AEO2008 Overview

Energy Trends to 2030

In preparing projections for the *Annual Energy Outlook 2008* (*AEO2008*), the Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between today and 2030.[1] This overview focuses on one case, the reference case, which is presented and compared with the *Annual Energy Outlook 2007* (*AEO2007*) reference case (see Table 1). Readers are encouraged to review the full range of alternative cases included in other sections of *AEO2008*.

As in previous editions of the *Annual Energy Outlook* (*AEO*), the reference case assumes that current policies affecting the energy sector remain unchanged throughout the projection period. Some possible policy changes—notably, the adoption of policies to limit or reduce greenhouse gas emissions—could change the reference case projections significantly.[2] EIA has examined many of the proposed greenhouse gas policies at the request of Congress; the reports are available on EIA's web site.[3]

Trends in energy supply and demand are affected by many factors that are difficult to predict, such as energy prices, U.S. and worldwide economic growth, advances in technologies, and future public policy decisions both in the United States and in other countries. As noted in *AEO2007*, energy markets are changing in response to readily observable factors such as the higher energy prices experienced since about 2000, the greater influence of developing countries on worldwide energy requirements, recently enacted legislation and regulations in the United States, and changing public perceptions on issues related to the use of alternative fuels, emissions of air pollutants and greenhouse gases, and the acceptability of various energy technologies, among others.

The *AEO2008* reference case makes several important changes from earlier *AEO*s to better reflect trends that are expected to persist in the economy and energy markets. For example, the projection for U.S. economic growth, a key determinant of U.S. energy demand, has been lowered, reflecting an updated projection of productivity improvement. Key energy market changes identified by EIA analysts and reflected in *AEO2008* include:

- Higher prices for crude oil and natural gas
- Higher delivered energy prices, reflecting both higher wellhead and minemouth prices and higher costs to transport, distribute, and refine fuels per unit supplied
- Slower projected growth in energy demand (particularly for natural gas but also for liquid fuels and coal)
- Faster projected growth in the use of nonhydroelectric renewable energy
- Higher domestic oil production, particularly in the near term
- Slower projected growth in energy imports, both natural gas and liquid fuels
- Slower projected growth in energy-related emissions of carbon dioxide (CO_2), which increase by 25 percent in the *AEO2008* reference case from 2006 to 2030, as compared with a projected 35-percent increase over the same period in the *AEO2007* reference case.

Although the adjustments outlined above are important, their implications for some parts of the overall energy outlook are limited. For example, coal, liquid fuel (excluding biofuels included in liquids), and natural gas meet 83 percent of total U.S. primary energy supply requirements in 2030—down only slightly from an 85-percent share in 2006—despite higher energy prices, lower total energy demand, and increased use of renewable energy when compared with *AEO2007*. With the *AEO2008* reference case assumptions, U.S. energy consumption will continue to be met predominantly by traditional fossil fuels.

Economic Growth

The *AEO2008* reference case reflects reduced expectations for economic growth. In the *AEO2008* reference case, U.S. gross domestic product (GDP) grows at an average annual rate of 2.6 percent from 2006 to 2030—0.3 percentage points slower than the rate in the *AEO2007* reference case over the same period.

[1]The early release version of the *AEO2008* reference case does not include consideration of H.R. 6, the Energy Independence and Security Act of 2007, which was signed into law on December 19, 2007. EIA is compiling a revised reference case that includes the impacts of H.R. 6.

[2]While at least some of the current laws and regulations will change and new ones will be created over the next 25 years, no one knows the specifics of what they will be or when they will be enacted. Consequently, the reference case provides a clear basis against which the impacts of new proposed policies and regulations can be assessed.

[3]See "Responses to Congressional and Other Requests," web site www.eia.doe.gov/oiaf/service_rpts.htm.

The main factor contributing to the slower rate of growth in GDP is a lower estimate of growth in labor productivity. Nonfarm business labor productivity grows by 2.1 percent per year in the *AEO2008* reference case, compared with 2.3 percent per year in *AEO2007*. Nonfarm employment growth is 0.9 percent per year in the *AEO2008* reference case, about the same as in *AEO2007*. From 2006 to 2030, total industrial shipments grow by 1.5 percent per year in the *AEO2008* reference case, as compared with 2.1 percent per year in *AEO2007*.

Energy Prices

EIA has raised the reference case path for world oil prices in *AEO2008* (although the upward adjustment is smaller than the last major adjustment, introduced in *AEO2006*). In developing its current oil price outlook, EIA explicitly considered four factors: (1) expected growth in world liquids consumption; (2) the outlook for conventional oil production in countries outside the Organization of the Petroleum Exporting Countries (non-OPEC producers); (3) growth in unconventional liquids production; and (4) OPEC behavior. Global economic growth has been strong over the past few years, despite high oil prices; and it now appears that, in the mid-term, the cost of non-OPEC conventional oil and unconventional liquids will be higher than previously assumed. As a result, in the *AEO2008* reference case, OPEC and non-OPEC production volumes and total world liquids production are similar to those in the *AEO2007* reference case, but the oil prices are higher.[4]

In the *AEO2008* reference case, real world crude oil prices (defined as the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, in 2006 dollars) decline gradually from current levels to $58 per barrel in 2016 ($70 per barrel in nominal dollars), as expanded investment in exploration and development brings new supplies to the world market. After 2016, real prices begin to rise (Figure 1), as demand continues to grow and higher cost supplies are brought to market. In 2030, the average real price of crude oil is $72 per barrel in 2006 dollars, or about $113 per barrel in nominal dollars. Alternative *AEO2008* cases address higher and lower world crude oil prices.

