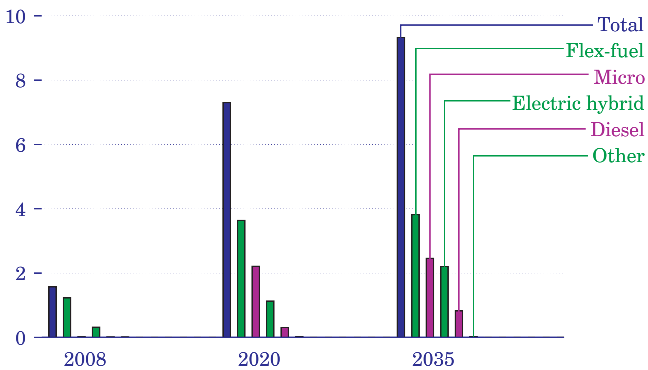
## Unconventional vehicle technologies approach 50 percent of sales in 2035

**Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2008, 2020, and 2035 (million vehicles sold)**



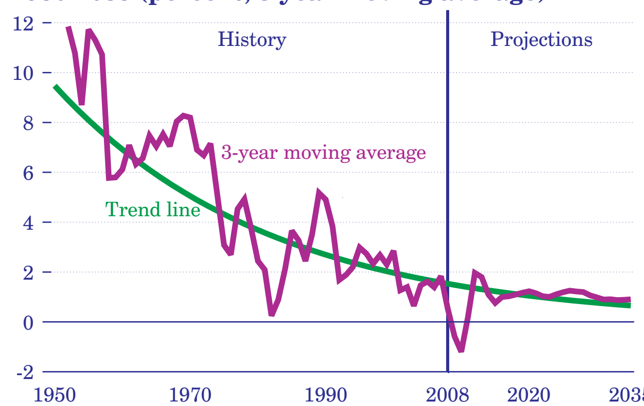

With more stringent CAFE standards and higher fuel prices, unconventional vehicles (vehicles that use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies) account for nearly 50 percent of new LDV sales in 2035 in the Reference case. Unconventional vehicle technologies play a significant role in meeting the new NHTSA CAFE standards for LDVs.

FFVs represent 41 percent of unconventional LDV sales in 2035 (Figure 58), the largest share among unconventional vehicle types. Manufacturers currently receive incentives for selling FFVs, through fuel economy credits that count toward CAFE compliance. However, due to limitations on gasoline blending, FFVs will also play a critical role in meeting the RFS mandate for biofuels. Although these credits are phased out by 2020, FFVs make up more than 20 percent of all new LDV sales in 2035, in part because of their increased availability.

Four types of hybrid vehicle are expected to be available for sale by 2035: standard gasoline-electric or diesel-electric hybrid (HEV), plug-in hybrid with an all-electric range of 10 miles (PHEV-10), plug-in hybrid with an all-electric range of 40 miles (PHEV-40), and micro hybrid (MHEV). MHEVs, in which the gasoline engine is turned off only when switching to battery power when the vehicle is idling, represent 53 percent of hybrid LDV sales and 13 percent of new LDV sales in 2035. HEVs have the second-largest share, at 37 percent of hybrid LDV sales. PHEV-10s make up 9 percent and PHEV-40s make up 2 percent of all hybrid LDV sales in 2035 in the Reference case, or about 500,000 PHEVS in total.

