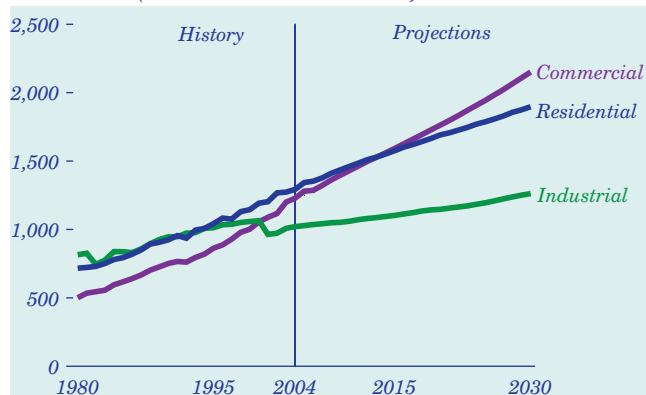


Continued Growth in Electricity Use Is Expected in All Sectors

Figure 55. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)



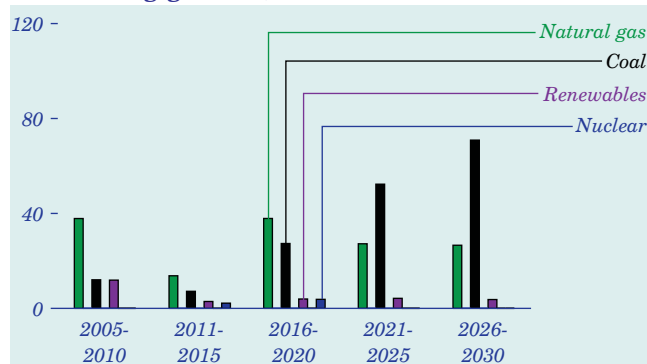
Total electricity sales increase by 50 percent in the AEO2006 reference case, from 3,567 billion kilowatthours in 2004 to 5,341 billion kilowatthours in 2030 (Figure 55). The largest increase is in the commercial sector, as service industries continue to drive economic growth. By customer sector, electricity demand grows by 75 percent from 2004 to 2030 in the commercial sector, by 47 percent in the residential sector, and by 24 percent in the industrial sector.

Efficiency gains are expected in both the residential and commercial sectors as a result of new standards in EPACT2005 and higher energy prices that prompt more investment in energy-efficient equipment. In the residential sector, the increase in electricity demand that results from a trend toward houses with more floorspace, in addition to population shifts to warmer regions, is mitigated by an increase in the efficiency of air conditioners and refrigerators. In the commercial sector, increases in demand as a consequence of larger building sizes and more intensive use of electrical equipment is offset by increases in the efficiency of heating, cooling, lighting, refrigeration, and cooking appliances.

Personal computers become more energy-efficient on average as residents and companies replace monitors that use cathode ray tubes with new models that use more efficient flat screens. New telecommunications technologies and medical imaging equipment increase electricity demand in the “other” commercial end-use category, which accounts for one-half of the increase in commercial demand. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation.

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

Figure 56. Electricity generation capacity additions by fuel type, including combined heat and power, 2005-2030 (gigawatts)



With growing electricity demand and the retirement of 65 gigawatts of inefficient, older generating capacity, 347 gigawatts of new capacity (including end-use CHP) will be needed by 2030. Most retirements are expected to be oil- and natural-gas-fired steam capacity, along with smaller amounts of oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not cost-competitive with newer plants.

Capacity decisions depend on the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for investments in some technologies. Natural gas plants are generally the least expensive capacity to build but are characterized by comparatively high fuel costs. Coal, nuclear, and renewable plants are typically expensive to build but have relatively low operating costs and, in addition, receive tax credits under EPACT2005.

