AEO2012 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2012* (*AEO2012*) Reference case focus on the factors that shape U.S. energy markets in the long term, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. The *AEO2012* Reference case provides the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. Some of the highlights in the *AEO2012* Reference case include:

Projected growth of energy use slows over the projection period, reflecting an extended economic recovery and increasing energy efficiency in end-use applications

Projected transportation energy demand grows at an annual rate of 0.2 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.8 percent per year. Energy consumption per capita declines by an average of 0.5 percent per year from 2010 to 2035. The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by 42 percent from 2010 to 2035.

Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.1 million barrels per day in 2007 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production in the Reference case to 6.7 million barrels per day in 2020, a level not seen since 1994. Even with a projected decline after 2020, U.S. crude oil production remains above 6.1 million barrels per day through 2035.

With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net petroleum imports make up a smaller share of total liquids consumption

U.S. dependence on imported petroleum liquids declines in the *AEO2012* Reference case, primarily as a result of growth in domestic oil production by more than 1 million barrels per day by 2020; an increase in biofuels use to more than 1 million barrels per day crude oil equivalent by 2024; and modest growth in transportation sector demand through 2035. Net petroleum imports as a share of total U.S. liquid fuels consumed drop from 49 percent in 2010 to 36 percent in 2035 in *AEO2012* (Figure 1). Proposed fuel economy standards covering vehicle model years 2017 through 2025 that are not included in the Reference case would further reduce projected liquids use and the need for liquids imports.

Natural gas production increases throughout the projection period

Much of the growth in natural gas production is a result of the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas. Shale gas production increases from 5.0 trillion cubic feet in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet in 2035 (49 percent of total U.S. dry gas production) (Figure 2).

Figure 1. U.S. liquid fuels supply, 1970-2035 (million barrels per day)

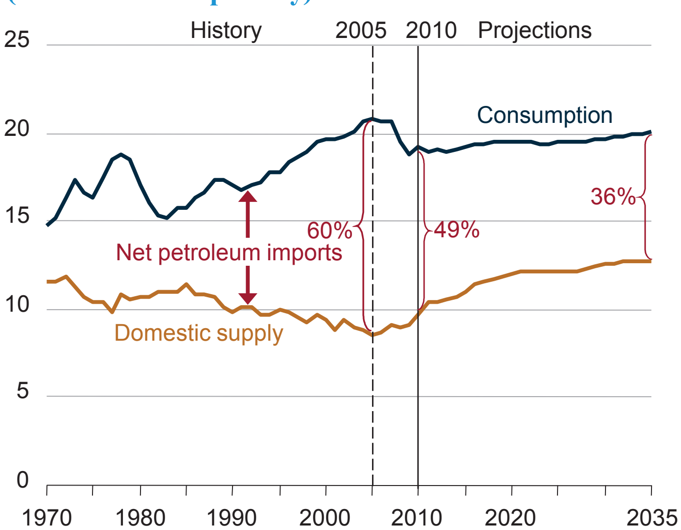
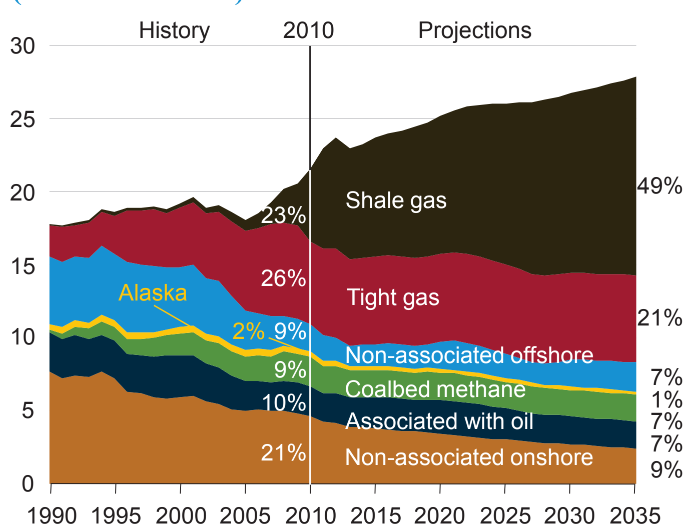


Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet)



Expected changes in the *AEO2012* complete release

The Reference case results shown in the *AEO2012* Early Release will vary somewhat from those included in the complete *Annual Energy Outlook (AEO)* that will be released in spring 2012, because some data and model updates were not available for inclusion in the Early Release. In particular, the complete *AEO2012* will include the Mercury and Air Toxics Standards issued by the U.S. Environmental Protection Agency (EPA) in December 2011; updated historical data and equations in the transportation sector, based on revised data from the National Highway Traffic Safety Administration (NHTSA) and the Federal Highway Administration; a new model for cement production in the industrial sector; a revised long-term macroeconomic projection based on an updated long-term projection from IHS Global Insight, Inc.; and an updated representation of biomass supply.

U.S. production of natural gas is expected to exceed consumption early in the next decade

The United States is projected to become a net exporter of liquefied natural gas (LNG) in 2016, a net pipeline exporter in 2025, and an overall net exporter of natural gas in 2021. The outlook reflects increased use of LNG in markets outside of North America, strong domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States compared to other global markets.

Use of renewable fuels and natural gas for electric power generation rises

The natural gas share of electric power generation increases from 24 percent in 2010 to 27 percent in 2035, and the renewables share grows from 10 percent to 16 percent over the same period. In recent years, the U.S. electric power sector's historical reliance on coal-fired power plants has begun to decline. Over the next 25 years, the projected coal share of overall electricity generation falls to 39 percent, well below the 49-percent share seen as recently as 2007 (Figure 3), because of slow growth in electricity demand, continued competition from natural gas and renewable plants, and the need to comply with new environmental regulations.

Total U.S. energy-related carbon dioxide emissions remain below their 2005 level through 2035

Energy-related carbon dioxide (CO_2) emissions grow by 3 percent from 2010 to 2035, to a total of 5,806 million metric tons in 2035. They are more than 7 percent below their 2005 level of 5,996 million metric tons in 2020 and are still below the 2005 level at the end of the projection period (Figure 4). Emissions per capita fall by an average of 1 percent per year from 2005 to 2035, as growth in demand for transportation fuels is moderated by higher energy prices and Federal corporate average fuel economy (CAFE) standards, and as electricity-related emissions are tempered by efficiency standards, State renewable portfolio standard (RPS) requirements, competitive natural gas prices that dampen coal use by electricity generators, and the need to comply with new environmental regulations. Proposed fuel economy standards covering model years 2017 through 2025 that are not included in the Reference case would further reduce projected energy use and emissions.