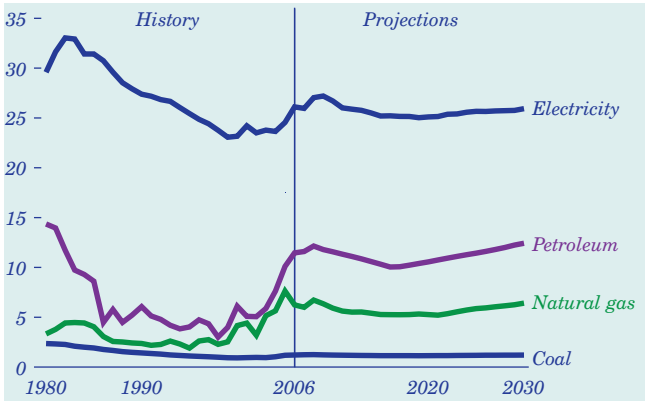
Oil prices currently are above EIA's reference case estimate of the long-run equilibrium price. Temporary shortages of experienced personnel, equipment, and construction materials in the oil industry, political instability in some major producing regions, and recent strong economic growth in major consuming nations have combined to push oil prices well above sustainable levels. Although some analysts believe that current high oil prices signal an unanticipated scarcity of petroleum resources, EIA's expectations regarding the ultimate size of both conventional and unconventional liquid resources have not changed since last year's *AEO*.

This year's reference case anticipates substantial increases in conventional oil production in several OPEC and non-OPEC countries over the next 10 years, as well as substantial development of unconventional production over the next 25 years. The prices in the *AEO2008* reference case are high enough to trigger entry into the market of some alternative energy supplies that are expected to become economically viable in the range of $30 to $60 per barrel (2006 dollars). They include oil sands, ultra-heavy oils, gas-to-liquids, and coal-to-liquids (CTL).

The *AEO2008* reference case represents EIA's current judgment about the most likely behavior of key OPEC members in the mid-term. In the projection, OPEC countries increase production at a rate that keeps their market share of world liquids in the range of 40 to 44 percent through 2030.

The *AEO2008* reference case also projects significant long-term potential for supply from non-OPEC producers. In several resource-rich regions—including Brazil, Azerbaijan, and Kazakhstan—high oil prices, expanded infrastructure, and new exploration and drilling technologies permit additional non-OPEC oil production. Also, with the economic viability of Canada's oil sands enhanced by higher world oil prices and advances in production technology, oil sands

Figure 1. Energy prices, 1980-2030 (2006 dollars per million Btu)



[4]The comparison of production levels was adjusted for the entry of Angola into OPEC in late 2007.

production is expected to reach 4 million barrels per day in 2030.

The price of natural gas also is higher in the *AEO2008* reference case. The real wellhead price of natural gas (in 2006 dollars) declines from current levels through 2017, as new supplies enter the market. After 2017, real natural gas prices rise to $6.60 per thousand cubic feet ($10.40 per thousand cubic feet in nominal dollars) in 2030. The higher prices in the *AEO2008* reference case reflect an increase in production costs associated with recent trends that were discussed in *AEO2007* but were not reflected fully in its reference case. The higher natural gas prices also are supported by higher oil prices.

Minemouth coal prices in the *AEO2008* reference case, both nationally and regionally, are generally similar to those projected in the *AEO2007* reference case. The largest regional price difference relative to the *AEO2007* reference case is in Wyoming's Powder River Basin, where the average minemouth price in 2030 is $0.70 (2006 dollars) per million British thermal units (Btu)—18.0 percent above the price in *AEO2007*—reflecting a less optimistic outlook for improvements in coal mining productivity. Average real minemouth coal prices (in 2006 dollars) fall from $1.21 per million Btu ($24.63 per short ton) in 2006 to $1.15 per million Btu ($22.63 per short ton) in 2020 in the *AEO2008* reference case, as prices moderate following a substantial run-up over the past few years. After 2020, the construction of new coal-fired power plants increases total coal demand, and prices rise to $1.21 per million Btu ($23.45 per short ton) in 2030. The 2020 and 2030 prices are 3.0 percent and 2.2 percent higher, respectively, than those in the *AEO2007* reference case. Without adjustment for inflation, the average minemouth price of coal in the *AEO2008* reference case is $1.90 per million Btu ($36.97 per ton) in 2030.

AEO2008 projects higher energy prices to consumers for most delivered fuels. For example, in 2030, the average delivered price for natural gas (in 2006 dollars) is more than $1 higher in the *AEO2008* reference case than was projected in *AEO2007*. In part, the higher prices are a result of higher prices paid to fossil fuel producers at the wellhead or minemouth; but they also result from updates made to assumptions about the costs to transport, distribute, and refine the fuels to make them more consistent with recent trends. For example, the margins between the delivered and wellhead prices of natural gas are higher than previously projected, as a result of declining use per customer and the cost of bringing supplies from new regions to market. Factors contributing to higher margins for liquid fuels include continued growth in the use of heavier and sourer crudes, growing demand for cleaner products, and the costs of refinery safety and emissions abatement.

Increases in diesel fuel prices in recent years have led railroads to implement fuel adjustment surcharges on coal shipments, which are incorporated in the *AEO2008* reference case. The average real delivered price of coal to power plants (in 2006 dollars) increases from $1.69 per million Btu ($33.85 per short ton) in 2006 to $1.82 per million Btu ($36.02 per short ton) in 2030, 4.6 percent higher than in the *AEO2007* reference case. In nominal dollars, the average delivered price of coal to power plants is projected to reach $2.88 per million Btu ($56.79 per short ton) in 2030.

Electricity prices follow trends in the delivered prices of fuels to power plants in the reference case, rising through 2009 and then declining for the next decade before, again, rising slowly. From a peak of 9.3 cents per kilowatthour (2006 dollars) in 2009, average delivered electricity prices decline to 8.5 cents per kilowatthour in 2019 and then increase to 8.8 cents per kilowatthour in 2030. In the *AEO2007* reference case, with slightly lower expectations for delivered fuel prices and lower construction costs for all new technologies, electricity prices reached 8.3 cents per kilowatthour (2006 dollars) in 2030. In nominal dollars, the average delivered electricity price in the *AEO2008* reference case reaches 13.9 cents per kilowatthour in 2030.

