings energy consumption relative to the reference case, two additional integrated cases were developed. For the residential and commercial demand modules:

- The *warmer temperature case* assumes that State-level heating and cooling degree-days trend to the average of the 5 warmest years of the past 30 years by 2025.
- The *colder temperature case* assumes that State-level heating and cooling degree-days trend to the average of the 5 coldest years of the past 30 years by 2025.

Industrial Sector Cases

In addition to the *AEO2005* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. The Industrial Demand Module was also used as part of and integrated *high renewables case*. For the industrial sector:

- The *2005 technology case* holds the energy efficiency of plant and equipment constant at the 2005 level over the forecast. In this case, delivered energy intensity falls by 1.0 percent annually. Because the level and composition of industrial output are the same in the reference, 2005 technology, and high technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. The *2005 technology case* was run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*10*]. The *high technology case* also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.1 percent per year in the reference case. The same assumption is also incorporated in the *integrated high renewable case*, which focuses on electricity generation. While the choice of 1 percent recovery is an assumption of the *high*

technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, delivered energy intensity falls by 1.6 percent annually in the *high technology case*. In the reference case, delivered energy intensity falls by 1.6 percent annually between 2003 and 2025.

Transportation Sector Cases

In addition to the *AEO2005* reference case, two standalone cases using the Transportation Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. For the transportation sector:

- The *2005 technology case* assumes that new fuel efficiency levels remain constant at 2005 levels through the forecast horizon unless emission and/or efficiency regulations require the implementation of technology that affects vehicle efficiency. For example, the new light truck corporate average fuel economy (CAFE) standards require an increase in fuel economy through 2007, and increases in heavy truck emission standards are required through 2010. As a result, the technology available for light truck efficiency improvement is frozen at 2007 levels, and the technology available to heavy trucks is frozen at 2010 levels.

- For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements and costs [*11*]. In the air travel sector, the *high technology case* reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight reduction materials, which provides a 25-percent improvement in new aircraft efficiency compared to the reference case in 2025. In the freight truck sector, the *high technology case* assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*12*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

In addition to the technology cases, two cases were developed to measure the impact of recently enacted carbon dioxide emission standards for light-duty vehicles in California (Assembly Bill 1493). These cases measure the energy and fuel price impacts that occur regionally, and vehicle sales impacts that occur in those States adopting A.B.1493.

- The *A.B.1493 California only case* assumes that only California adopts the new standards. The *A.B.1493 extended case* assumes that, in addition, New York, Maine, Massachusetts, and Vermont also adopt the light-duty vehicle carbon emissions standards. These cases assume that fuel economy impacts are limited to those States adopting the regulation, and that the fuel economy and sales mix of vehicles sold in all other States remain at the levels projected in the reference case. EIA estimates that meeting the requirements of A.B. 1493 will require new car fuel economy to increase from 27.5 miles per gallon in 2009 to 39.9 miles per gallon in 2016 and new light truck fuel economy to increase from 22.2 miles per gallon in 2009 to 26.4 miles per gallon in 2016.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze the uncertainties regarding future costs and performance of new generating technologies. Two of the cases examine alternative nuclear assumptions, and two examine alternative fossil technology assumptions. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs are either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *advanced nuclear cost case* reflect a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2025, relative to the reference case. Because the reference case assumes that some learning occurs regardless of new orders and construction, the reference case already projects a 10-percent reduction in capital costs between 2005 and 2025. The *advanced nuclear cost case* assumes a 28-percent reduction between 2005 and 2025.

- The *nuclear vendor estimate case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of their Advanced Pressurized Water Reactor (AP1000). In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be 18 percent lower initially than assumed in the reference case and 38 percent lower in 2025. For both advanced nuclear cases, cost and performance characteristics for all other technologies are as assumed in the reference case.

Fossil Technology Cases

- In the *high fossil technology case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2025. Because learning is assumed to occur in the reference case, costs and performance in the high case are reduced from initial levels by more than 10 percent. Heat rates in the *high fossil technology case* fall to between 17 and 23 percent below initial levels, and capital costs are reduced by 22 to 26 percent between 2005 and 2025, depending on the technology.
- In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period but remain fixed at the 2005 values assumed in the reference case.

Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

An additional integrated case was also run to analyze the potential impacts of the EPA's proposed Clean Air Interstate Rule. A detailed description of the rule and a discussion of the sensitivity case results are included in the "Legislation and Regulations" section of this report, pages 34-36.

- The *proposed Clean Air Interstate Rule (pCAIR) case* was run to analyze the potential effects of a rule proposed by the EPA that would cap emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) from electricity generators. The emissions caps in 2010 are 3.86 million short tons SO_2 and 1.6 million tons NO_x. In 2015 the requirements drop to 2.71 million tons SO_2 and 1.33 million tons NO_x. Generators can meet the targets through cap-and-trade programs, or by installing emission control technologies.

Renewable Fuels Cases

In addition to the *AEO2005* reference case, three integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less and more aggressive improvement in renewable technologies and the extension of existing production tax credits for wind and other renewables through 2015. The cases are as follows:

- In the *low renewables case*, capital costs, operations and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2005 levels through 2025.
- In the *high renewables case*, the levelized costs of energy for nonhydroelectric generating technologies using renewable resources are assumed to decline, to 10 percent below the reference case costs for the same technologies in 2025. For most renewable resources, lower costs are accomplished by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through a combination of performance improvement (an increased capacity factor) and capital cost reductions. Biomass supplies are also assumed to be 10 percent greater for each supply step. Annual limits are placed on the development of geothermal sites, because they require incremental development to assure that the resource is viable. In the *high renewables case*, the annual limits on capacity additions at geothermal sites are raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and forecast assumptions remain unchanged from those in the reference

case. In the *high renewables case*, the rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market, resulting in increased cellulosic ethanol supply compared with the reference case.

- Under the Working Families Tax Relief Act of 2004, the production tax credit for wind and some biomass has been extended to plants in service by December 31, 2005. It has also been expanded under the American Jobs Creation Act of 2004 to include other renewable resources. Although the credit has been allowed to expire and then retroactively extended several times, *AEO2005* does not assume its extension beyond 2005, consistent with the approach generally taken toward public policy in the forecast. The *PTC extension case*, discussed in "Issues in Focus," pages 58-62, assumes the extension of the PTC through 2015, as expanded in current law. All technology and cost assumptions are otherwise the same as in the *AEO2005* reference case.

Oil and Gas Supply Cases

Two alternative technology 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. A third case examines the impacts of potential obstacles that may restrict delivery of domestic and foreign natural gas supplies.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas in the *AEO2005* reference case were increased by 50 percent relative to the reference case. A number of key exploration and production technologies for unconventional natural gas were also increased by 50 percent in the *rapid technology case*. Key Canadian supply parameters were also increased to simulate the assumed impacts of more rapid oil and gas technology penetration on the Canadian supply potential. All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2005*, which is available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas in the *AEO2005* reference case were reduced by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also reduced by 50 percent in the *slow technology case*. Key Canadian supply parameters were also increased to simulate the assumed impacts of slow oil and gas technology penetration on Canadian supply potential. All other parameters in the model were kept at the reference case values.

- The *restricted natural gas supply case* acknowledges that the future supply of natural gas could be more constrained than is projected in the reference case, both because of public opposition to the construction of large new natural gas projects, and because the future rate of technological progress could be significantly lower than the historic rate. The *restricted natural gas supply case* incorporates three assumptions: (1) the Alaska natural gas pipeline is *not* built before 2025; (2) all proposed expansions at existing LNG terminals are constructed, but *no* new U.S. LNG regasification terminals are built during the forecast unless they are already fully permitted and under construction; and (3) the future rate of technological progress for oil and gas exploration and development is one-half the historic rate, as specified in the *slow technology case*.

Petroleum Market Cases

Two petroleum market cases were developed and analyzed. The first evaluates the impact of the EPA's new nonroad diesel rule on diesel consumption and prices. The second case is part of the *advanced renewable case*, which evaluates the impact of more optimistic assumptions about biomass supplies on the production and use of cellulosic ethanol.

