AEO2011 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2011 (AEO2011)* Reference case focus on the factors that shape U.S. energy markets in the long term. Under the assumption that current laws and regulations will remain generally unchanged throughout the projections, the *AEO2011* Reference case provides the basis for examination and discussion of energy market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies, rules, or regulations. Some of the highlights in the *AEO2011* Reference case are summarized in this Executive Summary.

A higher updated estimate of domestic shale gas resources supports increased natural gas production at prices below those in last year's Outlook

The technically recoverable unproved shale gas resource is 827 trillion cubic feet (as of January 1, 2009) in the *AEO2011* Reference case, 480 trillion cubic feet larger than in the *Annual Energy Outlook 2010 (AEO2010)* Reference case, reflecting additional information that has become available with more drilling activity in new and existing shale plays. The larger resource leads to about double the shale gas production and over 20 percent higher total lower 48 natural gas production in 2035, with lower natural gas prices, than was projected in the *AEO2010* Reference case (Figure 1).

Imports meet a major but declining share of total U.S. energy demand

Projected demand for energy imports is moderated by increased use of domestically produced biofuels, demand reductions resulting from the adoption of new efficiency standards, and rising energy prices. Rising fuel prices also spur domestic energy production across all fuels, which moderates growth in energy imports. The net import share of total U.S. energy consumption in 2035 is 18 percent, compared with 24 percent in 2009.

Non-hydro renewables and natural gas are the fastest growing fuels used to generate electricity, but coal remains the dominant fuel because of the large amount of existing capacity

Coal remains the dominant energy source for electricity generation (Figure 2) because of continued reliance on existing coal-fired plants. The U.S. Energy Information Administration (EIA) is not projecting any new central station coal-fired plants, however, beyond those already under construction or supported by clean coal incentives. The generation share from renewable resources increases from 11 percent in 2009 to 14 percent in 2035 in response to Federal tax credits in the near term and State requirements in the long term. Natural gas also plays a growing role due to lower natural gas prices and relatively low capital construction costs that make it more attractive than coal. The share of generation from natural gas increases from 23 percent in 2009 to 25 percent in 2035.

Industrial natural gas demand recovers, reversing recent trend

Industrial natural gas demand grows sharply in the near term, from 7.3 trillion cubic feet in 2009 to 9.4 trillion cubic feet in 2020. This growth reverses the recent downward trend, as a result of a strong recovery in near-term industrial production, growth in combined heat and power, and relatively low natural gas prices.

Assuming no changes in policy related to greenhouse gases, carbon dioxide emissions grow slowly, but do not again reach 2005 levels until 2027

After falling 3 percent in 2008 and nearly 7 percent in 2009, largely driven by the economic downturn, energy-related CO_2 emissions do not return to 2005 levels (5,980 million metric tons) until 2027. Assuming no new policies reducing greenhouse gases, CO_2 emissions then rise by an additional 5 percent from 2027 to 2035, reaching 6,315 million metric tons in 2035 (Figure 3).

Figure 1. Shale gas offsets declines in other U.S. supply to meet consumption growth and lower import need

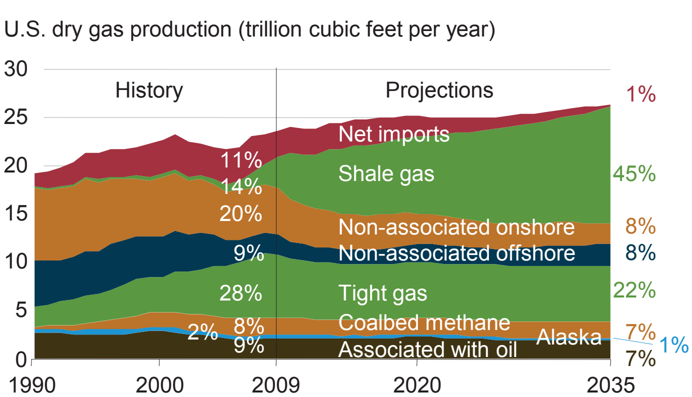
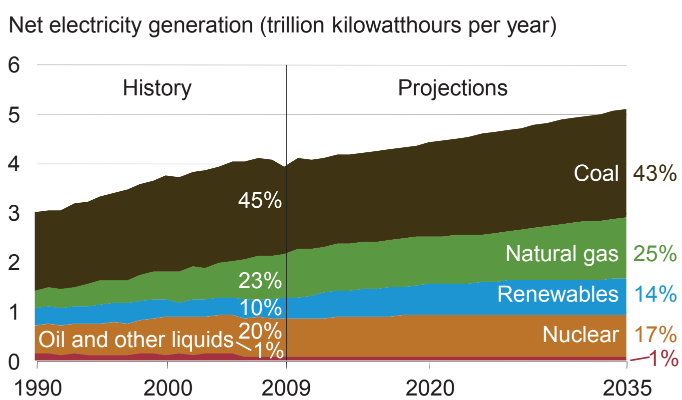


Figure 2. The projected fuel mix for electricity generation gradually shifts to lower carbon options



Introduction

In preparing the *AEO2011,* EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview focuses primarily on one case, the *AEO2011* Reference case, which is presented and compared with the *AEO2010* Reference case released in December 2009 (see Table 1). 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 *AEO2011* publication is released in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

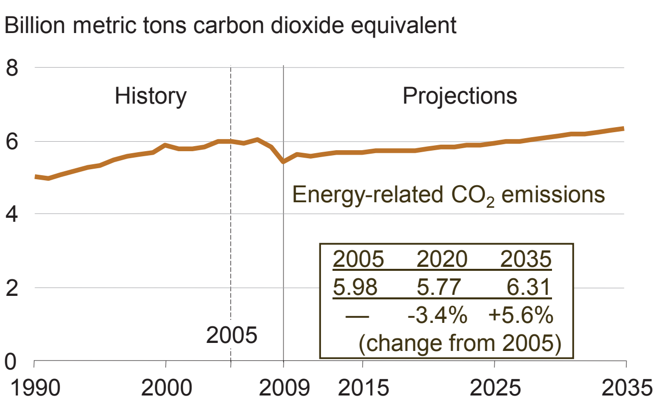
To provide a basis against which alternative cases and policies can be compared, the *AEO2011* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). EIA considers this practice to be a prudent approach. 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 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 *Annual Energy Outlook (AEO)* editions, the complete *AEO2011* will include many additional cases. The standard set of cases in the complete *AEO* will include cases that reflect the impacts of extending a variety of current energy programs beyond their current expiration dates, or the permanent retention of a broad set of current programs that are currently subject to sunset provisions, among others. In addition to the alternative cases prepared for *AEO2011,* EIA has examined proposed policies at the request of Congress over the past year. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates that were made for the *AEO2011* Reference case include:

- Significant update of the technically recoverable U.S. shale gas resources, more than doubling the volume of shale gas resources assumed in *AEO2010,* and also added new shale oil resources
- Revision of the methodology for determining natural gas prices to better reflect a lessening of the influence of oil prices on natural gas prices, in part because of the increase in shale gas supply and improvements in natural gas extraction technologies
- Update of the data and assumptions for offshore oil and gas production, pushing out the start of production for a number of projects as a result of the six-month drilling moratoria, and delaying Atlantic and Pacific offshore leasing beyond 2017[2]
- Increase of the limit for blending ethanol into gasoline for approved vehicles from 10 percent to 15 percent, as a result of the waiver granted by the U.S. Environmental Protection Agency (EPA) in October 2010
- Expanded the number of electricity regions from 13 to 22, allowing better regional representation of market structure and power flow
- Update of the costs for new power plants
- Update of the costs and sizes of electric and plug-in hybrid electric batteries
- Downward revision of light-duty vehicle travel demand due to the adoption of new estimation technique
- Incorporation of California's Low Carbon Fuel Standard, which reduces the carbon intensity of gasoline and diesel fuels in that State by 10 percent from 2012 through 2020
- Incorporation of changes in environmental rules at the State level. For example, California increased its RPS target from 20 percent to 33 percent by 2020.

Figure 3. In the *AEO2011* Reference case, energy-related carbon dioxide emissions grow to almost 6 percent over 2005 levels by 2035



Economic growth

Real gross domestic product (GDP) grows by an average of 2.7 percent per year from 2009 to 2035 in the *AEO2011* Reference case, the same as in the *AEO2010* Reference case. The Nation's population, labor force, and productivity grow at annual rates of 0.9 percent, 0.7 percent, and 2.0 percent, respectively, from 2009 to 2035.

[1]See "Responses to Congressional and Other Requests," at www.eia.gov/oiaf/service_rpts.htm.

[2]The Eastern Gulf of Mexico is under a Congressional drilling moratorium (Gulf of Mexico Energy Security Act of 2006) until 2022 so, as in the *AEO2010* Reference case, no lease sales are assumed in the *AEO2011* until after 2022.

Beyond 2011, the economic assumptions underlying the *AEO2011* Reference case reflect trend projections that do not include short-term fluctuations. The near-term scenario for economic growth is consistent with that in EIA's October 2010 *Short-Term Energy Outlook*.

It is important to note that one must exercise care in evaluating percent growth relative to 2009 levels throughout the projection results since 2009 was the low point of the economic downturn and associated energy consumption.

Energy prices

Crude oil

World oil prices declined sharply in the second half of 2008 from their peak in mid-July of that year. Real prices trended upward throughout 2009, and through November 2010 they remained generally in a range between $70 and $85 per barrel. Prices continue to rise gradually in the Reference case (Figure 4), as the world economy recovers and global demand grows more rapidly than liquids supplies 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 $125 per barrel in 2009 dollars, or about $200 per barrel in nominal dollars.

The *AEO2011* Reference case assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2009 and 2035, and that OPEC targets a relatively constant market share of total world liquids production. 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. Other factors causing uncertainty include OPEC investment decisions, which will affect future world oil prices 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 *AEO2011* publication when it is released in the spring of 2011.

The *AEO2011* Reference case also includes significant long-term potential for 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 5). 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 5.1 million barrels per day in 2035.

Liquid products

Real prices (in 2009 dollars) for motor gasoline and diesel in the *AEO2011* Reference case increase from $2.35 and $2.44 per gallon, respectively, in 2009 to $3.69 and $3.89 per gallon in 2035, lower than in the *AEO2010* Reference case. Annual average diesel prices are higher than gasoline prices throughout the projection because of stronger growth in demand for diesel than for motor gasoline.

Retail prices for E85 (a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) are projected to shift from a volumetric basis to an energy-equivalent basis relative to motor gasoline, in order to meet the renewable fuels standard (RFS) legislated in the Energy Independence and Security Act of 2007 (EISA2007). In 2022, the retail price of gasoline is $3.43 per gallon while the price of E85 is $2.68 per gallon, reflecting the higher energy content of gasoline versus E85 and delivering a similar cost for the two fuels per mile traveled.

Natural gas

Because of a revised representation of natural gas pricing and a significant increase in estimated technically recoverable shale gas resources, the price of natural gas at the wellhead is consistently lower in the *AEO2011* Reference case than it was in *AEO2010*.

Figure 4. World crude oil prices, 1980-2035

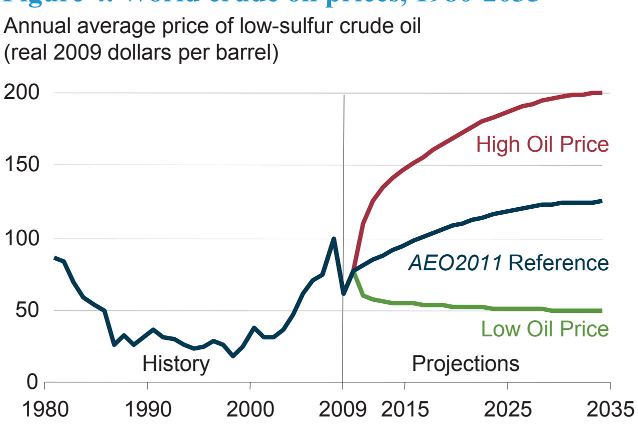
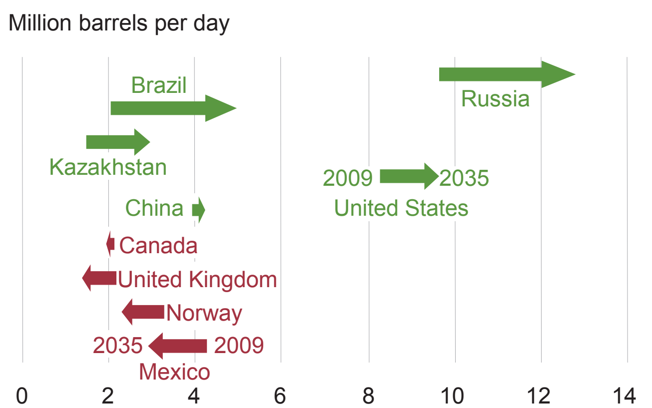


Figure 5. Change in conventional liquids production by top non-OPEC producers, 2009-2035



The annual average natural gas wellhead price remains under $5 per thousand cubic feet through 2022, but it increases thereafter because significantly more shale wells must be drilled to meet growth in natural gas demand and offset declines in natural gas production from other sources. As the shale gas resource base is developed, production gradually shifts to resources that are somewhat less productive and more expensive to produce. Natural gas wellhead prices (in 2009 dollars) reach $6.53 per thousand cubic feet in 2035, compared with $8.19 in *AEO2010*.