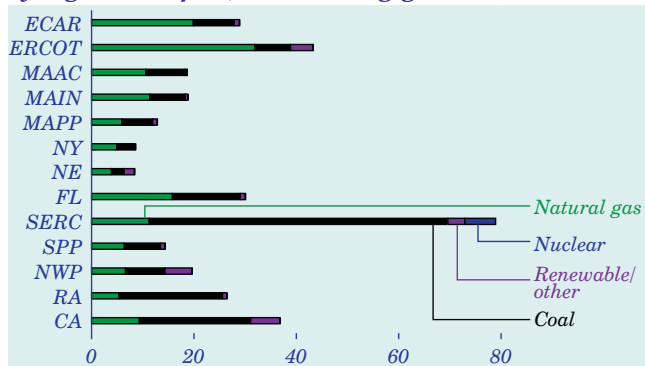
Coal-fired and natural-gas-fired plants account for about 50 percent and 40 percent, respectively, of the capacity additions from 2004 to 2030 (Figure 56). Coal-fired capacity is generally more economical to operate than natural-gas-fired capacity, because coal prices are considerably lower than natural gas prices. As a result, new natural-gas-fired plants are built to ensure reliability and operate for comparatively few hours when electricity demand is high.

About 8 percent of the expected capacity expansion consists of renewable generating units. New nuclear capacity additions total 6 gigawatts, but no additional new nuclear plants are built after 2020, when the EPACT2005 production tax credit expires.

Electricity Supply

Capacity Additions Are Expected To Be Required in All Regions

Figure 57. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2005-2030 (gigawatts)



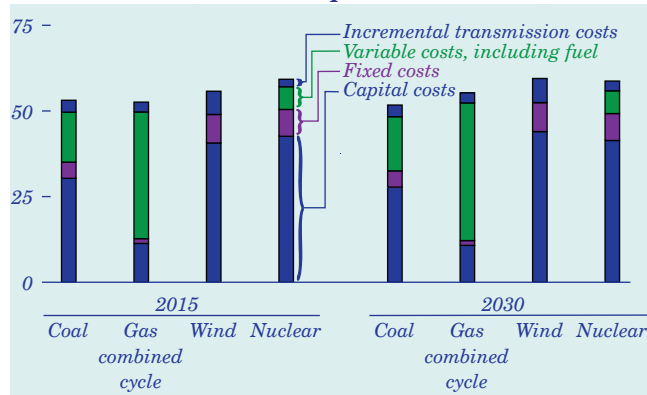
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030 (Figure 57). The largest amounts of new capacity are expected in the Southeast (FL and SERC) and the West (NWP, RA, and CA). In the Southeast, electricity demand represents a relatively large share of total U.S. electricity sales, and its need for new capacity is greater than in other regions.

With natural gas prices rising in the reference case, coal-fired plants make up most of the capacity additions through 2030. The largest concentrations of new coal-fired plants are in the Southeast and the West. In the Southeast, new coal-fired plants are built in view of the size of the electricity market and the corresponding need for additional capacity. In the West, where the capacity requirement is much smaller, the choice to build mostly coal-fired plants is based on the region's lower-than-average coal prices and higher-than-average natural gas prices.

Nationwide, some new natural-gas-fired plants are built to maintain a diverse capacity mix or to serve as reserve capacity. Most are located in the Midwest (MAPP, MAIN, and ECAR) and South (ERCOT and SPP). The Midwest has a surplus of coal-fired generating capacity and does not need to add many new coal-fired plants. In the South, natural gas prices are lower than the national average, and natural-gas-fired plants are more economical than in other regions.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 58. Levelized electricity costs for new plants, 2015 and 2030 (2004 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 58) [88]. 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.

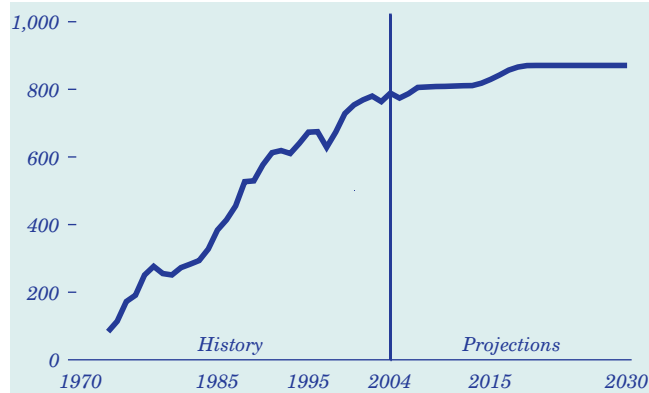
Capital costs decline over time (Table 16), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The efficiency of new plants is also assumed to improve through 2015, with heat rates for advanced combined cycle and coal gasification units declining to 6,333 and 7,200 Btu per kilowatthour, respectively.