Energy Consumption

Total primary energy consumption in the *AEO2008* reference case increases at an average rate of 0.9 percent per year, from 100.0 quadrillion Btu in 2006 to 123.8 quadrillion Btu in 2030—7.4 quadrillion Btu less than in the *AEO2007* reference case. In 2030, the levels of consumption projected for liquid fuels, natural gas, and coal are all lower in the *AEO2008* reference case than in the *AEO2007* reference case. Among the most important factors resulting in lower total energy demand in the *AEO2008* reference case are lower economic growth, higher energy prices, greater use of more efficient appliances, and slower growth in energy-intensive industries.

As a result of demographic trends and housing preferences, residential delivered energy consumption in the *AEO2008* reference case grows from 11.0 quadrillion Btu in 2006 to 13.3 quadrillion Btu in 2030, or

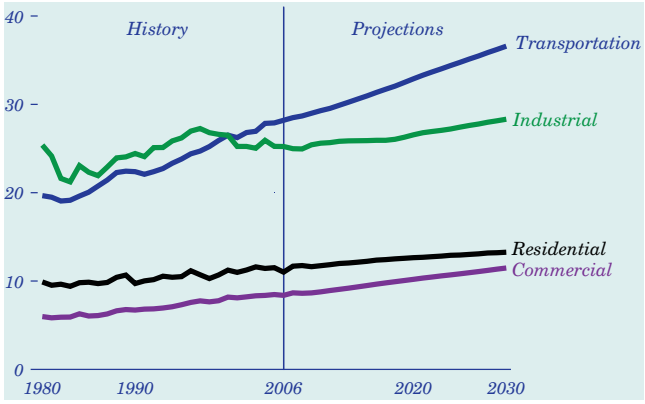
by 0.8 percent per year (Figure 2). Higher delivered energy prices, slower growth in the housing stock, increases in end-use efficiency for most services, and a revised accounting of heating and cooling degree-days to better reflect recent temperature trends contribute to the lower level of residential energy use in the *AEO2008* projection, which is 0.5 quadrillion Btu lower than the *AEO2007* projection.

Higher delivered energy prices and slower growth in commercial square footage lead to slower growth in commercial energy consumption in the *AEO2008* reference case than in the *AEO2007* reference case. Delivered commercial energy consumption grows from 8.4 quadrillion Btu in 2006 to 11.5 quadrillion Btu in 2030, almost 1 quadrillion Btu less than in the *AEO2007* reference case.

Since 1997, delivered energy consumption in the U.S. industrial sector has trended downward, falling from about 27 quadrillion Btu in 1997 to 25 quadrillion Btu in 2006. A number of factors have worked to reduce industrial energy consumption since 1997: economic weakness between 2000 and 2003, the hurricanes of 2005 that reduced activity in some industrial subsectors, and rising energy prices.

Delivered industrial energy consumption in the *AEO2008* reference case reaches 28.3 quadrillion Btu in 2030. The *AEO2008* reference case does not consider events such as hurricanes and includes steady economic growth and declining energy prices in the near term. Expected growth in the energy-intensive industries continues to be weak, however, as they face increased competition from foreign regions with lower relative energy prices. Growth in the energy-intensive manufacturing industries averages 0.8 percent per year from 2006 to 2030, slower than the 1.4-percent average growth in *AEO2007*.

Figure 2. Delivered energy consumption by sector, 1980-2030 (quadrillion Btu)



Total industrial energy consumption in *AEO2008* includes strong growth in nontraditional fuels, such as CTL and biofuels. Approximately 1.3 quadrillion Btu of coal is used to produce liquids in 2030, a practice not yet commercialized in 2006. Energy for biofuels in the industrial sector grows from 0.3 quadrillion Btu in 2006 to 0.8 quadrillion Btu in 2030. Delivered energy consumption in 2030 for industrial uses other than refining of conventional and nontraditional liquid fuels is projected to grow by only 0.2 quadrillion Btu above 2006 levels (21.5 quadrillion Btu in 2030 compared with 21.3 quadrillion Btu in 2006), despite growth in industrial shipments (excluding refining) that averages 1.5 percent per year from 2006 to 2030. The stronger growth in refining energy consumption results from increased production of nontraditional fuels and from the effects on oil refiners' energy use of both a heavier average crude oil slate and responses to emissions regulations.

Delivered energy consumption in the transportation sector grows to 36.6 quadrillion Btu in 2030 in the *AEO2008* reference case, 2.7 quadrillion Btu lower than in *AEO2007*. The lower projected level of consumption predominantly reflects the influence of slower economic growth, but it also reflects higher fuel prices. Travel demand for light-duty vehicles is a significant determinant of total transportation energy demand, and over the past 20 years it has grown at an average rate of 2.6 percent per year. In the *AEO2008* reference case, travel demand is projected to grow by 1.6 percent per year through 2030. The slower rate of growth reflects both demographic factors (for example, a slowdown in growth in labor force participation by women) and higher energy prices.

