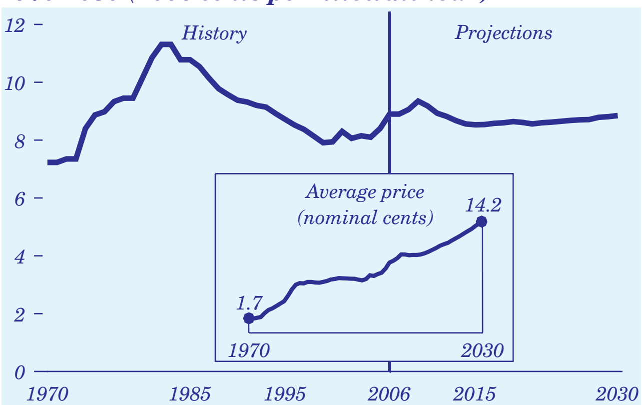
Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 71. Average U.S. retail electricity prices, 1970-2030 (2006 cents per kilowatthour)



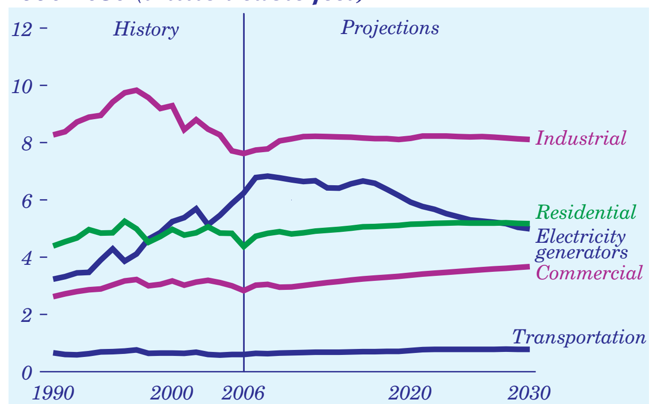
In the *AEO2008* reference case, continuing high fuel prices and escalating capital costs for new generating capacity lead to a jump in real electricity prices, peaking in 2009 at an annual average of 9.3 cents per kilowatthour (2006 dollars). Electricity prices fall to 8.5 cents per kilowatthour in 2015, as new sources of natural gas and coal are brought on line. From 2016 on, generally rising prices for natural gas and petroleum (in addition to the impact of State renewable fuel mandates) encourage power producers to increase their use of less expensive coal and renewable fuels. Retail electricity prices rise gradually after 2016, to 8.8 cents per kilowatthour in 2030 (Figure 71).

Customers in States with competitive retail markets for electricity experience the effects of changes in natural gas prices more rapidly than customers in States with regulated markets, because competitive prices are determined by the marginal cost of energy, and natural-gas-fired plants, with their higher operating costs, often set hourly marginal prices. After 2016, as other plant types set hourly prices more often, the price of natural gas has less influence on competitive retail markets. In the low and high oil and natural gas price cases, electricity prices range from 8.5 to 9.1 cents per kilowatthour in 2030.

Electricity distribution costs decline by 5 percent from 2006 to 2030, as technology improvements and a growing customer base lower the cost of the distribution infrastructure. Transmission costs increase by 30 percent, as additional investments are made in the grid to alleviate current constraints, facilitate competitive markets, and meet growing consumer demand for electricity.

Fastest Increase in Natural Gas Use Is Expected for the Buildings Sectors

Figure 72. Natural gas consumption by sector, 1990-2030 (trillion cubic feet)



In the reference case, total natural gas consumption increases from 21.7 trillion cubic feet in 2006 to a peak value of 23.8 trillion cubic feet in 2016, followed by a decline to 22.7 trillion cubic feet in 2030. The natural gas share of total energy consumption drops from 22 percent in 2006 to 20 percent in 2030.

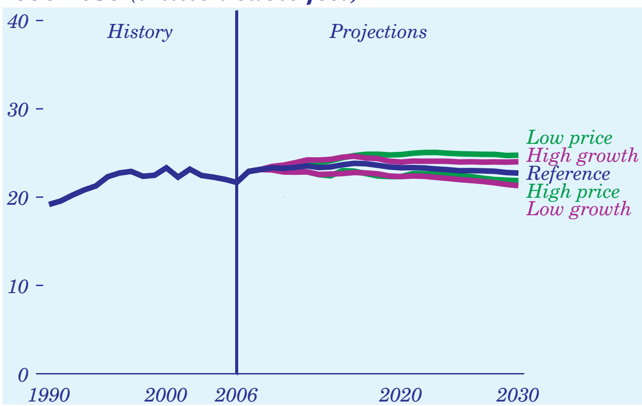
The projected path of total natural gas consumption depends almost entirely on the amount consumed in the electric power sector. Natural gas consumption for electricity generation in the power sector declines from current levels to 5.0 trillion cubic feet in 2030 in the reference case (Figure 72), as a result of a projected increase in natural gas prices that begins after 2016.

