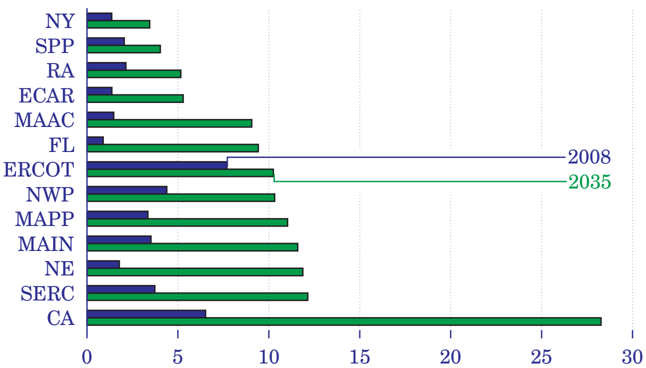
State portfolio standards increase renewable generating capacity

Figure 68. Regional growth in nonhydroelectric renewable electricity generation capacity, including end-use capacity, 2008-2035 (gigawatts)

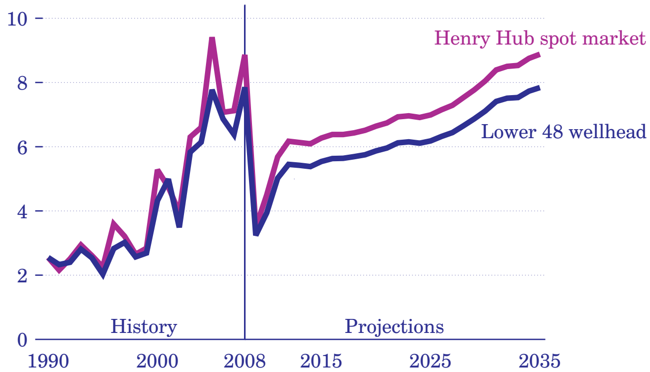


Regional additions of renewable generating capacity depend for the most part on State RPS programs. As of October 31, 2009, there were mandatory RPS programs in 30 States and nonbinding renewable goals in 5 States [*84*]. From 2008 to 2035, California installs the most renewable capacity, 22 gigawatts (Figure 68), primarily new wind capacity but also including 3.1 gigawatts of distributed PV capacity. New England installs more than 8 gigawatts of new wind capacity, representing the second-largest regional growth of the technology (see Figure F2 in Appendix F for a map of the regions). Florida and the Mid-Atlantic account for 80 percent of the dedicated biomass capacity installed by 2035 in the electric power sector (mostly later in the period).

Distributed biomass capacity corresponds largely with the location of cellulosic ethanol plants. Although the Southeast has ample biomass resources, only small amounts of renewable capacity are installed in the region's electric power sector in the absence of State RPS programs, whereas distributed biomass capacity increases by more than 6 gigawatts from 2008 to 2035. Geothermal energy, which is constrained geographically by the availability of local resources, is installed exclusively in the Southwest and California. The same regions have the greatest resource potential for large-scale solar capacity, but because of its high cost only a small amount is installed. Most of the increase in solar capacity consists of distributed PV, and some States in the Northeast (New Jersey, for example) have mandates or provide other incentives for PV installations. Approximately 1.6 gigawatts of distributed PV capacity is installed in the Mid-Atlantic region by 2035.

Natural gas prices rise but remain attractive relative to oil

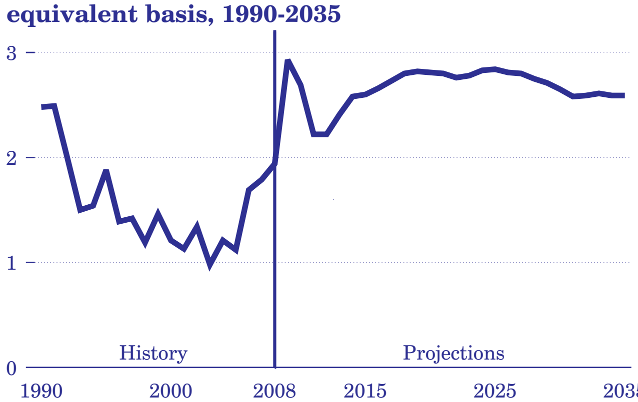
Figure 69. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2008 dollars per million Btu)



Average natural gas prices generally increase in the Reference case, as higher cost resources are brought on line to meet demand growth (Figure 69). The price increase is tempered by improvements in technology. There is a great deal of uncertainty about the long-term trend in natural gas prices, however, particularly in light of the growing development of shale gas resources.

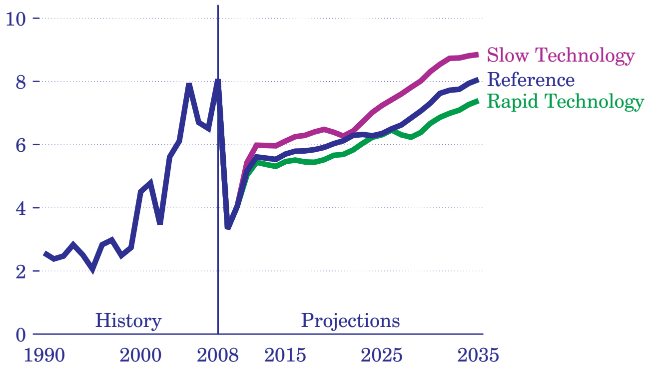
The ratio of low-sulfur light crude oil prices to Henry Hub natural gas prices on an energy equivalent basis remains high relative to the historical average throughout the projection (Figure 70). The ratio is maintained by growing worldwide demand for transportation fuels and robust North American natural gas supply relative to demand. Still, increased use of natural gas as a substitute for petroleum in some transportation uses and/or as a GTL feedstock could increase natural gas prices and narrow the ratio.

