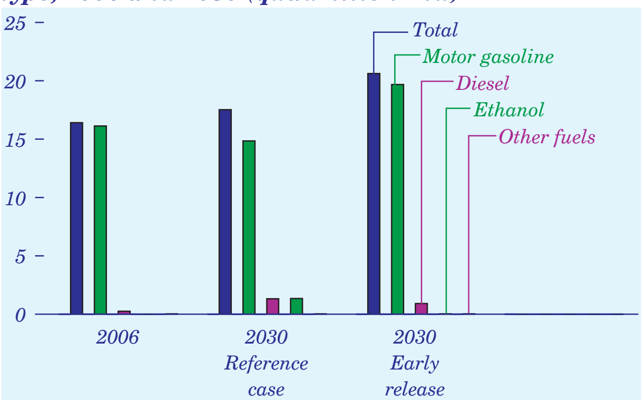
EISA2007 Reduces Light-Duty Vehicle Fuel Use by 3 Quadrillion Btu in 2030

Figure 59. Energy use for light-duty vehicles by fuel type, 2006 and 2030 (quadrillion Btu)



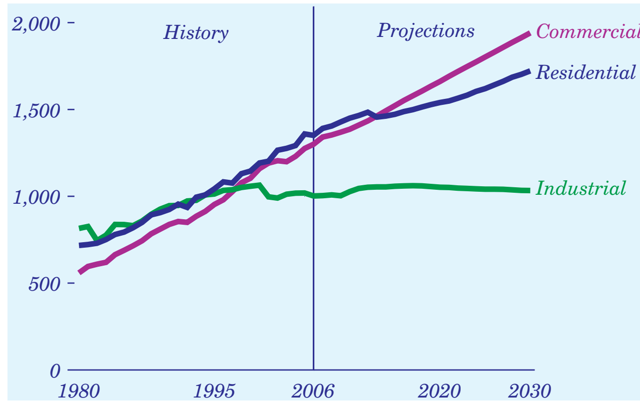
In the reference case, EISA2007 reduces energy consumption for LDVs by more than 3 quadrillion Btu in 2030, from 20.6 quadrillion Btu without EISA2007 to 17.5 quadrillion Btu with the bill (Figure 59). Although total vehicle sales are approximately the same in 2030 with and without EISA2007, higher CAFE standards lead to the savings in energy consumption.

With EISA2007, LDV motor gasoline consumption drops by 4.9 quadrillion Btu in 2030, from 19.7 quadrillion Btu to 14.8 quadrillion Btu. Much of the decline results from switching to unconventional technologies. Diesel fuel consumption in 2030, including biodiesel and BTL diesel, is 1.3 quadrillion Btu, 0.4 quadrillion Btu higher than without EISA2007; and E85 consumption is 1.3 quadrillion Btu in 2030, up from almost zero without EISA2007. The amount of ethanol used in blending is about the same in both cases because of EPA restrictions on ethanol fuel blending.

As a result of EISA2007, the motor gasoline share of fuel use for new LDVs in 2030 declines, and the shares of diesel and ethanol increase. In the reference case, motor gasoline accounts for 84.7 percent of the total, down from 95.4 percent without EISA2007. The diesel fuel share increases to 7.5 percent of total consumption, and the ethanol share increases to 7.7 percent [*82*].

Residential and Commercial Sectors Dominate Electricity Demand Growth

Figure 60. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)