- The impacts of the new 500 ppm and 15 ppm low sulfur diesel rule on nonroad diesel markets have been implemented in NEMS and are incorporated in the *AEO2005* reference case. To establish a basis for comparison, the *nonroad diesel emissions rule case* was developed, excluding the impacts of the rule, as discussed in "Legislation and Regulations," pages 14-17.

- The *high renewables case* uses more optimistic assumptions about the availability of renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price earlier than in the reference case. Commercialization of cellulosic ethanol follows the same path from year to year as the reference case but begins in 2006 rather than 2010.

Coal Market Cases

No alternative cases were run for coal markets in *AEO2005*.

Notes

[*1*] Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004).

[*2*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004).

[*3*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the PMM projection.

[*4*] Jet Information Services, Inc., *World Jet Inventory Year-End 2003* (Woodinville, WA, March 2004), and personal communications with Bill Francoins at Jet Information Services and Thomas C. Hoang at Boeing.

[*5*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*6*] The hurdle rate for a coal-to-liquids (CTL) plant is assumed to be 12.3 percent because of the higher economic risk involved in this technology.

[*7*] For gasoline blended with ethanol the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be extended through 2025, based on the fact that the ethanol tax credit has been continuously in force for the past 25 years and was just extended recently by the American Jobs Creation Act of 2004 from 2007 to 2010.

[*8*] High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[*9*] High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[*10*] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001).

[*11*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

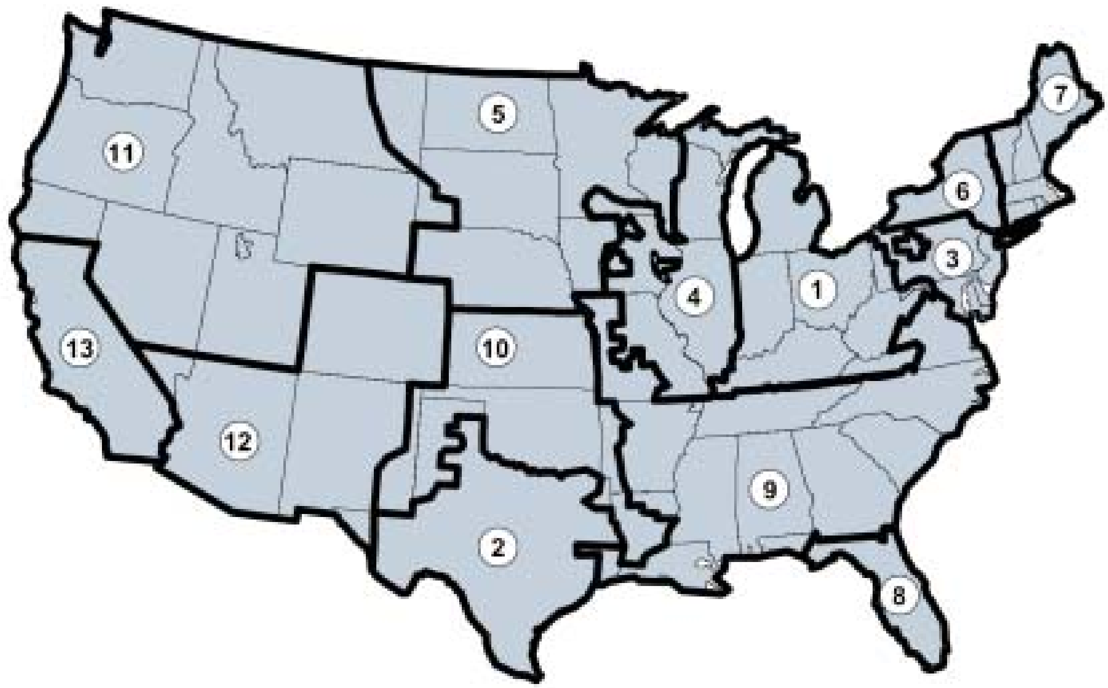
[*12*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