Introduction

In preparing the *AEO2012* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2012* Reference case and compares it with the *AEO2011* Reference case released in April 2011 (see Table 1 on pages 12-13). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2012* publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

Figure 3. Electricity generation by fuel, 1990-2035 (trillion kilowatthours per year)

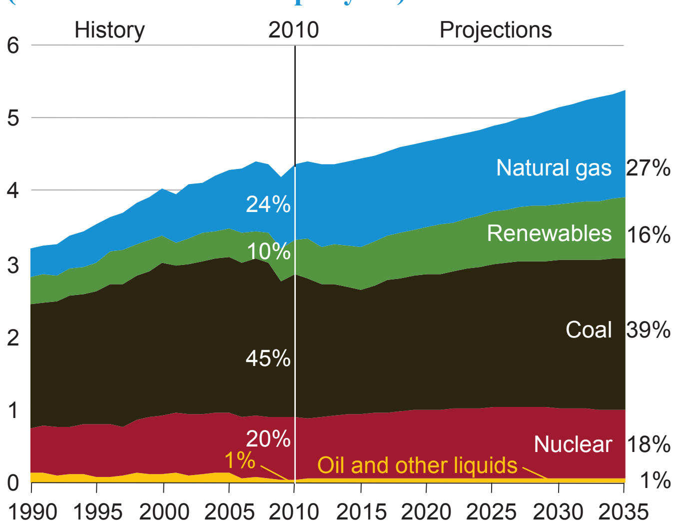
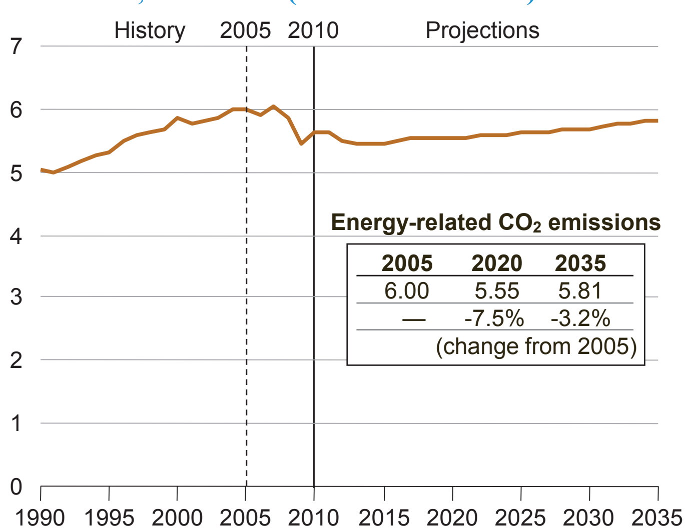


Figure 4. U.S. energy-related carbon dioxide emissions, 1990-2035 (billion metric tons)



To provide a basis against which alternative cases and policies can be compared, the *AEO2012* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). This assumption helps increase the comparability of the Reference case with other analyses, clarifies the relationship of the Reference case to other *AEO2012* cases, and enables policy analysis with less uncertainty arising from speculative legal or regulatory assumptions. Currently, there are many pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some existing laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *AEO* Reference case is completed, it may be considered in the projection.

As in past editions of the *AEO,* the complete *AEO2012* will include additional cases, many of which reflect the impacts of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2012,* EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates made for the *AEO2012* Reference case include the following:

- Industrial cogeneration was updated with historical rather than assumed capacity factors for new units and with updated investment decision procedures that reflect regional acceptance rates for new cogeneration facilities.
- A new heavy-duty vehicle model was adopted in the transportation module, with greater detail on size classes and end-use vehicle types to enable modeling of fuel economy regulations covering the heavy-duty vehicle fleet.
- The light-duty fleet model in the transportation module was updated to include a new algorithm for consumer purchase choice that compares fuel savings against incremental vehicle cost for advanced technologies, new technology cost and performance assumptions, and representation of fuel efficiency standards already in effect.
- Shale gas resource estimates for four plays (Haynesville, Fayetteville, Eagle Ford, and Woodford) were updated using the mean value of resource assessments recently released by the U.S. Geological Survey (USGS). The shale gas resource estimate for the Marcellus play was updated using new geologic data from the USGS and recent production data. EIA's estimate of Marcellus resources is substantially below the estimate used for *AEO2011* and falls within the 90-percent confidence range in the August 2011 USGS assessment, although it is higher than the USGS mean value.
- The tight oil resource estimate for the Bakken play was increased to include more of the Three Forks and Sanish zones.
- The handling of U.S. LNG exports of domestically sourced gas was updated, resulting in exports beginning in 2016.
- The electricity module was updated to incorporate the Cross-State Air Pollution Rule (CSAPR)[2] as finalized by the EPA in July 2011. CSAPR requires reductions in emissions from power plants that contribute to ozone and fine particle pollution in 28 States.
- Assumptions regarding the potential for capacity uprates at existing nuclear plants and the timing for existing nuclear plant retirements were revised.
- Updates were made to reflect recent information pertaining to retirement dates for existing power plants and scheduled in-service dates for new power plants.
- California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, was incorporated for electricity sector power plants serving California. As modeled, AB 32 imposes a limit on power sector CO_2 emissions, beginning in 2012 and declining at a uniform annual rate through 2020.

Economic growth

Recovery from the 2008-2009 recession is expected to show the slowest growth of any recovery since 1960. Table 2 compares average annual growth rates over a five-year period following U.S. recessions that have occurred since 1960. For the most recent

Table 2. Average annual growth rates over a five-year period following post-1960 recessions[a]

Recession ending	Real GDP	Real consumption	Real investment	Nonfarm employment	Unemployment rate
1975	3.7%	3.2%	7.3%	3.3%	-3.3%
1982	4.5%	4.7%	7.5%	2.6%	-8.6%
1991	3.3%	3.4%	8.5%	2.0%	-4.6%
2009[b]	2.5%	2.1%	9.4%	1.0%	-3.5%

[a]The recessions highlighted in Table 2 are recessions in which the annual GDP percentage change was negative when compared with the previous year's annual value of GDP. The 2001 recession was not included even though it technically qualified as a recession (where two successive quarters showed negative economic growth). The 2001-2002 recession showed a slowdown in annual GDP growth but did not show negative growth.
[b]Average over five-year period following the recession ending in 2009 includes projections for 2011-2014.

[1] See "Congressional Request," website www.eia.gov/analysis/reports.cfm?t=138.
[2]See U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website http://epa.gov/airtransport.

recession, the expected five-year average annual growth rate in real GDP from 2009 to 2014 is 1.3 percentage points below the corresponding average for the three past recessions, with consumption and non-farm employment recovering even more slowly. The slower growth in the early years of the projection has implications for the long term, with a lower economic growth rate leading to a slower recovery in employment and higher unemployment rates. Real GDP in 2035 is 4 percent lower in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case.

Real GDP grows by an average of 2.6 percent per year from 2010 to 2035 in the *AEO2012* Reference case, 0.1 percent per year lower than in the *AEO2011* Reference case. The Nation's population, labor force, and productivity grow at annual rates of 0.9 percent, 0.7 percent, and 1.9 percent, respectively, from 2010 to 2035.

Beyond 2012, the economic assumptions underlying the *AEO2012* Reference case reflect trend projections that do not include short-term fluctuations. Economic growth projections for 2012 are consistent with those published in EIA's October 2011 *Short-Term Energy Outlook*.

