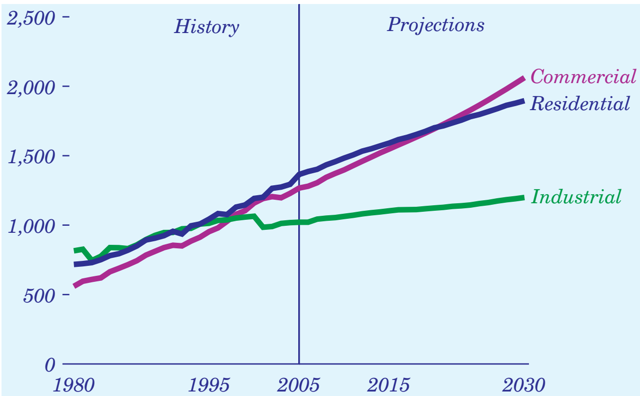
Continued Growth in Electricity Use Is Expected in All Sectors

Figure 53. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)



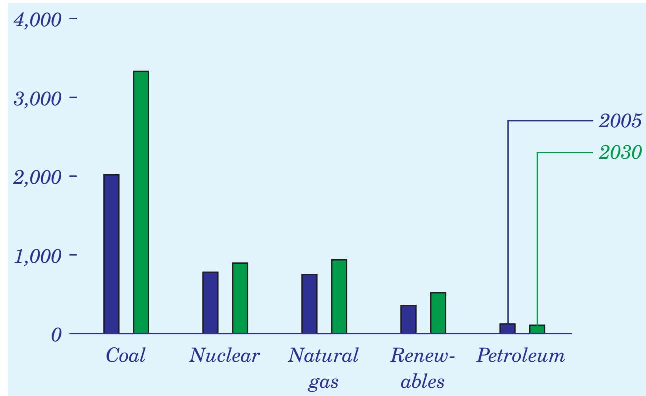
Total electricity sales increase by 41 percent in the *AEO2007* reference case, from 3,660 billion kilowatthours in 2005 to 5,168 billion kilowatthours in 2030. The largest increase is in the commercial sector (Figure 53), as service industries continue to drive growth. Electricity sales, which are strongly affected by the rate of economic growth, are projected to grow by 54 percent in the high growth case, to 5,654 billion kilowatthours in 2030, but by only 28 percent in the low growth case, to 4,682 billion kilowatthours in 2030.

By end-use sector, electricity demand in the reference case is projected to grow by 39 percent from 2005 to 2030 in the residential sector, by 63 percent in the commercial sector, and by 17 percent in the industrial sector. Growth in population and disposable income is expected to lead to increased demand for products, services, and floorspace, with a corresponding increase in demand for electricity for space heating and cooling and to power the appliances and equipment used by buildings and businesses. Population shifts to warmer regions will also increase the need for cooling.

The growth in demand for electricity is expected to be potentially offset by efficiency gains in both the residential and commercial sectors, and higher energy prices are expected to encourage investment in energy-efficient equipment. In both sectors, continuing efficiency gains are expected for electric heat pumps, air conditioners, refrigerators, lighting, cooking appliances, and computer screens. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 54. Electricity generation by fuel, 2005 and 2030 (billion kilowatthours)



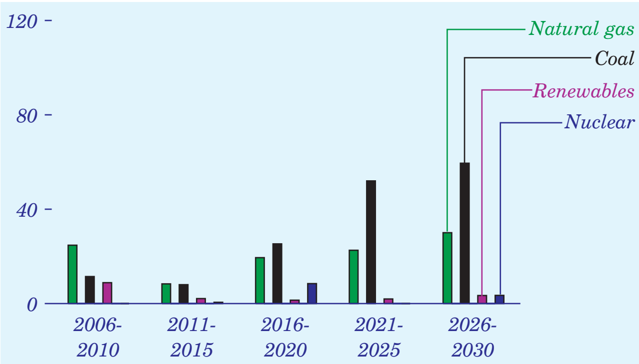
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to supply most of the Nation's electricity through 2030 (Figure 54). In 2005, coal-fired plants accounted for 50 percent of generation and natural-gas-fired plants for 19 percent. Most capacity additions over the next 10 years are natural-gas-fired plants, increasing the natural gas share to 22 percent and lowering the coal share to 49 percent in 2015. As natural gas becomes more expensive, however, more coal-fired plants are built. In 2030, the generation shares for coal and natural gas are 57 percent and 16 percent, respectively.