Regional Maps

G1. United States Census Divisions

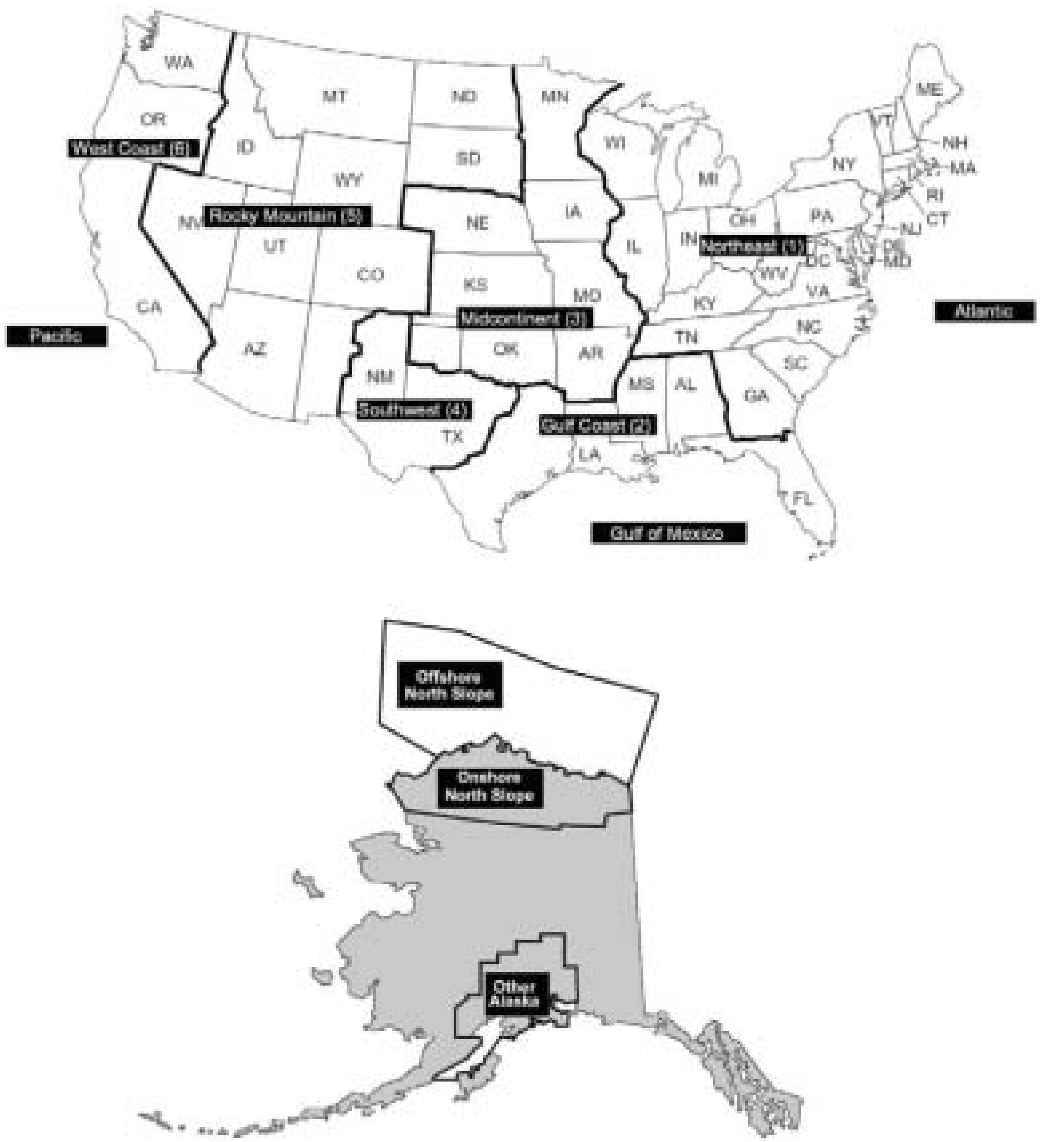
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G2. Electricity States Census Divisions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New KYork (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

