Annual Energy Outlook 2004 with Projections to 2025

Overview

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Key Energy Issues to 2025

For almost 4 years, natural gas prices have remained at levels substantially higher than those of the 1990s. This has led to a reevaluation of expectations about future trends in natural gas markets, the economics of exploration and production, and the size of the natural gas resource. The Annual Energy Outlook 2004 (AEO2004) forecast reflects such revised expectations, projecting greater dependence on more costly alternative supplies of natural gas, such as imports of liquefied natural gas (LNG), with expansion of existing terminals and development of new facilities, and remote resources from Alaska and from the Mackenzie Delta in Canada, with completion of the Alaska Natural Gas Transportation System and the Mackenzie Delta pipeline.

Crude oil prices rose from under $20 per barrel in the late 1990s to about $35 per barrel in early 2003, driven in part by concerns about the conflict in Iraq, the situation in Venezuela, greater adherence to export quotas by members of the Organization of Petroleum Exporting Countries (OPEC), and changing views regarding the economics of oil production. AEO2004 reflects changes in expectations about the relative roles of various basins in providing future crude oil supplies.

Outside OPEC, the major sources of growth in crude oil production in the AEO2004 forecast are Russia, the Caspian Basin, non-OPEC Africa, and South and Central America. U.S. dependence on imported oil has grown over the past decade, with declining domestic oil production and growing demand. This trend is expected to continue. Net imports, which accounted for 54 percent of total U.S. petroleum demand in 2002—up from 37 percent in 1980 and 42 percent in 1990—are expected to account for 70 percent of total U.S. petroleum demand in 2025 in the AEO2004 forecast, higher than the Annual Energy Outlook 2003 (AEO2003) projection of 68 percent.

The change in expectations for future natural gas prices, in combination with the substantial amount of new natural-gas-fired generating capacity recently completed or in the construction pipeline, has also led to a different view of future capacity additions. Although only a few years ago, natural gas was viewed as the fuel of choice for new generating plants, coal is now projected to play a more important role, particularly in the later years of the forecast. In the AEO2004 forecast, beyond the completion of plants currently under construction, little new generating capacity is expected to be added before 2010. With a higher long-term forecast for natural gas prices, the competitive position of coal is expected to improve. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower in the AEO2004 forecast than they were in AEO2003, and more additions of coal and renewable generating capacity are projected.

Economic Growth

In the AEO2004 reference case, the U.S. economy, as measured by gross domestic product (GDP), grows at an average annual rate of 3.0 percent from 2002 to 2025, slightly lower than the growth rate of 3.1 percent per year for the same period in AEO2003. Most of the determinants of economic growth in AEO2004 are similar to those in AEO2003, but there are some important differences. For example, AEO2004 starts with lower nominal interest rates than AEO2003; the rate of inflation is generally higher; and unemployment levels are higher. Consequently, differences between AEO2004 and AEO2003 cannot be explained simply by differences in GDP growth.

Energy Prices

In the AEO2004 reference case, the average world oil price increases from $23.68 per barrel (2002 dollars) in 2002 to $27.25 per barrel in 2003 and then declines to $23.30 per barrel in 2005. It then rises slowly to $27.00 per barrel in 2025, about the same as the AEO2003 projection of $26.94 per barrel in 2025 (Figure 1). Between 2002 and 2025, real world oil prices increase at an average rate of 0.6 percent per year in the AEO2004 forecast. In nominal dollars, the average world oil price is about $29 per barrel in 2010 and about $52 per barrel in 2025.

World oil demand is projected to increase from 78 million barrels per day in 2002 to 118 million barrels per day in 2025, less than the AEO2003 projection of 123 million barrels per day in 2025. In AEO2004, projected demand for petroleum in the United States and Western Europe and, particularly, in China, India, and other developing nations in the Middle East, Africa, and South and Central America is lower than was projected in AEO2003. Growth in oil production in both OPEC and non-OPEC nations leads to relatively slow growth in prices through 2025. OPEC oil production is expected to reach 54 million barrels per day in 2025, almost 80 percent higher than the 30 million barrels per day produced in 2002. The forecast assumes that sufficient capital will be available to expand production capacity..

Non-OPEC oil production is expected to increase from 44.7 to 63.9 million barrels per day between 2002 and 2025. Production in the industrialized nations (United States, Canada, Mexico, Western Europe, and Australia) remains roughly constant at 24.2 million barrels per day in 2025, compared with 23.4 million barrels per day in 2002. In the forecast, increased nonconventional oil production, predominantly from oil sands in Canada, more than offsets a decline in conventional production in the industrialized nations.

Figure 1. Energy price projections, 2002-2025: AEO2003 and AEO2004 compared (2002 dollars)

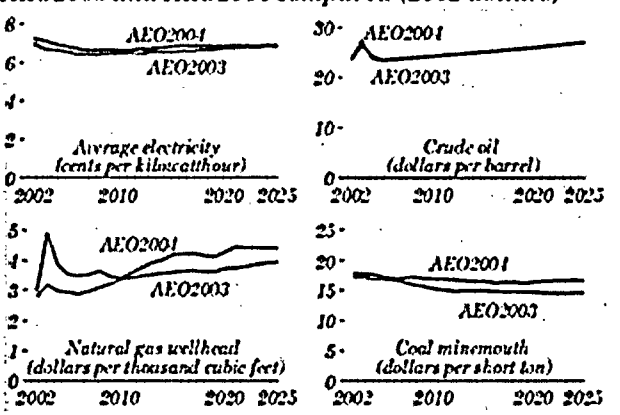

Figure data

The largest share of the projected increase in non-OPEC oil production is expected in Russia, the Caspian Basin, Non-OPEC Africa, and South and Central America (in particular, Brazil). Russian oil production is expected to continue to recover from the lows of the 1990s and to reach 10.9 million barrels per day in 2025, 43 percent above 2002 levels. Production from the Caspian Basin is expected to exceed 6.0 million barrels per day by 2025, compared with 1.7 million barrels per day in 2002. In 2025, projected production from South and Central America reaches 7.8 million barrels per day, up from 4.3 million barrels per day in 2002. A large portion of the increase in South and Central American production, 0.9 million barrels per day, is expected to come from nonconventional oil production in Venezuela. Non-OPEC African production is projected to grow from 3.1 million barrels per day in 2002 to 6.7 million barrels per day in 2025.

Average wellhead prices for natural gas (including both spot purchases and contracts) are projected to increase from $2.95 per thousand cubic feet (2002 dollars) in 2002 to $4.90 per thousand cubic feet in 2003, declining to $3.40 per thousand cubic feet in 2010 as the initial availability of new import sources (such as LNG) and increased drilling in response to the higher prices increase supplies. With the exception of a temporary decline in natural gas wellhead prices just before 2020, when an Alaska

pipeline is expected to be completed, wellhead prices are projected to increase gradually after 2010, reaching $4.40 per thousand cubic feet in 2025 (equivalent to about $8.50 per thousand cubic feet in nominal dollars). LNG imports, Alaskan production, and lower 48 production from nonconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. At $4.40 per thousand cubic feet, the 2025 wellhead natural gas price in AEO2004 is 44 cents higher than the AEO2003 projection. The higher price projection results from reduced expectations for onshore and offshore production of nonassociated gas, based on recent data indicating lower discoveries per well and higher costs for drilling in the lower 48 States.

In AEO2004, the average minemouth price of coal is projected to decline from $17.90 (2002 dollars) in 2002 to a low of $16.19 per short ton in 2016. Prices decline in the forecast because of increased mine productivity, a shift to western production, declines in rail transportation costs, and competitive pressures on labor costs. After 2016, however, average minemouth coal prices are projected to rise as productivity improvements slow and the industry faces increasing costs to open new mining areas to meet rising demand. In 2025, the average minemouth price is projected to be $16.57 per short ton, still lower than the real price in 2002 but considerably higher than the AEO2003 projection of $14.56 per short ton. In nominal dollars, projected minemouth coal prices in AEO2004 are equivalent to $32 per short ton in 2025.

Average delivered electricity prices are projected to decline from 7.2 cents per kilowatthour in 2002 to a low of 6.6 cents (2002 dollars) in 2007 as a result of cost reductions in an increasingly competitive market—where excess generating capacity has resulted from the recent boom in construction—and continued declines in coal prices. In markets where electricity industry restructuring is still ongoing, it contributes to the projected price decline through reductions in operating and maintenance costs, administrative costs, and other miscellaneous costs. After 2007, average real electricity prices are projected to increase, reaching 6.9 cents per kilowatthour in 2025 (equivalent to 13.2 cents per kilowatthour in nominal dollars). In AEO2003, real electricity prices followed a similar pattern but were projected to be slightly lower in 2025, at 6.8 cents per kilowatthour. The higher price projection in AEO2004 results primarily from higher expected costs for both generation and transmission of electricity. Higher generation costs reflect the higher projections for natural gas and coal prices in AEO2004, particularly in the later years of the forecast.