Energy prices

Crude oil

Prices for crude oil[3] in 2011 remained generally in a range between $85 and $110 per barrel. In 2011, WTI prices were lower than Brent prices because of pipeline capacity constraints that prevented complete arbitrage between WTI and Brent prices. Real imported sweet crude oil prices (2010 dollars) in the *AEO2012* Reference case rise to $120 per barrel in 2016 (Figure 5) as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil in the Reference case is about $145 per barrel in 2010 dollars, or about $230 per barrel in nominal dollars.

The *AEO2012* Reference case assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2010 and 2035, and that OPEC targets a relatively constant market share of total world liquids production. Uncertainty regarding OPEC members' actual investment and production decisions and the degree to which non-OPEC countries and countries outside the Organization for Economic Cooperation and Development (OECD) restrict access to potentially productive resources contributes to world oil price uncertainty and the economic viability of unconventional liquids. A wide range of price scenarios and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete *AEO2012* publication released in spring 2012.

The *AEO2012* Reference case also includes significant long-term potential for liquids supply from non-OPEC producers. In several resource-rich regions (including Brazil, Russia, and Kazakhstan), high oil prices, expanded infrastructure, and further investment in exploration and drilling contribute to additional non-OPEC oil production (Figure 6). Also, with the economic viability of Canada's oil sands supported by rising world oil prices and advances in production technology, Canadian oil sands production reaches 5.0 million barrels per day in 2035.

Liquid products

Real prices (in 2010 dollars) for motor gasoline and diesel delivered to the transportation sector in the *AEO2012* Reference case increase from $2.76 and $3.00 per gallon, respectively, in 2010 to $4.09 and $4.49 per gallon in 2035—higher levels than in the *AEO2011* Reference case. Annual average diesel prices are higher than gasoline prices throughout the projection because of stronger global growth in demand for diesel fuel than for motor gasoline.

Figure 5. Average annual world oil prices in three cases, 1980-2035 (real 2010 dollars per barrel)

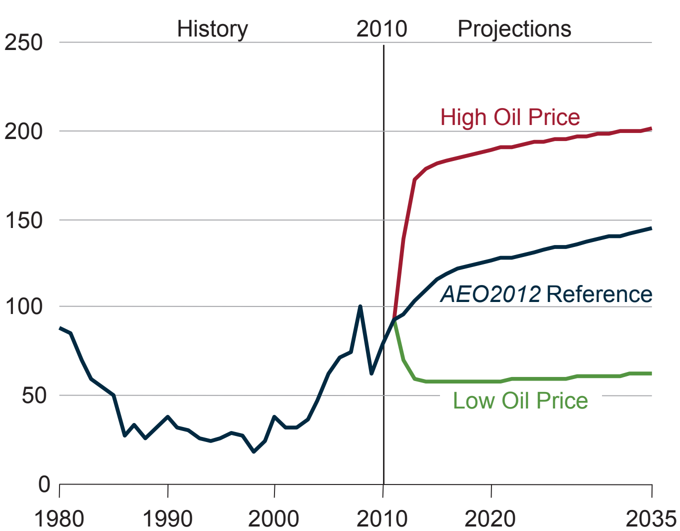
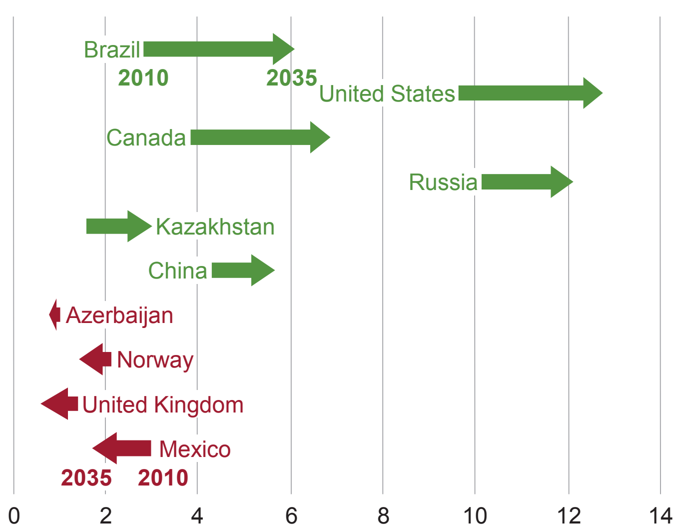


Figure 6. Change in liquids production by top non-OPEC producers, 2010-2035 (million barrels per day)



[3] Light sweet crude oil (West Texas Intermediate [WTI]) traded on NYMEX, which is a member exchange of the CME Group.

Natural gas

With increased production, average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (2010 dollars) through 2023 in the *AEO2012* Reference case. The projected prices reflect continued industry success in tapping the Nation's extensive shale gas resource. The resilience of drilling levels, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have high concentrations of crude oil, condensates, or natural gas liquids.

After 2023, natural gas prices generally increase as the numbers of tight gas and shale gas wells drilled increase to meet growing domestic demand for natural gas and offset declines in natural gas production from other sources. Natural gas prices rise as production gradually shifts to resources that are less productive and more expensive. Natural gas wellhead prices (in 2010 dollars) reach $6.52 per thousand cubic feet in 2035, compared with $6.48 per thousand cubic feet (2010 dollars) in *AEO2011*.

Coal

The average minemouth price of coal increases by 1.4 percent per year in the *AEO2012* Reference case, from $1.76 per million Btu in 2010 to $2.51 per million Btu in 2035 (2010 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The coal price outlook in the *AEO2012* Reference case represents a change from the *AEO2011* Reference case, where coal prices were essentially flat.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the *AEO2012* Reference case fall from 9.8 cents per kilowatthour in 2010 to as low as 9.2 cents per kilowatthour in 2019, as natural gas prices remain relatively low. Electricity prices tend to reflect trends in fuel prices—particularly, natural gas prices, because in much of the country natural gas-fired plants often set wholesale power prices. It can take time, however, for fuel price changes to affect electricity prices because of the varying lengths of fuel- and power-supply contracts and the periods between electricity rate cases.

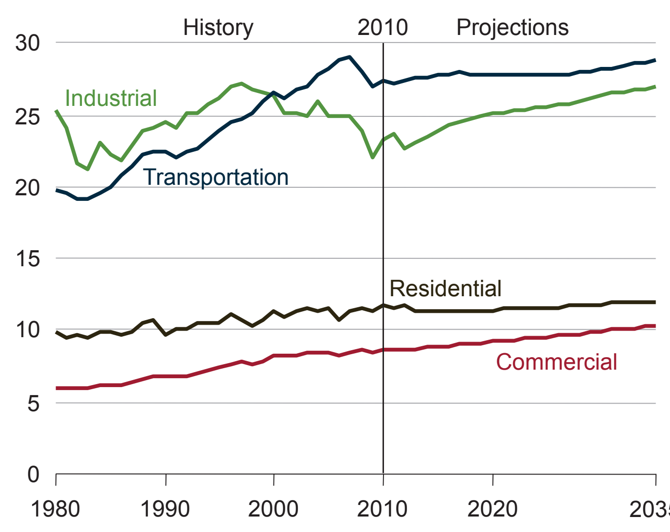
In the *AEO2012* Reference case, electricity prices are higher throughout the projection than they were in the *AEO2011* Reference case. Although natural gas prices to electricity generators are similar to those in *AEO2011*, the cost of coal is higher. In addition, reliance on natural gas-fired generation in the power sector increases partially as a result of new environmental regulation covering emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) that make it a more economical option. Electricity prices in 2035 are 9.5 cents per kilowatthour (2010 dollars) in the *AEO2012* Reference case, compared with 9.3 cents per kilowatthour in the *AEO2011* Reference case.