## Residential and commercial sectors dominate electricity demand growth

**Figure 59. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)**



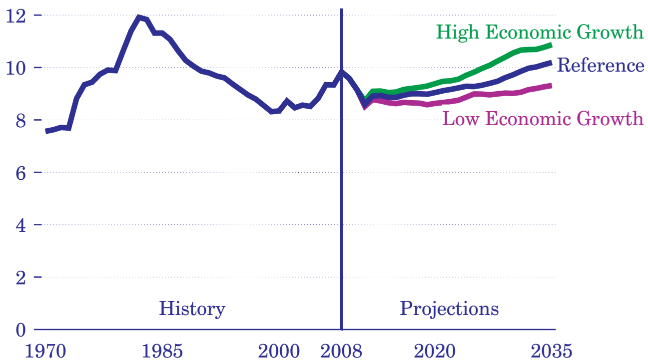

Electricity demand increases in response to population growth and economic growth and fluctuates in the short term in response to business cycles and weather trends. Over the long term, electricity demand growth has slowed progressively in each decade since the 1950s. After growing by 9.8 percent per year in the 1950s, electricity demand (including retail sales and direct use) increased by 2.4 percent per year in the 1990s, and from 2000 to 2008 it grew on average by 0.9 percent per year. The slower growth continues in the *AEO2010* Reference case, as increased demand for electricity services is offset by efficiency gains from new appliance efficiency standards and investment in energy-efficient equipment.

Total electricity demand increases by 30 percent in the Reference case (an average of 1.0 percent per year), from 3,873 billion kilowatthours in 2008 to 5,021 billion kilowatthours in 2035 (Figure 59). The largest percentage increase is in the commercial sector (42 percent), with the service industries continuing to lead the growth. Residential electricity demand increases by 24 percent, due to growth in population and disposable income and continued population shifts to warmer regions with greater cooling requirements. Total industrial electricity demand grows by only 3 percent from 2008 to 2035, as a result of efficiency gains and slow growth in industrial production, particularly in the energy-intensive industries.

In the transportation sector, penetration of PHEVs by 2035 is not sufficient to reverse the slowing trend in electricity demand growth, because for every 1 million PHEV-40 vehicles added, U.S. electricity demand increases by only about 0.1 percent.

## Electricity prices moderate in the near term, then rise gradually

**Figure 60. Average annual U.S. retail electricity prices in three cases, 1970-2035 (2008 cents per kilowatthour)**



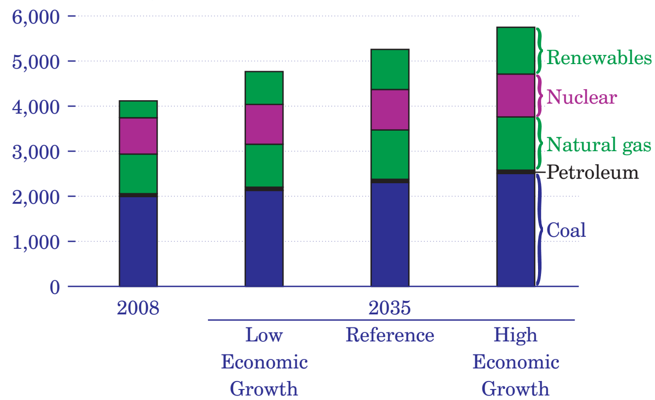

Real electricity prices vary, depending on the economy, fuel prices, regulations, competition in wholesale and retail markets, and costs of new generation. In the *AEO2010* Reference case, average annual electricity prices fall from 9.8 cents per kilowatthour (2008 dollars) in 2008 to 8.6 cents per kilowatthour in 2011 because of a drop in fossil fuel prices and lower demand that coincides with the startup of new renewable, natural gas, and coal-fired capacity. After 2011, prices rise to 10.2 cents per kilowatthour in 2035 (Figure 60) in response to rising fuel prices and the construction of new power plants as demand rises.

Electricity prices are influenced by economic activity. In the High Economic Growth case, electricity prices rise to 10.9 cents per kilowatthour in 2035; in the Low Growth case they rise to only 9.3 cents per kilowatthour.

Electricity prices are based on generation, transmission, and distribution costs. Fuel costs account for most of the generation costs for natural-gas- and oil-fired plants but much less for coal and nuclear plants. There are no fuel costs associated with wind and solar plants. In competitive wholesale markets, natural gas and liquid fuel costs often set hourly prices. With natural-gas-fired generation increasing throughout the Reference case projection, natural gas prices have the greatest impact on electricity prices. Transmission costs rise by 33 percent from 2008 to 2035, as new infrastructure is built but still make up only 9 percent of average electricity prices by the end of the projection period. Distribution costs vary over time and are about the same in 2035 as in 2008.