Energy Consumption

Total primary energy consumption in AEO2004 is projected to increase from 97.7 quadrillion British thermal units (Btu) in 2002 to 136.5 quadrillion Btu in 2025 (an average annual increase of 1.5 percent). AEO2003 projected total primary energy consumption at 139.1 quadrillion Btu in 2025. The AEO2004 projections for total petroleum and natural gas consumption in 2025 are lower than those in AEO2003, and the projections for coal, nuclear, and renewable energy consumption are higher. Higher natural gas prices in the AEO2004 forecast, and the effects of higher corporate average fuel economy (CAFE) standards for light trucks in the transportation sector, are among the most important factors accounting for the differences between the two forecasts.

Delivered residential energy consumption, excluding losses attributable to electricity generation, is projected to grow at an average rate of 1.0 percent per year between 2002 and 2025 (1.4 percent per year between 2002 and 2010, slowing to 0.8 percent per year between 2010 and 2025). The most rapid growth is expected in demand for electricity used to power computers, electronic equipment, and appliances. AEO2004 projects residential energy demand totaling 14.2 quadrillion Btu in 2025 (slightly higher than the 14.1 quadrillion Btu projected in AEO2003). The AEO2004 forecast includes more rapid growth in the total number of U.S. households than was projected in AEO2003; however, fewer new single-family homes are projected to be built than in the AEO2003 forecast, because the mix of single- and multi-family units has been revised, based on preliminary data on housing characteristics from the Energy Information Administration's 2001 Residential Energy Consumption Survey. Multi-family units tend to be smaller and use less energy per household, offsetting some of the increase in projected energy demand due to the increase in the number of U.S. households.

Delivered commercial energy consumption is projected to grow at an average annual rate of 1.7 percent

between 2002 and 2025, reaching 12.2 quadrillion Btu in 2025 (slightly less than the 12.3 quadrillion Btu projected in AEO2003). The most rapid increase in energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances. Commercial floorspace is projected to grow by an average of 1.5 percent per year between 2002 and 2025, identical to the rate of growth in AEO2003 for the same period.

Delivered industrial energy consumption in AEO2004 is projected to increase at an average rate of 1.3 percent per year between 2002 and 2025, reaching 33.4 quadrillion Btu in 2025 (lower than the AEO2003 forecast of 34.8 quadrillion Btu). The AEO2004 forecast includes slower projected growth in the dollar value of industrial product shipments and higher energy prices (particularly natural gas) than in AEO2003; however, those effects are offset in part by more rapid projected growth in the energy-intensive industries.

Delivered energy consumption in the transportation sector is projected to grow at an average annual rate of 1.9 percent between 2002 and 2025 in the AEO2004 forecast, reaching 41.2 quadrillion Btu in 2025 (2.5 quadrillion Btu lower than the AEO2003 projection). Two factors account for the reduction in projected transportation energy use from AEO2003 to AEO2004. First is the adoption of new Federal CAFE standards for light trucks—including sport utility vehicles. The new CAFE standards require that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model years 2007 and beyond. (The old standard was 20.7 miles per gallon in all years.) As a result, the average fuel economy for all new light-duty vehicles is projected to increase to 26.9 miles per gallon in 2025 in AEO2004, as compared with 26.1 miles per gallon in AEO2003. Second is the lower forecast for industrial product shipments in AEO2004, leading to a projection for freight truck travel in 2025 that is 7 percent lower than the AEO2003 projection.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,675 billion kilowatthours in 2002 to 5,485 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year (slightly below the 1.9-percent average annual increase projected in AEO2003). Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the residential and commercial sectors is partially offset in the AEO2004 forecast by improved efficiency in these and other, more traditional electrical applications, by the effects of demand-side management programs, and by slower growth in electricity demand for some applications, such as air conditioning, which have reached near-maximum penetration levels in regional markets.

Total demand for natural gas is projected to increase at an average annual rate of 1.4 percent from 2002 to 2025. From 22.8 trillion cubic feet in 2002, natural gas consumption increases to 31.4 trillion cubic feet in 2025 (Figure 2), primarily as a result of increasing use for electricity generation and industrial applications, which together account for almost 70 percent of the total projected growth in natural gas demand from 2002 to 2025. However, the annual rate of increase in natural gas demand varies over the projection period. In particular, the growth in demand for natural gas slows in the later years of the forecast (growing by 1.6 percent per year from 2002 to 2020, as compared with 0.6 percent per year from 2020 to 2025), as rising prices for natural gas make it less competitive for electricity generation. The AEO2004 projection for total consumption of natural gas in 2025 is 3.5 trillion cubic feet lower than in AEO2003.

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

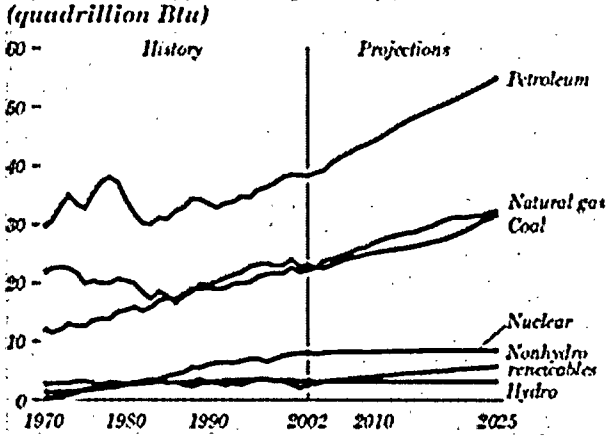

Figure data

In AEO2004, total coal consumption is projected to increase from 1,066 million short tons (22.2 quadrillion Btu) in 2002 to 1,567 million short tons (31.7 quadrillion Btu) in 2025. From 2002 to 2025, coal

use (based on tonnage) is projected to grow by 1.7 percent per year on average, compared with the AEO2003 projection of 1.4 percent per year. From 2002 to 2025, on a Btu basis, coal use is projected to grow by 1.6 percent per year. (Because of differences in the Btu content of coal across the Nation and changes in the regional mix of coal supply over time, the rate of growth varies, depending on whether it is measured in short tons or Btu.) The primary reason for the change in the rate of growth is higher natural gas prices in the AEO2004 forecast. In AEO2004, total coal consumption for electricity generation is projected to increase by an average of 1.8 percent per year (1.7 percent per year on a Btu basis), from 976 million short tons in 2002 to 1,477 million short tons in 2025, compared with the AEO2003 projection of 1,350 million short tons in 2025.

Total petroleum demand is projected to grow at an average annual rate of 1.6 percent in the AEO2004 forecast, from 19.6 million barrels per day in 2002 to 28.3 million barrels per day in 2025 AEO2003 projected a 1.8-percent annual average growth rate over the same period. The largest share of the difference between the two forecasts is attributable to the transportation sector. In 2025, total petroleum demand for transportation is 1.2 million barrels per day lower in AEO2004 than it was in AEO2003.

Total renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.9 percent per year, from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, primarily as a result of State mandates for renewable electricity generation. 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. Projected demand for renewables in 2025 in AEO2004 is 0.2 quadrillion Btu higher than in AEO2003, with more wind and geothermal energy consumption and less biomass fuel consumption expected in the AEO2004 forecast.

Energy Intensity

Energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of 1.5 percent in the AEO2004 forecast, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 3). This rate of improvement, the same as projected in AEO2003, is generally consistent with recent historical experience. With energy prices increasing between 1970 and 1986, energy intensity declined at an average annual rate of 2.3 percent, as the economy shifted to less energy-intensive industries, product mix changed, and more efficient technologies were adopted. Between 1986 and 1992, however, when energy prices were generally falling, energy intensity declined at an average rate of only 0.7 percent a year. Since 1992, it has declined on average by 1.9 percent a year.

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

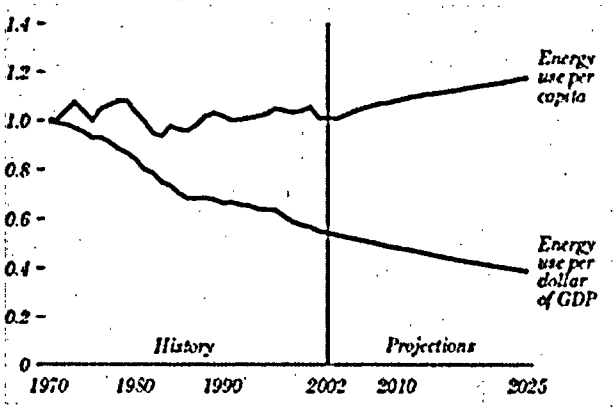

Figure data

Energy use per person generally declined from 1970 through the mid-1980s but began to increase as energy prices declined in the late 1980s and 1990s. Per capita energy use is projected to increase in the forecast, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.7 percent per year between 2002 and 2025 in AEO2004, the same as in AEO2003.

The potential for more energy conservation has

received increased attention recently as a potential contributor to the balancing of energy supply and demand as energy supplies become tighter and prices rise. AEO2004 does not assume policy-induced conservation measures beyond those in existing legislation and regulation or behavioral changes that could result in greater energy conservation.