Energy consumption by sector

Transportation

Delivered energy consumption in the transportation sector grows from 27.6 quadrillion Btu in 2010 to 28.8 quadrillion Btu in 2035 in the *AEO2012* Reference case (Figure 7). Energy consumption by light-duty vehicles (LDVs) (including commercial light trucks) initially declines in the Reference case, from 16.5 quadrillion Btu in 2010 to 15.7 quadrillion Btu in 2025, due to projected increases in the fuel economy of highway vehicles. Projected energy consumption for LDVs increases after 2025, to 16.3 quadrillion Btu in 2035. The *AEO2012* Reference case projections do not include proposed increases in LDV fuel economy standards—as outlined in the December 2011 EPA and NHTSA Notice of Proposed Rulemaking for 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards[4]—which would further significantly reduce LDV fuel use if they were incorporated in the projection. The lower projected level of energy consumption in *AEO2012* as compared with *AEO2011* is primarily the result of a reduction in vehicle-miles traveled resulting from the impact of lower projected economic growth and employment rates.

Figure 7. Delivered energy consumption by sector, 1980-2035 (quadrillion Btu)



Energy demand for heavy trucks increases from 5.1 quadrillion Btu in 2010 to 6.1 quadrillion Btu in 2035, compared with 6.7 quadrillion Btu in the *AEO2011* Reference

[4] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," *Federal Register*, Vol. 76, No. 231 (December 1, 2011), pp. 74854-75420, website www.gpo.gov/fdsys/pkg/FR-2011-12-01/html/2011-30358.htm.

case. Lower projected industrial output in *AEO2012* leads to slower growth in vehicle-miles traveled by freight trucks, which, in combination with projected increases in fuel economy due to new fuel efficiency and greenhouse gas regulations, leads to lower projected energy demand for heavy vehicles in *AEO2012* as compared with *AEO2011*. The *AEO2012* Reference case includes the fuel efficiency standards for medium- and heavy-duty vehicles published by the EPA and NHTSA in September 2011.[5]

Industrial

Approximately one-third of total U.S. delivered energy, 23.4 quadrillion Btu, was consumed in the industrial sector in 2010. In the *AEO2012* Reference case, total industrial delivered energy consumption grows by 16 percent, from 23.4 quadrillion Btu in 2010 to 27.0 quadrillion Btu in 2035. The largest user of energy is the bulk chemicals industry, which represented 21 percent of total energy consumption in the industrial sector in 2010. By 2026, however, the refining industry, defined as including energy use at petroleum, biofuels, and coal-to-liquids (CTL) facilities, becomes the largest energy-consuming industry in the *AEO2012* Reference case.

Collectively, the energy-intensive manufacturing industries—bulk chemicals, refining, paper products, iron and steel, aluminum, food, glass, and cement—produce slightly more than one-quarter of the total dollar value of industrial shipments while accounting for nearly two-thirds of industrial delivered energy consumption. Although the energy-intensive industries are expected to recover from the recent recession, their long-term growth is slowed by increased international competition and a shift in U.S. manufacturing toward higher value consumer goods. The dollar value of shipments from the energy-intensive manufacturing industries grows by 29 percent from 2010 to 2035 in the *AEO2012* Reference case, while the value of shipments from non-energy-intensive industries increases by 57 percent. As a result of the shift toward non-energy-intensive manufacturing, total industrial delivered energy consumption increases more slowly than total shipments, and the energy intensity of industrial production declines.

Industrial natural gas consumption in the *AEO2012* Reference case is lower than was projected in *AEO2011*, due to revised data for energy intensity in the bulk chemical industry and the adoption of an updated methodology for projecting industrial consumption of combined heat and power (CHP) that better accounts for utilization of both installed and planned capacity. Total industrial natural gas consumption is 8.7 quadrillion Btu in 2035 in the *AEO2012* Reference case, compared with 9.5 quadrillion Btu in the *AEO2011* Reference case.

Residential

Residential delivered energy consumption in the *AEO2012* Reference case grows from 11.7 quadrillion Btu in 2010 to 12.0 quadrillion Btu in 2035. Updated efficiency and cost parameters for major end-use equipment lead to some fuel switching from natural gas and petroleum to electricity in the residential sector due to competitive advantages. In 2035, delivered electricity use totals 5.9 quadrillion Btu and natural gas consumption totals 4.8 quadrillion Btu in the *AEO2012* Reference case, as compared with 5.5 quadrillion Btu and 4.9 quadrillion Btu, respectively, in the *AEO2011* Reference case.

Recent Federal rulemakings for residential equipment—including furnaces, central and room air conditioners, heat pumps, refrigerators, and freezers—were included in the *AEO2011* Reference case based on levels outlined in consensus agreements among efficiency advocates and manufacturers. The final rules have been consistent with levels specified in the consensus agreements.

Commercial

Slower growth in commercial sector activity leads to slower growth in the sector's energy consumption in the *AEO2012* Reference case relative to the *AEO2011* Reference case. Commercial delivered energy consumption grows from 8.7 quadrillion Btu in 2010 to 10.3 quadrillion Btu in 2035. Growth in commercial electricity use averages 1.0 percent per year from 2010 to 2035 in *AEO2012*, comparable to the projected 1.0-percent average annual growth in commercial floorspace. Distributed generation and CHP systems in the commercial sector generate 38 billion kilowatthours of electricity in 2035, 2 percent less than in the *AEO2011* Reference case. Although delivered electricity prices are higher in the *AEO2012* Reference case, slower growth in the commercial sector leads to less opportunity for the adoption of these technologies.

Energy consumption by primary fuel

Total primary energy consumption, which was 101.4 quadrillion Btu in 2007, grows by 10 percent in the *AEO2012* Reference case, from 98.2 quadrillion Btu in 2010 to 108.0 quadrillion Btu in 2035—6 quadrillion Btu less than the *AEO2011* projection for 2035. The fossil fuel share of energy consumption falls from 83 percent of total U.S. energy demand in 2010 to 77 percent in 2035.

Biofuel consumption has been growing and is expected to continue to grow over the projection period. However, the projected increase would present challenges, particularly for volumes of ethanol beyond the saturation level of the E10 gasoline pool. Those additional volumes are likely to be slower in reaching the market, as infrastructure and consumer demand adjust. In the *AEO2012* Reference case, some of the demand for biofuel, which in 2035 is projected to displace more than 600 thousand barrels per day of demand for other liquid fuels, is as a direct replacement for diesel and gasoline.