Figure 70. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on an energy equivalent basis, 1990-2035



Natural gas prices vary with economic growth and technology progress

Figure 71. Annual average lower 48 wellhead prices for natural gas in three technology cases, 1990-2035 (2008 dollars per thousand cubic feet)



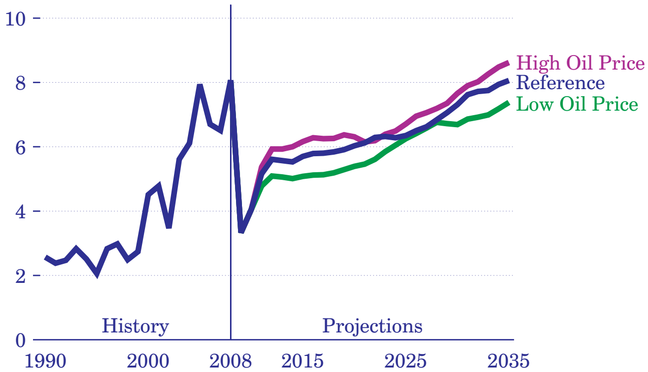
The extent to which natural gas prices increase in the *AEO2010* Reference case and in the Rapid and Slow Technology cases depends on assumptions about the rate of improvement in natural gas exploration and production technologies. Technology improvements, in addition to reducing drilling and operating costs and expanding the economically recoverable resource base, also affect the timing of production increases from sources such as shale gas.

Technology improvement is particularly important to the production of natural gas from shale formations, which can typically be produced at lower incremental cost, but require relatively high capital expenditures. The Reference case assumes that annual technology improvements follow historical trends. In the Rapid Technology case, exploration and development costs per well decline at a faster rate, which accelerates growth in production. Technology improvements also lead to earlier initial production and higher production rates, which result in favorable economics that encourage further growth. The downward pressure placed on natural gas prices by more rapid technology improvement is, however, offset somewhat by higher levels of consumption.

In the Slow Technology case, slower declines in exploration and development costs lead to higher natural gas prices and lower levels of consumption than in the Reference case (Figure 71). In both the Slow and Rapid Technology cases, as in the Reference case, completion of the Alaska pipeline (in 2020 and 2027 in the Slow Technology and Rapid Technology cases, respectively) results in a temporary decline in natural gas prices.

U.S. natural gas prices have limited sensitivity to oil prices

Figure 72. Annual average lower 48 wellhead prices for natural gas in three oil price cases, 1990-2035 (2008 dollars per thousand cubic feet)



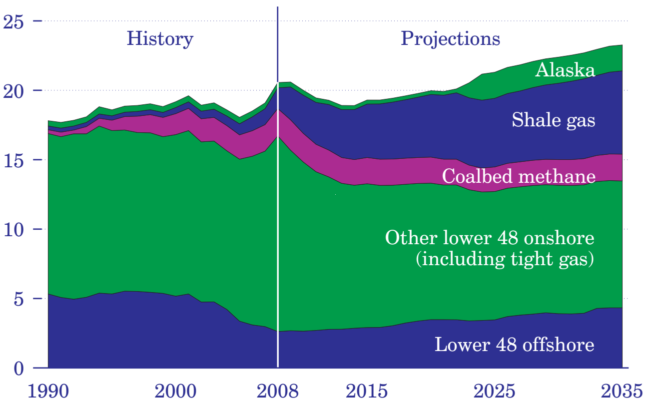
Oil prices have small but measurable impacts on domestic natural gas production and prices, causing them to increase in the High Oil Price case and decrease in the Low Oil Price case. Higher or lower oil prices lead to higher or lower levels of drilling activity, which affect the costs of labor and key commodities, such as steel, that factor into production costs for both industries. As a result, domestic natural gas prices rise and fall with oil prices (Figure 72). The changes are offset in part by increased production of liquids associated with natural gas production when oil prices are higher, as well as the increase in recovery of associated gas that comes with increased oil production.

Different oil price assumptions also affect domestic natural gas supply through their effects on global availability of natural gas exports. Although U.S. natural gas consumption is lower in the High Oil Price case, higher oil prices tend to increase natural gas consumption in international markets, where it is used instead of liquids and also to produce liquids, thereby reducing the amount of natural gas, particularly LNG, available for export to U.S. markets.