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

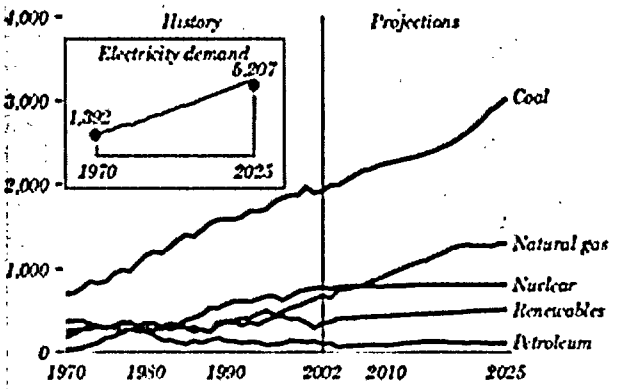

Figure data

Electricity Generation

In the AEO2004 forecast, the projected average price for natural gas delivered to electricity generators is 25 cents per million Btu higher in 2025 than was projected in AEO2003. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower than projected in AEO2003, generation from gas-fired plants in 2025 is lower, and generation from coal, petroleum, nuclear, and renewable fuels is higher. Cumulative natural gas capacity additions between 2003 and 2025 are 219 gigawatts in AEO2004, compared with 292 gigawatts in AEO2003. The AEO2004 projection of 1,304 billion kilowatthours of electricity generation from natural gas in 2025 is still nearly double the 2002 level of 682 billion kilowatthours (Figure 4), reflecting utilization of the new capacity added over the past few years and the construction of new natural-gas-fired capacity later in the forecast period to meet increasing demand and replace capacity that is expected to be retired. Less new gas-fired capacity is added in the later years of the forecast because of the projected rise in prices for natural gas and the current surplus of capacity in many regions of the country. In AEO2003, 1,678 billion kilowatthours of electricity was projected to be generated from natural gas in 2025.

The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 18 percent in 2002 to 22 percent in 2025 (as compared with 29 percent in the AEO2003 forecast). The share from coal is projected to increase from 50 percent in 2002 to 52 percent in 2025 as rising natural gas prices improve the cost competitiveness of coal-fired technologies. AEO2004 projects that 112 gigawatts of new coal-fired generating capacity will be constructed between 2003 and 2025 (compared with 74 gigawatts in AEO2003).

Nuclear generating capacity in the AEO2004 forecast is projected to increase from 98.7 gigawatts in 2002 to 102.6 gigawatts in 2025, including uprates of existing plants equivalent to 3.9 gigawatts of new capacity between 2002 and 2025. In AEO2003, total nuclear capacity reached a peak of 100.4 gigawatts in 2006 before declining to 99.6 gigawatts in 2025. In a departure from AEO2003, no existing U.S. nuclear units are retired in the AEO2004 reference case. Like AEO2003, AEO2004 assumes that the Browns Ferry nuclear plant will begin operation in 2007 but projects that no new nuclear facilities will be built before 2025, based on the relative economics of competing technologies.

Renewable technologies are projected to grow slowly because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies in the competition for new capacity. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. The production tax credit for wind and biomass is assumed to end on December 31, 2003, its statutory expiration date at the time AEO2004 was prepared.

Total renewable generation, including combined heat and power generation, is projected to increase from 339 billion kilowatthours in 2002 to 518 billion kilowatthours in 2025, at an average annual growth rate of 1.9 percent. AEO2003 projected slower growth in renewable generation, averaging 1.4 percent per year from 2002 to 2025.

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 5). Net imports are expected to constitute 36 percent of total U.S. energy consumption in 2025, up from 26 percent in 2002.

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

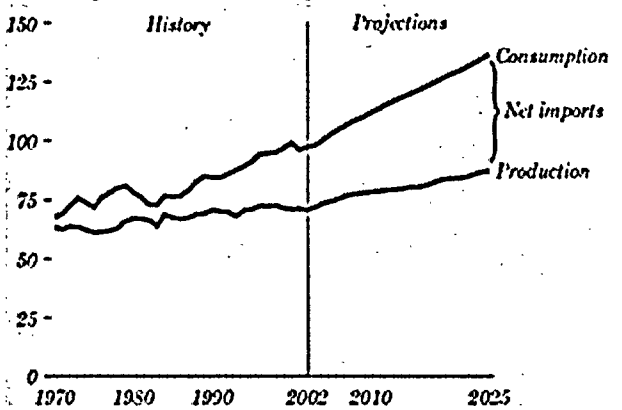

Figure data

Projected U.S. crude oil production increases from 5.6 million barrels per day in 2002 to a peak of 6.1 million barrels per day in 2008 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Beginning in 2009, U.S. crude oil production begins a gradual decline, falling to 4.6 million barrels per day in 2025—an average annual decline of 0.9 percent between 2002 and 2025. The AEO2004 projection for U.S. crude oil production in 2025 is 0.7 million barrels per day lower than was projected in AEO2003. The projections for Alaskan production and offshore production in 2025 both are lower than in AEO2003 (by 660,000 and 120,000 barrels per day, respectively), based on revised expectations about the discovery of new speculative fields in Alaska and on an update of the cost of offshore production.

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

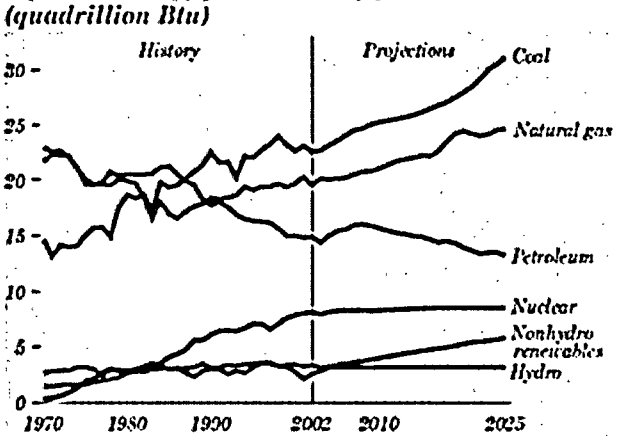

Figure data

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 AEO2004 forecast, increasing from 9.2 million barrels per day in 2002 to a peak of 9.7 million barrels per day in 2008, then declining to 8.6 million barrels per day in 2025 (Figure 6). The projected drop in total domestic petroleum supply would be greater without a projected increase of 590,000 barrels per day in the production of natural gas plant liquids (a rate of increase that is consistent with the projected growth in domestic natural gas production).

In 2025, net petroleum imports, including both crude oil and refined products (on the basis of barrels per day), are expected to account for 70 percent of demand, up from 54 percent in 2002. Despite an expected increase in domestic refinery distillation capacity of 5 million barrels per day, net refined petroleum product imports account for a growing portion of total net imports, increasing from 13 percent in 2002 to 20 percent in 2025 (as compared with 34 percent in AEO2003).

The most significant change made in the AEO2004 energy supply projections is in the outlook for natural gas. Total natural gas supply is projected to increase at an average annual rate of 1.4 percent in AEO2004, from 22.6 trillion cubic feet in 2002 to 31.3 trillion cubic feet in 2025, which is 3.3 trillion cubic feet less than the 2025 projection in AEO2003. Domestic natural gas production increases from 19.1 trillion cubic feet in 2002 to 24.1 trillion cubic feet in 2025 in the AEO2004 forecast, an average increase of 1.0 percent per year. AEO2003 projected 26.8 trillion cubic feet of domestic natural gas production in 2025.

The projection for conventional onshore production of natural gas is lower in AEO2004 than it was in AEO2003, because slower reserve growth, fewer new discoveries, and higher exploration and development costs are expected. In particular, reserves added per well drilled in the Midcontinent and Southwest regions are projected to be about 30 percent lower than projected in AEO2003. Offshore natural gas production is also lower in AEO2004 than in AEO2003 because of the tendency to find more

oil than natural gas in the offshore and at higher costs than previously anticipated. Recent data from the Minerals Management Service show that about three-quarters of the hydrocarbons discovered in deepwater fields are oil, compared with 50 percent assumed in AEO2003. Conventional production of associated-dissolved and nonassociated natural gas in the onshore and offshore remains important, meeting 39 percent of total U.S. supply requirements in 2025, down from 56 percent in 2002.

Canadian imports are also projected to be sharply lower in AEO2004 than in AEO2003. Net imports of natural gas from Canada are projected to remain at about the 2002 level of 3.6 trillion cubic feet through 2010 and then decline to 2.6 trillion cubic feet in 2025 (compared with the AEO2003 projection of 4.8 trillion cubic feet in 2025). The lower forecast in AEO2004 reflects revised expectations about Canadian natural gas production, particularly coalbed methane and conventional production in Alberta, based on data and projections from the Canadian National Energy Board and other sources.

Growth in U.S. natural gas supplies will be dependent on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 5.9 trillion cubic feet in 2002 to 9.2 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2018, total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2002 to 2.7 trillion cubic feet in 2025. The four existing U.S. LNG terminals (Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) all are expected to expand by 2007, and additional facilities are expected to be built in the lower 48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, with a new small facility in New England and a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving the California market. Total net LNG imports are projected to increase from 0.2 trillion cubic feet in 2002 to 4.8 trillion cubic feet in 2025, more than double the AEO2003 projection of 2.1 trillion cubic feet.