Coal

After peaking in 2010, the average U.S. minemouth coal price declines gradually as higher cost coal from mines in Appalachia, particularly Central Appalachia, is displaced with lower cost coal from other U.S. coal basins. After 2016, a leveling off in Appalachian coal production combined with growth in coal demand results in a gradual rise in coal prices through 2035. The Appalachian share of total coal production, on a Btu basis, declines from 40 percent in 2009 to 33 percent in 2016 and 29 percent in 2035. Throughout the entire projection period, the average U.S. coal price in the *AEO2011* Reference case remains above the prices projected in the *AEO2010* Reference case.

In the *AEO2011* Reference case, average real minemouth coal prices in 2009 dollars increase from $1.67 per million Btu ($33.26 per short ton) in 2009 to $1.79 per million Btu ($36.40 per short ton) in 2010, then decline to $1.62 per million Btu ($32.44 per short ton) in 2016 as demand for higher priced coal from Central Appalachia shifts to less expensive coal from other U.S. coal basins. A leveling off of Central Appalachian coal production, combined with increasing demand for coal, leads to a gradual increase in minemouth coal prices to $1.73 per million Btu ($34.11 per short ton) in 2035.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the *AEO2011* Reference case fall from 9.8 cents per kilowatthour in 2009 to as low as 8.9 cents per kilowatthour in 2016 as natural gas prices remain relatively low.

Electricity prices tend to reflect trends in fuel prices—particularly, natural gas prices, because natural gas represents a large share of total fuel costs, and in competitive areas natural gas-fired plants often are the marginal generators. There can be lags in the timing of price impacts, however, because fuel price contracts may affect the fuel costs passed through to electricity consumers.

In the *AEO2011* Reference case, lower costs for fuel lead to lower electricity prices than in the *AEO2010* Reference case. Electricity prices in 2035 (in 2009 dollars) are 9.2 cents per kilowatthour in the *AEO2011* Reference case, compared with 10.3 cents per kilowatthour in the *AEO2010* Reference case.

Energy consumption by sector

Transportation

The *AEO2011* Reference case does not include the proposed fuel economy standards for heavy-duty vehicles provided in *The Proposed Rule for Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in November 2010, nor does it include increases in fuel economy standards for light-duty vehicles, as outlined in the September 2010 EPA/NHTSA Notice of Upcoming Joint Rulemaking to Establish 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy (CAFE) Standards because the specifics of the new standards are not yet available.

AEO2011 assumes the adoption of CAFE standards for light-duty vehicles for model year 2011, as well as joint CAFE and greenhouse gas emissions standards set forth by the EPA and NHTSA for model years 2012 through 2016. The fuel economy standards are increased through model year 2020 to meet the statutory requirements of EISA2007. Beyond 2020, CAFE standards for both passenger cars and light-duty trucks are held constant. To attain the mandated fuel economy levels, the *AEO2011* Reference case includes a rapid increase in sales of unconventional vehicle technologies,[3] such as flex-fuel, hybrid electric, micro hybrid, plug-in, and diesel vehicles, as well as a lower ratio of light-duty truck sales to passenger car sales.

Delivered energy consumption in the transportation sector grows from 27.2 quadrillion Btu in 2009 to 31.8 quadrillion Btu in 2035 in the *AEO2011* Reference case (Figure 6), slightly lower than the 32.5 quadrillion Btu projected for 2035 in the *AEO2010* Reference case.

Energy consumption for light-duty vehicles grows from 16.7 quadrillion Btu in 2009 to 18.4 quadrillion Btu in 2035 in the *AEO2011*, about the same as projected in the *AEO2010* Reference case, as lower projections for vehicle-miles traveled are offset by relatively lower fuel economy improvements after CAFE standards applicable for model year 2020 are achieved.

Lower projected growth in light-duty vehicle travel demand (1.6 percent annually) is a result of the rate of economic recovery and prolonged high unemployment rates in the early part of the projection.

Energy demand for heavy trucks increases from 4.5 quadrillion Btu in 2009 to 6.7 quadrillion Btu in 2035, compared with 6.8 quadrillion Btu in the *AEO2010* Reference case. Relatively lower projected industrial output leads to lower vehicle-miles traveled by freight trucks, more than offsetting the relatively lower projected fuel economy of heavy vehicles.

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

Energy consumption for aircraft increases from 2.7 quadrillion Btu in 2009 to 3.1 quadrillion Btu in 2035 in the *AEO2011* Reference case, lower than the 3.3 quadrillion Btu projected in the *AEO2010* Reference case, due to relatively lower disposable personal income.

Industrial

Approximately one-third of delivered energy consumption in the United States occurs in the industrial sector (21.8 quadrillion Btu in 2009), and consumption in the *AEO2011* Reference case in 2035 is 2.2 quadrillion Btu higher than in the *AEO2010* Reference case, with most of the increase accounted for by natural gas. The largest users of energy in the industrial sector are the bulk chemical, refining, paper, mining, and construction industries. Those five industries together account for more than 61 percent of total industrial delivered energy consumption. Although the largest current user of energy is the bulk chemicals industry, the refining industry, which includes energy use at petroleum, biofuel, and coal-to-liquids (CTL) facilities, becomes the largest energy-consuming industry starting in 2027 in the *AEO2011* Reference case.

Collectively, the energy-intensive manufacturing industries—bulk chemicals, refining, paper products, iron and steel, aluminum, food, glass, and cement—produce about one-quarter of the total dollar value of industrial shipments while accounting for two-thirds of industrial delivered energy consumption. Although energy-intensive industries are expected to recover rapidly from the recent recession, long-term growth is slowed by increased competition from overseas manufacturers and a shift in U.S. manufacturing toward higher value consumer goods, which are less energy-intensive.