Internationally, there is a greater potential for shifting between oil and natural gas than in the United States. In addition, many European and Asian natural gas price contracts are tied to oil prices, and as a result world natural gas prices tend to move with oil prices. A stronger price linkage in the United States could occur with the development of new markets, such as GTL production, natural gas vehicles, or LNG exports.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 73. Natural gas production by source, 1990-2035 (trillion cubic feet)



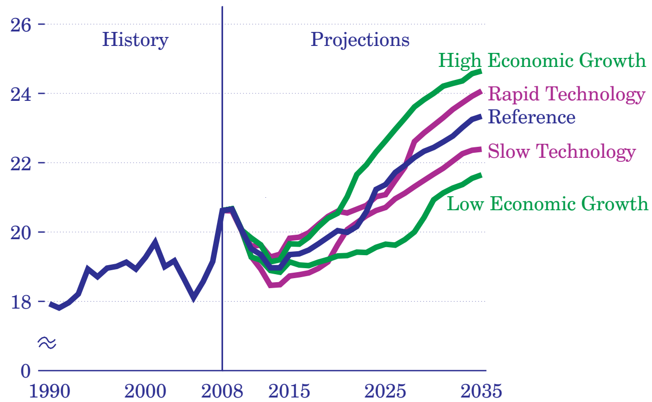
The increase in U.S. natural gas production from 2008 to 2035 in the *AEO2010* Reference case results primarily from continued growth in production of shale gas, recent discoveries in deep waters offshore, and, to a lesser extent, stranded natural gas brought to market after construction of the Alaska natural gas pipeline is completed in 2023 (Figure 73). Shale gas and coalbed methane make up 34 percent of total U.S. production in 2035, doubling their 17-percent share in 2008.

Shale gas is the largest contributor to the growth in production, while production from coalbed methane deposits remains relatively stable from 2008 to 2035. Advances in horizontal drilling and hydraulic fracturing techniques—as well as improved drill bits, steering systems, and instrumentation monitoring equipment—have contributed to higher success and recovery rates, reduced cycle times, lower costs, and shorter times required to bring new shale gas production to market.

Offshore natural gas, the bulk of which is from deep waters in the Gulf of Mexico, contributes significantly to domestic supply. Fields that started producing recently or are expected to start producing within the next few years include Great White, Norman, Shenzi, Tahiti, and Cascade. Production from the continued development of recent discoveries, as well as new discoveries, more than offsets production declines in older fields, resulting in a net increase in offshore production through 2035.

Economic growth and technology progress affect natural gas supply

Figure 74. Total U.S. natural gas production in five cases, 1990-2035 (trillion cubic feet)



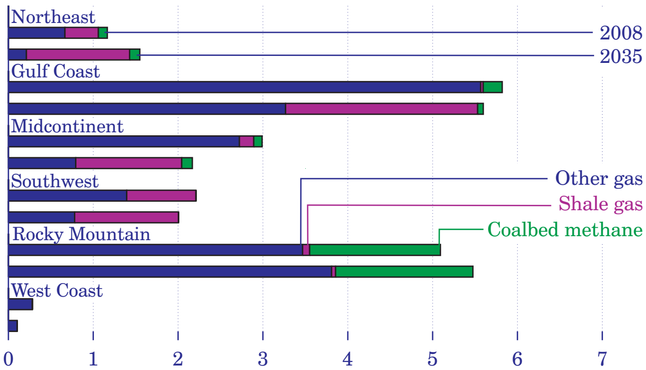
Growth in domestic natural gas production is affected by economic growth and advances in exploration and production technology. The effect of economic growth on domestic natural gas production results from its impact on natural gas consumption and prices. Improvements in technology reduce natural gas drilling and production costs, increase the productive capacity of natural gas wells, and increase the number of successful wells.

Natural gas consumption in 2035 is 2.1 trillion cubic feet higher in the High Economic Growth case than in the Reference case. More than one-half of the increase in the High Growth case is met by an increase of 1.3 trillion cubic feet in domestic production (Figure 74); the remainder is met by an increase in pipeline imports from Canada, supported in part by the introduction of Mackenzie Delta gas in 2032. Roughly one-third of the increase in domestic production comes from shale gas, one-third comes from other lower 48 onshore production, excluding coalbed methane production, and the balance comes from coalbed methane, offshore, and Alaska.

Annual production of natural gas from 2008 to 2035 is, on average, 0.4 trillion cubic feet higher in the Rapid Technology case than in the Reference case. The additional production from the lower 48 States places downward pressure on natural gas prices and delays construction of the Alaska natural gas pipeline—from 2023 in the Reference case to 2027 in the Rapid Technology case. In the Slow Technology case, average annual production of domestic natural gas from 2008 to 2035 is 0.5 trillion cubic feet lower than in the Reference case from 2008 to 2035.