Natural gas consumption in the electric power sector is highly responsive to price changes, because electricity producers can choose among different fuels on an ongoing basis. In contrast, consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. In those sectors, natural gas consumption increases steadily from 2006 through 2030.

In the industrial sector, natural gas consumption is projected to grow from 7.6 trillion cubic feet in 2006 to 8.1 trillion cubic feet in 2030. In the residential and commercial sectors (the buildings sectors), consumption increases from a combined total of 7.2 trillion cubic feet in 2006 to 8.8 trillion cubic feet in 2030. As a result, the buildings sectors show the greatest overall increase in natural gas consumption, in both percentage and absolute terms.

Natural Gas Consumption Varies With Fuel Prices and Economic Growth

Figure 73. Total natural gas consumption, 1990-2030 (trillion cubic feet)



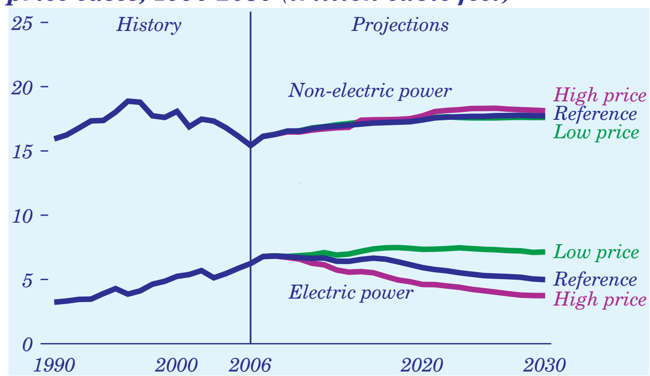
In the *AEO2008* projections, natural gas consumption varies with natural gas prices and economic growth rates. Higher natural gas prices reduce demand, and higher economic growth rates increase demand.

In the high and low price cases, natural gas consumption in 2030 ranges from 24.8 trillion cubic feet in the low case to 21.9 trillion cubic feet in the high case (Figure 73). High natural gas prices provide direct economic incentives for reducing natural gas consumption, whereas low prices encourage more consumption; however, the strength of the relationship depends on short- and long-term fuel substitution capabilities and equipment options within each consumption sector.

In the economic growth cases, consumption in 2030 varies from 24.0 trillion cubic feet in the high growth case to 21.3 trillion cubic feet in the low growth case. With faster economic growth, disposable income increases more rapidly, and consumers increase their energy purchases either by buying products that consume additional energy (such as larger homes), being less energy-efficient in using products they already own (for example, by setting thermostats higher in the winter and lower in the summer), or both.

Natural Gas Use in the Electric Power Sector Is Sensitive to Prices

Figure 74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030 (trillion cubic feet)



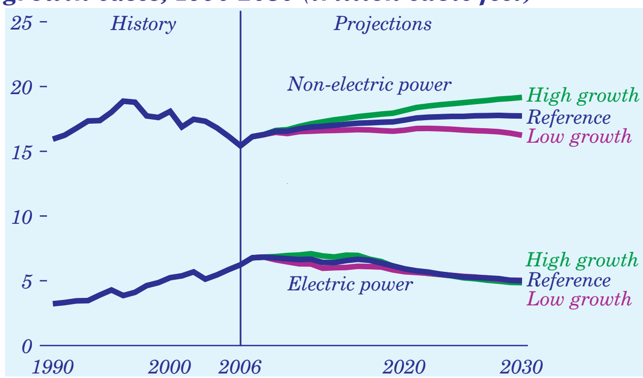
In the *AEO2008* projections, the largest variation in sectoral demand for natural gas in response to high and low price assumptions occurs in the electric power sector (Figure 74). Natural gas consumption by electricity producers in 2030, projected at 5.0 trillion cubic feet in the reference case, increases to 7.1 trillion cubic feet in the low price case but falls to 3.7 trillion cubic feet in the high price case.