The projected average fuel economy of new light-duty vehicles in 2030 is 30.0 miles per gallon, or 4.7 miles per gallon higher than the current average. Projected increases in new vehicle fuel economy reflect the existing Federal corporate average fuel economy (CAFE) standards for light trucks as well as market-driven increases in the sale of unconventional vehicle technologies,[5] such as flex-fuel, hybrid, and diesel vehicles, and a slowdown in the growth of new light truck sales. The substantial revisions to Federal

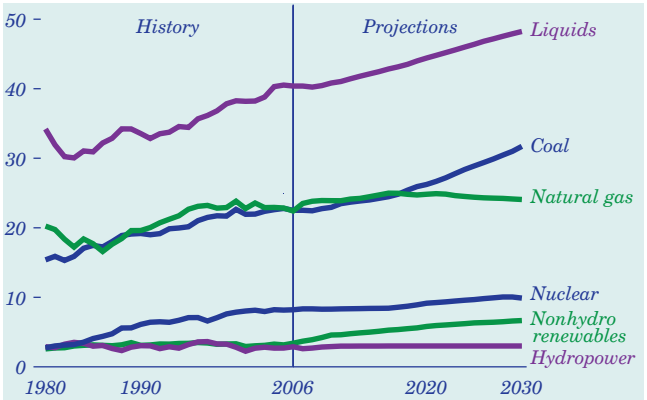
[5]Vehicles that can use alternative fuels or employ electric motors and advanced electricity storage, advanced engine controls, or other new technologies.

CAFE standards that are under consideration in the 110th Congress are not reflected in the *AEO2008* reference case.

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,821 billion kilowatthours in 2006 to 5,149 billion kilowatthours in 2030, increasing at an average annual rate of 1.3 percent in the *AEO2008* reference case. In comparison, the *AEO2007* reference case projected faster growth, averaging 1.5 percent per year, with total electricity consumption increasing to 5,478 billion kilowatthours in 2030. The reduced rate of growth in *AEO2008* results from slower economic growth and higher electricity prices.

The projection for natural gas consumption in the *AEO2008* reference case is sharply lower than in *AEO2007*. In *AEO2008*, natural gas consumption increases from 21.8 trillion cubic feet in 2006 to 24.3 trillion cubic feet in 2016, then declines to 23.4 trillion cubic in 2030 (Figure 3). Consumption is lower in all sectors, and particularly in the industrial and electricity power sectors. Industrial natural gas use is 1.3 trillion cubic feet lower in 2030 in the *AEO2008* reference case (8.5 trillion cubic feet compared with 9.8 trillion cubic feet in the *AEO2007* reference case) as a result of higher delivered natural gas prices, lower economic growth, and a reassessment of natural gas use in the energy-intensive industries. In 2030, electricity generation accounts for 5.1 trillion cubic feet of natural gas use in *AEO2008*, compared with 5.9 trillion cubic feet in *AEO2007*. The lower level of consumption in *AEO2008* results from higher natural gas prices and slower growth in electricity demand.

Figure 3. Energy consumption by fuel, 1980-2030 (quadrillion Btu)



Total coal consumption increases from 22.5 quadrillion Btu (1,114 million short tons) in 2006 to 31.7 quadrillion Btu (1,682 million short tons) in 2030 in the *AEO2008* reference case. As in the *AEO2007* reference case, coal consumption is projected to grow at a faster rate toward the end of the projection period, particularly after 2020, as coal use for new coal-fired generating capacity and for CTL production grows rapidly. In the *AEO2008* reference case, coal consumption in the electric power sector increases from 24.0 quadrillion Btu in 2020 to 28.5 quadrillion Btu in 2030, and coal use at CTL plants increases from 0.4 quadrillion Btu in 2020 to 1.3 quadrillion Btu in 2030.

Total consumption of liquid fuels grows from 20.7 million barrels per day in 2006 to 24.9 million barrels per day in 2030 in the *AEO2008* reference case (Figure 3), less than the *AEO2007* reference case projection of 26.9 million barrels per day in 2030. Liquid fuels consumption is lower in all sectors in *AEO2008* than in the *AEO2007* reference case, as a result of higher delivered prices for liquids and slower economic growth. Much of the difference is in the transportation sector.

The *AEO2008* reference case projects substantially greater use of renewable energy than was projected in *AEO2007*. Total consumption of marketed renewable fuels in the *AEO2008* reference case (including ethanol for gasoline blending, of which 1.4 quadrillion Btu is included with liquid fuels consumption in 2030) grows from 6.8 quadrillion Btu in 2006 to 12.2 quadrillion Btu in 2030.

Excluding hydroelectric power, renewable energy consumption grows from 3.4 quadrillion Btu in 2006 to 6.7 quadrillion Btu in 2030, compared with 5.5 quadrillion Btu in 2030 in the *AEO2007* reference case. The higher level of nonhydroelectric renewable energy consumption is partially a result of the higher energy prices in the *AEO2008* reference case. It also reflects a revised representation of State renewable portfolio standard (RPS) programs, which require that specific and generally increasing shares of electricity sales be supplied by renewable resources, such as wind, solar, geothermal, and sometimes biomass or hydropower. In previous *AEO*s, greater weight was placed on the "escape clauses" incorporated in many State RPS programs and on the fact that the costs of the programs to consumers would increase significantly if the Federal production tax credit (PTC) for qualifying renewable energy expired as provided

under current law. The updated representation of State RPS programs results in significant additional growth of renewable generation from wind, biomass, and geothermal resources.

The *AEO2008* reference case includes 17 billion gallons of ethanol consumption in 2030, 16 percent more than in the *AEO2007* reference case. With corn and biofeedstock supplies increasing, and with price advantages over other motor gasoline blending components, ethanol consumption grows from 5.6 billion gallons in 2006 to 13.5 billion gallons in 2012 in the *AEO2008* reference case—far exceeding the requirement for 7.5 billion gallons in 2012 in the Renewable Fuel Standard that was enacted as part of the Energy Policy Act of 2005 (EPACT2005). Gasoline blending accounts for nearly all the projected consumption of ethanol.

Ethanol supply in *AEO2008* is dominated by domestic corn-based production, particularly in the near term, as a result of its cost advantages and eligibility for tax credits. Domestic ethanol production slows in the mid- to long term with expiration of the ethanol tax credit in December 2010. The *AEO2008* reference case also expects strong growth in ethanol imports after 2010, reflecting the pending expiration of the tariff on imported ethanol in January 2009.