Nuclear and renewable generation increase as new plants are built, stimulated by Federal tax incentives and rising fossil fuel prices. Nuclear generation also increases modestly with improvements in plant performance and expansion of existing facilities, but the nuclear share of total generation falls from 19 percent in 2005 to 15 percent in 2030. The generation share from renewable capacity (about 9 percent of total electricity supply in 2005) remains roughly constant at about 9 percent.

Relative fuel costs, particularly for natural gas and coal, affect both the utilization of existing capacity and technology choices for new plants. Natural-gas-fired plants are projected to provide 27 percent of total electricity supply in 2030 in the low price case but only 11 percent in the high price case, while the projected share of total generation from coal-fired plants is 45 percent in the low price case but increases to 61 percent in the high price case. Changes in environmental policies would also affect the *AEO2007* projections for capacity additions.

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

Figure 55. Electricity generation capacity additions by fuel type, including combined heat and power, 2006-2030 (gigawatts)



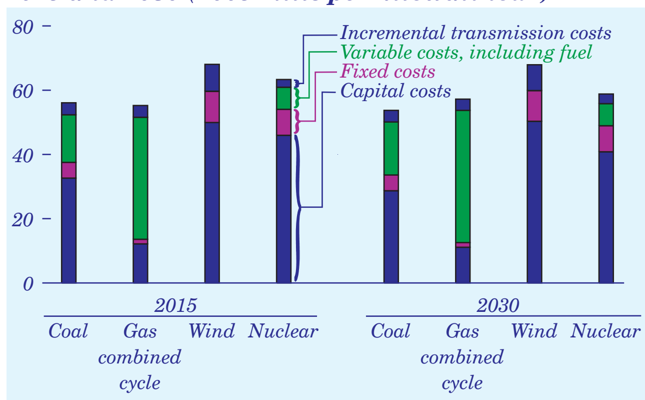
In the reference case, 292 gigawatts of new generating capacity (including end-use CHP) is required by 2030 to meet growth in electricity demand and to replace inefficient, older generating plants that are retired. Capacity decisions depend on the costs and operating efficiencies of different options, fuel prices, demand growth, and the availability of Federal tax credits for investments in some technologies.

Coal-fired capacity, which typically is expensive to build but has relatively low operating costs, accounts for about 54 percent of the total capacity additions from 2006 to 2030 (Figure 55). Natural-gas-fired plants, which generally are the least expensive capacity to build but have comparatively high fuel costs, represent 36 percent of the projected additions. Renewable and nuclear plants, which have high investment costs and low operating costs, account for 6 percent and 4 percent of total additions, respectively. Of the 12 gigawatts of new nuclear capacity expected by 2030, 3 gigawatts is added after the EPACT2005 PTC expires in 2020.

Different fuel price paths or growth rates for electricity demand can affect the quantity and mix of capacity additions. In the low and high price cases, variations in fuel prices have little impact on total capacity additions but do affect the mix of capacity types. Because fuel costs are a larger share of total expenditures for new natural-gas-fired capacity, higher fuel prices lead to more coal-fired additions. In the economic growth cases, capacity additions range from 191 gigawatts in the low growth case to 398 gigawatts in the high growth case, but with similar shares for the different generating technologies in both cases.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 56. Levelized electricity costs for new plants, 2015 and 2030 (2005 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 56) [*167*]. The *AEO2007* 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.