Much of the variation in projected natural gas demand in the electric power sector between the low and high price cases is the result of different projections for the amount of natural-gas-fired generating capacity built—and consequently the amount of electricity generated from natural gas—from 2007 to 2030. In the high price case, a cumulative 65.4 gigawatts of new natural-gas-fired generating capacity is added in the electric power sector between 2007 and 2030. In the low price case, cumulative natural-gas-fired capacity additions in the electric power sector total 131.1 gigawatts over the same period.

When natural gas prices are high, electric power producers can quickly substitute generation from coal and other fuels for power generated from natural gas. In contrast, in the residential, commercial, industrial, and transportation sectors, fuel price assumptions have a considerably smaller effect on natural gas consumption, because fuel substitution options are limited and the stocks of equipment that use natural gas have relatively slow turnover rates. In 2030, total natural gas consumption in those sectors ranges from 18.1 trillion cubic feet in the high price case to 17.6 trillion cubic feet in the low price case.

Natural Gas Use in Other Sectors Is More Sensitive to Economic Growth

Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030 (trillion cubic feet)

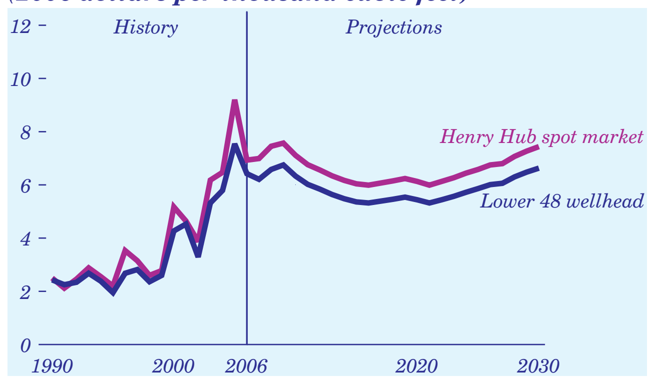


The largest variation in natural gas consumption in the residential, commercial, industrial, and transportation end-use sectors results from different assumptions about economic growth rates. In the high economic growth case, natural gas consumption in those end-use sectors is projected to total 19.2 trillion cubic feet in 2030. In the low growth case, the projected total in 2030 is 16.2 trillion cubic feet (Figure 75). Most of the difference between the projections in the two cases is attributable to the industrial sector, where growth in economic output has a greater impact on natural gas consumption than it does in the residential, commercial, and transportation sectors. In the industrial sector, projected natural gas consumption in 2030 varies from 7.2 trillion cubic feet in the low growth case to 9.0 trillion cubic feet in the high growth case.

Natural gas consumption in the electric power sector is sensitive to natural gas prices because other fuels, such as coal, can be substituted directly for natural gas in generating electricity. In the high and low economic growth cases, however, natural gas consumption in the electric power sector shows little variation from the reference case projection. Natural gas use for electricity generation in 2030 varies from 5.0 trillion cubic feet in the low growth case to 4.9 trillion cubic feet in the high growth case. In the high economic growth case, when natural gas consumption in the electric power sector begins to rise, natural gas prices increase significantly, and in response coal and nuclear power are substituted for natural gas.

Projected Natural Gas Prices Fall from Current Levels Before Rising

Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2006 dollars per thousand cubic feet)



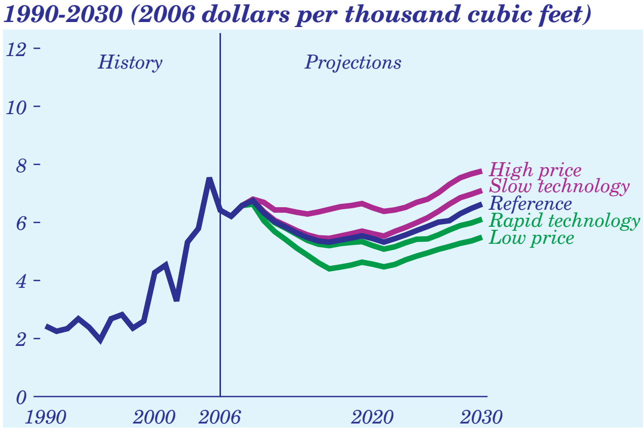
In the *AEO2008* reference case, lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu ($5.99 per thousand cubic feet) in 2016 and then rise to $7.22 per million Btu ($7.43 per thousand cubic feet) in 2030 (Figure 76).

Current high natural gas prices are expected to stimulate the development of new gas supplies and constrain growth in natural gas consumption. Greater availability of natural gas supplies leads to a decline in prices through 2016. After 2016, wellhead natural gas prices increase largely as a result of the increased cost of developing the remaining U.S. natural gas resource base.