Natural gas production grows in Northeast, Rocky Mountain regions

Figure 75. Lower 48 onshore natural gas production by region, 2008 and 2035 (trillion cubic feet)



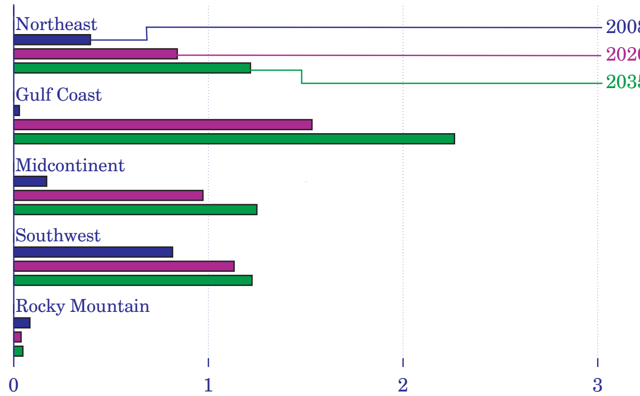
A 4-fold increase in shale gas production from 2008 to 2035 more than offsets a 31-percent decline in other lower 48 onshore natural gas production in the *AEO-2010* Reference case. Significant increases in shale gas production are expected in the Northeast, Gulf Coast, and Midcontinent regions (Figure 75). (See Figure F4 in Appendix F for a map of the regions.) Coalbed methane production, which has grown rapidly over the past several decades, is relatively stable through 2035 and is confined largely to the Rocky Mountain region.

In the Northeast, natural gas production grows by 34 percent from 2008 to 2035 in the Reference case, led by increased development of shale gas. The growth has the potential to replace some of the Northeast's current natural gas supply that comes from the U.S. Gulf Coast and from Canada, resulting in more Gulf Coast supply available to other regions. This has the potential to moderate natural gas prices at the Henry Hub.

While U.S. shale gas production increases, total onshore natural gas production declines slightly in the Gulf Coast region, by 27 percent in the Midcontinent region, and by 9 percent in the Southwest from 2008 to 2035. The Rocky Mountain region is expected to see an increase in total production (8 percent), largely from tight sand formations (which are included in the "other gas" category). The largest decline in total natural gas production, about 63 percent, is projected for the West Coast region, where no shale gas or coalbed methane is produced.

Shale gas production grows substantially in most regions

Figure 76. Shale gas production by region, 2008, 2020, and 2035 (trillion cubic feet)



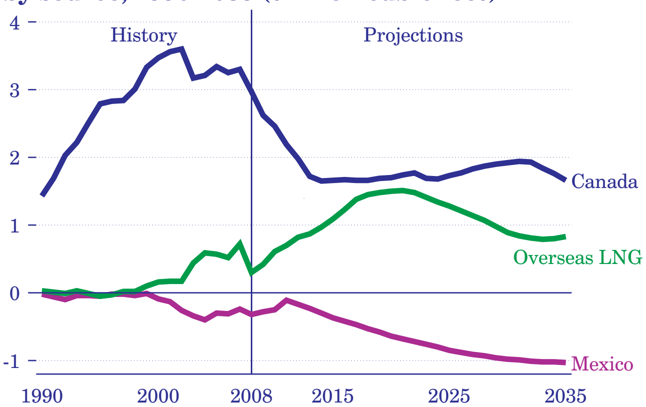
Growth in natural gas production from shale formations offsets declines in other supply sources nationwide throughout the *AEO2010* Reference case projection. The growth depends, in part, on future growth in demand for natural gas. With an assumed 347 trillion cubic feet of technically recoverable shale gas, the potential for increased production is large. The true potential of the U.S. shale gas resource remains uncertain, however, as estimates vary and experience continues to provide new information.

Shale gas production occurs in new and sometimes previously abandoned areas, where its production may require increases in processing, storage, and pipeline capacity. Although production from the Antrim shale has started declining, and development in parts of the Marcellus shale has been inhibited somewhat by limitations on the issuance of drilling permits [*85*], shale gas production in the Northeast region more than doubles from 2008 to 2035 in the Reference case (Figure 76).

In the Gulf Coast region, where the Haynesville play is expected to become a major contributor, shale gas compensates for almost 91 percent of the decline in other natural gas production. In the Midcontinent region, production from the Fayetteville and Woodford shales offsets approximately 57 percent of the decline in other natural gas production. And in the Southwest region, production from the older Barnett shale play offsets approximately 66 percent of the decline in other natural gas production. There is no projected shale gas production in the West Coast region.

U.S. net imports of natural gas decline as domestic production rises

Figure 77. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



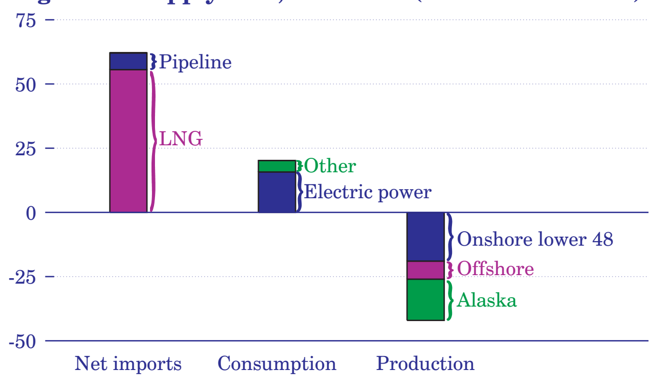
U.S. net imports of natural gas decline in the Reference case from 13 percent of total supply in 2008 to 6 percent in 2035. The reduction consists primarily of lower imports from Canada and higher exports to Mexico, as a result of demand growth in both countries that outpaces the growth in their production, as well as increased U.S. production.