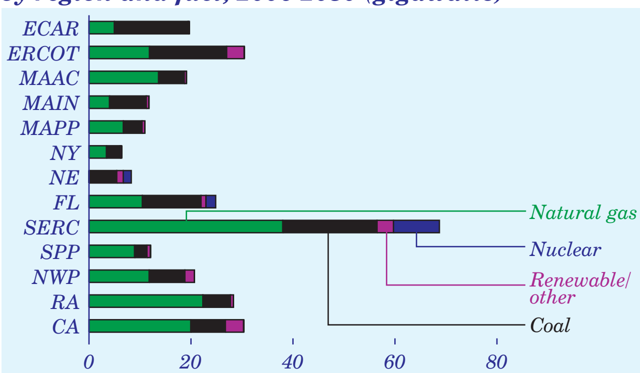
Capital costs decline over time (Table 16), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, 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 from 6,572 and 8,309 Btu per kilowatthour, respectively, in 2005 to 6,333 and 7,200 Btu per kilowatthour in 2015.

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

Costs	2015 Advanced coal	2015 Advanced combined cycle	2030 Advanced coal	2030 Advanced combined cycle
	2005 mills per kilowatthour			
Capital	32.64	12.16	28.71	11.12
Fixed	4.89	1.44	4.89	1.44
Variable	14.82	37.97	16.49	41.17
Incremental transmission	3.72	3.67	3.64	3.49
Total	**56.07**	**55.24**	**53.73**	**57.22**

Largest Capacity Additions Expected in the Southeast and the West

Figure 57. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2006-2030 (gigawatts)



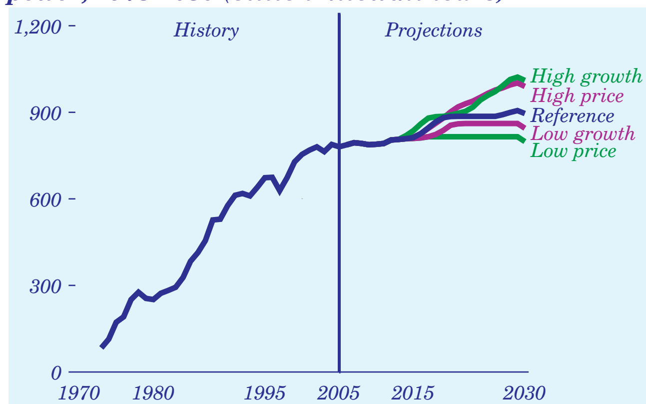
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030. The largest amounts of new capacity are expected in the Southeast (FL and SERC) and the 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 (Figure 57).

With natural gas prices rising in the reference case, coal-fired plants make up most of the capacity additions through 2030, given the assumption that current environmental policies are maintained indefinitely. 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 Southeast (FL and SERC). The Midwest has a surplus of coal-fired generating capacity and does not need to add many new coal-fired plants. In the Southeast, natural-gas-fired plants are needed along with coal-fired plants to maintain diversity in the capacity mix.

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 58. Electricity generation from nuclear power, 1973-2030 (billion kilowatthours)



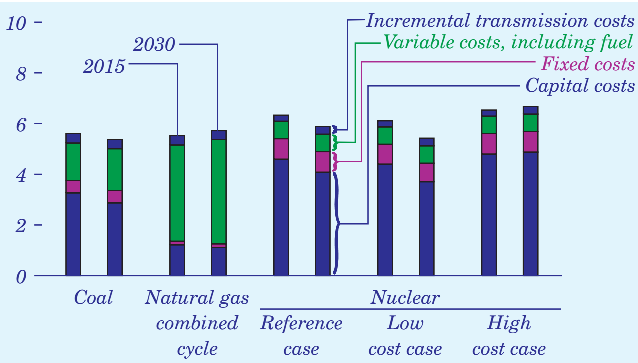
In the *AEO2007* reference case, nuclear capacity increases from 100.0 gigawatts in 2005 to 112.6 gigawatts in 2030. The change includes 2.7 gigawatts of capacity expansion at existing plants, 12.5 gigawatts of capacity at new plants, and 2.6 gigawatts of retirements of older units. EPACT2005 provides an 8-year PTC of 1.8 cents per kilowatthour for up to 6 gigawatts of new nuclear capacity built before 2021; however, the credit can be shared for additional capacity at a lower credit value. The reference case assumes that 9.0 gigawatts will be built by 2020 and will receive tax credits worth 1.2 cents per kilowatthour. The increase in capacity at existing units assumes that all uprates approved, pending, or expected by the NRC will be carried out.