[5] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, grows from 37.2 quadrillion Btu (19.2 million barrels per day) in 2010 to 38.0 quadrillion Btu (20.1 million barrels per day) in 2035 in the *AEO2012* Reference case (Figure 8). As in *AEO2011*, biofuel consumption accounts for most of the growth; with expectations of additional waivers, the biofuel portion of liquid fuels consumption in 2035 is 3.9 quadrillion Btu in *AEO2012*, slightly (0.2 quadrillion Btu) higher than projected in *AEO2011*. The transportation sector dominates demand for liquid fuels, with its share (as measured by energy content) growing slowly from 72 percent of total liquids consumption in 2010 to 73 percent in 2035.

In the *AEO2012* Reference case, natural gas consumption rises from 24.1 trillion cubic feet in 2010 to 26.5 trillion cubic feet in 2035, about the same level as in the *AEO2011* Reference case. The largest share of the growth is for electricity generation. Demand for natural gas in electricity generation grows from 7.4 trillion cubic feet in 2010 to 8.9 trillion cubic feet in 2035. A portion of the growth is attributable to the retirement of 33 gigawatts of coal-fired capacity over the projection period.

Total coal consumption—including the portion of CTL consumed as liquids—increases from 20.8 quadrillion Btu (1,051 million short tons) in 2010 to 22.1 quadrillion Btu (1,155 million short tons) in 2035 in the *AEO2012* Reference case. Coal consumption, mostly for electric power generation, falls off through 2015 as retirements of coal-fired capacity more than offset an increase of about 9 gigawatts in capacity due to come online in 2011 and 2012. After 2015, coal-fired generation increases slowly as the remaining plants are used more intensively. Coal consumption in the electric power sector in 2035 in the *AEO2012* Reference case is about 2.1 quadrillion Btu (98 million short tons) lower than projected in the *AEO2011* Reference case.

Total consumption of marketed renewable fuels grows by 2.8 percent per year in the *AEO2012* Reference case. Growth in consumption of renewable fuels results mainly from the implementation of the Federal renewable fuel standard (RFS) for transportation fuels and State RPS programs for electricity generation. Marketed renewable fuels include wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 3.9 quadrillion Btu is included with liquid fuel consumption in 2035. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.4 quadrillion Btu in 2010 to 3.4 quadrillion Btu in 2035, with biomass accounting for 30 percent of the growth and wind 44 percent. Consumption of solar energy grows the fastest, but starting from a small base it accounts for only a small share of the total in 2035.

Energy intensity

Population is a key determinant of energy consumption through its influence on demand for travel, housing, consumer goods, and services. U.S. energy use per capita was fairly constant over the 1990 to 2007 period, but it began to fall after 2007. In the *AEO2012* Reference case, energy use per capita continues to decline due to the impact of an extended economic recovery and improving energy efficiency. Total U.S. population increases by 25 percent from 2010 to 2035, but energy use grows by only 10 percent, and energy use per capita declines at an annual average rate of 0.5 percent per year from 2010 to 2035 (Figure 9).

From 1990 to 2010, energy use per dollar of GDP declined on average by 1.7 percent per year, in large part because of shifts within the economy from manufactured goods to the service sectors, which use relatively less energy per dollar of GDP. The increase in dollar value that the service sectors add to GDP (in constant dollar terms) was 15 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30 percent in 1991 to 22 percent in 2010. In the *AEO2012* Reference case, the industrial share of total shipments fluctuates in a

Figure 8. U.S. primary energy consumption by fuel, 1980-2035 (quadrillion Btu per year)

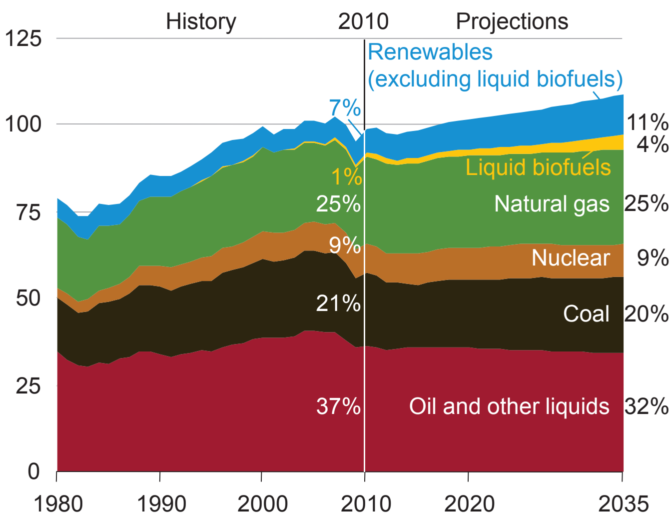
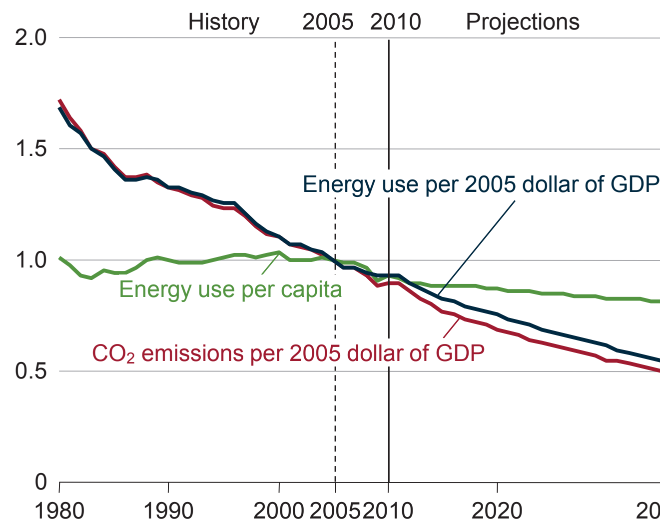


Figure 9. Energy use per capita and per dollar of gross domestic product and emissions per dollar of gross domestic product, 1980-2035 (index, 2005=1)



narrow range between 22.1 and 23.4 percent from 2011 through 2025, then declines slowly to 20.7 percent in 2035 (Figure 10). Energy use per 2005 dollar of GDP declines by 42 percent from 2010 to 2035 in *AEO2012* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less energy-intensive industries), rising energy prices, and the adoption of policies that promote energy efficiency.

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2012* Reference case, however, as lower carbon fuels account for a bigger share of total energy use, CO_2 emissions per dollar of GDP decline more rapidly than energy use per dollar of GDP, falling by more than 50% from 2005 to 2035, at an annual rate of 2.3 percent per year.

Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2012* Reference case (Figure 11). The decline in energy imports reflects increased domestic crude oil and natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from the adoption of new efficiency standards and from rising energy prices. The net import share of total U.S. energy consumption in 2035 is 13 percent, compared with 22 percent in 2010. (The share was 29 percent in 2007, but it dropped considerably during the recession.)

Liquids

U.S. production of domestic crude oil in the *AEO2012* Reference case increases from 5.5 million barrels per day in 2010 to 6.7 million barrels per day in 2020, 11 percent higher than in *AEO2011* (Figure 12). Even with a projected decline after 2020, U.S. crude oil production remains above 6.1 million barrels per day through 2035. The higher level of production results mainly from increased onshore oil production, predominantly tight oil. In *AEO2012*, onshore tight oil production accounts for 31 percent of lower 48 onshore oil production in 2035, compared with 12 percent in 2010. As with shale gas, the application of recent technology advances significantly increases the development of tight oil resources. Offshore crude oil production in the Gulf of Mexico trends upward over time, fluctuating between 1.4 and 2.0 million barrels per day, as new large development projects are started. Alaska's oil production decline is slowed by the development of offshore projects.