G3. Oil and Gas Supply Model Regions

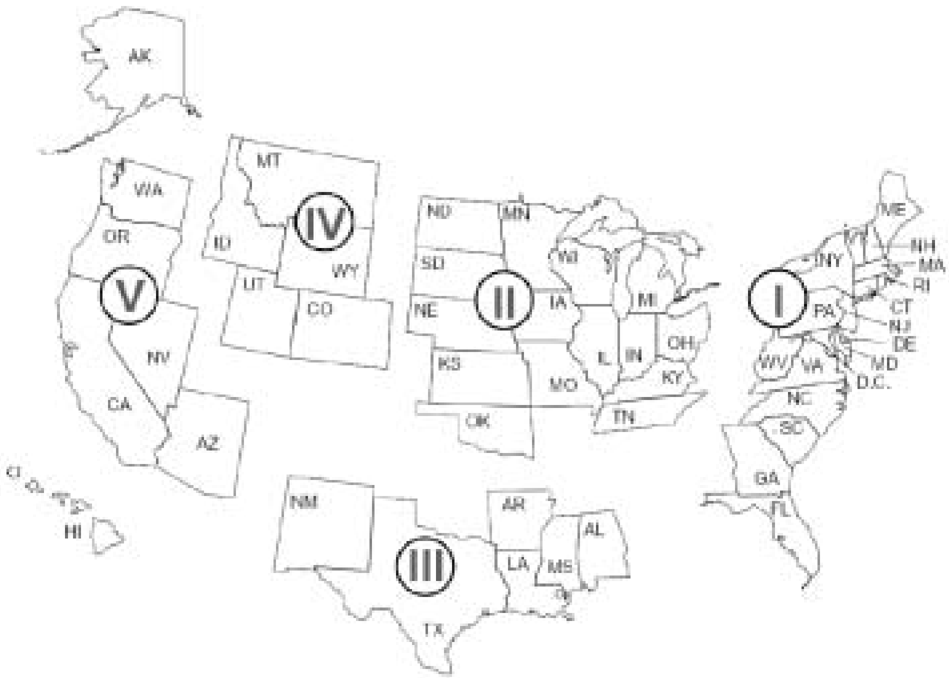


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G4. Natural Gas Transmission and Distribution Model Regions

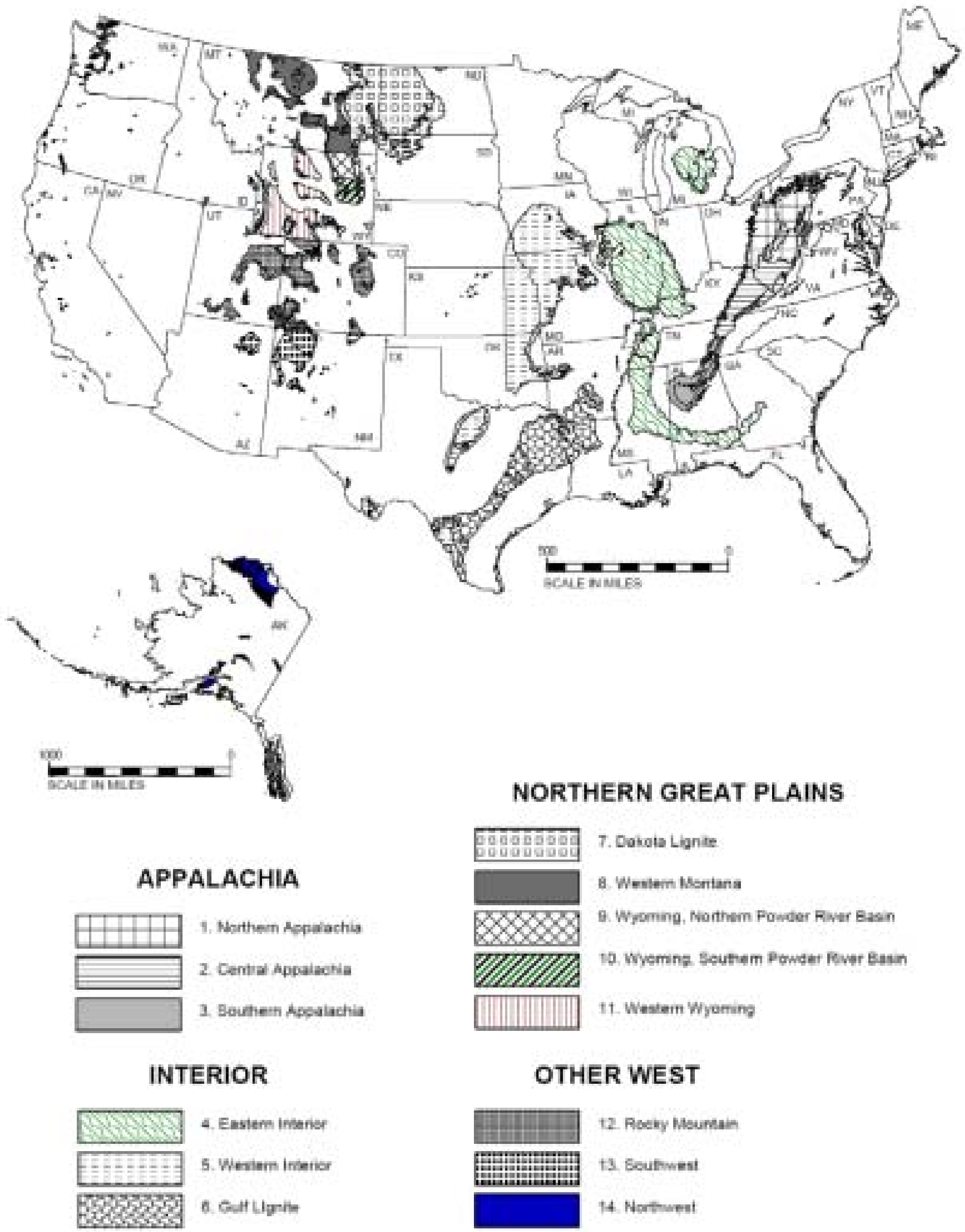
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G5. Petroleum Administration for Defense Districts