## Coal-fired power plants provide largest share of electricity supply

**Figure 61. Electricity generation by fuel in three cases, 2008 and 2035 (billion kilowatthours)**



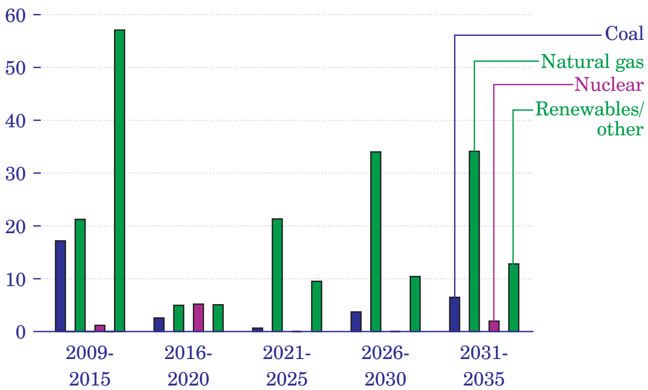

In the Reference case, without GHG regulations, coal accounts for the largest share of total electricity generation (Figure 61). With slow growth in electricity demand, little new coal-fired capacity is added, and the coal share falls from 48 percent in 2008 to 44 percent in 2035. (A 3-percent premium is added to the financing cost for $CO_2$-intensive technologies to reflect the potential for $CO_2$ regulation to reduce the competitiveness of coal with other technologies.)

The natural gas share of generation, at 21 percent in 2008, rose in 2009 when natural gas prices fell. Over the next few years, with slow growth in electricity demand, completion of coal plants under construction, and addition of new renewable capacity, the gas share falls, before trending up to 21 percent in 2035. The near- to mid-term downturn in natural gas generation might be dampened if new policies made coal use for electricity generation less attractive, or if growth in renewable generation were slower than projected. Renewable generation, supported by Federal and State tax incentives and ARRA funding, shows the strongest growth in the Reference case and is 2.4-fold higher in 2035 than in 2008. The renewable share of generation grows from 9 percent in 2008 to 17 percent in 2035. Although generation from nuclear plants increases by 11 percent, their share of total generation falls from 20 percent in 2008 to 17 percent in 2035.

Growth in demand for electricity varies with different assumptions about future economic conditions. In 2035, total generation in the High Economic Growth case is 9 percent above the Reference case projection, and in the Low Economic Growth case it is 9 percent below the Reference case.

## Most new capacity additions use natural gas and renewables

**Figure 62. Electricity generation capacity additions by fuel type, 2009-2035 (gigawatts)**



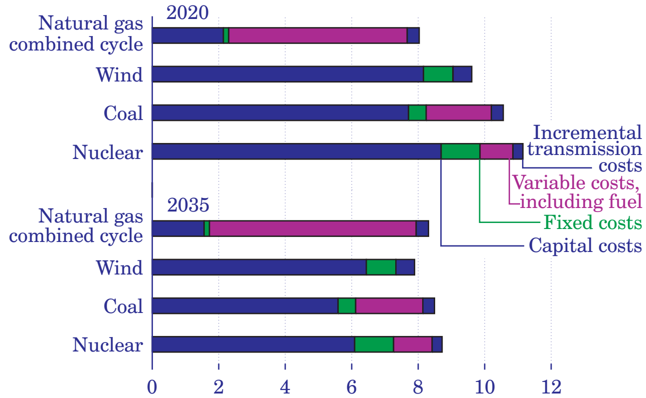

Decisions to add capacity and the choice of fuel type depend on a number of factors [*82*]. With growing electricity demand and the expected retirement of 45 gigawatts of existing capacity, 250 gigawatts of new generating capacity (including end-use CHP) will be needed between 2009 and 2035 (Figure 62).