The faster growth in tight oil production in *AEO2012* offsets slower growth in enhanced oil recovery (EOR) production, as the economics of tight oil plays are more favorable than the economics of CO_2-EOR projects. In addition, the quantity of CO_2 available in 2035 from planned CTL plants necessary for CO_2-EOR production is 52 percent lower in *AEO2012* than was projected in *AEO2011*, due to a reduction in the number of CTL projects expected in *AEO2012*.

Figure 10. Outputs from the industrial and service sectors, 1990-2035 (trillion 2005 dollars)

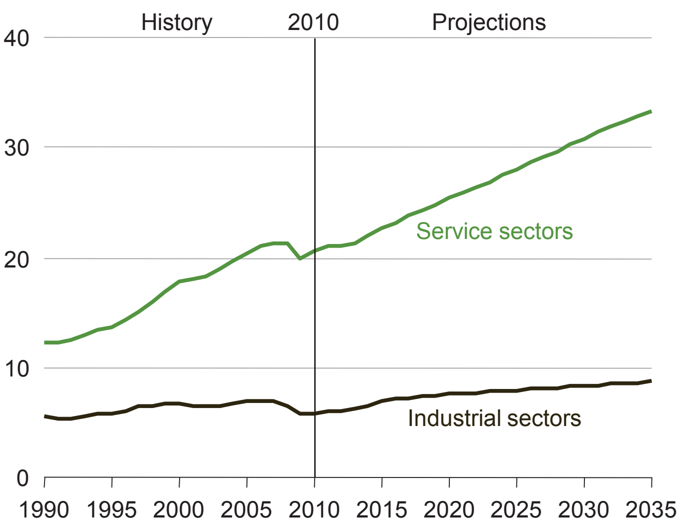


Figure 11. Total energy production and consumption, 1980-2035 (quadrillion Btu)

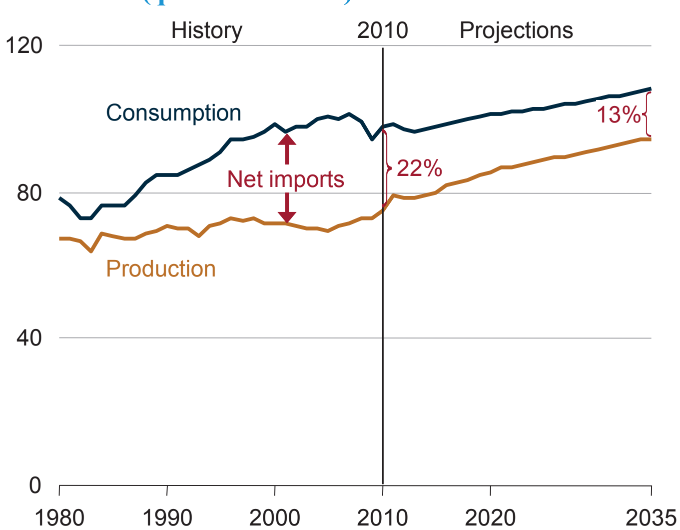
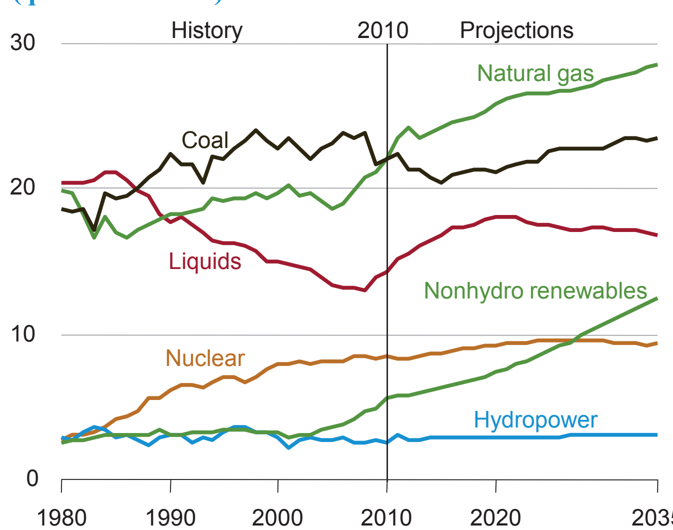


Figure 12. Energy production by fuel, 1980-2035 (quadrillion Btu)



Consequently, CO_2-EOR in *AEO2012* accounts for 11 percent of cumulative lower 48 onshore oil production from 2010 to 2035, as compared with 21 percent in *AEO2011*.

U.S. dependence on imported liquid fuels continues to decline in *AEO2012*, primarily as a result of increased domestic oil production, increased production of biofuels driven by the EISA2007 RFS, and lower demand for transportation fuels in *AEO2012* compared with *AEO2011*. Imported liquid fuels as a share of total U.S. liquid fuel use reached 60 percent in 2005 and 2006 before falling to 50 percent in 2010, and the percentage continues to decline over the projection period in *AEO2012*, to 37 percent in 2035—significantly lower than the 42-percent share in *AEO2011*.

Although liquids production from many sources is higher in *AEO2012* than was projected in the *AEO2011* Reference case, production of advanced cellulosic biofuels is lower. Over the past three consecutive years, production goals for cellulosic ethanol in the EISA2007 RFS have not been achieved. While EIA has projected a need for waivers in all Reference case projections since the passage of the EISA2007 RFS, EIA's view of technology development and market penetration rates for cellulosic biofuel technologies has grown somewhat more pessimistic in *AEO2012*.

Natural gas

Cumulative natural gas production from 2010 through 2035 in the *AEO2012* Reference case is 7 percent higher than in *AEO2011*, even though the estimated natural gas resource base is lower. This primarily reflects increased shale gas production resulting from the application of recent technological advances, as well as continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas. Production levels for tight gas and coalbed methane exceed those in the *AEO2011* Reference case through 2035, making significant contributions to the overall increase in production. Offshore natural gas production in the Gulf of Mexico fluctuates between 2.0 and 2.8 trillion cubic feet per year as new large projects directed toward liquids development are started over time.

In the *AEO2012* Reference case, the estimated unproved technically recoverable resource (TRR) of shale gas for the United States is 482 trillion cubic feet, substantially below the estimate of 827 trillion cubic feet in *AEO2011*. The decline largely reflects a decrease in the estimate for the Marcellus shale, from 410 trillion cubic feet to 141 trillion cubic feet. Both EIA and USGS have recently made significant revisions to their TRR estimates for the Marcellus shale. Drilling in the Marcellus accelerated rapidly in 2010 and 2011, so that there is far more information available today than a year ago. Indeed, the daily rate of Marcellus production doubled during 2011 alone. Using data though 2010, USGS updated its TRR estimate for the Marcellus to 84 trillion cubic feet, with a 90-percent confidence range from 43 to 144 trillion cubic feet—a substantial increase over the previous USGS estimate of 2 trillion cubic feet dating from 2002. For *AEO2012*, EIA uses more recent drilling and production data available through 2011 and excludes production experience from the pre-shale era (before 2008). EIA's TRR estimate for the entire Northeast also includes TRR of 16 trillion cubic feet for the Utica shale, which underlies the Marcellus and is still relatively little explored. The complete *AEO2012* publication will include a more in-depth examination of the factors that affect resource estimates.