Table 16. Costs of producing electricity from new plants, 2015 and 2030

Costs	2015		2030	
	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
<i>2004 mills per kilowatthour</i>				
Capital	30.34	11.33	27.78	10.76
Fixed	4.73	1.40	4.73	1.40
Variable	14.58	36.97	15.82	40.18
Incremental transmission	3.47	2.88	3.40	2.94
Total	53.12	52.58	51.73	55.28

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 59. Electricity generation from nuclear power, 1973-2030 (billion kilowatthours)



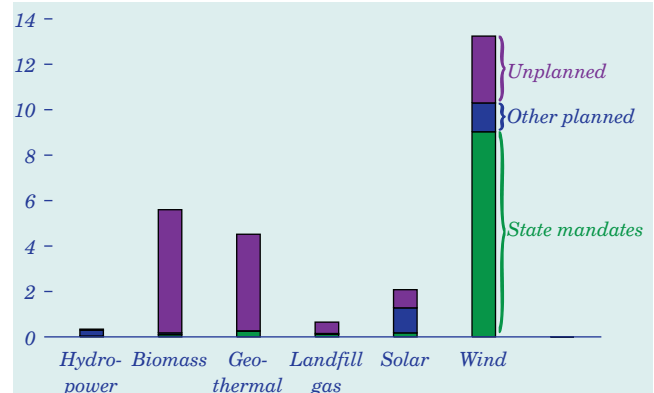
In the *AEO2006* reference case, nuclear capacity increases from 99.6 gigawatts in 2004 to 108.8 gigawatts in 2030. The increase includes 6.0 gigawatts of capacity at new plants stimulated by EPACT2005 tax incentives and 3.2 gigawatts of capacity expansion at existing plants. EPACT2005 provides an 8-year production tax credit of 1.8 cents per kilowatthour for up to 6 gigawatts of capacity built before 2021. If the capacity limit is reached before 2020, the credit program ends, and no additional units are expected. The increase in capacity at existing units assumes that all uprates approved, pending, or expected by the NRC will be carried out.

All existing nuclear plants are expected to continue operating through 2030, although most will be beyond their original license expiration dates by then. As of September 2005, the NRC had approved license renewals for 35 nuclear units, and 14 other applications were being reviewed. As many as 28 additional applicants have announced intentions to pursue license renewals over the next 7 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Because of the increase in capacity, from new capacity and uprates, and the continued strong performance of existing units, nuclear generation grows from 789 billion kilowatthours in 2004 to 871 billion kilowatt-hours in 2030 (Figure 59). That increase is not sufficient, however, for nuclear power to maintain its current 20-percent share of total generation. In 2030, even with a national average capacity factor of more than 90 percent, nuclear power accounts for about 15 percent of total U.S. generation.

State Programs Support Renewable Generating Capacity Additions

Figure 60. Additions of renewable generating capacity, 2004-2030 (gigawatts)



From 2004 to 2030, 26.4 gigawatts of new renewable generating capacity is added in the reference case, including 21.9 gigawatts in the electric power sector and 4.5 gigawatts in the end-use sectors. Nearly one-half of the total (11.7 gigawatts in the electric power sector and 0.75 in the end-use sectors) is at least partially stimulated by State programs, with the remainder resulting from commercial projects.

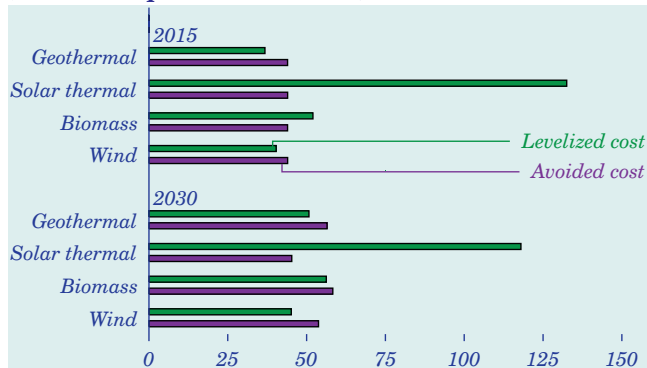
Overall, 9.0 gigawatts of central-station capacity, primarily in near-term projects, results from specific State standards: 3.7 gigawatts in Texas, 3.4 in California, 0.9 in Nevada, and 0.5 in Minnesota. Three States—Montana, New Mexico, and New York—add 100 to 200 megawatts each. Ten States—Arizona, Colorado, Hawaii, Illinois, Massachusetts, Maine, New Jersey, Pennsylvania, Vermont, and Wisconsin—add less than 100 megawatts each. Several States without specific requirements also add new renewable capacity, including nearly 400 megawatts in Washington, 300 in Oklahoma, 200 in Iowa, 150 in Kansas, and smaller amounts elsewhere.