In the Reference case, imports from Canada decline rapidly through 2014 (Figure 77), as increased production from growing sources, such as shale gas, is not yet sufficient to offset the decline in other sources. After 2014, U.S. imports from Canada stabilize at 1.7 to 1.9 trillion cubic feet per year through 2035. However, the size of Canada's shale gas resource is uncertain at present. In the Low Technology and High Economic Growth cases, which include higher natural gas prices, a pipeline from the Mackenzie Delta is constructed before 2035. With lower natural gas prices, it is not completed by 2035.

U.S. imports of LNG increase to a high of 1.5 trillion cubic feet in 2021 as new liquefaction capacity is built in exporting countries, then decline as demand from other importing countries grows to absorb more of the output from the new capacity. Other importing countries have few economical alternatives to LNG, whereas the United States has ample supplies of domestic natural gas. Therefore, U.S. import levels depend primarily on the amount of excess liquefaction capacity available. Domestic production keeps U.S. natural gas prices low relative to world LNG prices, which remain tied to oil prices in many foreign markets. Actual import volumes are likely to vary notably around the trend line.

High LNG supply case illustrates uncertainty in future import levels

Figure 78. Cumulative difference from Reference case natural gas supply and consumption in the High LNG Supply case, 2008-2035 (trillion cubic feet)



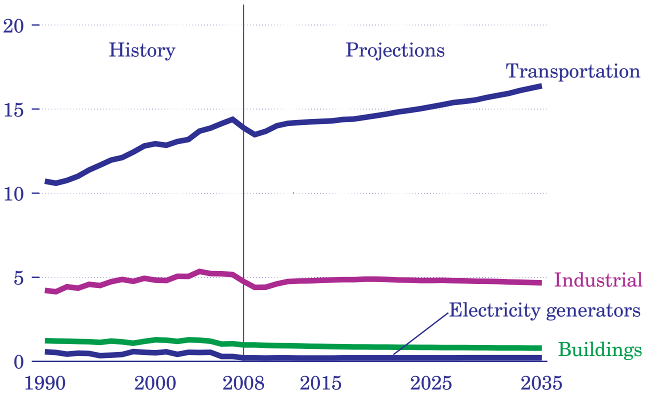
U.S. imports of LNG depend on world liquefaction capacity, world demand for LNG, and U.S. natural gas prices. When there is excess natural gas supply in world markets (for example, during years with warmer weather than normal), more LNG becomes available for U.S. imports. The *AEO2010* High LNG case assumes the availability of more LNG imports to North America than in the Reference case—up to 5 times more in 2035 and cumulatively 2.9 times more from 2009 to 2035, or a total of 70 trillion cubic feet.

The increase in LNG imports results in lower wellhead prices, with annual wellhead prices lower in the High LNG case than in the Reference case by 7 to 18 percent ($0.55 to $1.42 per thousand cubic feet) during the period from 2020 to 2035. A major impact of the increase in LNG imports in the High LNG case is on the timing of the Alaska pipeline, which is opened in 2023 in the Reference case but delayed until 2033 in the High LNG case. In the lower 48 States, a major impact of increased LNG imports is reduced production of onshore natural gas and an even larger percentage reduction in offshore production, because lower prices imply that fewer U.S. natural gas resources are economical to produce.

Effects on U.S. natural gas consumption in the High LNG case are primarily in the price-responsive electricity generation sector, where natural gas competes with coal and renewables. The electricity generation sector accounts for 80 percent of the cumulative difference in consumption between the two cases (Figure 78).

Transportation uses spur growth in liquid fuels consumption

Figure 79. Liquid fuels consumption by sector, 1990-2035 (million barrels per day)



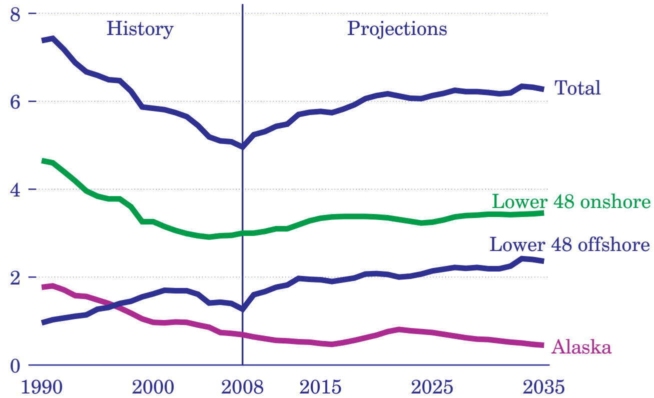
U.S. consumption of liquid fuels—including fuels from petroleum and, increasingly, those derived from fuels such as biomass, coal, and natural gas—totals 22.1 million barrels per day in 2035 in the Reference case, an increase of 2.5 million barrels per day over the 2008 total (Figure 79). In all sectors except transportation, liquid fuel consumption remains at roughly the same level over the projection period. As a result, the transportation sector accounts for 74 percent of total liquid fuels consumption in 2035, up from 71 percent in 2008.

Motor gasoline, ultra-low-sulfur diesel, and jet fuel are the main fuels consumed in the transportation sector. Although EIA expects that the most recent increases in U.S. CAFE standards will increase the fuel efficiency of motor vehicles, the growth in demand for transportation services that results from increases in population and GDP outpaces the expected improvements in efficiency.