Natural gas prices in the reference case are determined largely by the cost of supplying natural gas from the remaining U.S. and Canadian resource base. In the future, however, the U.S. natural gas market is expected to become more integrated with natural gas markets worldwide, as a result of increased U.S. access to, and reliance on, LNG supplies from foreign sources. As a consequence, international market conditions will have a stronger influence on domestic natural gas prices in the United States, causing even greater uncertainty in future U.S. natural gas prices than would be the case if the United States relied exclusively on natural gas supplies from North America.

Prices Vary With Resource Size and Technology Progress Assumptions

Figure 77. Lower 48 wellhead natural gas prices, 1990-2030 (2006 dollars per thousand cubic feet)

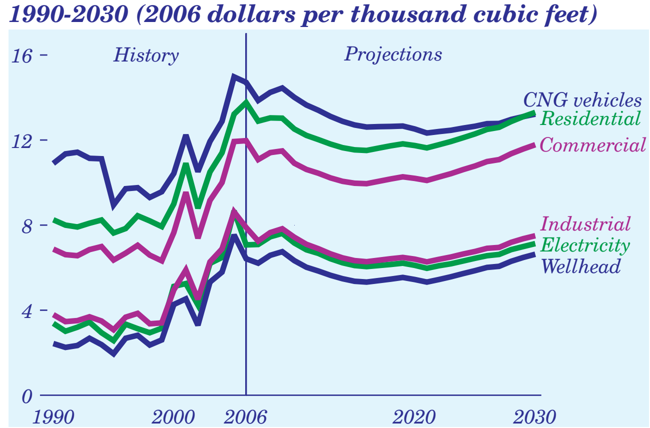


In the high price case, oil prices are assumed to be higher and the unproven natural gas resource base is assumed to be 15 percent smaller than the estimates used in the reference case. The low price case assumes lower oil prices and a 15-percent larger unproven resource base than in the reference case. A smaller domestic natural gas resource base increases exploration and production (E&P) costs, leading to higher natural gas prices. As a result, U.S. wellhead prices (and the price of LNG worldwide) are higher in the high price case and lower in the low price case than in the reference case (Figure 77). In 2030, domestic wellhead natural gas prices are projected to average $7.77 (2006 dollars) per thousand cubic feet in the high price case, compared with $5.49 per thousand cubic feet in the low price case.

Technological progress affects the future production of natural gas by reducing production costs and expanding the economically recoverable resource base. In the *AEO2008* reference case, the rate of improvement in natural gas production technology is based on the historical rate. The slow oil and natural gas technology case assumes an improvement rate 50 percent lower than in the reference case. As a result, future capital and operating costs are higher, causing the projected average wellhead price of natural gas to increase to $7.10 per thousand cubic feet in 2030. The rapid technology case assumes a rate of technology improvement 50 percent higher than in the reference case, reducing natural gas development and production costs. In the rapid technology case, wellhead natural gas prices are projected to average $6.11 per thousand cubic feet in 2030.

Delivered Natural Gas Prices Follow Trends in Wellhead Prices

Figure 78. Natural gas prices by end-use sector, 1990-2030 (2006 dollars per thousand cubic feet)



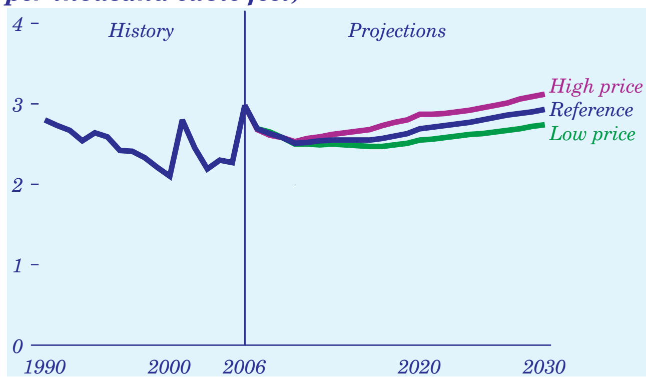
Trends in delivered natural gas prices largely reflect changes in projected wellhead prices. In the *AEO2008* reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead natural gas prices decline, then increase along with wellhead prices over the rest of the projection period (Figure 78).