Natural-gas-fired plants account for 46 percent of capacity additions in the Reference case, as compared with 37 percent for renewables, 12 percent for coal-fired plants, and 3 percent for nuclear. Escalating construction costs have the largest impact on the more capital-intensive generation technologies, including renewables, coal, and nuclear. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations reduces the competitiveness of coal (reflected in the *AEO2010* Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity). The incentives extended and expanded by the ARRA have previously resulted in considerable growth in renewable capacity, and this trend is expected to continue.

Capacity additions also are affected by demand growth and by fuel prices. Capacity additions from 2009 to 2035 range from 158 gigawatts in the Low Economic Growth case to 341 gigawatts in the High Economic Growth case. With higher fuel costs in the *AEO2010* High Oil Price case, fewer natural-gas-fired plants are added, because fuel costs make up a relatively large share of their total expenditures.

## Costs and regulatory uncertainties vary across options for new capacity

**Figure 63. Levelized electricity costs for new power plants, 2020 and 2035 (2008 cents per kilowatthour)**



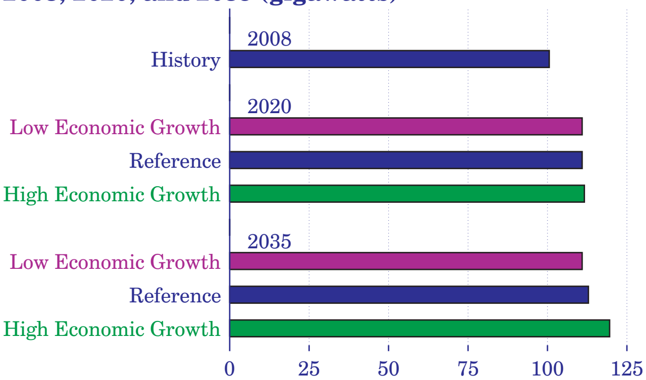

Technology choices for new generating capacity typically are made to minimize costs while meeting local and Federal emissions standards. Capacity expansion decisions consider capital, operating, and transmission costs. Coal-fired, nuclear, and renewable plants are capital-intensive, while operating (fuel) expenditures make up most of the costs for gas-fired capacity (Figure 63) [*83*]. Capital costs depend on such factors as equipment costs, interest rates, and cost-recovery periods. Fuel costs can vary according to fuel prices, plant operating efficiency, resource availability, and transportation costs. Some technologies and fuels also receive subsidies, such as PTCs and ITCs.

Regulatory uncertainty also affects capacity planning decisions. New coal-fired plants could be required to install CCS equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, however, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain experience with a given technology. In the *AEO2010* Reference case, capital costs of new technologies are adjusted upward initially, to reflect the optimism inherent in early estimates of project costs. The costs decline as project developers gain experience, and the decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

## EPACT2005 tax credits stimulate some nuclear builds

**Figure 64. Electricity generating capacity at U.S. nuclear power plants in three cases, 2008, 2020, and 2035 (gigawatts)**



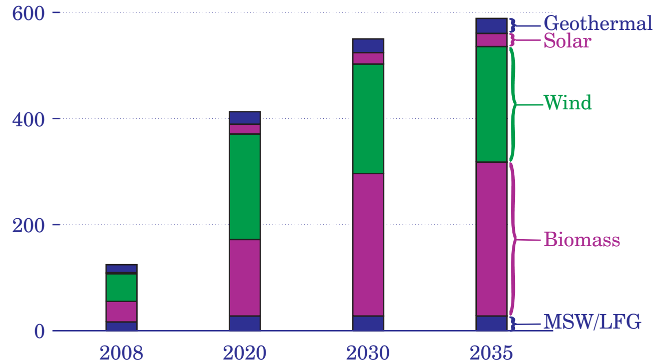

In the *AEO2010* Reference case, nuclear power capacity increases from 100.6 gigawatts in 2008 to 112.9 gigawatts in 2035 (Figure 64), including 4.0 gigawatts of expansion at existing plants and 8.4 gigawatts of new capacity. The Reference case includes a second unit at the Watts Bar site, where construction was halted in 1988 when the plant was partially completed. Estimated costs for new nuclear plants have continued to rise, making new investments in nuclear power uncertain. In the Reference case, only about six new nuclear power plants are completed by 2035.