As domestic coal demand grows in AEO2004, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,105 million short tons in 2002 to 1,543 million short tons in 2025. Projected production in 2025 is 103 million short tons higher than in AEO2003 because of a substantial increase in projected coal demand for electricity generation resulting from higher natural gas prices. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental production. In 2025, nearly two-thirds of coal production is projected to originate from the western States.

Renewable energy production is projected to increase from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, with growth in industrial biomass, ethanol for gasoline blending, and most sources of renewable electricity generation (including conventional hydroelectric, geothermal, biomass, and wind). The AEO2004 projection for renewable energy production in 2025 is 0.2 quadrillion Btu higher than was projected in AEO2003 as a result of higher projections for electricity generation from geothermal and wind energy.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,729 million metric tons in 2002 to 8,142 million metric tons in 2025 in AEO2004, an average annual increase of 1.5 percent (Figure 7). This is slightly less than the projected rate of increase over the same period in AEO2003, 1.6 percent per year.

By sector, projected carbon dioxide emissions from residential, commercial, and electric power sector sources are higher in AEO2004 than they were in AEO2003 because of an updated estimate of 2002 emissions and higher projected energy consumption in each of the three sectors—particularly, coal

consumption for electricity generation in the electric power sector. Projected carbon dioxide emissions from the industrial and transportation sectors are lower in the AEO2004 forecast, because of lower projections for industrial natural gas consumption and the new CAFE standards for light trucks as well as other changes in the transportation sector that lead to lower petroleum consumption. The AEO projections do not include future policy actions or agreements that might be taken to reduce carbon dioxide emissions.

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

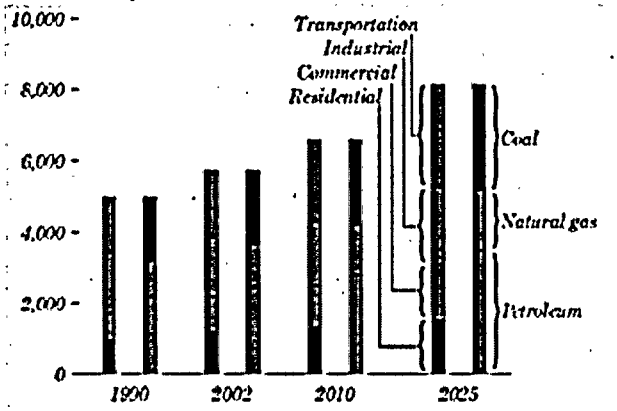

Figure data

Table 1. Total energy supply and disposition in the *AEO2004* reference case: summary, 2001-2025

Printer Friendly Version

Energy and economic factors	2001	2002	2010	2015	2020	2025	Average Annual change, 2002-2025 (%)
Primary energy production (quadrillion Btu)							
Petroleum	14.70	14.47	15.66	14.91	13.95	13.24	-0.4%
Dry natl gas	20.23	19.56	21.05	22.20	24.43	24.64	1.0%
Coal	23.97	22.70	25.25	26.14	27.92	31.10	1.4%
Nuclear	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable	5.25	5.84	7.18	7.84	8.45	9.00	1.9%
Other	0.53	1.13	0.88	0.79	0.81	0.84	-1.3%
Total	72.72	71.85	78.30	80.36	84.09	87.33	0.9%
Net imports (quadrillion Btu)							
Petroleum	23.29	22.56	28.13	33.20	37.25	41.69	2.7%
Natural gas	3.69	3.58	5.63	6.39	6.63	7.41	3.2%
Coal/other	-0.67	-0.51	0.06	0.26	0.43	0.61	NA
Total	26.31	25.63	33.82	39.84	44.31	49.71	2.9%
Consumption (quadrillion Btu)							
Pet products	38.49	38.11	44.15	48.26	51.35	54.99	1.6%
Natural gas	23.05	23.37	26.82	28.74	31.21	32.21	1.4%
Coal	22.04	22.18	25.23	26.32	28.30	31.73	1.6%
Nuclear	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable	5.25	5.84	7.18	7.84	8.46	9.00	1.9%
Other	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	96.94	97.72	111.77	119.75	127.92	136.48	1.5%
Petroleum Production (million barrels per day)							
Dom. crude	5.74	5.62	5.93	5.53	4.95	4.61	-0.9%
Othr domestic	3.11	3.60	3.59	3.72	3.94	3.98	0.4%
Net imports	10.90	10.54	13.17	15.52	17.48	19.67	2.7%
Consumption	19.71	19.61	22.71	24.80	26.41	28.30	1.6%
Natural gas (trillion cubic feet)							
Production	19.79	19.13	20.59	21.72	23.69	24.08	1.0%
Net imports	3.60	3.49	5.50	6.24	6.47	7.24	3.2%
Consumption	22.48	22.78	26.15	28.03	30.44	31.41	1.4%
Coal (million short tons)							
Production	1,138	1,105	1,230	1,285	1,377	1,543	1.5%
Net imports	-29	-23	-2	6	14	23	NA
Consumption	1,060	1,066	1,229	1,291	1,391	1,567	1.7%
Prices (2002 dollars)							
World oil ($/barrel)	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
US natural gas wellhead ($/tcf)	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
US coal ($/short ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Avg electricity price (cents/kwh)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%
Economic indicators							
Real GDP (billion 1996$)	9,215	9,440	12,190	14,101	16,188	18,520	3.0%
GDP chain-type price index(1996=1.000)	1.094	1.107	1.301	1.503	1.774	2.121	2.9%
Real disposable personal income (billion 1996$)	6,748	7,032	8,894	10,330	11,864	13,826	3.0%
Value of industrial.shipments (billion 1996$)	5,368	5,285	6,439	7,345	8,344	9,491	2.6%
Energy intensity (thousandBtu/1996 $ of GDP)	10.53	10.36	9.17	8.50	7.91	7.37	-1.5%
Carbon dioxide emissions(MMtons)	5,691.7	5,729.3	6,558.8	7,028.4	7,535.6	8,142.0	1.5%

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Annual Energy Outlook 2004 with Projections to 2025

Market Trends - Electricity

Index (click to jump links)

Electricity Sales

Electricity Use Is Expected To Grow More Slowly Than GDP

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

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 67). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is offset by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. Continued saturation of electric appliances, installation of more efficient equipment, and the promulgation of efficiency standards are expected to hold growth in electricity sales to an average of 1.8 percent per year between 2002 and 2025.

Figure 67. Population, gross domestic product, and electricity sales, 1965-2025 (5-year moving average annual percent growth)

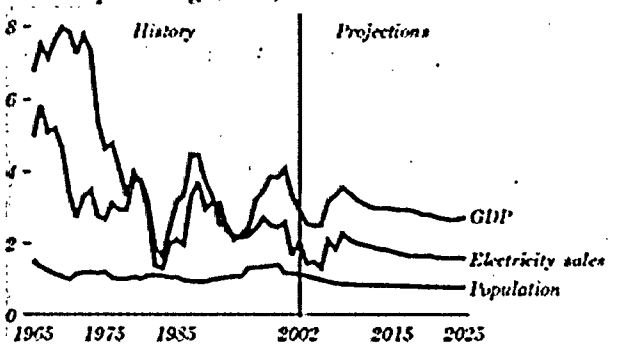
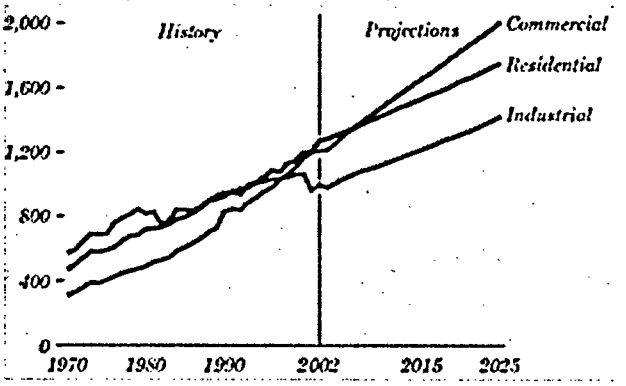


Figure data

Changing consumer markets could mitigate the slowing of electricity demand growth seen in the *AEO2004* projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset some or all of the projected efficiency gains.

Figure 68. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



Continued Growth in Electricity Use Is Expected in All Sectors

Electricity consumption is projected to increase in all the end-use sectors (Figure 68). The highest growth rate is projected for the commercial sector, at 2.2 percent per year from 2002 to 2025, compared with 1.6 percent for industrial and 1.4 percent for residential electricity demand. Residential demand, which grew faster in the past, varies by season, day, and time of day. Driven by summer peaks, the periodicity of residential demand increases the peak-to-average load ratio for load-serving entities, which must rely on quick-starting turbines or internal combustion units to meet peak demand. From 2000 to 2003, 69 gigawatts of peaking capacity was added—more than the total additions of 59 gigawatts of peaking capacity projected for 2004 to 2025.

Figure data

The projected growth in commercial and industrial electricity demand from 2002 to 2025 (2.2 and 1.6 percent per year, respectively) will require significant additions of baseload generating capacity. From 2000 to 2003, 112 gigawatts of combined-cycle capacity, which is efficient in both baseload and cycling applications, was installed. As a result, only about 12 gigawatts of currently unplanned baseload capacity is projected to be added from 2004 to 2010. After 2010, more rapid growth in baseload capacity is expected.