The combination of Federal production tax credits and State programs results primarily in new wind power. More than 93 percent of the capacity additions stimulated by State programs are wind plants (Figure 60). State programs also spur small amounts of PV and solar thermal capacity, totaling 180 megawatts. On the other hand, with the Federal production tax credit assumed to expire on December 31, 2007, its potential to trigger capacity additions using technologies with longer lead times, such as biomass, geothermal, and hydropower, is limited.

Electricity Supply

Renewables Are Expected To Become More Competitive Over Time

Figure 61. Levelized and avoided costs for new renewable plants in the Northwest, 2015 and 2030 (2004 mills per kilowatthour)

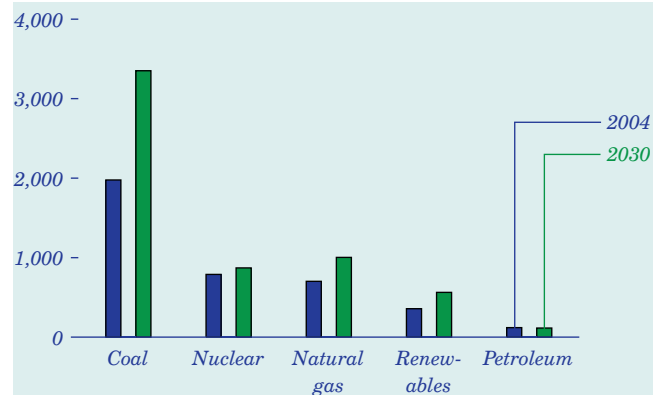


The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the market price for power only during 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 [89] for baseload energy (Figure 61). 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.

Wind and solar are intermittent technologies that can be used only when resources are available. With relatively low operating costs and limited resource availability, their avoided costs are determined largely by the operating costs of the most expensive units in operation when their resources are available. Solar generators tend to operate during peak load periods, when natural-gas-fired combustion turbines and combined-cycle units with higher fuel costs tend to determine the avoided cost. The levelized cost of solar thermal generation is significantly higher than its avoided cost through 2030. 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-moderate operating costs of combined-cycle and coal-fired plants, which set power prices during intermediate load hours. In some regions and years, the levelized costs for wind power are below its avoided costs.

Natural Gas and Coal Meet Most Needs for New Electricity Supply

Figure 62. Electricity generation by fuel, 2004 and 2030 (billion kilowatthours)



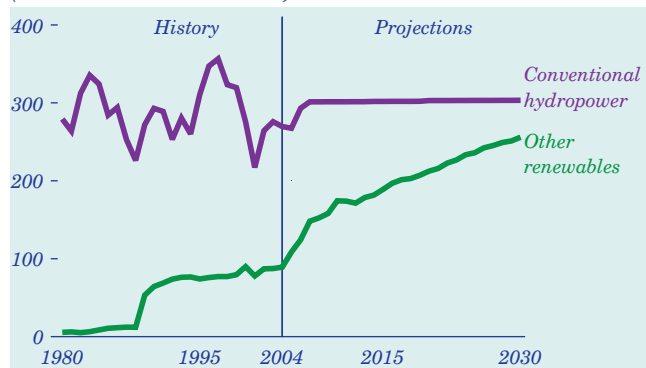
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to supply most of the Nation's electricity through 2030 (Figure 62). Coal-fired plants accounted for 50 percent of all electricity generation in 2004, and their share increases to 57 percent in 2030. In the near term, coal use increases gradually as a result of greater utilization of existing facilities, but its share of total generation remains relatively constant. In the longer term, the share of coal-fired generation increases as new plants begin to operate.