Total industrial shipments increase by 55 percent from 2009 to 2035 in the *AEO2011* Reference case, while growth in the energy-intensive manufacturing industries, which drive total industrial energy consumption, is much slower (30 percent). As a result, industrial delivered energy consumption increases by only 19 percent. Most significant is the increase of nearly 79 percent in shipments from the iron and steel industry from 2009 to 2035, which requires a 15-percent increase in the industry's energy consumption. The steep increase in shipments and energy consumption in the iron and steel industry results from relatively low levels of shipments and energy consumption in 2009, during the economic downturn. Because this industry is an energy-intensive, trade-exposed industry, it is sensitive to market and price fluctuations and, therefore, returns quickly to pre-recession production levels.

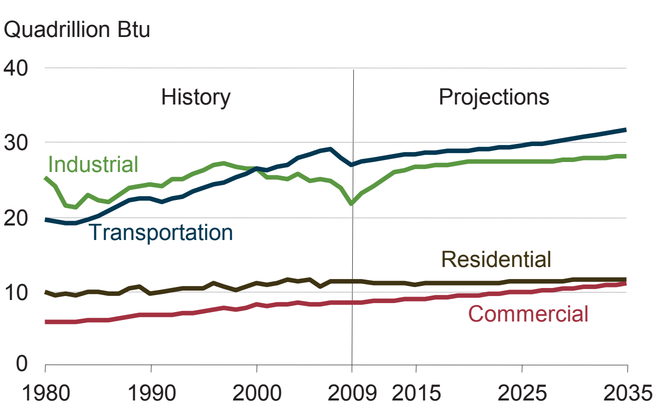
The higher level of industrial natural gas consumption in the *AEO2011* Reference case relative to *AEO2010* is the result of a revised projection for industrial production, which includes a shift in the U.S. product slate, a more rapid economic recovery in the near term, lower natural gas prices, and faster growth in combined heat and power (CHP) production. In 2035, natural gas consumption for use in CHP is approximately 0.9 quadrillion Btu higher in the *AEO2011* Reference case than was projected in *AEO2010*, while total natural gas use in the industrial sector in 2035 is just over 1.2 quadrillion Btu higher in *AEO2011*. The increase in natural gas use for CHP corresponds to faster growth of industrial production in small, non-energy-intensive industries (such as metal-based durable goods manufacturing), which are heavy users of CHP.

Energy consumption in the refining industry also drives growth in total industrial delivered energy consumption. In 2009, energy consumption for refining represents 16 percent of the industrial sector total, and it grows to 27 percent in 2035, very similar to the *AEO2010* projection. Although total shipments from the refining industry are largely unchanged from those in the *AEO2010* Reference case, the industry becomes slightly less energy-intensive as a result of the use of more natural gas liquids (NGL) for refinery inputs and less use of heavy inputs, such as unfinished oils.

Residential

Residential delivered energy consumption in the *AEO2011* Reference case grows from 11.1 quadrillion Btu in 2009 to 11.7 quadrillion Btu in 2035, 0.4 quadrillion Btu less than in the *AEO2010* Reference case.

Figure 6. Delivered energy consumption by sector, 1980-2035



The recent consensus agreement among efficiency advocates and manufacturers[4] leads to lower projected energy use for residential refrigerators and freezers, clothes washers, clothes dryers, dishwashers, and room air conditioners.

The latest efficiency rulemaking for residential water heaters includes a provision for higher standards on electric and natural gas heaters above 55 gallons capacity. The new standard, combined with water consumption standards in the consensus agreement for dishwashers and clothes washers, reduces the need for residential water heating.

Limits on the availability of interconnection services for customers who have distributed generation and other market barriers leads to slow growth of distributed generation in the residential sector than would have otherwise occurred.

[4]Association of Home Appliance Manufacturers and the American Council for an Energy Efficient Economy, "Agreement on Minimum Federal Efficiency Standards, Smart Appliances, Federal Incentives, and Related Matters for Specified Appliances" (July 30, 2010), at www.aham.org/ht/a/GetDocumentAction/i/49956.

Residential solar photovoltaic and wind capacity is 10.5 gigawatts in 2035 in the *AEO2011* Reference case, down from 11.2 gigawatts in the *AEO2010* Reference case in 2035.

Commercial

Despite efficiency gains, lower real electricity and natural gas prices lead to growth in commercial energy consumption in the *AEO2011* Reference case similar to that in the *AEO2010* Reference case. Delivered commercial energy consumption grows from 8.5 quadrillion Btu in 2009 to 11.0 quadrillion Btu in 2035, about the same as in the *AEO2010* Reference case.

Growth in commercial electricity use averages 1.4 percent per year from 2009 to 2035. Equipment standards, more efficient computing equipment, and improved handling of the impact of building shell improvements help to offset increases in demand for electricity to power other electronic equipment and the impact of lower electricity prices relative to *AEO2010*.

Distributed generation and combined heat and power systems in the commercial sector generate 38 billion kilowatthours of electricity in 2035, 19 percent less than in the *AEO2010* Reference case. Lower electricity prices and consideration of regional interconnection limits, however, slow the adoption of these technologies in the *AEO2011* Reference case relative to the *AEO2010* Reference case.

Energy consumption by primary fuel

Total primary energy consumption, which was 101.7 quadrillion Btu in 2007, grows by 21 percent in the *AEO2011* Reference case, from 94.8 quadrillion Btu in 2009 to 114.3 quadrillion Btu in 2035, to about the same level as in the *AEO2010* projection in 2035. The fossil fuel share of energy consumption falls from 84 percent of total U.S. energy demand in 2009 to 78 percent in 2035, reflecting the impacts of CAFE standards and provisions in the American Recovery and Reinvestment Act of 2009 (ARRA), Energy Improvement and Extension Act of 2008 (EIEA2008), Energy Independence and Security Act of 2007 (EISA2007), and State legislation.