In addition to sectoral sales, combined heat and power plants in 2002 produced 134 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. Combined heat and power generation is expected to increase to 210 billion kilowatthours in 2025, as demand for manufactured products increases.

Electricity Generating Capacity

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

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

In 2000 and 2001, higher wholesale electricity prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000, 42 gigawatts in 2001 and 72 gigawatts in 2002 and are on pace to build 45 gigawatts in 2003 (Figure 69). More recently, however, developers have reported that they are delaying or canceling planned plants. New additions slowed in 2003, and that trend is expected to continue in the near term.

Figure 69. Additions to electricity generating capacity, 1999-2003 (gigawatts)

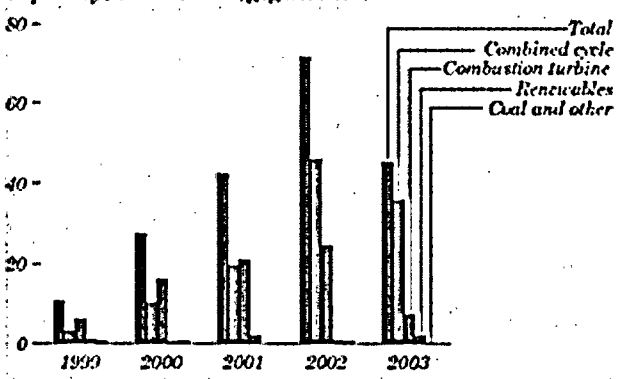


Figure data

Most of the recent additions are natural-gas-fired. Of the 187 gigawatts added between 2000 and 2003, 175 gigawatts is natural-gas-fired, including 110 gigawatts of efficient combined-cycle capacity and 65 gigawatts of combustion turbine capacity, which is used mainly when demand for electricity is high. Only about 5 gigawatts of new renewable plants—mostly wind—and less than 1 gigawatt of new coal-fired capacity were added over the same period.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 70. New generating capacity and retirements, 2002-2025 (gigawatts)

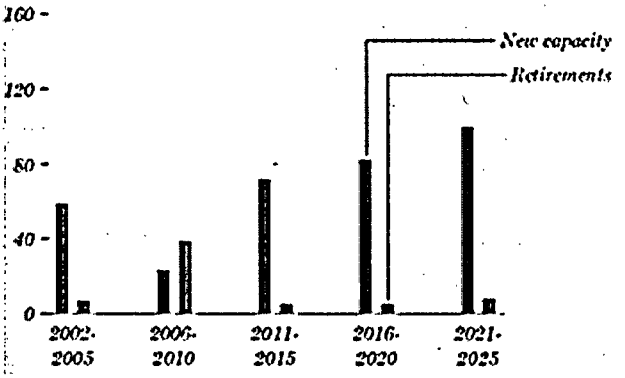


Figure data

Although recent capacity additions will meet near-term needs for electricity generation, more capacity will be needed eventually, as electricity use grows and older, inefficient plants are retired. From 2002 to 2025, 356 gigawatts of new generating capacity is expected to be needed (Figure 70), most of it after 2010, when the current excess supply situation has subsided. For example, between 2002 and 2010, only 88 gigawatts of new capacity (57 gigawatts of which is already in development) is projected to be needed— equivalent to approximately 11 gigawatts of capacity annually. Between 2011 and 2025, however, the amount of new capacity needed is projected to grow to 268 gigawatts—an average of 19 gigawatts annually.

In addition to meeting the growing demand for electricity, new plants will be built to replace older plants that are expected to be retired. From 2002 to 2025, a total of 62 gigawatts of capacity is expected to be retired, virtually all fossil fired. The largest component of retirements is expected to be older oil- and natural-gas-fired steam plants, as well as smaller amounts of older oil- and natural-gas-fired combustion turbines and coal-fired plants, which are not competitive with newer natural gas combustion turbine or combined-cycle plants. For oil- and natural-gas-fired steam plants, 35 out of 134 gigawatts of existing capacity is expected to be retired. For combustion turbines and coal-fired plants, 15 and 10 gigawatts of capacity are expected to be retired, respectively. Many older oil- and natural-gas-fired steam plants have efficiencies less than 30 percent. In contrast, the efficiencies of new combined-cycle plants are near 50 percent, and they are expected to continue to improve.

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

Figure 71. Electricity generation capacity additions by fuel type, including combined heat and power, 2002-2025 (gigawatts)

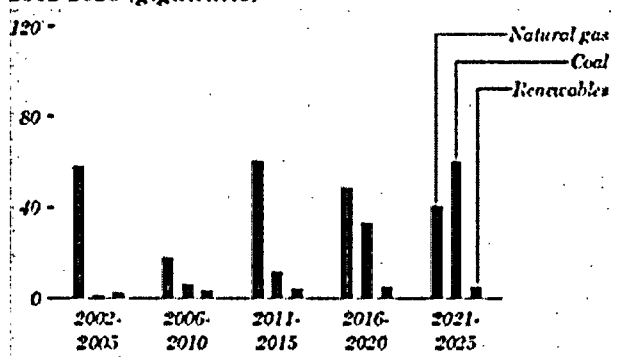


Figure data

With growing demand after 2010, 356 gigawatts of new generating capacity (including end-use combined heat and power) will be needed by 2025, with about half coming on line between 2016 and 2025. Of the new capacity, nearly 62 percent is projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technology (Figure 71).

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 all the capacity expansion expected over the forecast. Two new coal-fired plants (just over 1 gigawatt of capacity) are already under construction, scheduled for operation by 2006. From 2011 to 2025, 105 gigawatts of new coal-fired capacity is expected to be brought on line—more than one-half of it after 2020. From 2011 on, coal-fired capacity is expected to account for 40 percent of all capacity additions. Coal additions comprise 40 percent of total unplanned additions over the forecast. Most of the coal capacity is expected to be advanced pulverized coal. With higher capital costs and relatively inexpensive fuel, integrated coal gasification additions are limited to 6 gigawatts of commercial penetration.

Renewable technologies account for just over 5 percent of expected capacity expansion by 2025— primarily wind and biomass units. Distributed generation, mostly gas-fired microturbines, is expected to add just over 12 gigawatts. Oil-fired steam plants, which have higher fuel costs and lower efficiencies, are

not expected to account for any new capacity in the forecast, other than limited industrial combined heat and power applications.

Least Expensive Technology Options Are Likely Choices for New Capacity

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 72) [*111*]. 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.

Figure 72. Levelized electricity costs for new plants, 2010 and 2025 (2002 mills per kilowatthour)

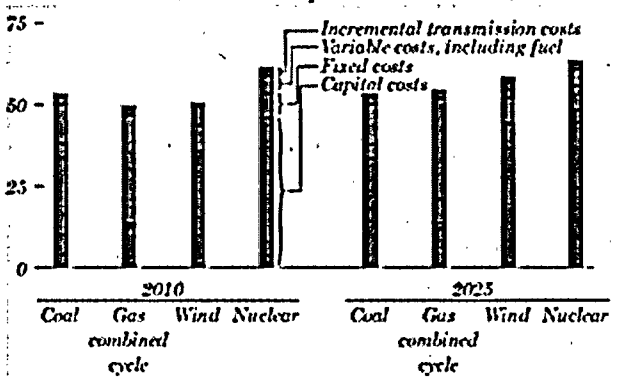


Figure data

The costs (other than fuel) and performance characteristics for new plants are expected to improve over time (Table 21), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,350 and 7,200 Btu per kilowatthour, respectively, by 2010.

Table 21. Costs of producing electricity from new plants, 2010 and 2025

Printer Friendly Version

Costs	2010 Advanced coal	2010 Advanced combined cycle	2025 Advanced coal	2025 Advanced combined cycle
	2002 mills per kilowatthour			
Capital	33.77	12.46	33.62	12.33
Fixed	4.58	1.36	4.58	1.36
Variable	11.69	32.95	11.74	37.91
Incremental transmission	3.38	2.89	3.26	2.78
Total	53.43	49.65	53.20	54.38

Electricity Fuel Costs and Prices

Natural Gas Fuel Costs Are Expected To Rise, Coal and Nuclear To Decline

Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. Falling coal prices have reduced the fuel share of operating costs for coal-fired plants—to about 74 percent in 2001—whereas volatile prices and rapidly increasing usage rates have raised the fuel share for natural-gas-fired combined-cycle plants, to 90 percent in 2001. For nuclear units, fuel costs typically are a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power units than for plants that use fossil fuels.