Because of comparatively high fuel prices, natural-gas-fired plants are not used as intensively as coal-fired plants. Natural-gas-fired plants provided 18 percent of total supply in 2004, and their share declines slightly to 17 percent in 2030. Natural-gas-fired generation increases initially as the recent wave of newer, more efficient plants come online, but it declines toward the end of the forecast period as natural gas prices continue to rise.

Both nuclear and renewable generation increase as new plants are built, stimulated by Federal tax incentives and rising fossil fuel prices. Modest increases in nuclear generation also result from improvements in plant performance and expansion of existing facilities, but the share of generation from nuclear plants declines from 20 percent in 2004 to 15 percent in 2030 as total generation grows at a faster rate than nuclear generation. The share of generation from renewable capacity increases slightly, to account for about 9 percent of total electricity supply in 2030.

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 63. Grid-connected electricity generation from renewable energy sources, 1980-2030 (billion kilowatthours)

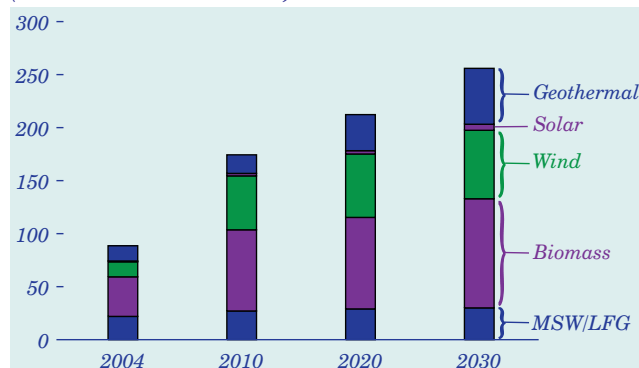


Despite technology improvements, rising fossil fuel costs, and public support, the contribution of renewable fuels to U.S. electricity supply remains relatively small in the *AEO2006* reference case at 9.4 percent of total generation in 2030, up from 9.0 percent in 2004 (Figure 63). Although conventional hydropower remains the largest source of renewable generation through 2030, a lack of untapped large-scale sites, coupled with environmental concerns, limits its growth, and its share of total generation falls from 6.8 percent in 2004 to 5.1 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, however, bolstered by technology advances and State and Federal supports. The share of non-hydropower renewables increases by 95 percent, from 2.2 percent of total generation in 2004 to 4.3 percent in 2030.

Biomass is the largest source of renewable electricity generation among the nonhydropower renewable fuels. Co-firing with coal is relatively inexpensive when low-cost biomass resources are available; and as the cost of biomass increases over time, new dedicated biomass facilities, such as IGCC plants, are built. Electricity generation from biomass increases from 0.9 percent of total generation in 2004 to 1.7 percent in 2030, with 38 percent of the increase coming from biomass co-firing, 36 percent from dedicated power plants, and 26 percent from new on-site CHP capacity.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 64. Nonhydroelectric renewable electricity generation by energy source, 2004-2030 (billion kilowatthours)



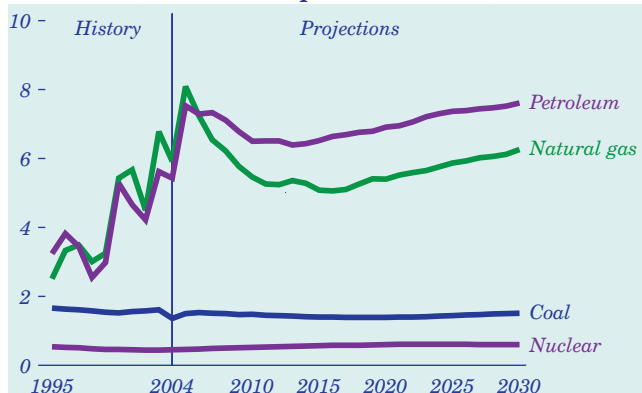
Electricity generation from wind and geothermal energy also increases in the reference case (Figure 64). There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of Federal production tax credits. In the reference case, generation from wind power increases from 0.4 percent of total generation in 2004 to 1.1 percent in 2030. Generation from geothermal facilities increases from 0.4 percent of total generation in 2004 to 0.9 percent in 2030, despite limited opportunities for the development of new sites. Most of the suitable sites, restricted mainly to Nevada and California, involve relatively high up-front costs and performance risks; and although geothermal power plants are eligible for the Federal production tax credit through 2007, the long construction lead times required make it unlikely that significant new capacity could be built in time to benefit from the current credit.