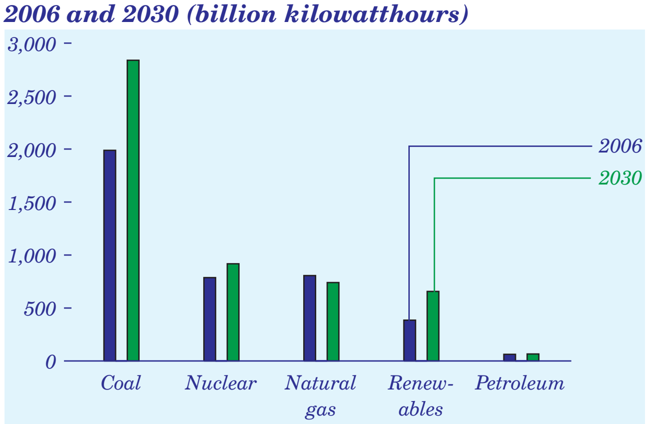


Total electricity sales increase by 29 percent in the *AEO2008* reference case, from 3,659 billion kilowatthours in 2006 to 4,705 billion in 2030, at an average rate of 1.1 percent per year. The relatively slow growth follows the historical trend, with the growth rate slowing in each succeeding decade. Electricity sales, which are strongly affected by economic growth, increase by 39 percent in the high growth case, to 5,089 billion kilowatthours in 2030, but by only 18 percent in the low growth case, to 4,319 billion kilowatthours in 2030. In the reference case, the largest increase is in the commercial sector, at 49 percent from 2006 to 2030 (Figure 60), as service industries continue to drive growth. Electricity demand grows by 27 percent in the residential sector and by only 3 percent in the industrial sector. Growth in population and disposable income leads to increased demand for products, services, and floorspace. Population shifts to warmer regions also increase the need for cooling.

Efficiency gains offset growth in electricity demand, as higher energy prices encourage investment in energy-efficient equipment. In both the residential and commercial sectors, continuing efficiency gains in electric heat pumps, air conditioners, refrigerators, lighting (notably LED lighting), cooking appliances, and computer screens slow the growth of electricity demand. The new standards set in EISA2007 for lighting and other appliances (such as boilers, dehumidifiers, dishwashers, and clothes washers) further dampen electricity demand throughout the projection. Slow growth in industrial production, particularly in the energy-intensive industries, limits electricity demand growth in the industrial sector.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 61. Electricity generation by fuel, 2006 and 2030 (billion kilowatthours)



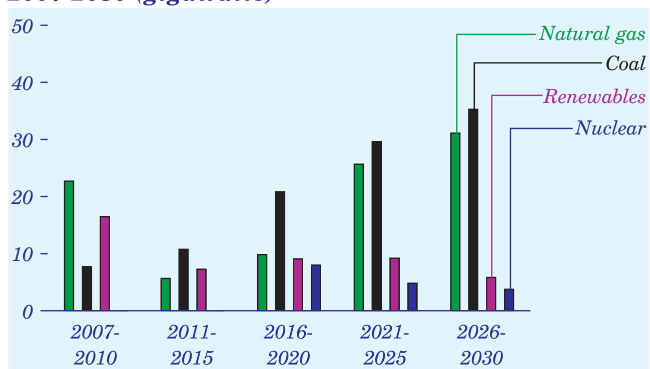
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to be the dominant source of electricity generation through 2030 (Figure 61). Although natural-gas-fired plants with lower capital costs make up most of the capacity additions over the next 10 years, more coal-fired plants are built in the later years as natural gas fuel costs increase. The natural gas share of generation falls from 20 percent in 2006 to 14 percent in 2030, while the coal share increases from 49 percent to 54 percent.

Federal tax incentives, State renewable energy programs, and rising fossil fuel prices lead to increases in renewable and nuclear capacity and generation, as new plants are built. The generation share from renewable capacity increases by 32 percent from 2006 to 2030 and represents 13 percent of total electricity supply in 2030. With capacity additions and improvements in performance at existing nuclear facilities, nuclear generation also increases; however, the nuclear share of total generation falls slightly, from 19 percent in 2006 to 18 percent in 2030.

Technology choices for new plants and utilization of existing capacity are affected by relative fuel costs and changes in environmental policies. For example, natural-gas-fired plants are projected to supply 21 percent of total electricity supply in 2030 in the low price case but only 10 percent in the high price case, but coal-fired plants supply 49 percent of the total in the low price case and 57 percent in the high price case. Changes in environmental policies could also have a significant effect on the fuel shares of total generation.

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

Figure 62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030 (gigawatts)



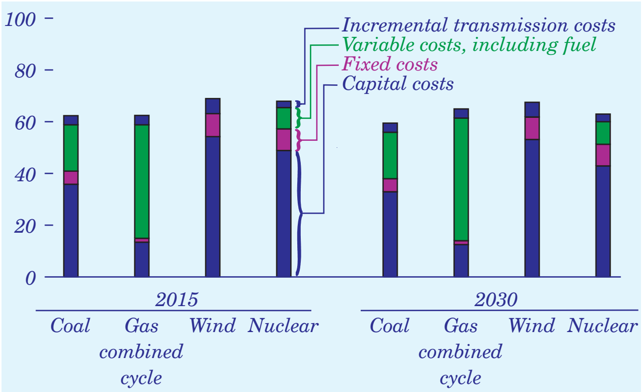
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 45 gigawatts of capacity, 263 gigawatts of new generating capacity (including end-use CHP) will be needed by 2030.