Growth in demand for transportation fuels is met primarily by diesel fuel and biofuels. While motor gasoline consumption (including ethanol used in E10) increases by 0.1 million barrels per day from 2008 to 2035 in the Reference case, consumption of diesel fuel and E85 increases by 1.0 and 1.2 million barrels per day, respectively, over the period. Growth in demand for biofuels is primarily a result of the EISA2007 RFS. Growth in demand for diesel fuel results from the increasing sales of diesel LDVs that are needed to meet the new CAFE standards, as well as an increase in shipping that leads to more consumption of diesel by heavy freight trucks.

U.S. crude oil production increases as projected world oil prices rise

Figure 80. Domestic crude oil production by source, 1990-2035 (million barrels per day)

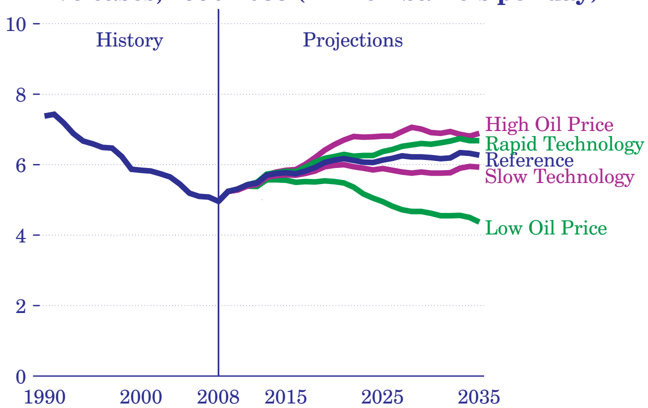


Total U.S. crude production increases from 2008 to 2035, as rising world oil prices spur both onshore and offshore drilling. In the short term, a vast majority of the increase comes from deepwater offshore fields. Fields that started producing in 2009 or are expected to start in the next few years include Great White, Norman, Tahiti, Gomez, Cascade, and Chinook. All are in water deeper than 800 meters, and most are in the Central Gulf of Mexico. Production from those fields, combined with increased production from fields that started producing in 2007 and 2008, contributes to the near-term growth in offshore production. Over the longer term, production from the continued development of other recent discoveries, as well as new discoveries, offsets production declines in older fields, resulting in an increase in production through 2035 (Figure 80).

Removal of the Congressional moratorium on drilling in the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the Outer Continental Shelf also allows for more crude oil production from offshore areas in the Pacific after 2016, in the Atlantic after 2021, and in the Eastern Gulf of Mexico after 2025 [*86*]. In 2035, U.S. crude oil production includes 0.4 million barrels per day from the Pacific offshore, 0.2 million from the Atlantic offshore, and 0.1 million from the Eastern Gulf of Mexico. Lower 48 onshore production of crude oil continues to increase through 2035, primarily as a result of wider application of CO_2 EOR techniques. EOR makes up 37 percent of total onshore production in 2035, up from 12 percent in 2008. Continued exploitation of the Bakken shale formation and the startup of oil shale liquids production after 2023 also contribute to the growth in onshore oil production.

U.S. oil production depends on prices and technology

Figure 81. Total U.S. crude oil production in five cases, 1990-2035 (million barrels per day)

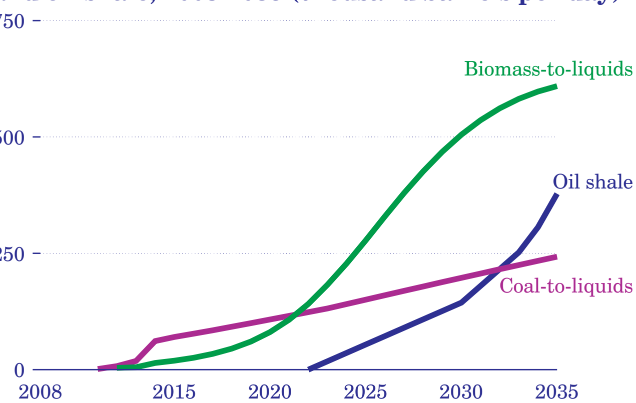


U.S. crude oil production, both onshore and offshore, is sensitive to future world oil prices and advances in technology. The rate of growth in domestic crude oil production depends largely on assumptions about world oil prices (Figure 81), as remaining onshore resources typically require more costly secondary or tertiary recovery techniques. Generally, high-cost projects are more economical when world oil prices are high. However, long lead times from discovery to production limit the increase in production, particularly offshore, over the projection period. Production from deepwater offshore projects and from lower 48 onshore EOR projects accounts for most of the variation in domestic production in the High and Low World Oil Price cases.

Different assumptions about rates of technology improvement also have significant effects on crude oil production, through their effects on exploration and development costs, success rates, and production efficiencies. Advances in horizontal drilling and hydraulic fracturing techniques, as well as improved drill bits, steering systems, and instrumentation monitoring equipment, are among the key advances that have contributed to increases in domestic production over the past few years, reversing the historical trend of declining U.S. crude oil production. Horizontal drilling, in particular, is regarded by many as one of the most valuable technologies introduced in the industry, because it can be used in many situations where conventional drilling is impossible or prohibitively expensive.