Most existing nuclear units are expected to continue operating through 2030, based on the assumption that they will apply for and receive license renewals. Four units, totaling 2.6 gigawatts, are projected to be retired in 2030, when the date of their original licenses plus a 20-year renewal is reached.

Projected nuclear capacity additions vary, depending on overall demand for electricity and the prices of other fuels. Across the five main *AEO2007* cases, nuclear generation grows from 780 billion kilowatthours in 2005 to between 799 and 1,010 billion kilowatthours in 2030 (Figure 58). In the low price case, the delivered price of natural gas in 2030 is 10 percent lower than in the reference case, and new nuclear plants are not economical. In the high price and high growth cases, respectively, 24 and 27 gigawatts of new nuclear capacity are projected, because more capacity is needed and the cost of alternatives is higher.

When Lower Costs Are Assumed, New Nuclear Plants Are More Competitive

Figure 59. Levelized electricity costs for new plants by fuel type, 2015 and 2030 (2005 cents per kilowatthour)

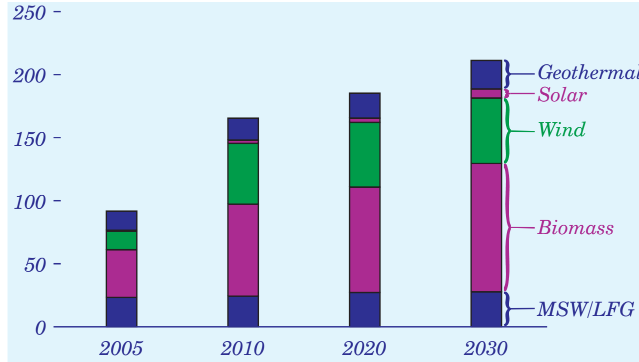


The reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new designs. Because no new nuclear plants have been ordered in this country since 1977, there is no reliable estimate of what they might cost. To test the significance of uncertainty in the assumptions, alternative cases vary key parameters. The low nuclear cost case assumes capital and operating costs 10 percent below those in the reference case in 2030, reflecting a 25-percent reduction in overnight capital costs from 2006 to 2030. The high nuclear cost case assumes no change in capital costs for advanced nuclear technologies from their 2006 levels.

Nuclear generating costs in the low nuclear cost case are more competitive with the generating costs for new coal- and natural-gas-fired units toward the end of the projection period (Figure 59). (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 9.0 gigawatts of new nuclear capacity by 2020, leading to lower costs in the future and an additional 3.5 gigawatts after the tax credits expire. In the low nuclear cost case, 28.5 gigawatts of new nuclear capacity is added between 2005 and 2030. The additional nuclear capacity displaces primarily new coal-fired capacity. In the high nuclear cost case, where capital costs are higher than expected, only 6 gigawatts of nuclear capacity is projected to be built, all due to the Federal tax credits.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 60. Nonhydroelectric renewable electricity generation by energy source, 2005-2030 (billion kilowatthours)

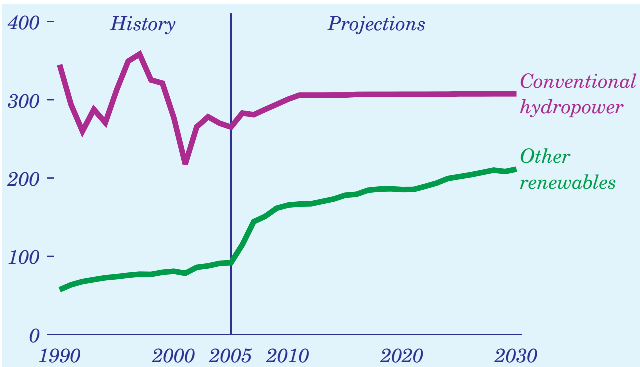


There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC, which was set to expire at the end of 2007 but has been extended to 2008. In the *AEO2007* reference case, generation from wind power increases from 0.4 percent of total generation in 2005 to 0.9 percent in 2030 (Figure 60). Generation from geothermal facilities, while increasing, is not projected to gain market share and remains at its 2005 level of 0.4 percent of total generation in 2030, because opportunities for the development of new sites are limited. 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 PTC, 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 stays at 0.5 percent of total generation. 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 [*168*]. Grid-connected solar generation increases to 0.1 percent of total generation in 2030.