Figure 73. Fuel prices to electricity generators, 1990-2025 (2002 dollars per million Btu)

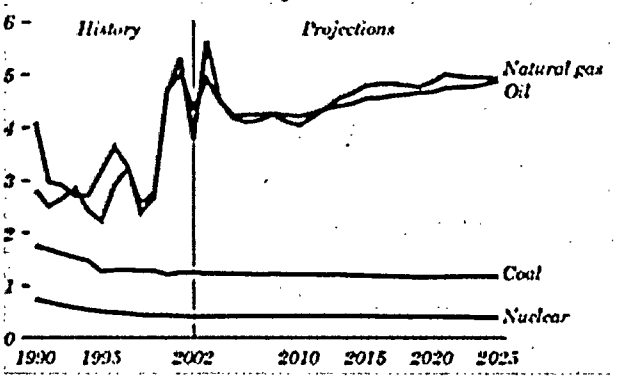


Figure data

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. After recent price spikes, natural gas prices to electricity suppliers are projected to rise by 1.2

percent per year in the forecast, from $3.77 per million Btu in 2002 to $4.92 in 2025 (Figure 73). Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2025. Delivered petroleum prices to utilities are expected to increase by 0.5 percent per year from 2002 to 2025, leading to a slight decrease in oil-fired generation. Despite increasing fuel costs, the market share of total generation met by natural gas is projected to increase from 18 percent in 2002 to 23 percent in 2025 due to the greater efficiency of natural gas capacity.

Figure 74. Average U.S. retail electricity prices, 1970-2025 (2002 cents per kilowatthour)

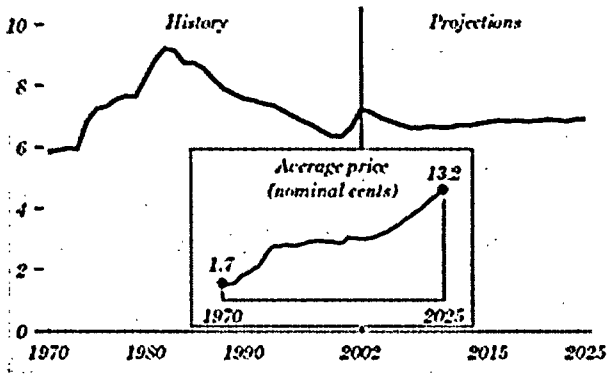


Figure data

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Average U.S. electricity prices, in real 2002 dollars, are expected to decline by 8 percent, from 7.2 cents per kilowatthour in 2002 to 6.6 cents in 2008 (Figure 74), and to remain relatively stable until 2011. From 2011 they are projected to increase gradually, by 0.3 percent per year, to 6.9 cents per kilowatthour in 2025, generally following the trend of the generation component of electricity price, which currently makes up 64 percent of electricity prices. The distribution component, accounting for about 28 percent of the total electricity price, is expected to decline at an average annual rate of 0.7 percent as the cost of the distribution infrastructure is spread out over a growing amount of total electricity sales. Transmission prices are expected to increase at an average annual rate of 0.9 percent because of the increased investment needed to meet the projected growth in electricity demand. Delivered electricity prices for residential, commercial, and industrial customers are projected to fall by 5, 10, and 9 percent, respectively, from 2002 to 2013 and then to regain about half of those losses by 2025.

Figure 75. Electricity generation by fuel, 2002 and 2025 (billion kilowatthours)

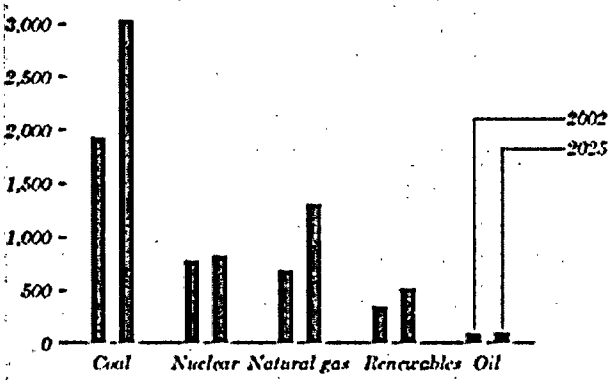


Figure data

In 2003, 17 States and the District of Columbia had competitive retail electricity markets in operation. Four States—Montana, Nevada, New Mexico, and Oklahoma—have delayed opening competitive retail markets. Arkansas repealed its restructuring legislation in February 2003. California's competitive retail market remains suspended, and some of its large power contracts have been renegotiated. States have cited a lack of operational wholesale markets and inadequate generation and transmission capacity as reasons for delaying retail competition.

Figure 76. Nuclear power plant capacity factors, 1973-2025 (percent)

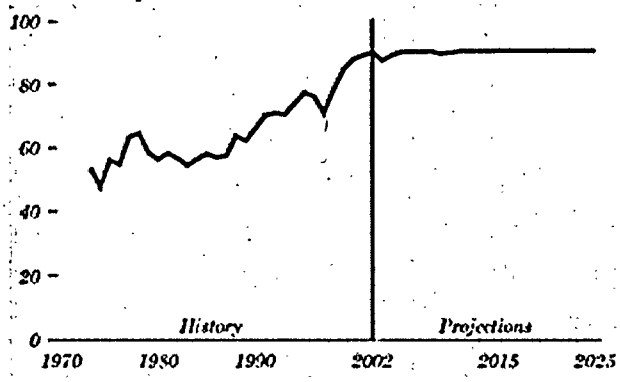


Figure data

Electricity from Nuclear Power

Natural Gas Is Expected To Surpass Nuclear Power in Electricity Supply

As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2025 (Figure 75). In 2002, coal accounted for 1,928 billion kilowatthours or 50 percent of total generation, including output at combined heat and power plants. Coal-fired generation is projected to maintain a 50-percent share through 2010 and grow to 52 percent in 2025 at 3,029 billion kilowatthours. The huge investment in existing coal-fired plants and high utilization rates at those plants are expected to keep coal in its dominant position. By 2025, it is projected that 25 gigawatts of coal-fired capacity will be retrofitted with scrubbers to comply with environmental regulations. A total of 112 gigawatts of new coal-fired capacity is projected to be added through 2025, primarily after 2015, when higher natural gas prices lead to the increasing share for coal-fired generation. As a result of improvements in performance and ongoing expansions of existing capacity, electricity generation from nuclear power plants is expected to increase modestly through 2017 before leveling off through the remainder of the forecast period.

In percentage terms, natural-gas-fired generation shows the largest increase in the forecast, from 18 percent of total electricity supply in 2002 to 21 percent in 2010 and 23 percent in 2025. As a result, by 2007, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2002. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 90 percent in 2002 (Figure 76). It is assumed that these performance improvements will be maintained as plants age, leading to a weighted average capacity factor of 91 percent after 2010.

In the reference case, no nuclear units are projected to be retired from 2002 to 2025. Nuclear capacity grows slightly due to assumed increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 18 applications for power uprates in 2002, and another 9 were approved or pending in 2003. 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 3.9 gigawatts in

Figure 77. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

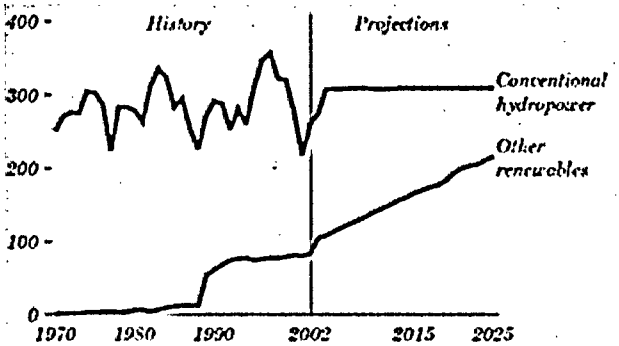


Figure data

Figure 78. Nonhydroelectric renewable electricity generation by energy source, 2002-2025 (billion kilowatthours)

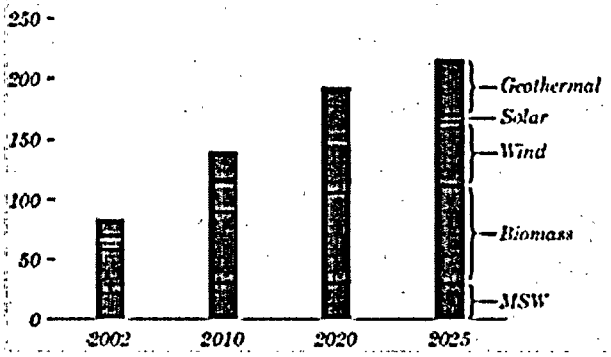


Figure data

Figure 79. Additions of renewable generating capacity, 2003-2025 (gigawatts)

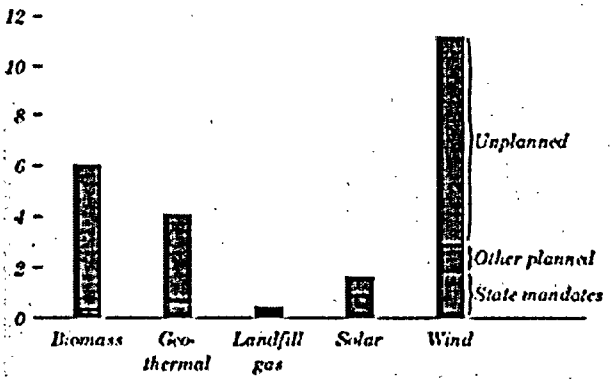


Figure data

total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2002 and 2025, because natural gas and coal-fired units are projected to be more economical.

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 licensed lifetimes. As of October 2003, license renewals for 16 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 26 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.