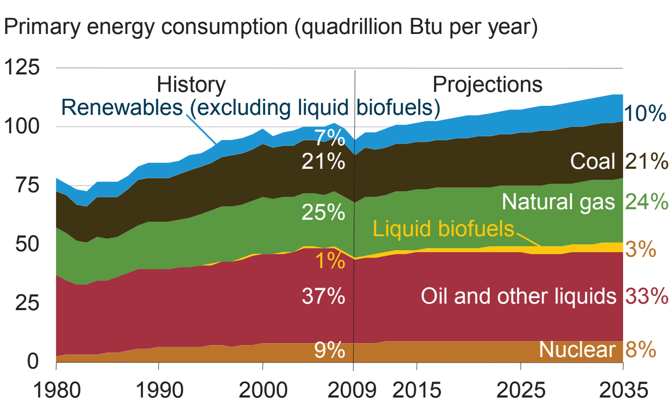
Although the situation is uncertain, EIA's present view of the projected rates of technology development and market penetration of cellulosic biofuel technologies suggests that available quantities of cellulosic biofuels will be insufficient to meet the RFS targets for cellulosic biofuels before 2022, triggering both waivers and a modification of applicable volumes, as provided in Section 211(o) of the Clean Air Act as amended in EISA2007. The modification of volumes reduces the overall target in 2022 from 36.0 billion gallons to 25.7 billion gallons in the *AEO2011* Reference case, equal to the *AEO2010* Reference case.[5]

Total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, grows from 36.6 quadrillion Btu (18.8 million barrels per day) in 2009 to 41.8 quadrillion Btu (22.0 million barrels per day) in 2035 in the *AEO2011* Reference case (Figure 7). The transportation sector dominates demand for liquid fuels, and its share (as measured by energy content) grows only slightly, from 72 percent of total liquids consumption in 2009 to 74 percent in 2035. As in *AEO2010*, biofuel consumption accounts for most of the growth; with expectations of additional waivers, the biofuel portion of liquid fuels consumption is 3.9 quadrillion Btu in *AEO2011*, about the same as in *AEO2010*.

In the *AEO2011* Reference case, natural gas consumption rises from 22.7 trillion cubic feet in 2009 to 26.5 trillion cubic feet in 2035. The total in 2035 is about 1.6 trillion cubic feet higher than in the *AEO2010* Reference case due to lower natural gas prices.

Total coal consumption, which was 22.7 quadrillion Btu in 2007, increases from 19.7 quadrillion Btu (1,000 million short tons) in 2009 to 25.2 quadrillion Btu (1,302 million short tons) in 2035 in the *AEO2011* Reference case. Coal consumption, mostly for electric power generation, grows gradually throughout the projection period, as existing plants are used more intensively, and a few new plants already under construction are completed and enter service. Coal consumption in the electric power sector in 2035 in the *AEO2011* Reference case is about 1.3 quadrillion Btu (53 million short tons) lower than in the *AEO2010* Reference case, however, as a result of higher levels of natural gas use for electric power generation due to relatively lower natural gas prices in the *AEO2011* Reference case.

Figure 7. Energy consumption by fuel, 1980-2035



Total consumption of marketed renewable fuels grows by 2.9 percent per year in the *AEO2011* Reference case. Growth in the consumption of renewable fuels results mainly from the implementation of the Federal RFS for transportation fuels and State renewable portfolio standard (RPS) programs for electricity generation. Marketed renewable fuels include wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal 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

[5]The accounting of RFS volumes is based on ethanol-equivalent gallons rather than actual physical volumes.

3.9 quadrillion Btu is included with liquids fuel consumption in 2035. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.2 quadrillion Btu in 2009 to 3.3 quadrillion Btu in 2035.

Energy intensity

The energy intensity of the U.S. economy, measured as primary energy use (in Btu) per dollar of GDP (in 2005 dollars), declines by 40 percent from 2009 to 2035 in the *AEO2011* Reference case as the result of a continued shift from energy-intensive manufacturing to services, rising energy prices, and the adoption of policies that promote energy efficiency (Figure 8). The Reference case reflects observed historical relationships between energy prices and energy conservation. To the extent that consumer preferences change over the projection, the improvement in energy intensity or energy consumption per capita could be greater or smaller.

Since 1992, the energy intensity of the U.S. economy has declined on average by 2 percent per year, in large part because the economic output of the service sectors, which use relatively less energy per dollar of output, has grown at a pace almost 6 times that of the industrial sector (in constant dollar terms). As a result, the share of total shipments accounted for by the industrial sectors fell from 31 percent in 1992 to 24 percent in 2009. In the *AEO2011* Reference case, the industrial share of total shipments continues to decline, but at a slower rate, to 21 percent in 2035 (Figure 9).

Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. The U.S. population increases by 27 percent from 2009 to 2035 in the *AEO2011* Reference case, and energy consumption grows by 21 percent over the same period. Energy consumption per capita declines by an average of 0.2 percent per year from 2009 to 2035 in the *AEO2011* Reference case, similar to the decline in the *AEO2010* Reference case.

Energy production and imports

Net imports of energy meet a major, but declining, share of total U.S. energy demand in the *AEO2011* Reference case (Figure 10). The projected growth in energy imports is moderated by increased use of biofuels (much of which are produced domestically), demand reductions resulting from the adoption of new efficiency standards, and rising energy prices. Rising fuel prices also spur domestic energy production across all fuels, particularly natural gas from plentiful shale gas resources, and temper the growth of energy imports. The net import share of total U.S. energy consumption in 2035 is 18 percent, compared with 24 percent in 2009. (The share was 29 percent in 2007, but it dropped considerably during the recession.)

Liquids

U.S. dependence on imported liquid fuels measured as a share of total U.S. liquid fuel use, which reached 60 percent in 2005 and 2006 before falling to 52 percent in 2009, is expected to continue declining over the projection period, to 42 percent in 2035.

In the *AEO2011* Reference case, U.S. domestic crude oil production increases from 5.4 million barrels per day in 2009 to 5.7 million barrels per day in 2035 (Figure 11). Production increases are expected from onshore enhanced oil recovery (EOR) projects, shale oil plays, and deepwater drilling in the Gulf of Mexico. Cumulatively, oil production in the lower 48 States in the *AEO2011* Reference case is approximately the same as in the *AEO2010* Reference case, but the pattern differs in that more onshore and less offshore oil is produced in *AEO2011*.

Onshore oil production is higher in *AEO2011* as a result of an increase in EOR, as well as increased oil production from shale oil sources, for which the estimate has been increased relative to *AEO2010*. In *AEO2011*, EOR accounts for 33 percent of cumulative onshore oil production. The bulk of the EOR production uses CO_2. For CO_2-enhanced EOR oil production, naturally produced CO_2 or man-made CO_2 captured from sources such as natural gas plants and power plants is injected into a reservoir to allow the oil to flow more easily to the well bore.