Electricity Generation

U.S. electricity consumption—including both purchases from electric power producers and on-site generation—increases steadily in the *AEO2008* reference case, at an average rate of 1.3 percent per year. In comparison, electricity consumption grew by annual rates of 4.2 percent, 2.6 percent, and 2.3 percent in the 1970s, 1980s, and 1990s, respectively. The growth rate in the *AEO2008* projection is lower than in the *AEO2007* reference case (1.5 percent per year), and it leads to lower projections of electricity generation.

In the *AEO2008* reference case, electricity generation from natural-gas-fired power plants increases sharply from 2006 to 2007 then remains relatively flat for the next 5 years, before rising slowly through 2016. Coal-fired generation increases less rapidly than in the *AEO2007* reference case. After 2016, however, generation from new coal, nuclear, and renewable plants displaces some natural-gas-fired generation (Figure 4). In the *AEO2008* reference case, 756 billion kilowatthours of electricity is generated from natural gas in 2030, 19 percent less than the 937 billion kilowatthours in 2030 in the *AEO2007* reference case.

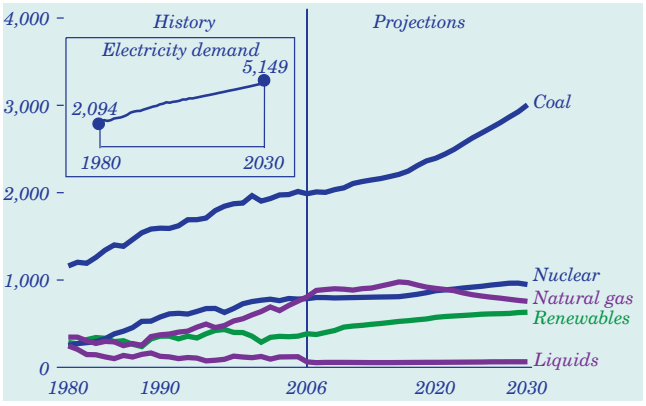
In the *AEO2008* reference case, the natural gas share of electricity generation (including generation in the end-use sectors) remains between 20 percent and 21 percent through 2018, before falling to 14 percent in 2030. The coal share declines slightly, from 49 percent in 2006 to 48 percent in 2017, before increasing to 55 percent in 2030. Additions to coal-fired generating capacity in the *AEO2008* reference case total 130 gigawatts from 2006 to 2030 (as compared with 156 gigawatts in the *AEO2007* reference case), including 9 gigawatts at CTL plants and 45 gigawatts at integrated gasification combined-cycle plants. Given the assumed continuation of current energy and environmental policies in the reference case, carbon capture and sequestration (CCS) technology does not come into use during the projection period.

Nuclear generating capacity in the *AEO2008* reference case increases from 100.2 gigawatts in 2006 to 118.8 gigawatts in 2030. The increase includes 20 gigawatts of capacity at newly built nuclear power plants (63 percent more than in the *AEO2007* reference case) and 2.7 gigawatts expected from uprates of existing plants, partially offset by 4.5 gigawatts of retirements.

Rules issued by the Internal Revenue Service in 2006 for the EPACT2005 production tax credit for new nuclear plants allow the credits to be shared out on a prorated basis to more than 6 gigawatts of new capacity. In the *AEO2008* reference case, the credits are shared out to 9 gigawatts of new nuclear capacity, and 11 additional gigawatts of capacity is built without credits.

Total electricity generation from nuclear power plants grows from 787 billion kilowatthours in 2006 to 949 billion kilowatthours in 2030 in the *AEO2008*

Figure 4. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



reference case, accounting for about 17 percent of total generation in 2030. Additional nuclear capacity is built in some of the alternative *AEO2008* cases, particularly those that project higher demand for electricity or even higher fossil fuel prices.

The use of renewable technologies for electricity generation is stimulated by improved technology, higher fossil fuel prices, and extension of the tax credits in EPACT2005. The reference case also includes State RPS programs where the legislation is in place. Total renewable generation in the *AEO2008* reference case, including combined heat and power (CHP) and end-use generation, grows by 2.1 percent per year, from 385 billion kilowatthours in 2006 to 631 billion kilowatthours in 2030. The projection for renewable generation in the *AEO2008* reference case, which includes State and regional programs, is significantly higher than the comparable *AEO2007* projection.

In 2030, emissions of sulfur dioxide from electric power plants are projected to be 63 percent lower, emissions of nitrogen oxides 37 percent lower, and emissions of mercury 71 percent lower in the *AEO2008* reference case than their 2006 levels. The reductions are about the same as projected in *AEO2007*.

Energy Production and Imports

Net imports of energy are expected to continue to meet a major share of total U.S. energy demand (Figure 5). In the *AEO2008* reference case, the net import share of total U.S. energy consumption in 2030 is 29 percent, slightly less than the 30-percent share in 2006. Rising fuel prices over the projection period are expected to spur increases in domestic energy production (Figure 6) and to moderate the growth in demand, tempering the projected growth in imports.

The projection for U.S. crude oil production in the *AEO2008* reference case is higher than in the *AEO2007* reference case, primarily due to more production from the expansion of enhanced oil recovery (EOR) operations and, to a lesser extent, higher crude oil prices. U.S. crude oil production in the *AEO2008* reference case increases from 5.1 million barrels per day in 2006 to a peak of 6.4 million barrels per day in 2019, with production increases from the deep waters of the Gulf of Mexico and from onshore EOR projects. Domestic production subsequently declines to 5.6 million barrels per day in 2030, as increased production from new smaller discoveries are inadequate to offset the declines in large fields in Alaska and the Gulf of Mexico.