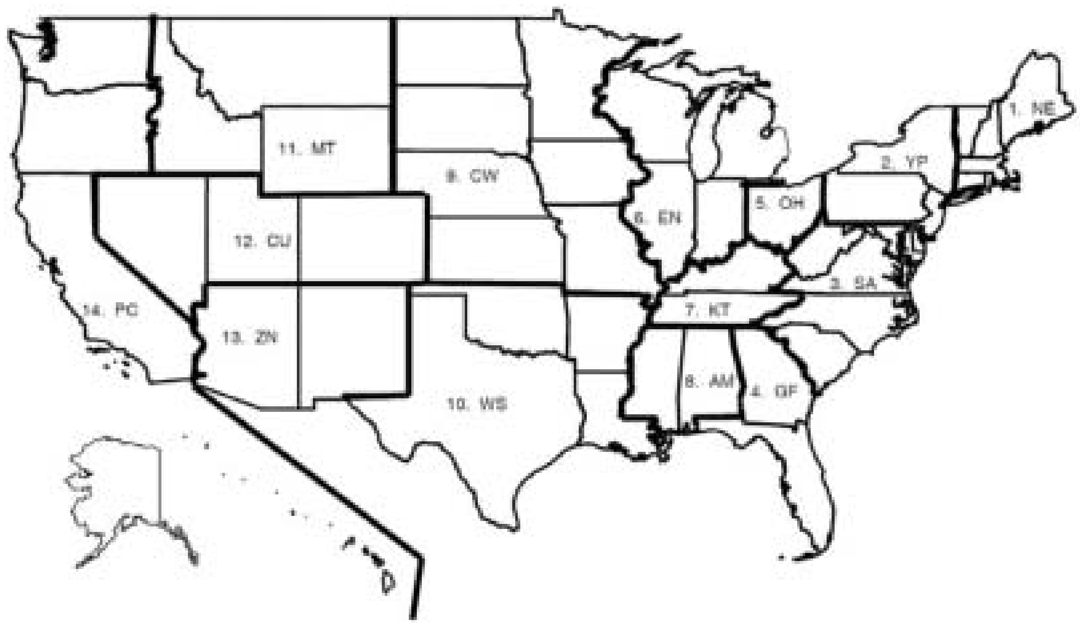


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G6. Coal Supply Regions



G7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Appendix H
Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.861
Consumption	million Btu per short ton	20.754
Coke Plants	million Btu per short ton	27.425
Industrial	million Btu per short ton	22.468
Residential and Commercial	million Btu per short ton	24.916
Electric Power Sector	million Btu per short ton	20.381
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	25.972
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.975
Petroleum Products		
Consumption[2]	million Btu per barrel	5.345
Motor Gasoline[2]	million Btu per barrel	5.194
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[2]	million Btu per barrel	3.612
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[2]	million Btu per barrel	5.533
Unfinished Oils	million Btu per barrel	5.825
Imports[2]	million Btu per barrel	5.435
Exports[2]	million Btu per barrel	5.846
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.735
Natural Gas		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
End-Use Sectors	Btu per cubic foot	1,029
Electric Power Sector	Btu per cubic foot	1,020
Imports	Btu per cubic foot	1,023
Exports	Btu per cubic foot	1,010
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
[1]Coal conversion factors vary from year to year. Values correspond to those published by EIA for 2003 and may differ slightly from model results.
[2]Conversion factors vary from year to year. 2010 values are reported.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

The Energy Information Administration
2005 EIA Midterm Energy Outlook and Modeling Conference

Renaissance Hotel, Washington, DC ***April 12, 2005***

8:30 a.m. - 8:45	**Opening Remarks - *Guy F. Caruso***, *Administrator*, Energy Information Administration
8:45 a.m. - 9:15	**Overview of the *Annual Energy Outlook 2005* - *John Conti***, *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:15 a.m. - 10:15	**Keynote Address: International Oil Markets - *Speaker to be announced***
10:30 a.m. - 12:00	**Concurrent Sessions A** **1. The Midterm Outlook for Conventional International Oil Supply, Demand, and Prices: Have the Fundamentals Changed?** **2. Siting Issues in the Development of U.S. LNG Receiving Terminals** **3. Is There a Future for Nuclear Power in the U.S.?**