Figure 8. Energy use per capita and per 2005 dollar of gross domestic product, 1980-2035

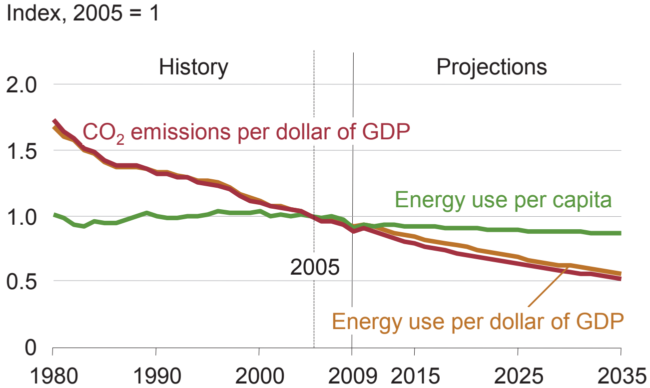
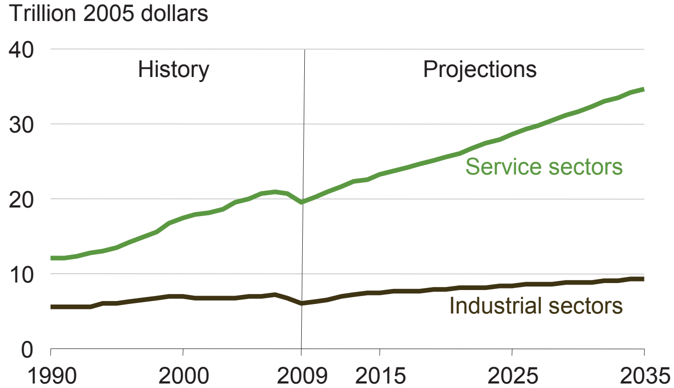


Figure 9. Outputs from the industrial and service sectors, 1990-2035



Offshore oil production in *AEO2011* is lower than in *AEO2010* throughout most of the projection period because of expected delays in near-term projects, in part as a result of drilling moratoria and in part due to the change in lease sales expected in the Pacific and Atlantic outer continental shelf (OCS), as well as increased uncertainty about future investment in offshore production.

As with natural gas, the application of horizontal drilling together with hydrofracturing techniques have allowed significant increases in the development of shale oil resources (oil resident in shale rock). With *AEO2011* incorporating five key shale oil plays (as opposed to two in *AEO2010*), oil production rises significantly in areas of the country where shale oil is being produced, including the Rocky Mountains (primarily from the Bakken shale), the Gulf Coast (primarily from the Eagle Ford and Austin Chalk plays), the Southwest (primarily from the Avalon play), and California (primarily from the Lower Monterey and Santos plays).

Natural gas

The addition of shale gas resources in existing plays that can be produced at prices under $7 per thousand cubic feet results in higher shale gas production overall and a higher rate of development in the *AEO2011* Reference case than in the *AEO2010* Reference case. Cumulative natural gas production in the lower 48 States over the projection period in the *AEO2011* Reference case is 25 percent higher than in the *AEO2010* Reference case as a result of greater supply availability from shale gas plays.

In the *AEO2010* Reference case, technically recoverable unproved shale gas resources were estimated at 347 trillion cubic feet; in the *AEO2011* Reference case they are estimated at 827 trillion cubic feet. The revised estimate results from the availability of additional information as more drilling activity takes place in both existing and new shale plays.

As a result of updated shale gas resources in existing plays (key additions were in the Marcellus, Haynesville, and Eagle Ford plays) and an assumption of increased well productivity for the newer plays, shale gas production in 2035 in the *AEO2011* Reference case is almost double that in the *AEO2010* Reference case.

There is considerable uncertainty about the amounts of recoverable shale gas in both developed and undeveloped areas. Well characteristics and productivity vary widely not only across different plays but within individual plays. Initial production rates can vary by as much as a factor of 10 across a formation, and the productivity of adjacent gas wells can vary by as much as a factor of 2 or 3. Many shale formations, such as the Marcellus Shale, are so large that only a small portion of the entire formation has been intensively production-tested. Environmental considerations, particularly in the area of water usage, lend additional uncertainty. Although significant updates have been made to the estimates of undiscovered shale gas resources in newer areas, most of the resulting additions are not economically recoverable at *AEO2011* prices and have little, if any, impact on the projection.

The Alaska natural gas pipeline, expected to be completed in 2023 in the *AEO2010* Reference case, is not constructed in the *AEO2011* Reference case. This change is a result of increased capital cost assumptions and lower natural gas wellhead prices, which make it uneconomical to proceed with the project over the projection period.

Although net pipeline imports of natural gas from Canada and Mexico decline to lower levels in 2035 in the *AEO2011* Reference case than were projected in the *AEO2010* Reference case, the cumulative volumes of net imports over the projection period are higher in *AEO2011*. The higher levels of cumulative net pipeline imports in *AEO2011* result largely from a decrease in Canada's domestic consumption of natural gas and an increase in the country's assumed shale gas resources and production.

Total U.S. net imports of LNG in the *AEO2011* Reference case are lower than in the *AEO2010* Reference case, due in part to less world liquefaction capacity and greater world regasification capacity, as well as increased use of LNG in markets outside North America. For example, spot market purchases of LNG in Europe are expected to displace pipeline gas supplies that are indexed to world oil prices. Lower natural gas prices in the United States are also a contributing factor.

Figure 10. Total energy production and consumption, 1980-2035

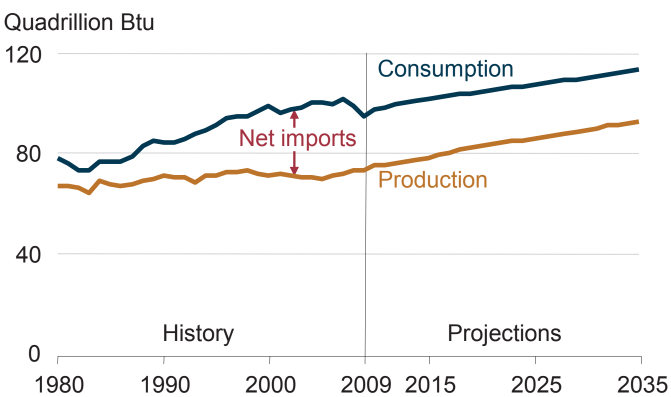
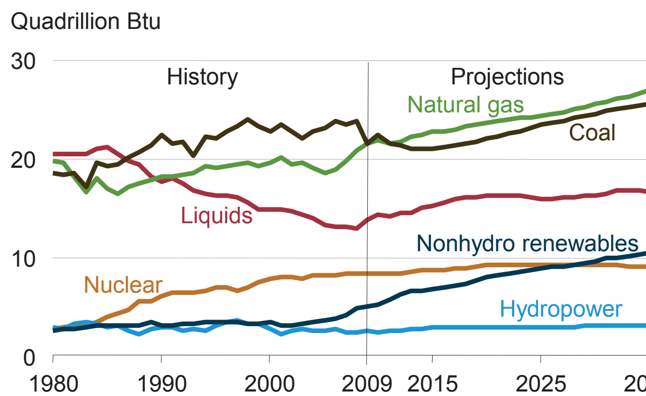


Figure 11. Energy production by fuel, 1980-2035



Coal

Although coal remains the leading fuel for U.S. electricity generation, its share of total electricity generation is consistently lower in the *AEO2011* Reference case than in the *AEO2010* Reference case through about 2023 (but similar thereafter). As a consequence, while still growing in most projection years, total coal production is slightly lower in the *AEO2011* Reference case than in the *AEO2010* Reference case.