Liquids production from biomass, coal, and oil grows as oil prices rise

Figure 82. Liquids production from biomass, coal, and oil shale, 2008-2035 (thousand barrels per day)



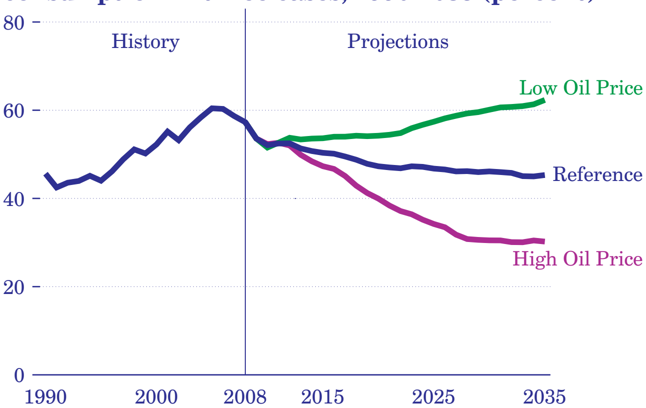
Liquids produced from BTL and CTL, as well as oil shale production, become more significant as world oil prices increase. BTL production shows the most rapid rise in the *AEO2010* Reference case (Figure 82), as increases in the costs of petroleum-based feedstocks make alternative feedstocks, such as biomass, more cost-competitive. In addition, the carbon-mitigating potential of BTL fuels makes them more attractive in a carbon-conscious environment. Financial and technical difficulties, however, continue to provide major challenges to the penetration of BTL technology in the liquid fuels industry.

CTL production also grows in the Reference case, more rapidly than BTL in the early years but more slowly after 2020, so that total CTL production in 2035 is less than one-half the total for BTL. Although advances in coal liquefaction technology have made it commercially available in other countries, including South Africa, China, and Germany, the technical and financial risks of building what would be essentially a first-of-a-kind facility in the United States have discouraged significant investment thus far. In addition, the possibility of new legislation aimed at reducing U.S. GHG emissions creates further uncertainty for future investment in CTL.

With ongoing improvement in oil shale technology, commercial production starts in 2023 and increases rapidly to 1.7 percent of total U.S. liquids supply in 2035. However, oil shale development suffers from environmental, technical, and financial uncertainties similar to those for CTL.

Imports of liquid fuels vary with world oil price assumptions

Figure 83. Net import share of U.S. liquid fuels consumption in three cases, 1990-2035 (percent)



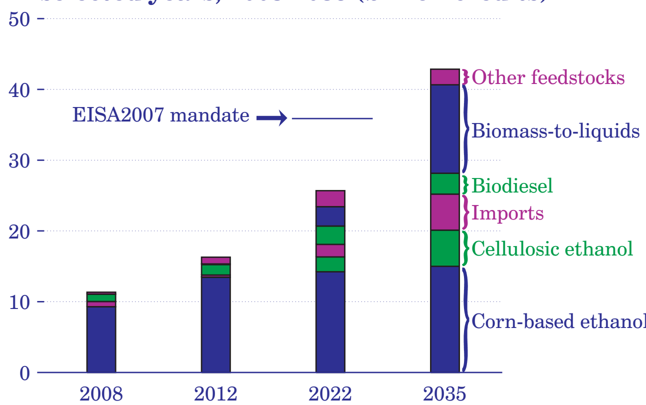
U.S. imports of liquid fuels, which grew steadily from the mid-1980s to 2005, decline significantly from 2008 to 2035 in the *AEO2010* Reference and High Oil Price cases, even as they continue to provide a major part of total U.S. liquids supply. Higher prices lead to more domestic production of oil and in combination with the RFS lead to more domestic biofuel production, while at the same time the higher energy prices moderate growth in overall demand for liquids.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 57 percent in 2008 and about 54 percent in 2009. That trend continues in the projections, with the net import share falling to 45 percent in the Reference case and to 30 percent in the High Oil Price case in 2035. Increased domestic production of crude oil and biofuels reduces the need for imports of crude oil and petroleum products in the High Oil Price case, but the import share of total consumption is still substantial (Figure 83). In the Low Oil Price case, the net import share rises to 62 percent in 2035. With lower prices for liquid fuels, demand increases while domestic production decreases, and more imports are needed to meet demand.

The above projections for net import shares are based on total U.S. consumption of all liquid fuels, including biofuels and other alternative fuels. When only petroleum consumption is considered (instead of total liquid fuels consumption), the net import share of petroleum declines from 57 percent in 2008 to 49 percent in 2035 in the Reference case.

EISA2007 RFS targets are not met in 2022 but are surpassed later

Figure 84. EISA2007 RFS credits earned in selected years, 2008-2035 (billion credits)



EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to ethanol-equivalent gallons produced [*87*], except for the biodiesel schedule, which is based on actual volumes. BTL distillates receive a 1.7-gallon credit for each gallon produced, because the energy content of BTL fuels is higher than the energy content of ethanol. In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels—including 16 billion gallons from cellulosic biofuels—are required in 2022.