Figure 80. Nonhydroelectric renewable electricity generation by energy source in four cases, 2010 and 2025 (billion kilowatthours)

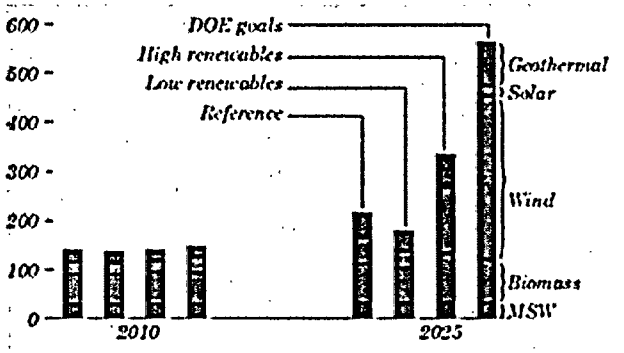


Figure data

Electricity from Renewable Sources

Increases in Nonhydropower Renewable Generation Are Expected

In the *AEO2004* reference case, despite improvements and incentives, grid-connected generators that use renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply, increasing from 343 billion kilowatthours of generation in 2002 (9.0 percent of total generation) to 525 billion kilowatthours in 2025 (9.1 percent of generation). Low precipitation in 2002 held hydroelectric generation to 260 billion kilowatthours. In the reference case, conventional hydropower provides 309 billion kilowatthours annually, amounting to 5.3 percent of total generation in 2025 (Figure 77).

Nonhydroelectric renewables account for 6.6 percent of projected additions to U.S. generating capacity from 2002 to 2025 and 6.8 percent of the projected increase in generation. Generation from nonhydropower renewables is projected to increase from 83 billion kilowatthours in 2002 (2.2 percent of generation) to 216 billion in 2025 (3.7 percent of generation). Biomass is the largest source of nonhydroelectric renewable generation in the forecast, including combined heat and power systems and biomass co-firing in coal-fired power plants. Electricity output from biomass combustion is projected to increase from 37 billion kilowatthours in 2002 (1.0 percent of generation) to 81 billion kilowatthours in 2025 (1.3 percent of generation). Most of the increase (54 percent) is expected from combined heat and power and the rest primarily from dedicated biomass plants. Nevertheless, generation using biomass co-fired in coal-burning plants reaches as much as 16 percent of biomass generation in 2016 before declining to 6 percent in 2025.

Biomass, Wind, and Geothermal Lead Growth in Renewables

AEO2004 projects significant increases in electricity generation from both wind and geothermal power (Figure 78). From 4.8 gigawatts in 2002, total wind capacity is projected to increase to 8.0 gigawatts in 2010 and 16.0 gigawatts in 2025. Generation from wind capacity is projected to increase from about 11 billion kilowatthours in 2002 (0.3 percent of generation) to 53 billion in 2025 (0.9 percent). Nevertheless, the mid-term prospects for wind power are uncertain, depending on future cost and performance, transmission availability, extension of the Federal production tax credit after 2003, other incentives, energy security, public interest, and environmental preferences. Geothermal output, all located in the West, is projected to increase from 13 billion kilowatthours in 2002 (0.3 percent of generation) to 47 billion in 2025 (0.8 percent).

Generation from municipal solid waste and landfill gas is projected to increase by nearly 9 billion kilowatthours, to about 31 billion kilowatthours (0.5 percent of generation) in 2025. No new waste-burning capacity is expected to be added in the forecast. Solar technologies are not expected to make significant contributions to U.S. grid-connected electricity supply through 2025. In total, grid-connected photovoltaic

and solar thermal generators together provided about 0.6 billion kilowatthours of electricity generation in 2002 (0.02 percent of generation), and they are projected to supply nearly 5 billion kilowatthours (0.08 percent) in 2025 [*112*].

State Mandates Call for More Generation From Renewable Energy

AEO2004 projects additions of 23 gigawatts of new nonhydroelectric renewable generating capacity from 2002 to 2025, including 18 gigawatts in the electric power sector, 4 gigawatts in combined heat and power, and 1 gigawatt in small-scale end-use applications. In the electric power sector, 3.1 gigawatts of new capacity is projected as a result of State mandates (wind power 1.9 gigawatts, geothermal 0.7 gigawatts, biomass 0.3 gigawatts, landfill gas 0.2 gigawatts, and solar photovoltaic plus thermal, 0.1 gigawatts) and the rest from commercial projects (Figure 79). The commercial projects include 0.08 gigawatts of central-station solar thermal and 0.3 gigawatts of grid-connected central-station photovoltaic capacity that is assumed to be built for testing, demonstration, environmental, and other reasons.

In the reference case, a number of States with mandates and renewable portfolio standards are projected to add significant amounts of renewable capacity after 2002. They include California (1,210 megawatts), Minnesota (921 megawatts), Nevada (470 megawatts), Pennsylvania (95 megawatts, built in West Virginia), Texas (270 megawatts), New Mexico (205 megawatts), and Massachusetts (175 megawatts). Other States with smaller requirements include Arizona, Connecticut, Illinois, and Wisconsin. Most identified new capacity is expected to be constructed in the near term—43 percent by 2003 and two-thirds by 2006. Because the Federal production tax credit for wind plants is scheduled to expire on December 31, 2003, 1,664 megawatts (58 percent) of currently planned new wind capacity is projected to be built before the end of 2003.

With Lower Cost Assumptions, Wind and Geothermal Capacity Increase

The low renewables case assumes that the cost and performance characteristics for key nonhydropower renewable energy technologies remain fixed at current levels; the high renewables case assumes cost reductions of 10 percent on a site-specific basis [*113*]; the DOE goals case assumes lower capital costs, higher capacity factors, and lower operating costs, based on the renewable energy goals of the U.S. Department of Energy [*114*]. In each case, assumptions for nonrenewable technologies are the same as in the reference case.

In the low renewables case, construction of new renewable capacity is considerably lower than projected in the reference case (Figure 80). In the high renewables case, additions of geothermal, biomass, and wind capacity are substantially higher than projected in the reference case, with most of the incremental capacity added between 2010 and 2025; however, nonhydropower renewables remain relatively small contributors to total generation, at 139 billion kilowatthours (3.1 percent of the total) in 2010 and 334 billion kilowatthours (5.7 percent) in 2025.

In the DOE goals case, still more wind and geothermal generating capacity is projected to be added. Geothermal electricity generation in 2010 is lower in the DOE goals case than in the reference case, but in 2025 it is almost double the reference case projection, at 90 billion kilowatthours, or approximately 1.6 percent of total generation. Generation from wind power in 2010 is 29 percent higher in the DOE goals case, at 31 billion kilowatthours, than in the reference case, and in 2025 it is more than six times higher, at 331 billion kilowatthours or 5.7 percent of total generation.

Electricity Alternative Cases

Gas-Fired Technologies Lead New Additions of Generating Capacity

The *AEO2004* 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 fossil goals case assumes improved costs and efficiencies as a result of accelerated research and development, as specified by the Department of Energy's Fossil Energy program goals. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2004 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 81). In the high fossil and fossil goals cases, advanced technologies are used for 78 percent (213 gigawatts) and 75 percent (182 gigawatts) of projected gas-fired capacity additions, compared with 19 percent (35 gigawatts) in the low fossil case. The coal share of total capacity additions varies from 16 percent to 37 percent. In the low fossil case, only a negligible amount of advanced coal-fired generating capacity is added. In the high cases, advanced coal technologies are more competitive, making up almost half of all coal-fired capacity additions in the high fossil fuel case and 95 percent in the fossil goals case.

Figure 81. Cumulative new generating capacity by technology type in four fossil fuel technology cases, 2002-2025 (gigawatts)

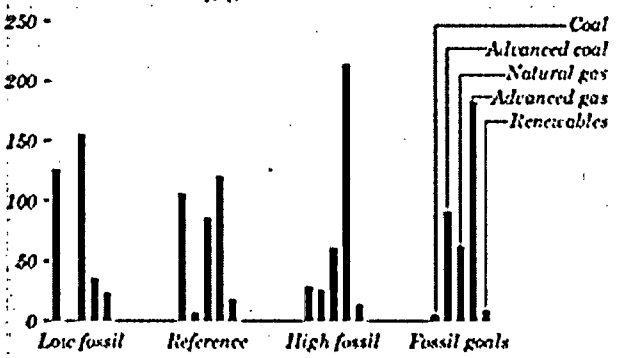


Figure data

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

The *AEO2004* 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 advanced nuclear cost cases analyze the sensitivity of the projections to yet lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 10 percent below the reference case in 2025, reflecting a 19-percent reduction in overnight capital costs from 2005 to 2025. The nuclear goals 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 advanced nuclear cost case are not competitive with the generating costs projected for new coal- and natural-gas-fired units, but toward the end of the projection period the costs assumed in the nuclear goals case are competitive (Figure 82). No nuclear capacity is added when costs are reduced by only 10 percent relative to the reference case, but with the greater reductions assumed in the nuclear goals case, 26 gigawatts of new nuclear capacity is added by 2025. The additional nuclear capacity displaces primarily coal and a smaller amount of natural gas capacity. The projections in Figure 82 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.