Among the other alternative fuel technologies, generation from municipal solid waste (MSW) and LFG slips from 0.5 percent of total generation in 2004 to 0.5 percent in 2030. Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale customer-sited PV applications grow rapidly [90]. Grid-connected solar generation remains at less than 0.1 percent of total generation through 2030.

Electricity Fuel Costs and Prices

Fuel Costs Drop From Recent Highs, Then Increase Gradually

Figure 65. Fuel prices to electricity generators, 1995-2030 (2004 dollars per million Btu)

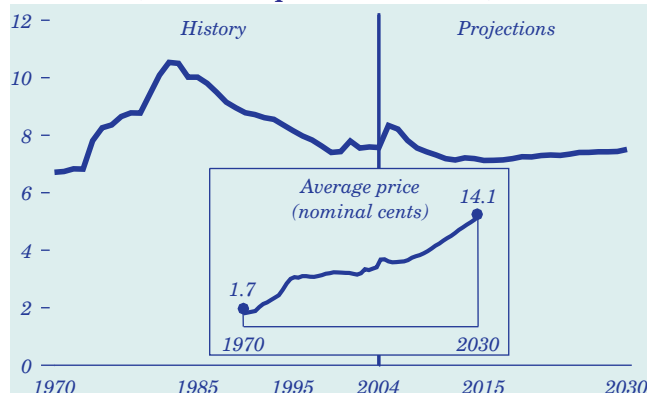


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. In the reference case, fuel costs account for about two-thirds of the generating costs for new natural-gas-fired plants, less than one-third for new coal-fired units, and less than one-tenth for new nuclear power plants in 2030. For most fuels, delivered prices to electricity generators peak by 2006, fall in the middle years of the projections, and then increase steadily through 2030. As a yearly average, natural gas prices drop to \$5.06 in 2016 and then rise to \$6.26 per million Btu in 2030 (Figure 65). Similarly, petroleum prices decline to \$6.39 in 2013 and then rise to \$7.61 per million Btu in 2030. Coal prices remain relatively low, with highs of about \$1.50 per million Btu at the beginning and end of the projection period and lows of about \$1.40 in the middle years. Nuclear fuel costs, averaging \$0.45 per million Btu in 2004, rise to \$0.60 per million Btu in 2030.

Electricity generation from natural-gas-fired power plants, which have relatively low capital costs and emissions levels, increased in the early years of this decade. More recently, higher fuel prices have increased the cost of natural-gas-fired generation. For example, the price of natural gas to generators jumped by 37 percent from 2004 to 2005. With natural gas prices rising after 2016 in the reference case, the natural gas share of total electricity generation drops, and both coal-fired and renewable generation increase.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 66. Average U.S. retail electricity prices, 1970-2030 (2004 cents per kilowatthour)



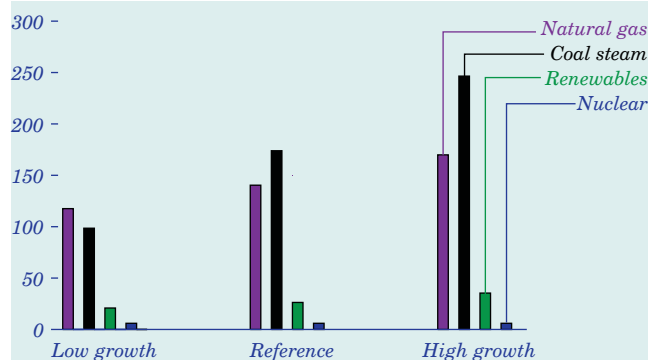
Electricity prices are determined primarily by the costs of generation, which make up about two-thirds of the total retail price. The 2004-2005 spikes in natural gas and petroleum prices, along with elevated coal prices, led to a jump in electricity prices. Average retail prices (in 2004 dollars) fall to 7.1 cents per kilowatthour in 2015, as new sources of natural gas and coal are brought on line. After 2015, natural gas and petroleum prices rise steadily, and power producers increase their reliance on lower priced coal. As a result, retail electricity prices rise gradually, to 7.5 cents per kilowatthour in 2030 (Figure 66).