As U.S. coal use grows in the *AEO2011* Reference case, domestic coal production increases at an average rate of 0.7 percent per year, from 21.6 quadrillion Btu (1,075 million short tons) in 2009 to 25.8 quadrillion Btu (1,305 million short tons) in 2035. Production from mines west of the Mississippi River trends upward over the entire projection period. Following a substantial decline in output between 2009 and 2015, coal production east of the Mississippi River remains relatively constant from 2015 through 2035. On a Btu basis, 60 percent of domestic coal production originates from States west of the Mississippi River in 2035, up from 50 percent in 2009.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 93 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2011* Reference case (21.8 quadrillion Btu in 2035) is about 1.3 quadrillion Btu less than in the *AEO2010* Reference case (23.1 quadrillion Btu in 2035). For the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices that support increased generation from natural gas in the *AEO2011* Reference case.

Electricity generation

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,745 billion kilowatthours in 2009 to 4,880 billion kilowatthours in 2035 in the *AEO2011* Reference case, increasing at an average annual rate of 1.0 percent. The growth rate in the *AEO2011* Reference case is about the same as in the *AEO2010* Reference case.

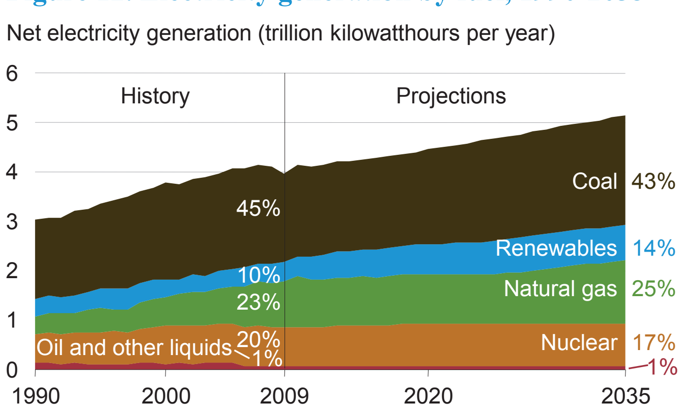
Although the mix of investments in new power plants includes fewer coal-fired plants than other fuel technologies, a total of 21 gigawatts of coal-fired generating capacity is added from 2009 to 2035 in the *AEO2011* Reference case. Coal remains the dominant energy source for electricity generation (Figure 12) because of continued reliance on existing coal-fired plants and the addition of some new plants in the absence of an explicit Federal policy to reduce greenhouse gas emissions. Concerns about greenhouse gas emissions continue to slow the expansion of coal-fired capacity in the *AEO2011* Reference case, even under current laws and policies. Lower 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. Total coal-fired generating capacity grows to 330 gigawatts in 2035 in the *AEO2011* Reference case.

Compared with the *AEO2010* Reference case, electricity generation from natural gas is higher 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 are also much cheaper to build than new renewable or nuclear plants. In 2020, natural gas-fired generation in *AEO2011* is 29 percent higher than in *AEO2010*, and in 2035 it is still 17 percent higher.

Nuclear generating capacity in the *AEO2011* Reference case increases from 101 gigawatts in 2009 to 111 gigawatts in 2035, with 6.3 gigawatts of new capacity (5 new plants) and the balance coming from rerated capacity. Electricity generation from nuclear power plants grows 10 percent, from 799 billion kilowatthours in 2009 to 879 billion kilowatthours in 2035, accounting for about 17 percent of total generation in 2035 (compared with 20 percent in 2009). Higher construction costs for new nuclear plants in *AEO2011,* along with lower projected natural gas prices, make new nuclear capacity slightly less attractive than was projected in the *AEO2010* Reference case.

Increased renewable energy consumption in the electric power sector, excluding hydropower, accounts for 23 percent of the growth in electricity generation from 2009 to 2035. Generation from renewable resources grows in response to key Federal tax credits, but it is lower in the *AEO2011* Reference case than in the *AEO2010* Reference case because of lower natural gas prices and higher costs for new wind power plants. The drop in renewable generation relative to *AEO2010* is seen primarily in lower projections for wind and biomass generation. Growth in renewables is also supported by the many State requirements for renewable generation. The share of generation coming from renewable fuels (including conventional hydro) grows from 11 percent in 2009 to 14 percent in 2035. In the *AEO2011* Reference case, Federal subsidies for renewable generation are assumed to expire as enacted. Their extension could have a large impact on renewable generation.

Figure 12. Electricity generation by fuel, 1990-2035



Energy-related carbon dioxide emissions

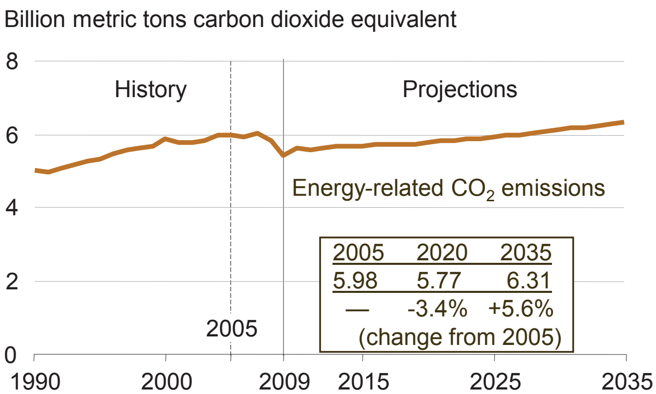
After falling by 3 percent in 2008 and nearly 7 percent in 2009, largely driven by the economic downturn, total U.S. energy-related CO_2 emissions do not return to 2005 levels

(5,980 million metric tons) until 2027, and then rise by an additional 5 percent from 2027 to 2035, reaching 6,315 million metric tons in 2035 (Figure 13). Energy-related CO_2 emissions grow by 0.2 percent per year from 2005 to 2035. Emissions per capita fall by an average of 0.8 percent per year from 2005 to 2035, as growth in demand for electricity and transportation fuels is moderated by higher energy prices, efficiency standards, State RPS requirements, and Federal CAFE standards.