All existing nuclear units continue to operate through 2035 in the Reference case, which assumes that they will apply for, and receive, operating license renewals, including in some cases a second 20-year extension after they reach 60 years of operation. With costs for natural-gas-fired generation rising and future regulation of GHG emissions uncertain, the economics of keeping existing nuclear power plants in operation are favorable.

Nuclear capacity additions vary with assumptions about overall demand for electricity and the prices of other fuels. The amount of nuclear capacity added also is sensitive to assumptions about future plans and policies for limiting or reducing GHG emissions. Across the Oil Price and Economic Growth cases, nuclear capacity additions from 2008 to 2035 vary from 6 to 15 gigawatts. The first 6 gigawatts of new nuclear capacity is built in all cases, based on tax incentives and loan guarantees. More new nuclear capacity is built in the High Economic Growth and High Oil Price cases, because overall capacity requirements are higher and/or alternatives are more expensive.

## Biomass and wind lead growth in renewable generation

**Figure 65. Nonhydroelectric renewable electricity generation by energy source, 2008-2035 (billion kilowatthours)**

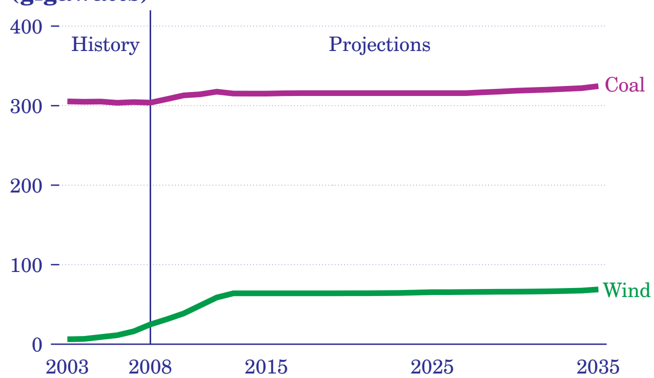



Use of renewable energy resources in the electric power sector increases sharply in the *AEO2010* Reference case (Figure 65). Nonhydroelectric renewable generation accounts for 41 percent of the growth in total electricity generation from 2008 to 2035, supported by extension of Federal tax credits, State requirements for renewable electricity generation, and the loan guarantee program in EPACT2005 and ARRA. Wind power and biomass provide the largest share of the growth. Generation from wind power increases from 1.3 percent of total generation in 2008 to 4.1 percent in 2035. Generation from biomass, both in the electric power sector and from end-use cogeneration, grows from 0.9 percent of total generation in 2008 to 5.5 percent in 2035. A large portion of the increase in biomass generation comes from increased co-firing—a process in which biomass is mixed with coal in existing coal-fired plants, displacing some of the coal that would otherwise be burned.

Renewable electricity generation also grows in the end-use sectors as a result of the EISA2007 RFS, which requires increased use of biofuels produced at biorefineries. At some BTL facilities, synthetic gas from the biomass conversion process is used for electricity generation. As in previous *AEO*s, solar technologies are too costly for widespread use in wholesale power applications, but demonstration programs and State policies support some growth in central-station PV. In addition, State programs, Federal tax rebates, and utility programs encourage small-scale, distributed PV generation applications, which grow rapidly over the projection period.