Customers in States with competitive retail markets for electricity see the effects of natural gas prices in their electricity bills more rapidly than those in regulated States, because their prices are determined to a greater extent by the marginal cost of energy—the average operating cost of the last, most expensive unit run each hour—rather than the average of all plant costs. Natural gas plants, with their higher operating costs, often set the hourly marginal price.

Distribution costs, which accounted for more than one-quarter of retail electricity prices in 2004, decline by 14 percent from 2004 to 2030, as the cost of distribution infrastructure is spread over a growing customer base, and technology improvements lower the costs of billing, metering, and call-center services. Because of the additional investment needed to meet consumers' growing electricity use and to facilitate competitive wholesale energy markets, transmission costs rise by 27 percent, increasing their share of the total electricity price from 7 percent to 9 percent.

Faster Economic Growth Stimulates Capacity Additions, Particularly Coal

Figure 67. Cumulative new generating capacity by technology type in three economic growth cases, 2004-2030 (gigawatts)



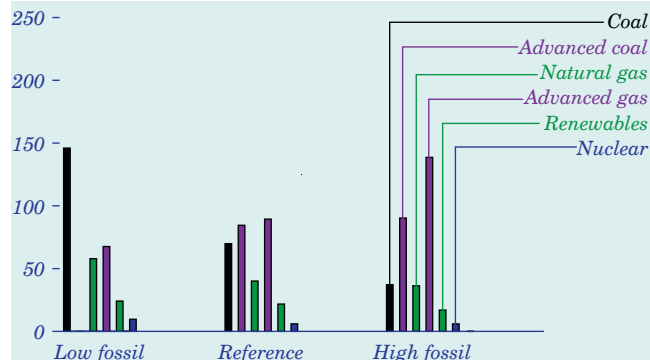
The need for new generating capacity, particularly coal-fired capacity, is influenced by economic growth. From 2004 to 2030, average annual GDP growth ranges from 2.4 percent in the low economic growth case to 3.5 percent in the high economic growth case. The difference leads to a 21-percent variation in the level of electricity demand in 2030 between the low and high economic growth cases, with a corresponding difference of 215 gigawatts in the amount of new capacity added from 2004 through 2030, including CHP in the end-use sectors.

Most (65 percent) of the capacity added in the high economic growth case, relative to the reference case, consists of new coal-fired plants. Higher demand for electricity and lower interest rates in the high economic growth case make new coal plants attractive. The stronger demand growth assumed in the high growth case also stimulates additions of renewable plants and, to a lesser degree, new natural-gas-fired capacity (Figure 67). In the low economic growth case, total capacity additions are reduced by 104 gigawatts, and 73 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2030 are 4 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 2030 are 4 percent lower in the low economic growth case than in the reference case. In the high economic growth case, a 9-percent increase in consumption of fossil fuels results in a 10-percent increase in CO₂ emissions from electricity generators in 2030.

Natural-Gas-Fired Capacity Additions Vary With Cost and Performance

Figure 68. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2004-2030 (gigawatts)



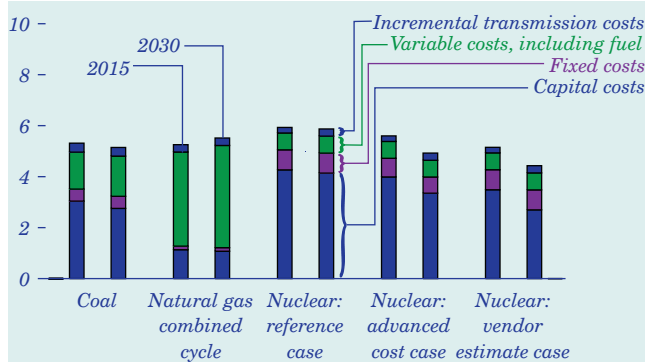
The cost and performance characteristics for various fossil fuel generating technologies in the *AEO2006* reference case are determined in consultation with industry and government specialists. To test the significance of uncertainty in the assumptions, alternative cases vary key parameters. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies in 2030 are assumed to be 10 percent lower than in the reference case. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2006 levels.