In the *AEO2012* Reference case, the United States becomes a net exporter of LNG starting in 2016 and an overall net exporter of natural gas in 2021. U.S. LNG exports are assumed to start with a capacity of 1.1 billion cubic feet per day in 2016 and increase by an additional 1.1 billion cubic feet per day in 2019. Over the projection period, cumulative net pipeline imports of natural gas from Canada and Mexico in the *AEO2012* Reference case are less than 50 percent of those projected in the *AEO2011* Reference case, with the United States becoming a net pipeline exporter of natural gas in 2025. In the *AEO2012* Reference case, net pipeline imports from Canada fall by 62 percent over the projection period, and net pipeline exports to Mexico grow by 440 percent. Cumulative U.S. LNG imports from 2011 through 2035 are down by 20 percent in *AEO2012* compared with *AEO2011*, due in part to increased use of LNG in markets outside North America, strong domestic production, and relatively low U.S. natural gas prices in comparison with other global markets. As in the *AEO2011* Reference case, the Alaska natural gas pipeline is not constructed in the *AEO2012* Reference case, because assumed high capital costs and low natural gas wellhead prices make it uneconomical to proceed with the pipeline project over the projection period.

Coal

Although coal remains the leading fuel for U.S. electricity generation, its share of total generation is lower in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case. As a consequence, while still growing in most projection years after 2015, total coal production is lower in the *AEO2012* Reference case than in the *AEO2011* Reference case, with the gap between the two outlooks increasing substantially over the period from 2020 to 2035.

In the *AEO2012* Reference case, domestic coal production increases at an average rate of 0.3 percent per year, from 22.1 quadrillion Btu (1,084 million short tons) in 2010 to 23.5 quadrillion Btu (1,188 million short tons) in 2035. Mines in the West account for nearly all the projected increase in overall production, although even Western coal production is expected to decline somewhat between 2010 and 2015 as low natural gas prices and the retirement of a sizable amount of coal-fired generating capacity leads to a decline in overall coal consumption in the electricity sector. On a Btu basis, the share of domestic coal production originating from mines in the West increases from 47 percent in 2010 to 56 percent in 2035, and the Appalachian share declines from 39 percent to 29 percent during the same period, with most of the decline occurring by 2020. In the Interior region, coal production remains relatively stable over the projection period, with production in 2035 higher than in 2010.

Electricity generation currently accounts for 93 percent of total U.S. coal consumption. In the *AEO2012* Reference case, projected coal consumption in the electric power sector in 2035 (19.6 quadrillion Btu) is about 2 quadrillion Btu less than in the *AEO2011* Reference case (21.6 quadrillion Btu). For the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices and higher coal prices that, taken together, support increased generation from natural gas in the *AEO2012* Reference case. More generation from nonhydroelectric renewables and slightly lower overall demand for electricity, particularly in regions that rely heavily on coal-fired generation, also contribute to the reduced outlook for electricity sector coal consumption in the *AEO2012* Reference case. With a more robust outlook for coal imports by Asian countries, *AEO2012* shows higher coal exports than *AEO2011*.

Electricity generation

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,879 billion kilowatthours in 2010 to 4,775 billion kilowatthours in 2035 in the *AEO2012* Reference case, increasing at an average annual rate of 0.8 percent, about the same rate as in the *AEO2011* Reference case.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens coal use in the future. The *AEO2012* Reference case includes the impacts of the CSAPR, which was finalized in July 2011 and was not represented in the *AEO2011* Reference case. CSAPR requires reductions in SO_2 and NO_X emissions in roughly one-half of the States, with an initial target in 2012 and further reductions in 2014. Even so, coal remains the dominant energy source for electricity generation, but its share of total generation declines from 45 percent in 2010 to 39 percent in 2035 (see Figure 3 on page 2). Market concerns about GHG emissions continue to slow the expansion of coal-fired capacity in the *AEO2012* Reference case, even under current laws and policies. Low projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements outpace new additions, total coal-fired generating capacity falls from 318 gigawatts in 2010 to 301 gigawatts in 2035 in the *AEO2012* Reference case.

Electricity generation using natural gas is higher in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case, particularly over the next 10 years, during which natural gas prices are expected to remain low. New natural gas-fired plants also are much cheaper to build than new renewable or nuclear plants. In 2015, natural gas-fired generation in *AEO2012* is 13 percent higher than in *AEO2011*, and in 2035 it is still 6 percent higher.

Electricity generation from nuclear power plants grows by 11 percent in the *AEO2012* Reference case, from 807 billion kilowatthours in 2010 to 894 billion kilowatthours in 2035, accounting for about 18 percent of total generation in 2035 (compared with 20 percent in 2010). Nuclear generating capacity increases from 101 gigawatts in 2010 to a high of 115 gigawatts in 2025, after which a few retirements result in a decline to 112 gigawatts in 2035. *AEO2012* incorporates new information about planned nuclear plant construction, as well as an updated estimate of the potential for capacity uprates at existing units. A total of 10 gigawatts of new nuclear capacity is projected through 2035, as well as an increase of 7 gigawatts achieved from uprates to existing nuclear units. About 6 gigawatts of existing nuclear capacity is retired, primarily in the last few years of the projection, as not all owners of existing nuclear capacity apply for and receive license renewals to operate their plants beyond 60 years.

Increased generation from renewable energy in the electric power sector, excluding hydropower, accounts for 33 percent of the overall growth in electricity generation from 2010 to 2035. Generation from renewable resources grows in response to Federal tax credits, State-level policies, and Federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of the production process. Near-term market growth in some sectors, such as solar energy, is projected to result in significantly reduced costs in the *AEO2012* Reference case, increasing the projected growth for those resources as compared with the *AEO2011* projections. More retirements of coal-fired capacity are expected in the *AEO2012* Reference case than were projected in *AEO2011* because of slower growth in electricity demand, continued competition from natural gas and renewable plants, and the need to comply with new environmental regulations. Growth in renewable generation is supported by many State requirements, as well as new regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 10 percent in 2010 to 16 percent in 2035. In the *AEO2012* Reference case, Federal subsidies for renewable generation are assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation.

Energy-related CO_2 emissions

Although total U.S. energy-related CO_2 emissions increased by almost 4 percent in 2010, they do not return to their 2005 level (5,996 million metric tons) by the end of the *AEO2012* projection period (see Figure 4 on page 2). Emissions per capita fall by an average of 1 percent per year from 2005 to 2035, as growth in demand for transportation fuels is moderated by higher energy prices and Federal CAFE standards. In addition, electricity-related emissions are tempered by efficiency standards, State RPS requirements, and implementation of the CSAPR, which helps shift the fuel mix away from coal toward lower carbon fuels.