Figure 82. Levelized electricity costs for new plants by fuel type in the advanced nuclear cost case, 2015 and 2025 (2002 cents per kilowatthour)

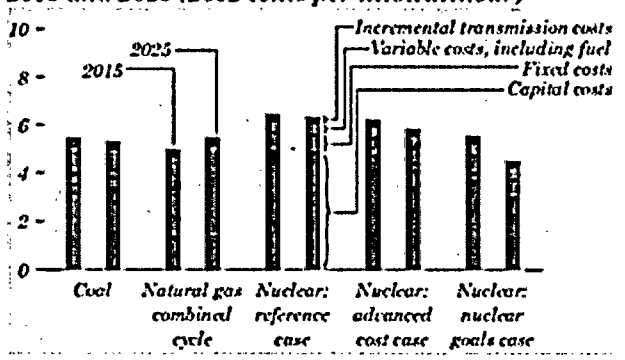


Figure data

Rapid Economic Growth Would Boost New Natural Gas and Coal Capacity

The projected annual average growth rate for GDP from 2002 to 2025 ranges from 3.5 percent in the high economic growth case to 2.4 percent in the low economic growth case. The difference leads to a 5-percent change in projected electricity demand in 2010 and a 14-percent change in 2025, with a corresponding difference of 138 gigawatts in the amount of new capacity projected to be built from 2002 to 2025 in the high and low economic growth cases.

Figure 83. Cumulative new generating capacity by technology type in three economic growth cases, 2002-2025 (gigawatts)

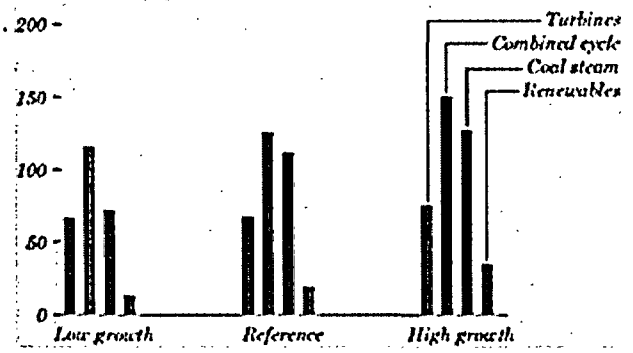


Figure data

More than one-half of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new natural-gas-fired plants. The stronger demand growth assumed in the high growth case is also projected to stimulate additions of coal-fired and renewable plants, accounting for 23 and 24 percent, respectively, of the increase in projected capacity additions in the high economic growth case over those projected in the reference case (Figure 83). In the low economic growth case, total capacity additions are reduced by 65 gigawatts, and 61 percent of that projected reduction is in coal-fired capacity additions.

Figure 84. Cumulative new generating capacity by type in two cases, 2002-2025 (gigawatts)

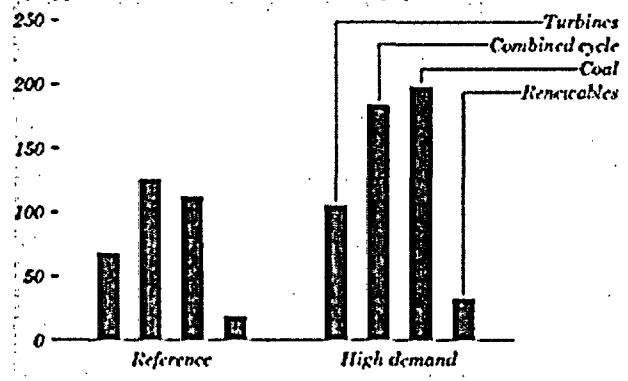


Figure data

Average electricity prices in 2025 are 6 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 5 percent lower than in the reference case. In the high economic growth case, a 4-percent increase in consumption of fossil fuels results in a 4-percent increase in carbon dioxide emissions from electricity generators in 2025.

High Demand Increases Capacity Needs, Particularly for Coal

Electricity consumption grows in the forecast, but the projected rate of increase is less than historical rates because of assumptions made about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year from 2002 to 2025, as compared with annual growth of 2.2 percent per year from 1990 to 1999. In the reference case, electricity demand is projected to grow by 1.8 percent per year. As a result, electricity demand is 6 percent higher in the high demand case than in the reference case in 2010 and 18 percent higher in 2025.

In the high demand case, 41 gigawatts more generating capacity is projected to be built from 2002 to 2010 than in the reference case. The difference grows to 206 gigawatts in 2025 (Figure 84). The shares of coal- and natural-gas-fired capacity additions in the electric power sector (including combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 37 percent and 58 percent, respectively, in the high demand case and 33 percent and 61 percent in the reference case. Increases in fossil fuel consumption of 6 percent in 2010 and 18 percent in 2025 lead to a higher level of carbon emissions from electricity generators (5 percent higher in 2010 and 18 percent higher in 2025). More rapid growth in electricity demand also leads to higher projected prices for electricity in 2025, averaging 7.1 cents per kilowatthour in the high demand case, compared with 6.9 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the higher electricity prices.

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Annual Energy Outlook 2004 with Projections to 2025

Forecast Comparisons

Table 30. Comparison of electricity forecasts, 2015 and 2025 (billion kilowatthours, except where noted)

Printer Friendly Version

Projection	2002	AEO2004 Reference	AEO2004 Low economic growth	AEO2004 High economic growth	Other forecasts GII	Other forecasts EVA	Other forecasts EEA	Other forecasts SEER
		2015						
Average end-use price (2002 cents per kilowatthour)	7.2	6.8	6.5	7.2	7.1	6.8	NA	NA
Residential	8.4	8.1	7.7	8.6	8.3	8.2	NA	NA
Commercial	7.8	7.2	6.8	7.6	7.6	7.5	NA	NA
Industrial	5.0	4.7	4.4	5.0	4.7	4.4	NA	NA
Net energy for load, including CHP	3,851	4,936	4,754	5,109	4,766	5,118	4,889	4,976
Coal	1,928	2,373	2,331	2,376	2,281	2,083	2,268	2,403
Oil	88	122	105	142	50	20	115	60
Natural gas [a]	687	1,120	1,013	1,258	1,162	1,627	1,264	1,221
Nuclear	780	812	812	812	783	827	765	801
Hydroelectric/other [b]	346	477	465	485	460	534	397	467
Nonutility sales to grid [c]	27	63	54	74	NA	NA	41	NA
Net imports	22	32	28	36	30	27	38	24
Electricity sales	3,492	4,429	4,263	4,583	4,289	4,534	4,405	4,470
Residential	1,268	1,531	1,515	1,546	1,557	1,659	1,557	1,555
Commercial/other [d]	1,230	1,682	1,663	1,701	1,582	1,685	1,584	1,650
Industrial	994	1,216	1,086	1,335	1,151	1,190	1,263	1,265
Capability, including CHP (gigawatts) [e]	921	1,037	1,006	1,067	997	1,046	1,049	NA
Coal	315	326	323	325	357	300	339	NA
Oil and natural gas	390	480	454	509	400	375	478	NA
Nuclear	99	102	102	102	98	102	95	NA
Hydroelectric/other	117	130	128	131	142	269 [f]	137	NA
				2025				
Average end-use price (2002 cents per kilowatthour)	7.2	6.9	6.6	7.3	6.9	6.8	NA	NA
Residential	8.4	8.1	7.6	8.8	8.1	8.2	NA	NA
Commercial	7.8	7.3	6.9	7.8	7.5	7.4	NA	NA
Industrial	5.0	4.8	4.5	5.1	4.5	4.3	NA	NA
Net energy for load, including CHP	3,851	5,794	5,408	6,159	5,630	6,080	NA	5,797
Coal	1,928	3,029	2,735	3,169	2,911	2,320	NA	3,044
Oil	88	97	103	105	26	22	NA	64
Natural gas [a]	687	1,317	1,249	1,457	1,410	2,278	NA	1,457
Nuclear	780	816	816	816	785	841	NA	754
Hydroelectric/other [b]	346	527	498	604	473	593	NA	462
Nonutility sales to grid [c]	27	95	72	120	NA	NA	NA	NA
Net imports	22	8	7	8	24	26	NA	16
Electricity sales	3,492	5,207	4,861	5,527	5,072	5,341	NA	5,319
Residential	1,268	1,747	1,686	1,781	1,840	1,986	NA	1,747
Commercial/other [d]	1,230	2,038	1,967	2,095	1,883	2,037	NA	2,100
Industrial	994	1,422	1,207	1,650	1,350	1,317	NA	1,472

Capability, including CHP (gigawatts)[e]	921	1,217	1,149	1,291	1,164	1,168	NA	NA
Coal	315	416	377	432	444	329	NA	NA
Oil and natural gas	390	557	536	598	476	452	NA	NA
Nuclear	99	103	103	103	98	104	NA	NA
Hydroelectric/other	117	141	134	159	146	283[f]	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 *AEO2004*, 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: *AEO2004:* AEO2004 National Energy Modeling System, runs AEO2004.D101703E (reference case), LM2004.D101703A (low economic growth case), and HM2004.D101703A (high economic growth case). GII: Global Insight, Inc., *Spring/Summer 2003 U.S. Energy Outlook* (July 2002). EVA: Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (July 2003). EEA: Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2003). SEER: Strategic Energy and Economic Research, Inc., *2003 Energy Outlook* (May 2003).

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