## Wind power dominates renewable capacity growth in the near term

**Figure 66. Grid-connected coal-fired and wind-powered generating capacity, 2003-2035 (gigawatts)**



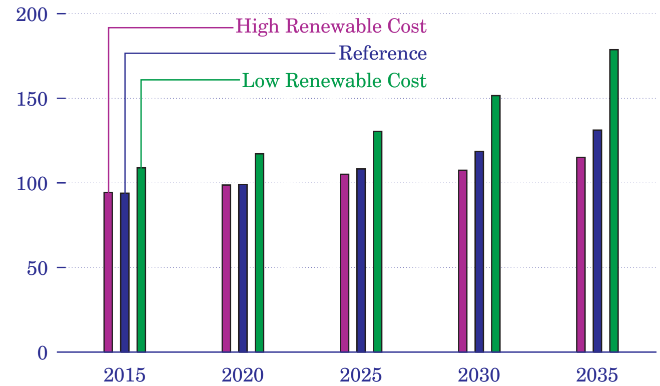

In the *AEO2010* Reference case, renewable capacity—particularly, wind-powered capacity—increases rapidly from 2008 to 2013 in response to the Federal PTC for wind, ARRA funding, and State RPS legislation. Growth in renewable capacity slows dramatically after 2014 because of the expiration of the Federal PTC for wind and the completion of projects expected to be supported by ARRA funding. The growth before 2013 is adequate to meet State RPS-mandated renewable requirements through about 2030; however, renewable capacity begins to grow again after 2030 to meet the State RPS mandates.

Installed wind capacity grew by about 19 gigawatts from 2003 to 2008, a trend that continues in the Reference case with the installation of 39 gigawatts from 2008 to 2013, more than doubling wind capacity in the United States (Figure 66). The near-term growth of other renewable capacity, however, is limited. Geothermal capacity is restricted to a relatively small number of suitable sites; solar capacity remains too costly for widespread implementation; and energy crops do not become economical before 2015. Other biomass resources that could be used for electric power generation are used instead to produce biofuels in order to meet the Federal RFS, leading to a small increase in electricity generation at biorefineries.

With new generation needed in the later years of the projection, State RPS programs lead to the installation of more dedicated renewable capacity. Dedicated biomass capacity increases by nearly 5 gigawatts from 2030 to 2035, largely using biomass feedstocks from energy crops. As a result, co-firing of renewables in coal-fired boilers decreases late in the projection.

## Higher or lower costs affect growth in renewable generation capacity

**Figure 67. Nonhydropower renewable generation capacity in three cases, 2015-2035 (gigawatts)**




Renewable generation grows from a 9-percent share of total electricity production in 2008 to a 17-percent share in 2035 in the Reference case. The increase is supported by Federal tax credits, State RPS programs, and a premium added to the cost of long-lived carbon-intensive technologies, reflecting market behavior with regard to potential carbon regulations.

In the Reference case, capital costs for renewable capacity in 2035 are 20 to 50 percent lower than in 2008. Two additional cases show the effects of technology costs on the use of renewables for generation (Figure 67). In the Low Renewable Cost case, costs for renewable generation technologies in 2035 are 25 percent lower than in the Reference case, but in the High Renewable Cost case they do not change from their 2009 levels. In the Low Renewable Cost case, renewable generation in 2035 totals 1,145 billion kilowatthours, or a 22-percent share of all generation. In the High Renewable Cost case, total renewable generation in 2035 is 786 billion kilowatthours and accounts for 15 percent of generation. Although the costs for renewable generation are higher in the High Renewable Cost case, its growth is still supported by PTCs in the early years of the projection and continued State mandates for renewable electricity in the later years.

With lower costs, geothermal electricity generation in the Low Renewable Cost case is almost 70 percent higher than in the Reference case in 2035, and generation from biomass and wind also show significant increases. In the High Renewable Cost case, wind actually increases from its Reference case value in 2035, reflecting a decrease in biomass combustion at biofuels plants.