Total domestic liquids supply, including crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs (e.g., ethanol), generally increases throughout the *AEO2008* reference case, as growth in CTL production offsets the decline in crude oil production after 2019. Total domestic liquids supply grows from 8.2 million barrels per day in 2006 to 10.2 million barrels per day in 2030.

In the *AEO2008* reference case, the net import share of total liquids supplied, including crude oil and refined products, drops from 60 percent in 2006 to 55 percent in 2010, stays relatively stable through 2020, and then increases to 59 percent in 2030. Net crude oil imports in 2030 are 1.3 million barrels per day lower, and net product imports are 0.3 million barrels per day lower, in the *AEO2008* reference case than in the *AEO2007* reference case. The primary reason for the difference between the *AEO2008* and *AEO2007* projections for net imports of liquid fuels is the lower level of total liquids consumption in 2030 in the *AEO2008* reference case.

Figure 5. Total energy production and consumption, 1980-2030 (quadrillion Btu)

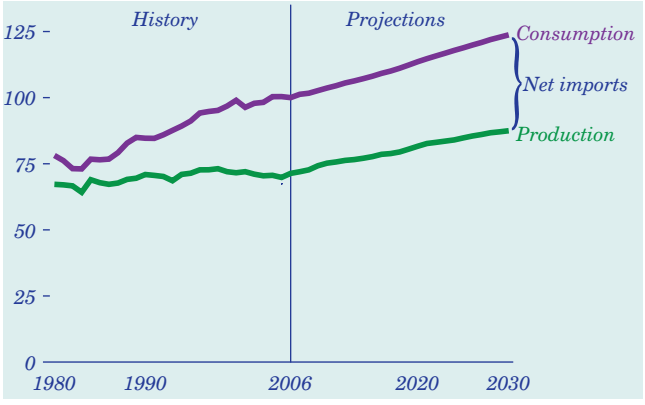
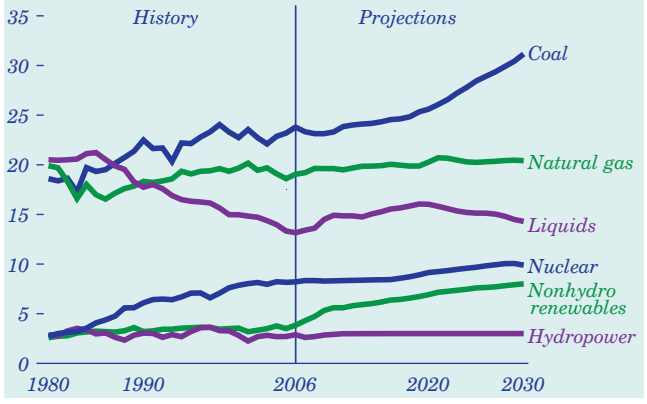


Figure 6. Energy production by fuel, 1980-2030 (quadrillion Btu)



Total domestic natural gas production, including supplemental natural gas supplies, increases from 18.6 trillion cubic feet in 2006 to 20.2 trillion cubic feet in 2021 before declining to 19.9 trillion cubic feet in 2030 in the *AEO2008* reference case. The projections are lower than in the *AEO2007* reference case, primarily because of the higher costs associated with exploration and development and, particularly in the last decade of the projection, lower demand for natural gas.

In the *AEO2008* reference case, lower 48 offshore natural gas production shows a pattern similar to that in the *AEO2007* reference case, growing from 3.0 trillion cubic feet in 2006 to a peak of 4.5 trillion cubic feet in 2019 as new resources come online in the Gulf of Mexico. After 2019, lower 48 offshore production declines to 3.5 trillion cubic feet in 2030. After a small near-term increase, onshore conventional production of natural gas in the *AEO2008* reference case declines steadily, as it did in *AEO2007*.

Onshore production of unconventional natural gas in *AEO2008* is expected to be a major contributor to growth in U.S. supply, increasing from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030. As in *AEO2007*, most of the increase in unconventional production is projected to come from gas shale, which more than doubles over the projection, from 1.0 trillion cubic feet in 2006 to 2.3 trillion cubic feet in 2030.

The Alaska natural gas pipeline is expected to be completed in 2020 (2 years later than in the *AEO2007* reference case) because of delays in the resolution of issues between Alaska's State government and industry participants. After the pipeline goes into operation, Alaska's total natural gas production in the *AEO2008* reference case increases to 2.0 trillion cubic feet in 2021 (from 0.4 trillion cubic feet in 2006) and then to 2.4 trillion cubic feet in 2030 as the result of a subsequent expansion. The pipeline connecting the MacKenzie Delta in Canada to the United States is not constructed in the *AEO2008* reference case, unlike in *AEO2007*, because cost estimates recently filed by the industry substantially exceed the estimates included in *AEO2007*, and as a result the project is not economical with the *AEO2008* reference case prices.

Net pipeline imports of natural gas from Canada and Mexico, predominantly from Canada, fall from 2.9 trillion cubic feet in 2006 to 0.5 trillion cubic feet in 2030 in the *AEO2008* reference case (compared with 0.9 trillion cubic feet in *AEO2007*). The difference between the *AEO2008* and *AEO2007* projections for 2030 is largely a result of increased exports to Mexico. The higher level of exports to Mexico is the result of a lower assumed growth rate for Mexico's natural gas production in the *AEO2008* reference case than in *AEO2007*. Net imports from Canada also decline, reflecting resource depletion in Alberta and Canada's growing domestic demand, which are offset in part by increases in unconventional natural gas production from coal seams and tight formations.

Total net imports of liquified natural gas (LNG) to the United States in the *AEO2008* reference case increase from 0.5 trillion cubic feet in 2006 to 2.9 trillion cubic feet in 2030, as compared with 4.5 trillion cubic feet in 2030 in *AEO2007*. The lower projection is attributable to two factors: higher costs throughout the LNG industry, especially in the area of liquefaction, and decreased U.S. natural gas consumption due to higher natural gas prices, slower economic growth, and expected greater competition for supplies within the global LNG market.