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

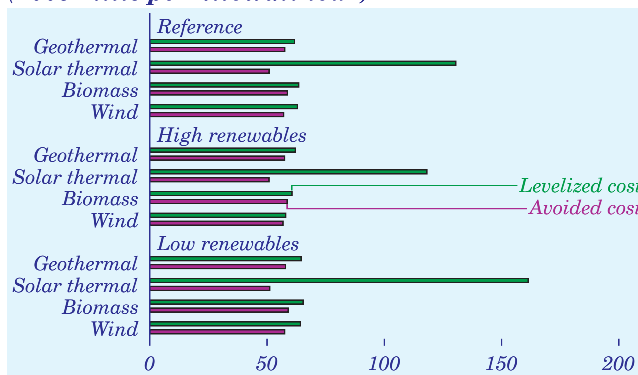


Despite technology improvements, rising fossil fuel costs, and public support, the contribution of renewable fuels to U.S. electricity supply remains relatively small in the *AEO2007* reference case at 9.0 percent of total generation in 2030—about the same as their share in 2005 (Figure 61). Although conventional hydropower remains the largest source of renewable generation through 2030, environmental concerns and the scarcity of untapped large-scale sites limit its growth, and its share of total generation falls from 6.6 percent in 2005 to 5.3 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, however, bolstered by technology advances and State and Federal supports. The share of nonhydropower renewable generation increases by 60 percent, from 2.3 percent of total generation in 2005 to 3.6 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. As low-cost feedstocks begin to be exhausted, however, more costly biomass resources are used, and new dedicated biomass facilities, such as IGCC plants, are built. Electricity generation from biomass increases from 1.0 percent of total generation in 2005 to 1.8 percent in 2030, with approximately 47 percent of the increase coming from biomass co-firing, 29 percent from dedicated power plants, and 25 percent from new on-site CHP capacity.

Renewables Are Expected To Become More Competitive Over Time

Figure 62. Levelized and avoided costs for new renewable plants in the Northwest, 2030 (2005 mills per kilowatthour)

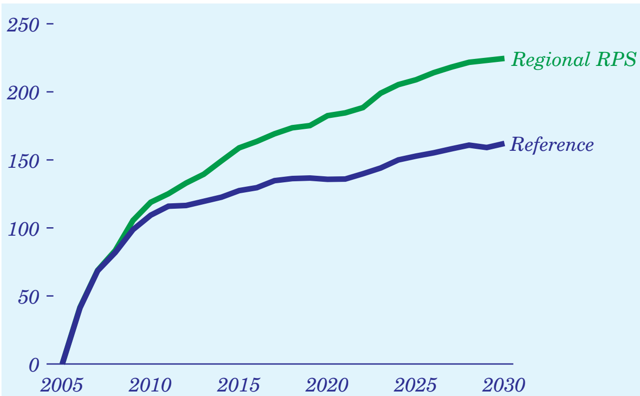


The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the market price for power only during 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 [*169*] for baseload energy. 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 determine avoided costs. The levelized cost of solar thermal generation is significantly higher than its avoided cost through 2030 (Figure 62). The availability of wind resources varies among regions, but wind plants tend to displace intermediate load generation. Thus, the avoided costs of wind power are 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, levelized costs for wind power are approximately equal to its avoided costs.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 63. Renewable electricity generation, 2005-2030 (billion kilowatthours)