With different cost and performance assumptions, the mix of generating technologies changes (Figure 68). In the high fossil case, natural gas technologies make up the largest share of new capacity additions; in the reference and low fossil cases, coal technologies account for most of the new capacity additions. In the high fossil case, advanced technologies are used for 79 percent of all natural-gas-fired capacity additions and 71 percent of all coal-fired capacity additions by 2030; in the low fossil case, advanced technologies are used for only 54 percent of natural-gas-fired capacity additions and a negligible percentage of coal-fired capacity additions, but almost 10 gigawatts of nuclear generating capacity is added by 2030. The average efficiency of fossil-fuel-fired power plants varies only slightly among the three cases—from 36 percent in the low fossil case to almost 38 percent in the high fossil case in 2030—because plant owners are not expected to upgrade the large base of older generating units.

Electricity Alternative Cases

New Nuclear Plants Are Competitive When Lower Costs Are Assumed

Figure 69. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2030 (2004 cents per kilowatthour)

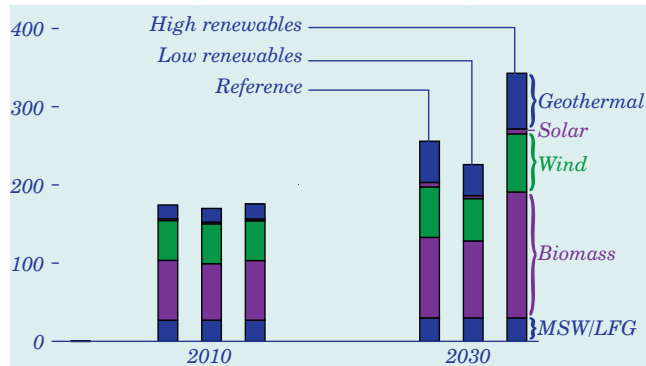


The reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new designs. Because no new nuclear plants have been ordered in this country since 1977, there is no reliable estimate of what they might cost. In recent years, various nuclear vendors have argued that their new plants will be simpler and less costly. Two alternative nuclear cost cases address this uncertainty. The advanced nuclear cost case assumes capital and operating costs 20 percent below those in the reference case in 2030, reflecting a 31-percent reduction in overnight capital costs from 2006 to 2030. The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 44 percent in 2030, consistent with estimates from British Nuclear Fuels Limited (Westinghouse) for the manufacture of its AP1000 advanced pressurized-water reactor.

Nuclear generating costs in the alternative nuclear cost cases are competitive with the generating costs for new coal- and natural-gas-fired units toward the end of the projection period (Figure 69). (The figure shows average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary by region.) In the reference case, Federal tax credits result in 6 gigawatts of new nuclear capacity. In the advanced nuclear case 34 gigawatts of new nuclear capacity is added between 2004 and 2030, and in the vendor estimate case 77 gigawatts of new nuclear capacity is added. The additional nuclear capacity displaces primarily new coal-fired capacity.

Lower Cost Assumptions Increase Biomass and Geothermal Capacity

Figure 70. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2030 (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 2030 on a site-specific basis for hydroelectric, geothermal, biomass, wind, and solar capacity.

In the low renewables case, construction of new renewable capacity is less than projected in the reference case (Figure 70). In the high renewables case, more additions of biomass, geothermal, and wind capacity are projected through 2030 than in the reference case, with most of the incremental capacity added between 2020 and 2030.

Biomass, available in some quantity in all U.S. regions, provides desirable baseload and intermediate-load capacity. In the high renewables case, the largest increase in generation relative to the reference case is seen for biomass, which nearly doubles in 2030. Geothermal resources are limited to the West, and despite limited opportunities for expansion, generation increases by 39 percent from 2004 to 2030. Generation from wind power, with significant expansion in the reference case over current capacity, increases by a modest 15 percent over the reference case in 2030, and there is little or no increase in generation from solar and hydropower. Even with the assumptions of reduced costs, nonhydropower renewables account for less than 6 percent of total generation in 2030 in the high renewables case.