U.S. LNG regasification capacity increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the *AEO2008* reference case with the addition of five new regasification facilities that are currently under construction (four along the Gulf Coast and one off the coast of New England). Given global LNG supply constraints, overall capacity utilization at the U.S. LNG import facilities is expected to remain under 35 percent through 2013, after which it is expected to increase to 57 percent in 2017 and remain in the range of 55 to 58 percent through 2030.

The future direction of the global LNG market is one of the key uncertainties in the *AEO2008* reference case. With many new international players entering LNG markets, competition for the available supply is strong, and the supplies available to the U.S. market may vary considerably from year to year. The *AEO2008* reference case has been updated to reflect current market dynamics, which could change considerably as worldwide LNG markets evolve.

As domestic coal demand grows in the *AEO2008* reference case, U.S. coal production increases at an average rate of 1.1 percent per year, from 23.8 quadrillion Btu (1,163 million short tons) in 2006 to 31.2 quadrillion Btu (1,595 million short tons) in 2030—7 percent less than in the *AEO2007* reference case. Production from mines west of the Mississippi River provides the largest share of the incremental coal production. On a

Btu basis, 60 percent of domestic coal production originates from States west of the Mississippi River in 2030, up from an estimated 49 percent in 2006.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 91 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2008* reference case, at 28.5 quadrillion Btu in 2030, is less than in the *AEO2007* reference case (31.1 quadrillion Btu in 2030). Slower growth in overall electricity demand, combined with more generation from nuclear and renewable energy, underlies the reduced outlook for electricity sector coal consumption. Another fast-growing market for coal is CTL. Coal use in CTL plants grows from 0.7 quadrillion Btu (42 million short tons) in 2020 to 2.4 quadrillion Btu (157 million short tons) in 2030. Coal use for CTL production becomes the second largest use of coal (after electric power generation) in 2025 in the *AEO2008* reference case.

Energy Intensity

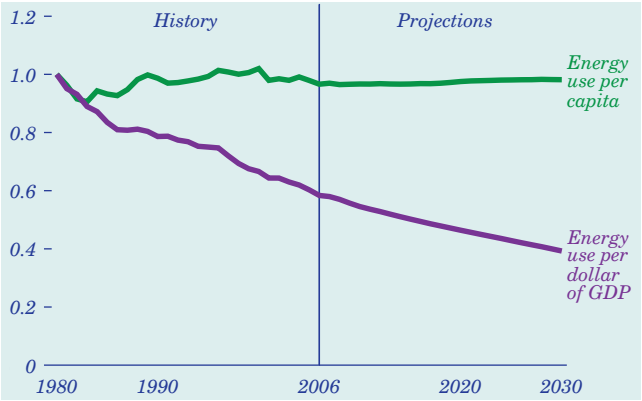
Energy intensity, measured as energy use (in thousand Btu) per dollar of GDP (in 2000 dollars), is projected to decline at an average annual rate of 1.6 percent from 2006 to 2030 in the *AEO2008* reference case (Figure 7). Although energy use generally increases as the economy grows, continuing improvement in the energy efficiency of the U.S. economy and a shift to less energy-intensive activities are projected to keep the rate of energy consumption growth lower than the rate of GDP growth.

Since 1992, the energy intensity of the U.S. economy has declined on average by 2.0 percent per year, in part because the share of industrial shipments accounted for by the energy-intensive industries has fallen from 30 percent in 1992 to 21 percent in 2006. In the *AEO2008* reference case, the energy-intensive industries' share of total industrial shipments continues to decline, although at a slower rate, to 18 percent in 2030.

Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. Since 1990, population has increased by about 20 percent and energy consumption by a comparable 18 percent in the United States, with annual variations in energy use per capita resulting from variations in weather and economic factors. The age, income, and geographic distribution of population also affects energy consumption growth. The aging of the population, a gradual shift from the North to the South, and rising per-capita income will influence future trends. Overall, population in the reference case increases by 22 percent from 2006 to 2030. Over the same period, energy consumption increases by 24 percent. The result is an increase in energy consumption per capita at an annual rate of 0.1 percent per year from 2006 to 2030—slightly slower than in the *AEO2007* reference case.

Recently, as energy prices have risen, the potential for more energy conservation has received increased attention. Although some additional energy conservation is induced by higher energy prices in the *AEO2008* reference case, no policy-induced conservation measures are assumed beyond those in existing legislation and regulation, nor does the reference case assume behavioral changes beyond those observed in the past.

Figure 7. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



Energy-Related Carbon Dioxide Emissions

Absent the application of CCS technology (which is not expected to come into use without changes in current policies that are not included in the reference case), CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption and carbon content, with coal having the highest carbon content, natural gas the lowest, and liquid fuels in between. In the *AEO2008* reference case, the coal share of total energy use increases from 23 percent in 2006 to 26 percent in 2030, while the share of natural gas falls from 22 percent to 19 percent, and the liquids share declines from 40 percent to 39 percent. The combined share of carbon-neutral renewable and nuclear

energy grows from 15 percent in 2006 to 16 percent in 2030.

Taken together, projected growth in the absolute level of primary energy consumption and a shift toward a fuel mix with slightly higher average carbon content causes projected energy-related emissions of CO_2 to grow by 25 percent from 2006 to 2030 (Figure 8)—slightly higher than the projected 23-percent increase in total energy use. Over the same period, the economy becomes less carbon intensive as the percentage increase in CO_2 emissions is about one-third of the projected increase in GDP, and emissions per capita increase by only 3 percent. In the *AEO2008* reference case, projected energy-related CO_2 emissions grow from 5,890 million metric tons in 2006 to 7,373 million metric tons in 2030. In the *AEO2007* reference case, energy-related CO_2 emissions grew by 35 percent, reaching 7,950 million metric tons in 2030, reflecting both a higher projection of overall energy use and, to a lesser extent, a different mix of energy sources.