1:15 p.m. - 2:45	**Concurrent Sessions B** **1. Adaptation of U.S. Refineries to Market Challenges** **2. Unconventional Gas Production: Challenges, Successes, and Future Outlook** **3. Power Sector Emissions Issues**
3:00 p.m. - 4:30	**Concurrent Sessions C** **1. World Outlook for Unconventional Oil Production** **2. When Should We Expect To See Hydrogen Vehicles?** **3. State Incentives for Renewable Energy: Successes and Challenges**

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The conference will be held at the *Renaissance Hotel*, (202) 898-9000. The *Renaissance Hotel* is located at 999 Ninth Street, NW, Washington, DC 20001, near the Gallery Place Metro station.

Information

For information, contact Peggy Wells, Energy Information Administration, at (202) 586-8845, peggy.wells@eia.doe.gov.

Conference Handouts

Handouts provided in advance by the conference speakers will be posted online by March 29, 2005, at www.eia.doe.gov/oiaf/aeo/conf/handouts.html in lieu of being provided at the conference.

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Conference registration is free, but space is limited.
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Energy Information Administration, EI-84
1000 Independence Avenue, SW
Washington, DC 20585
Phone: (202) 586-8845
Fax: (202) 586-3045

Or register by e-mail to peggy.wells@eia.doe.gov.

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Title: ____________________
Organization: ____________________
Address: ____________________
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Fax: ____________________
E-mail: ____________________

Please indicate which sessions you will be attending:

- ❐ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

- ❐ Midterm Outlook for Conventional International Oil Supply, Demand, and Prices
- ❐ Siting Issues in the Development of U.S. LNG Receiving Terminals
- ❐ Is There a Future for Nuclear Power in the U.S.?

Concurrent Sessions B

- ❐ Adaptation of U.S. Refineries to Market Challenges
- ❐ Unconventional Gas Production: Challenges, Successes, and Future Outlook
- ❐ Power Sector Emissions Issues

Concurrent Sessions C

- ❐ World Outlook for Unconventional Oil Production
- ❐ When Should We Expect To See Hydrogen Vehicles?
- ❐ State Incentives for Renewable Energy: Successes and Challenges

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