Natural-gas-fired plants generally have lower capacity costs but higher fuel costs than coal-fired plants. As a result, coal-fired plants typically are more economical, and they account for 40 percent of total capacity additions from 2006 to 2030, compared with a 36-percent share for natural gas (Figure 62). Renewable and nuclear plants tend to have high investment costs and relatively low operating costs. EPACT2005 and State RPS programs are expected to stimulate generation from renewable and nuclear plants, which represent 18 percent and 6 percent of total additions, respectively.

The quantity and mix of capacity additions can also be affected by different fuel price paths or growth rates for electricity demand. Because fuel costs are a larger share of total expenditures for new natural-gas-fired capacity, the higher fuel costs in the high price case lead to more coal-fired additions. In the economic growth cases, capacity additions range from 182 gigawatts in the low growth case to 349 gigawatts in the high growth case, although the generation shares for different technologies are similar in the two cases.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 63. Levelized electricity costs for new plants, 2015 and 2030 (2006 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 63) [*83*]. The *AEO2008* reference case assumes a capital recovery period of 20 years, with the cost of capital based on competitive market rates.

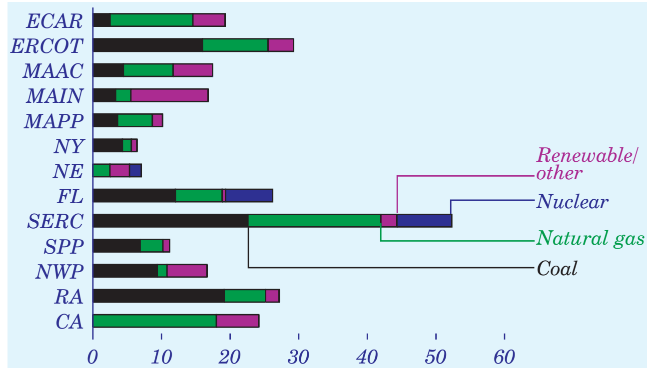
Real capital costs decline over time (Table 6) at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, 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 2025, with heat rates for advanced combined cycle and coal gasification units declining from 6,752 and 8,765 Btu per kilowatthour in 2006 to 6,333 and 7,450 Btu per kilowatthour, respectively, in 2025.

Table 6. Costs of producing electricity from new plants, 2015 and 2030

	2015		2030	
Costs	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2006 mills per kilowatthour			
Capital	35.83	13.44	32.91	12.50
Fixed	5.05	1.49	5.05	1.49
Variable	17.93	43.87	17.94	47.41
Incremental transmission	3.50	3.62	3.54	3.54
Total	**62.31**	**62.42**	**59.44**	**64.94**

Largest Capacity Additions Expected in the Southeast and the West

Figure 64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030 (gigawatts)



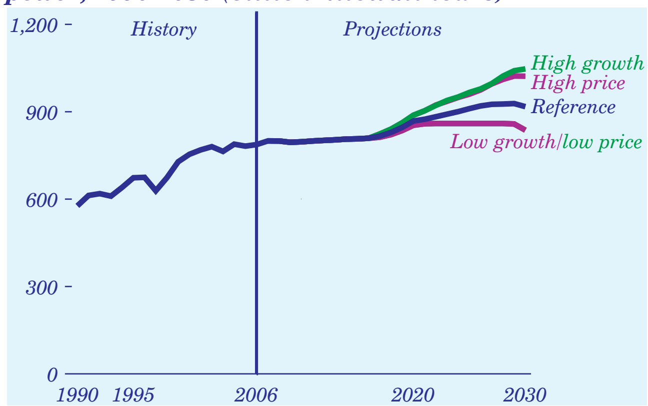
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030. The largest amount of new capacity is expected in the Southeast (FL and SERC), which represents a relatively large and growing share of total U.S. electricity sales and thus requires more capacity than other regions (Figure 64). The growth in demand for electricity in the Southeast is well above the national average.