Energy-related CO_2 emissions reflect the mix of fossil fuels consumed because of their different carbon contents. Given the high carbon content of coal and its current use to generate more than one-half of the U.S. electricity supply, prospects for CO_2 emissions depend in part on growth in electricity demand. After a decline from 2007 to 2009, electricity sales resume growth in 2012 in the *AEO2011* Reference case, but the growth is tempered by a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, shifts in housing growth, and the continued transition to a more service-oriented economy. With modest electricity demand growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO_2 emissions grow by 18 percent from 2009 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.

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 grow by 16 percent from 2009 to 2035—lower than the 21-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive, as energy-related CO_2 emissions per dollar of GDP decline by 42 percent.

Figure 13. U.S. energy-related carbon dioxide emissions, 1990-2035



List of Acronyms

AEO	*Annual Energy Outlook*
AEO2010	*Annual Energy Outlook 2010*
AEO2011	*Annual Energy Outlook 2011*
ARRA	American Recovery and Reinvestment Act
CAFE	Corporate Average Fuel Economy
CHP	Combined heat and power
CTL	Coal-to-liquids
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GDP	Gross domestic product
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
OCS	Outer Continental Shelf
OECD	Organization for Economic Cooperation
OPEC	Organization of the Petroleum Exporting Countries
RFS	Renewable Fuels Standard
RPS	Renewable Portfolio Standard

Table 1. Comparison of projections in the *AEO2011* and *AEO2010* Reference cases, 2008-2035

			2025		2035	
Energy and economic factors	2008	2009	*AEO2011*	*AEO2010*	*AEO2011*	*AEO2010*
Primary energy production (quadrillion Btu)						
Petroleum	12.92	13.91	15.93	15.46	16.17	15.87
Dry natural gas	20.83	21.50	24.25	21.90	26.78	23.92
Coal	23.85	21.58	23.71	24.36	25.84	25.19
Nuclear power	8.43	8.35	9.22	9.29	9.19	9.41
Hydropower	2.53	2.69	3.02	2.98	3.09	2.99
Biomass	3.94	3.51	7.13	6.90	8.98	9.27
Other renewable energy	1.12	1.29	2.55	3.07	3.13	3.36
Other	0.19	0.34	0.90	0.94	0.82	0.81
Total	**73.80**	**73.17**	**86.72**	**84.91**	**94.00**	**90.83**
Net imports (quadrillion Btu)						
Liquid fuels	23.94	20.94	20.31	21.06	20.44	21.30
Natural gas	3.07	2.73	1.37	2.25	0.37	1.53
Coal/other (- indicates export)	-1.11	-0.90	-0.74	-0.31	-0.50	0.53
Total	**25.90**	**22.77**	**20.93**	**23.00**	**20.31**	**23.36**
Consumption (quadrillion Btu)						
Liquid fuels	38.46	36.62	39.86	40.14	41.80	42.02
Natural gas	23.85	23.32	25.61	24.24	27.15	25.56
Coal	22.38	19.69	22.55	23.63	24.31	25.11
Nuclear power	8.43	8.35	9.22	9.29	9.19	9.41
Hydropower	2.53	2.69	3.02	2.98	3.09	2.99
Biomass	3.07	2.51	4.67	4.70	5.38	5.83
Other renewable energy	1.12	1.29	2.55	3.07	3.13	3.36
Net electricity imports	0.31	0.32	0.27	0.21	0.25	0.22
Total	**100.14**	**94.79**	**107.77**	**108.26**	**114.30**	**114.51**
Liquid fuels (million barrels per day)						
Domestic crude oil production	4.96	5.36	5.80	6.13	5.73	6.27
Other domestic production	3.39	3.66	5.73	4.91	6.82	5.73
Net imports	11.15	9.72	9.41	9.82	9.43	10.00
Consumption	19.52	18.81	20.98	20.99	21.97	22.06
Natural gas (trillion cubic feet)						
Dry gas production + supplemental	20.35	21.02	23.70	21.37	26.16	23.34
Net imports	2.98	2.64	1.30	2.17	0.32	1.46
Consumption	23.22	22.72	24.96	23.57	26.45	24.86
Coal (million short tons)						
Production	1,186	1,087	1,203	1,249	1,320	1,299
Net imports	-49	-38	-29	-14	-18	20
Consumption	1,121	1,000	1,174	1,235	1,302	1,319

Table 1. Comparison of projections in the *AEO2011* and *AEO2010* Reference cases, 2008-2035

			2025		2035	
Energy and economic factors	2008	2009	*AEO2011*	*AEO2010*	*AEO2011*	*AEO2010*
Prices (2009 dollars)						
Imported low-sulfur, light crude oil (dollars per barrel)	100.51	61.66	117.48	115.09	125.03	133.22
Imported crude oil (dollars per barrel)	93.44	59.04	107.53	104.49	114.05	121.37
Domestic natural gas at wellhead (dollars per thousand cubic feet)	8.17	3.71	5.46	6.35	6.53	8.06
Domestic coal at minemouth (dollars per short ton)	31.54	33.26	33.46	28.19	34.11	28.10
Average electricity price (cents per kilowatthour)	9.8	9.8	8.9	9.3	9.2	10.2
Economic indicators						
Real gross domestic product (billion 2005 dollars)	13,229	12,881	20,015	17,561	25,692	22,362
GDP chain-type price index (2005 = 1.000)	1.086	1.096	1.452	1.662	1.753	2.059
Real disposable personal income (billion 2005 dollars)	10,043	10,100	15,114	13,974	19,230	18,168
Value of manufacturing shipments (billion 2005 dollars)	6,720	6,017	8,397	6,997	9,298	7,786
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.57	7.36	5.38	6.16	4.45	5.12
Carbon dioxide emissions (million metric tons)	5,819.9	5,424.9	5,931.1	6,015.8	6,315.5	6,320.4

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: *AEO2011* National Energy Modeling System, run REF2011.D120810C; and *AEO2010* National Energy Modeling System, run AEO2010R.D111809A.