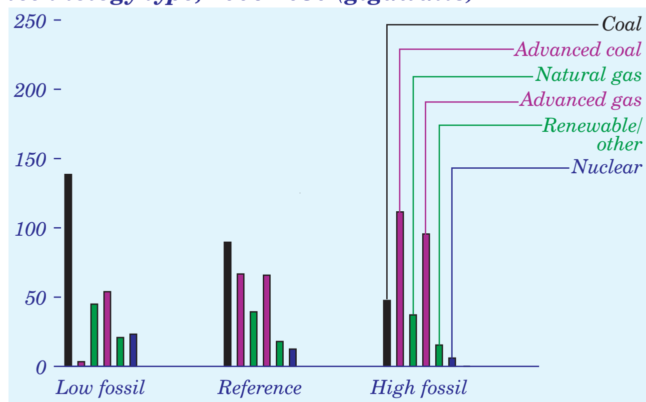
In 2005, 23 States and the District of Columbia had RPS or similar programs in effect. An alternative case was prepared for *AEO2007* to examine the potential impacts of full compliance with those programs. Because NEMS does not provide projections at the State level, the *AEO2007* regional RPS case assumed that all States would reach their goals within each program's legislative framework, and the results were aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of restraints on the funding of its RPS program.

In the regional RPS case, State renewable energy programs are projected to result in a national total of 61 billion kilowatthours of additional nonhydropower renewable generation in 2030 relative to the reference case, a 29-percent increase (Figure 63). Most of the additional generation is projected to come from biomass resources, with smaller increases for wind, municipal waste, and geothermal generation, which together account for 8 percent of the projected increase.

Nearly 5 gigawatts of additional new dedicated biomass capacity is projected for the mid-Atlantic region in the RPS case, as a result of the implementation of aggressive standards and the limited availability of other renewable resources. Florida, New York, and New England each would add 500 megawatts or more biomass capacity, whereas States in the West would add little new capacity beyond that projected in the reference case.

Fossil-Fired Capacity Additions Vary With Cost and Performance

Figure 64. Cumulative new generating capacity by technology type, 2006-2030 (gigawatts)

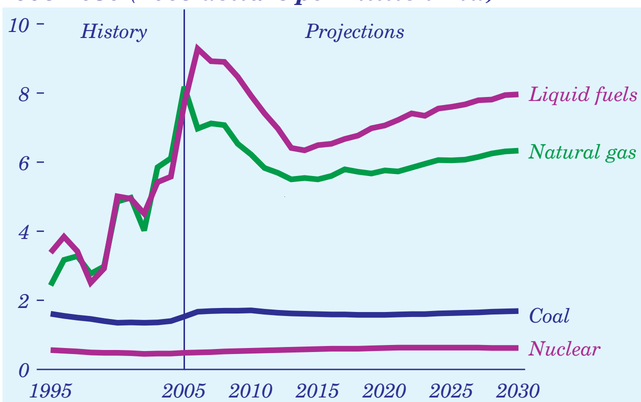


The cost and performance of various generating technologies in the reference case are determined in consultation with industry and government specialists. To test the significance of uncertainty in the assumptions, alternative cases vary key parameters. In the high fossil technology case, capital costs, 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 technology case assumes no change from the 2006 capital costs and heat rates for advanced technologies.

With different cost and performance assumptions, the mix of generating technologies changes (Figure 64). In all cases, assuming continuation of current environmental policies, coal technologies account for at least 50 percent of new capacity additions; in the high fossil technology case, 70 percent of coal-fired additions use advanced technologies, compared with only 2 percent in the low fossil case. Natural-gas-fired capacity makes up 35 to 42 percent of new additions in all cases. Advanced technologies represent 72 percent of those additions in the high fossil case and 55 percent in the low fossil case. The improved economics of advanced fossil technologies in the high fossil case result in fewer nuclear and renewable builds and more retirements of older steam units. Electricity prices are 2 percent lower in 2030 in the high fossil case than in the reference case. Because fossil-fired capacity is more costly in the low fossil case, more nuclear capacity (11 gigawatts) and slightly more renewable capacity are added; however, the higher costs of operating less efficient fossil-fired capacity in the low fossil technology case cause projected electricity prices in 2030 to be 2 percent higher than in the reference case.