Energy-related CO_2 emissions reflect the mix of fossil fuels consumed. Given the high carbon content of coal and its use to generate 45 percent of the U.S. electricity supply in 2010, prospects for CO_2 emissions depend, in part, on growth in electricity demand as well as the portion of that demand satisfied by coal-fired generation. After declining from 2007 to 2009, electricity sales grew in 2010 by 4.3 percent. Electricity sales continue to grow through 2035 in the *AEO2012* Reference case, but the growth is tempered by a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards and a continued transition to a more service-oriented economy. The combination of slow demand growth, competitive natural gas prices, and CSAPR included in the *AEO2012* Reference case lowers the consumption of coal within the first 5 years of the projection period; as a result, emissions from coal combustion in the power sector in 2015 are 149 million metric tons below the *AEO2011* Reference case projection. With modest growth in electricity demand and increased use of renewables for electricity generation, electricity-related CO_2 emissions grow by a total of 4.9 percent (0.2 percent per year) from 2010 to 2035. Growth in CO_2 emissions from transportation activity also slows in comparison with the recent pre-recession experience, as Federal CAFE standards increase the efficiency of the vehicle fleet, employment recovers slowly, and higher fuel prices moderate growth in travel. The *AEO2012* Reference case projections do not include proposed increases in fuel economy standards for model years 2017 through 2025, which are expected to further reduce fuel use and emissions.

Taken together, these factors tend to slow the growth in primary energy consumption and CO_2 emissions. As a result, energy-related CO_2 emissions in 2035 are only 3 percent higher than in 2010 (as compared with the 10-percent increase in total energy use), and the carbon intensity of U.S. energy consumption falls from 57.4 to 53.8 kilograms per million Btu (6.3 percent). Over the same period, U.S. economic activity becomes less carbon-intensive, as energy-related CO_2 emissions per dollar of GDP decline by 45 percent.

List of Acronyms

AB 32	Global Warming Solutions Act of 2006
AEO	*Annual Energy Outlook*
AEO2011	*Annual Energy Outlook 2011*
AEO2012	*Annual Energy Outlook 2012*
Btu	British thermal units
CAFE	Corporate average fuel economy
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CSAPR	Cross-State Air Pollution Rule
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GDP	Gross domestic product
LDVs	Light-duty vehicles
LNG	Liquefied natural gas
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NO_X	Nitrogen oxides
OCS	Outer Continental Shelf
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
SO_2	Sulfur dioxide
TRR	Technically recoverable resource
USGS	United States Geological Survey

Table 1. Comparison of projections in the *AEO2012* and *AEO2011* Reference cases, 2009-2035

			2025		2035	
Energy and economic factors	2009	2010	*AEO2012*	*AEO2011*	*AEO2012*	*AEO2011*
Primary energy production (quadrillion Btu)						
Petroleum	13.93	14.37	17.48	16.19	16.81	16.72
Dry natural gas	21.09	22.10	26.63	24.60	28.51	27.00
Coal	21.63	22.08	22.51	23.64	23.51	26.01
Nuclear power	8.36	8.44	9.60	9.17	9.35	9.14
Hydropower	2.67	2.51	2.97	3.04	3.06	3.09
Biomass	3.72	4.05	6.73	7.20	9.68	8.63
Other renewable energy	1.11	1.34	2.13	2.58	2.80	3.22
Other	0.47	0.64	0.76	0.88	0.88	0.78
Total	**72.97**	**75.52**	**88.79**	**87.29**	**94.59**	**94.59**
Net imports (quadrillion Btu)						
Liquid fuels[a]	20.90	20.35	16.33	19.91	16.22	19.85
Natural gas	2.76	2.66	-0.81	1.14	-1.39	0.23
Coal/other (- indicates export)	-0.90	-1.58	-1.44	-0.51	-1.29	-0.50
Total	**22.77**	**21.43**	**14.08**	**20.54**	**13.54**	**19.58**
Consumption (quadrillion Btu)						
Liquid fuels[a]	36.49	37.25	37.04	39.84	38.00	41.70
Natural gas	23.42	24.71	25.80	25.73	27.11	27.24
Coal	19.62	20.76	20.60	22.61	21.57	24.30
Nuclear power	8.36	8.44	9.60	9.17	9.35	9.14
Hydropower	2.67	2.51	2.97	3.04	3.06	3.09
Biomass	2.72	2.88	4.52	4.71	5.85	5.25
Other renewable energy	1.11	1.34	2.13	2.58	2.80	3.22
Net electricity imports	0.32	0.29	0.28	0.27	0.24	0.25
Total	**94.70**	**98.16**	**102.93**	**107.95**	**107.97**	**114.19**
Liquid fuels (million barrels per day)						
Domestic crude oil production	5.36	5.47	6.42	5.88	6.12	5.95
Other domestic production	3.66	4.22	5.71	5.84	6.66	6.84
Net imports	9.72	9.53	7.39	9.22	7.36	9.14
Consumption	18.81	19.17	19.46	20.99	20.08	21.93
Natural gas (trillion cubic feet)						
Dry gas production + supplemental	20.65	21.65	26.07	24.04	27.90	26.38
Net imports	2.68	2.58	-0.84	1.08	-1.43	0.18
Consumption	22.85	24.13	25.20	25.07	26.48	26.55
Coal (million short tons)						
Production	1,089	1,098	1,144	1,202	1,204	1,333
Net imports	-38	-64	-57	-19	-49	-18
Consumption	997	1,051	1,087	1,182	1,155	1,315

Table 1. Comparison of projections in the *AEO2012* and *AEO2011* Reference cases, 2009-2035 (continued)

			2025		2035	
Energy and economic factors	2009	2010	*AEO2012*	*AEO2011*	*AEO2012*	*AEO2011*
Prices (2010 dollars)						
Imported low-sulfur, light crude oil (dollars per barrel)	62.37	79.39	132.50	118.57	144.56	126.03
Imported crude oil (dollars per barrel)	59.72	75.87	121.23	108.34	132.69	114.69
Domestic natural gas at wellhead (dollars per thousand cubic feet)	3.85	4.16	5.23	5.47	6.52	6.48
Domestic coal at minemouth (dollars per short ton)	33.62	35.61	43.87	33.51	49.24	34.22
Average electricity price (cents per kilowatthour)	9.9	9.8	9.3	9.0	9.5	9.3
Economic indicators						
Real gross domestic product (billion 2005 dollars)	12,703	13,088	19,176	20,020	24,639	25,692
GDP chain-type price index (2005 = 1.000)	1.097	1.110	1.459	1.450	1.762	1.749
Real disposable personal income (billion 2005 dollars)	9,883	10,062	14,474	15,118	18,252	19,224
Value of manufacturing shipments (billion 2005 dollars)	4,052	4,260	5,735	6,016	6,270	6,770
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.45	7.50	5.37	5.39	4.38	4.44
Carbon dioxide emissions (million metric tons)	5,425	5,634	5,618	5,938	5,806	6,311

[a]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
Notes: Quantities reported in quadrillion Btu 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. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.
Sources: AEO2012 National Energy Modeling System, run REF2012.D121011B; and AEO2011 National Energy Modeling System, run REF2011.D020911A.