Figure 8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030 (million metric tons)

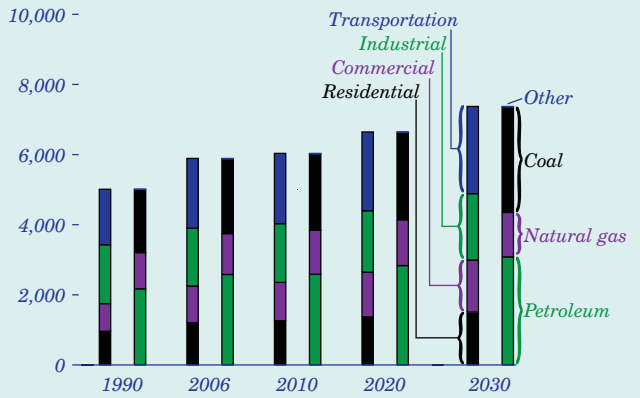


Table 1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030

Energy and economic factors	2006	2010		2020		2030	
		AEO2008	*AEO2007*	*AEO2008*	*AEO2007*	*AEO2008*	*AEO2007*
Primary energy production (quadrillion Btu)							
Petroleum	13.16	14.92	14.42	16.02	14.85	14.30	13.71
Dry natural gas	19.04	19.61	19.93	20.28	21.41	20.41	21.15
Coal	23.79	23.31	24.47	25.61	26.61	31.16	33.52
Nuclear power	8.21	8.31	8.23	9.15	9.23	9.89	9.33
Hydropower	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.97	4.11	4.22	4.93	4.69	5.52	5.26
Other renewable energy	0.88	1.50	1.18	1.99	1.33	2.49	1.44
Other	0.42	0.55	0.67	0.64	0.89	0.72	1.12
Total	**71.35**	**75.22**	**76.13**	**81.62**	**82.09**	**87.48**	**88.63**
Net imports (quadrillion Btu)							
Petroleum	26.70	24.49	25.19	26.72	28.92	31.20	34.74
Natural gas	3.56	4.13	4.67	4.40	5.48	3.51	5.59
Coal/other (- indicates export)	-0.28	-0.26	-0.19	1.03	0.93	1.79	1.57
Total	**29.99**	**28.36**	**29.66**	**32.15**	**35.33**	**36.50**	**41.90**
Consumption (quadrillion Btu)							
Liquid fuels	40.39	40.82	41.76	44.41	46.52	48.23	52.17
Natural gas	22.42	23.90	24.73	24.83	27.04	24.07	26.89
Coal	22.52	22.94	24.24	26.23	27.29	31.71	34.14
Nuclear power	8.21	8.31	8.23	9.15	9.23	9.89	9.33
Hydropower	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.52	3.08	3.30	3.83	3.64	4.17	4.06
Other renewable energy	0.88	1.50	1.18	1.99	1.33	2.49	1.44
Net electricity imports	0.19	0.18	0.04	0.18	0.04	0.20	0.04
Total	**100.00**	**103.64**	**106.50**	**113.61**	**118.16**	**123.76**	**131.16**
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.10	5.91	5.67	6.39	5.89	5.63	5.39
Other domestic production	3.14	3.70	4.03	4.01	4.49	4.59	5.08
Net imports	12.45	11.64	11.79	12.70	13.56	14.81	16.37
Consumption	20.65	21.18	21.59	23.01	24.03	24.93	26.95
Natural gas (trillion cubic feet)							
Production	18.57	19.13	19.42	19.77	20.86	19.90	20.61
Net imports	3.46	4.01	4.55	4.28	5.35	3.41	5.45
Consumption	21.78	23.22	24.02	24.12	26.26	23.39	26.12
Coal (million short tons)							
Production	1,176	1,152	1,202	1,300	1,336	1,607	1,704
Net imports	-15	-11	-7	45	41	75	68
Consumption	1,114	1,141	1,195	1,344	1,377	1,682	1,772
Prices (2006 dollars)							
Imported low-sulfur, light crude oil (dollars per barrel)	66.02	66.89	59.23	61.05	53.64	71.87	60.93
Imported crude oil (dollars per barrel)	59.05	58.93	52.76	52.80	47.89	62.07	53.21
Domestic natural gas at wellhead (dollars per thousand cubic feet)	6.42	6.09	5.93	5.42	5.39	6.60	6.16
Domestic coal at minemouth (dollars per short ton)	24.63	24.53	24.94	22.63	22.24	23.45	23.29
Average electricity price (cents per kilowatthour)	8.9	9.1	8.3	8.6	8.1	8.8	8.3
Economic indicators							
Real gross domestic product (billion 2000 dollars)	11,319	12,555	12,790	16,177	17,077	20,832	22,494
GDP chain-type price index (index, 2000=1.000)	1.166	1.267	1.253	1.509	1.495	1.838	1.815
Real disposable personal income (billion 2000 dollars)	8,397	9,594	9,568	12,811	13,000	16,916	17,535
Value of manufacturing shipments (billion 2000 dollars)	5,723	5,882	6,298	7,044	7,779	8,226	9,502
Primary energy intensity (thousand Btu per 2000 dollar of GDP)	**8.83**	**8.25**	**8.33**	**7.02**	**6.92**	**5.94**	**5.83**
Carbon dioxide emissions (million metric tons)	**5,890**	**6,034**	**6,214**	**6,646**	**6,944**	**7,373**	**7,950**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity.

Sources: AEO2008 National Energy Modeling System, run AEO2008.D112607A; and AEO2007 National Energy Modeling System, run AEO2007.D112106A.