With natural gas prices rising in the reference case, coal-fired plants account for the largest share of capacity additions through 2030, given the assumption that current environmental policies are maintained indefinitely. The largest concentration of new coal-fired capacity is in the Southeast, where new coal-fired plants are built to accommodate growth in the electricity market and the corresponding need for additional capacity.

Natural gas, renewable, and nuclear plants represent the remaining capacity additions. Natural-gas-fired plants are built to maintain a diverse capacity mix, to serve as reserve capacity, or to meet environmental regulations. About three-fourths of the additions are located in the Southeast, the West (NWP, RA, and CA), and the Midwest (ECAR, MAIN, and MAPP). Renewable capacity is also needed because of State and Federal renewable energy policies, and the Midwest accounts for the largest share of renewable capacity additions. Most nuclear additions are expected in the Southeast, where suppliers have expressed interest in building new nuclear plants.

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 65. Electricity generation from nuclear power, 1990-2030 (billion kilowatthours)

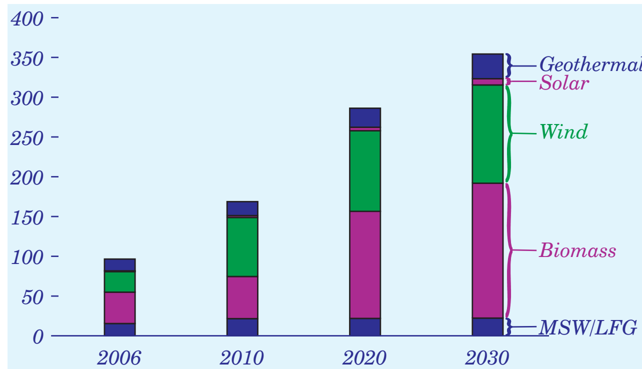


In the *AEO2008* reference case, nuclear capacity grows from 100.2 gigawatts in 2006 to 114.9 gigawatts in 2030, including 2.7 gigawatts of expansion at existing plants, 16.6 gigawatts of new capacity, and 4.5 gigawatts of retirements. EPACT2005 provides an 8-year PTC of 1.8 cents per kilowatthour for up to 6 gigawatts of new nuclear capacity built before 2021. The credit also can be shared for additional capacity but at a lower credit value. The reference case projects 8.0 gigawatts of new nuclear capacity (which will receive the tax credits) by 2020. Early builds are expected to bring down the cost of nuclear capacity and, when combined with rising fossil fuel costs, to result in additional nuclear builds after 2020. All uprates approved, pending, or expected by the NRC at existing units are assumed to 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. Seven units, totaling 4.5 gigawatts, are projected to be retired after 2028, when the end 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. In the five main *AEO2008* cases, nuclear generation grows from 787 billion kilowatthours in 2006 to between 837 and 1,047 billion kilowatthours in 2030 (Figure 65). In the low price case, the delivered price of natural gas in 2030 is 15 percent lower than in the reference case, and new nuclear plants become less economical. In the high price and high growth cases, respectively, 30 and 33 gigawatts of new nuclear capacity are projected, because more capacity is needed and the cost of alternatives is higher.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030 (billion kilowatthours)

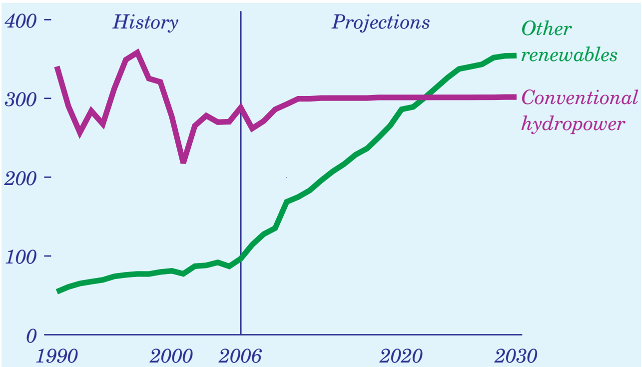


There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC, which is expected to expire at the end of 2008. In the *AEO2008* reference case, generation from wind power increases from 0.6 percent of total generation in 2006 to 2.4 percent in 2030 (Figure 66). Biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2006 (1.0 percent of the total) to 170 billion kilowatthours (3.2 percent). Generation from geothermal facilities also grows, but at a slower rate, increasing from 0.4 percent of total generation in 2006 to 0.6 percent in 2030. Current assessments show limited potential for expansion at conventional geothermal sites.