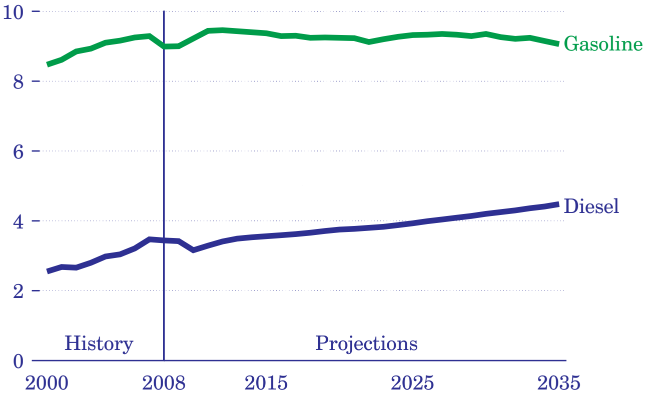
If available biofuel quantities are inadequate to meet the initial targets, EISA2007 provides for application of waivers and modification of applicable credit volumes. In the Reference case only 25.7 billion gallons of RFS credits are generated in 2022 (Figure 84), because economic and technological factors prevent cellulosic biofuel production from providing the credits that would be needed to meet the requirement.

Corn ethanol makes the largest contribution toward the RFS mandate, providing up to 14.2 billion credits in 2022. Cellulosic ethanol contributes 2.1 billion credits to the advanced and cellulosic biofuel requirement in 2022, and BTL contributes 2.5 billion credits. The remaining 6.9 billion gallons of credits for advanced biofuels in 2022 include ethanol imports, biodiesel, and renewable diesel. As the technologies mature, production of cellulosic ethanol and BTL increases to 5.1 billion and 9.6 billion gallons of credits, respectively, in 2035. Production of biofuels ultimately surpasses the RFS requirement as higher oil prices and lower production costs improve their competitiveness.

Liquid fuels refinery capacity

Refinery operations shift focus to diesel fuel production

Figure 85. U.S. motor gasoline and diesel fuel consumption, 2008-2035 (million barrels per day)



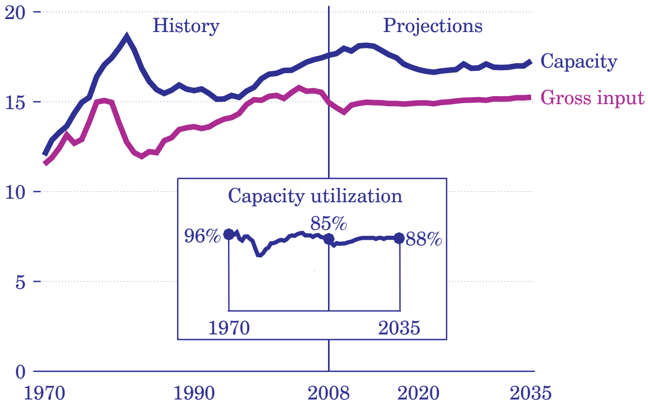
Diesel consumption increases steadily from 2008 to 2035 in the *AEO2010* Reference case, while motor gasoline consumption remains relatively flat (Figure 85). Increased consumption of ethanol in E85 is the main reason for the absence of substantial growth in petroleum-based gasoline consumption, which increases by less than 0.1 million barrels per day. In addition, however, the combination of increased diesel output and decreased refinery capacity leads to a shift in the product slate of U.S. refineries. Diesel consumption increases by approximately 1.0 million barrels per day from 2008 to 2035 in the Reference case, and diesel exports increase by approximately 0.2 million barrels per day. The increase in domestic demand for diesel fuel is a result of increased freight shipping activity.

Despite recent decreases in both demand for petroleum products and capacity utilization rates, total capacity expands in the near term as planned additions are completed. The planned additions are focused on diesel output for use in both domestic and foreign markets.

After peaking in 2012, refinery capacity is expected to decline by a total of approximately 0.8 million barrels per day from 2012 through 2035 as diesel fuel consumption continues to grow in the Reference case, resulting in a growing diesel share of refinery output.

Near-term increase in refinery capacity leads to a lower utilization rate

Figure 86. U.S. refinery capacity, 1970-2035 (million barrels per day)



New projects to add capacity are underway at some domestic refineries, and most of those projects are scheduled to come on line in the next several years, adding approximately 500,000 barrels per day of new refining distillation capacity by the end of 2012. Two large expansion projects in Port Arthur, Texas, and Garyville, Louisiana, make up the majority of the new capacity [*88*]. The additional capacity will be added, in part, to meet the increase in demand for ultra-low-sulfur diesel fuel from 2008 to 2035. Some of it will be configured to process heavier and less desirable crude oils, capitalizing on their lower costs. In the near term, however, because the current economic downturn reduces demand for motor fuels, capacity utilization falls to approximately 80 percent in 2010 from 85 percent in 2008 (Figure 86).

After 2012, approximately 1.5 million barrels per day of existing capacity is taken out of service by 2022 in the *AEO2010* Reference case. The reduction in operating capacity, coupled with growth in demand for diesel fuel, increases capacity utilization to around 89 percent in 2020, and it remains at roughly that level through 2035. Given the current economic climate, the potential for future carbon mitigation legislation that could affect refiners, and the overall level of demand, EIA does not expect future capacity additions after 2013 in the Reference case or Low Oil Price case. Excess refinery capacity is fully utilized in the Low Oil Price case, but no new capacity is built.