Fuel Costs Drop from Recent Highs, Then Increase Gradually

Figure 65. Fuel prices to electricity generators, 1995-2030 (2005 dollars per million Btu)



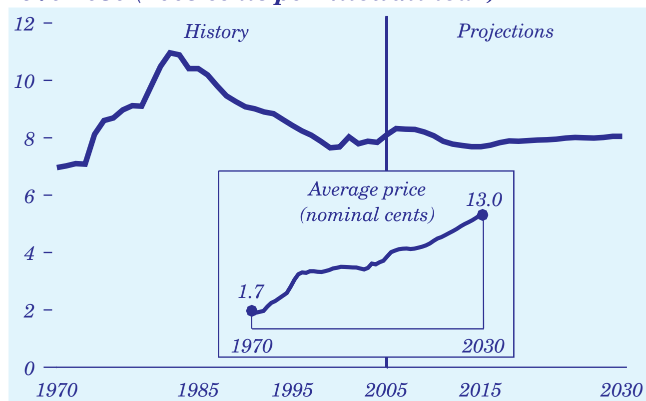
Electricity production costs are a function of fuel, operation and maintenance, and capital costs. In the reference case, fuel costs account for about two-thirds of production costs for new natural-gas-fired plants, less than one-third for new coal-fired units, and about one-tenth for new nuclear power plants in 2030. Generation from natural-gas-fired power plants increased in the early 2000s, but rising natural gas prices have increased their generation costs. After a 34-percent jump from 2004, natural gas prices were $8.18 per million Btu (2005 dollars) in 2005.

In the reference case, the price of natural gas delivered to the electric power sector drops to $5.50 per million Btu in 2013, then rises to $6.33 per million Btu in 2030 (Figure 65). Coal prices to the electric power sector remain relatively low, peaking at $1.71 per million Btu in 2010, falling to $1.69 per million Btu in 2018, and remaining at that level through 2030. Accordingly, the natural gas share of generation (including utilities, independent power producers, and end-use CHP) peaks at 22 percent in 2016, then drops to 16 percent in 2030 as prices rise, while the coal share increases from 50 percent in 2016 to 57 percent in 2030. Nuclear fuel costs rise steadily, to $0.62 per million Btu in 2030.

In the low and high price cases, coal prices to the power sector in 2030 are $1.51 and $1.80 per million Btu, respectively, and natural gas prices are $5.71 and $7.79 per million Btu. As a result, the respective coal and natural gas shares of total generation in 2030 are projected to be 45 percent and 27 percent in the low price case, as compared with 61 percent and 11 percent in the high price case.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 66. Average U.S. retail electricity prices, 1970-2030 (2005 cents per kilowatthour)



In the reference case, retail electricity prices peak at 8.3 cents per kilowatthour (2005 dollars) in 2006, then fall to 7.7 cents per kilowatthour in 2015 as new sources of natural gas and coal are brought on line. After 2013, fossil fuel prices rise slowly but steadily, and retail electricity prices also rise gradually after 2015, to 8.1 cents per kilowatthour in 2030 (Figure 66). Customers in States with competitive retail markets for electricity are expected to see the effects of changes in natural gas prices in their electricity bills more rapidly than those in regulated States, because competitive prices are determined by the marginal cost of energy rather than the average of all plant costs, and natural-gas-fired plants, with their higher operating costs, often set hourly marginal prices.

Electricity distribution costs are projected to decline by 8 percent from 2005 to 2030, as technology improvements and a growing customer base lower the cost of the distribution infrastructure. Transmission costs, on the other hand, increase by 29 percent, because additional investment is needed to meet consumers' growing demand for electricity and to facilitate competition in wholesale energy markets.

Economic expansion increases electricity consumption by businesses, factories, and residents as they buy and use more electrical equipment. Thus, over the long term, the rate of economic growth has a greater effect on the range of electricity prices than do oil and natural gas prices, because power suppliers can substitute coal, nuclear, and renewable fuels for expensive natural gas. In the low and high economic growth cases, electricity prices are 7.8 and 8.4 cents per kilowatthour, respectively, in 2030.