For consistency in reporting, nonbiogenic municipal solid waste (MSW) is separated from renewable generation. Nonrenewable materials, such as plastics, have made up an increasing proportion of MSW, and 44 percent of the energy value of MSW in 2005 was from nonbiogenic sources; in the *AEO2008* reference case, that share is held constant over the projection period. (All growth in generation from MSW and landfill gas facilities is attributed to landfill gas only.) 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 [*84*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 67. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

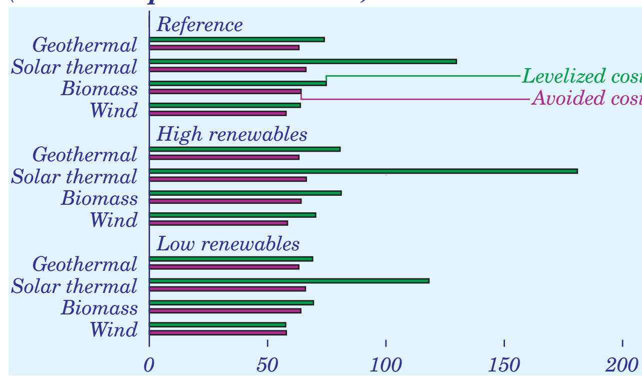


With State RPS programs included in the reference case, renewable electricity generation grows by more than 270 billion kilowatthours. In 2030, total renewable generation is 656 billion kilowatthours or 12.5 percent of total domestic power production. Although conventional hydropower remains the largest source of renewable generation through 2030 (Figure 67), environmental concerns and the scarcity of untapped large-scale sites limit its growth, and its share of total generation falls from 7.1 percent in 2006 to 5.8 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, bolstered by legislatively mandated State RPS programs, technology advances and State and Federal supports, although the Federal PTC is assumed to expire at the end of 2008 per existing law. The share of nonhydropower renewable generation increases from 2.4 percent of total generation in 2006 to 6.8 percent in 2030.

Wind is the largest source of renewable generation among the nonhydropower renewable fuels, with 124 billion kilowatthours of generation in 2030, up from 26 billion kilowatthours in 2006. Initially helped by the Federal PTC, its growth continues as States meet their RPS requirements. Biomass also grows strongly, as generation from both dedicated facilities and co-firing applications increases to 83 billion kilowatthours in 2030, with an additional 87 billion kilowatthours generated in end-use systems. In the near term, market penetration by the unproven biomass gasification technology is slow, while co-firing expands more rapidly. The strong growth in end-use generation is led by the renewable fuels mandate. Facilities producing BTL fuels also use the feedstocks for electricity production.

Renewables Are Expected To Become More Competitive Over Time

Figure 68. Levelized and avoided costs for new renewable plants in the Northwest, 2030 (2006 mills per kilowatthour)

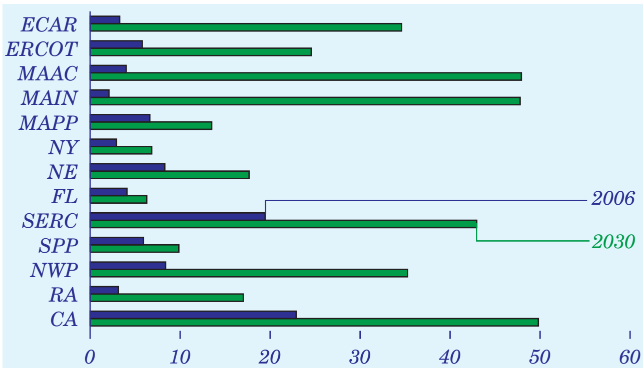


The projected cost of renewable generation in *AEO2008* is significantly higher than projected in previous *AEO*s, primarily as a result of increases in the installation cost of new generating capacity observed throughout the electric power industry. Broad indexes of utility construction costs suggest increases of approximately 15 percent over previous EIA estimates. Available data for specific renewable capacity markets, such as wind power, confirm both the direction and general magnitude of the cost increases when applied more narrowly to renewable generation. For *AEO2008*, the cost increases are applied to all power-sector installations, and they are expected to be persistent rather than short-term cost spikes. In general, renewable generation is expected to remain more expensive than the generation it would displace, that is, its avoided cost (Figure 68).

In addition to the increase in capital costs, EIA reassessed the cost and performance of dedicated biomass generation technology. According to an independent expert review, previous EIA estimates for biomass gasification technology understated its cost even before the industry-wide increase in capital costs. Although higher installation costs make biomass more expensive, significant growth in dedicated biomass capacity is expected in regions with stringent RPS requirements and limited supplies of lower cost resources, such as wind. In the near term, growth in renewable generation in those regions is met largely by biomass co-firing in existing coal plants—an option with relatively low capital costs. The higher efficiency of dedicated plants makes them increasingly attractive, however, as biomass fuels with higher energy value are used to meet RPS mandates.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 69. Regional growth in nonhydroelectric renewable electricity generation, 2006-2030 (billion kilowatthours)

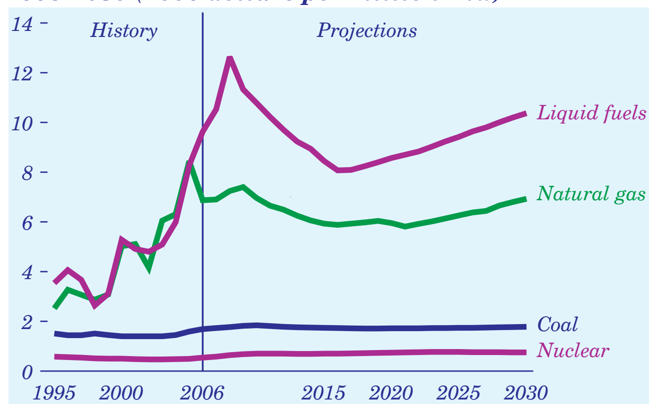


In October 2007, 25 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs were modeled in the *AEO2008* reference case [*85*], but States with voluntary goals were assumed not to have any impact on the national energy mix. Because NEMS does not provide projections at the State level, the reference case assumes that all States will reach their goals within each program's legislative framework, and the results are 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 limits to authorized funding for its RPS program.

In the reference case, wind capacity grows much more rapidly than projected in previous *AEO*s, to 40 gigawatts in 2030 [*86*]. Much of the qualifying capacity in the Midwest, Northeast, Southwest, and Pacific Northwest is expected to consist of wind farms. In one midwestern region (MAIN), 11 gigawatts of wind turbine capacity is projected to be on line in 2030, as compared with 220 megawatts in 2006. In the Mid-Atlantic region, State RPS programs are the driving force behind additional dedicated biomass gasification plants. Approximately 3 gigawatts of new capacity, along with co-firing, provides 37 billion kilowatthours of generation annually. Most of the new biomass capacity is projected to come on line in the Mid-Atlantic region from 2006 to 2030 (Figure 69). While the growth in wind capacity is the most dramatic, biomass co-firing and geothermal power plants also contribute to the baseload generation needed to satisfy State RPS requirements.

Fuel Costs Drop from Recent Highs, Then Increase Gradually

Figure 70. Fuel prices to electricity generators, 1995-2030 (2006 dollars per million Btu)



Fuel costs account for about two-thirds of the generating costs of new natural-gas-fired plants, less than one-third for new coal-fired plants, and less than one-tenth for new nuclear power plants in 2030. For many renewable fuels, such as wind and solar, fuel is free. Capital and operations and maintenance expenses make up the balance of the costs. As a result, natural-gas-fired generation tends to be the most sensitive—and wind and solar the least sensitive—to changes in fuel costs.

In the reference case, prices for fossil fuels delivered to electricity generators peak between 2005 and 2010, as the result of a boom in U.S. and foreign demand, combined with constraints on supply growth and political instability in oil- and gas-producing nations. Fossil fuel prices fall in the middle years of the projection, however, as new supplies come on line to meet growing demand. Prices then increase steadily as demand once again starts to outpace supply (Figure 70). Nuclear and biomass fuel prices rise gradually throughout the projection, as a result of worldwide growth in the demand for nuclear fuel and depletion of local biomass stocks.

Electricity generation from relatively low-cost, low-polluting, natural-gas-fired plants increased significantly in the early years of this decade. More recently, higher costs and increasing volatility of supply and prices have characterized natural gas markets. Consequently, in the reference case, the natural gas share of total electricity generation drops after 2016, and both coal-fired and renewable generation increase.