Natural gas transmission and distribution margins in the industrial and electric power sectors fall over time, because production facilities in those sectors typically are connected directly to transmission pipelines, and pipeline rates are projected to fall as their depreciation expenses decline more rapidly than their costs increase. In the residential and commercial sectors, in contrast, transmission and distribution rates for natural gas rise over time, because increases in building efficiency reduce natural gas consumption at each building site, and distribution expenses thus are spread over a lower total volume of system throughput. As a result, average U.S. transmission and distribution margins increase slowly from 2006 to 2030 in the reference case.

All the *AEO2008* cases assume that sufficient transmission and distribution capacity will be built to accommodate the projected growth in natural gas consumption. If public opposition were to prevent infrastructure expansion, however, delivered prices could be higher than projected.

Transmission and Distribution Margins Vary Inversely With Volumes

Figure 79. Average natural gas transmission and distribution margins, 1990-2030 (2006 dollars per thousand cubic feet)

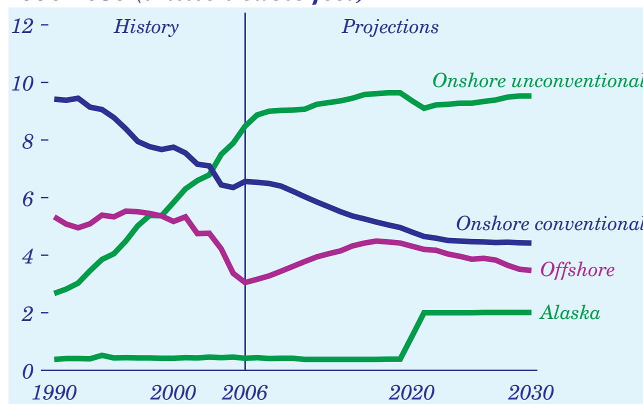


The transmission and distribution margin for natural gas delivered to end users is the difference between the average delivered price and the average source price, which is the quantity-weighted average of the lower 48 wellhead price and the average import price. It reflects both the capital and operating costs for pipelines and the volume of natural gas transported. Although operating costs vary with the level of pipeline utilization, capital costs are fixed for the most part. Variations in pipeline throughput result in higher or lower transmission and distribution costs per thousand cubic feet of natural gas transported. Thus, because the high and low price case projections show the greatest variation in total natural gas consumption, the greatest variation in transmission and distribution margins is also seen in those cases.

In the high price case, total natural gas consumption in 2030 is projected to be only 21.9 trillion cubic feet. As a result, the average transmission and distribution margin for delivered natural gas is projected to increase from $2.98 per thousand cubic feet in 2006 to $3.12 per thousand cubic feet in 2030 (2006 dollars). In the low price case, total natural gas consumption in 2030 grows to 24.8 trillion cubic feet, and the average transmission and distribution margin in 2030 drops to $2.74 per thousand cubic feet as the existing pipeline system is used at a higher capacity factor. In the reference case, with projected natural gas consumption of 22.7 trillion cubic feet in 2030, the projected average transmission and distribution margin in 2030 is $2.93 per thousand cubic feet (Figure 79).

Unconventional Production Is a Growing Source of U.S. Gas Supply

Figure 80. Natural gas production by source, 1990-2030 (trillion cubic feet)



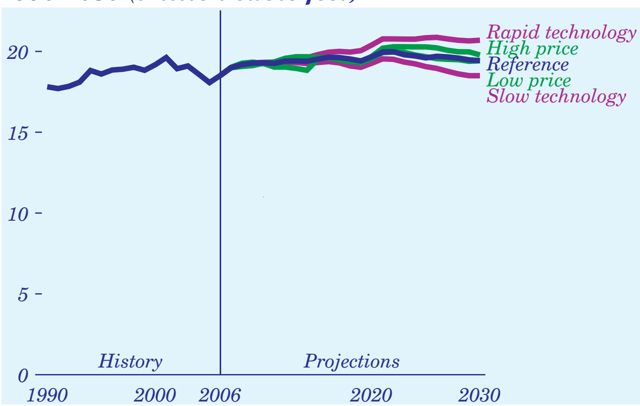
Total U.S. natural gas production grows modestly in the reference case, from 18.5 trillion cubic feet in 2006 to 19.4 trillion cubic feet in 2030, as depletion of the onshore lower 48 conventional resource base is offset by increased production from unconventional sources and from Alaska. Offshore production increases from 3.0 trillion cubic feet in 2006 to 4.5 trillion cubic feet in 2017, then declines to 3.5 trillion cubic feet in 2030. Production in shallow waters declines slowly through 2030. Production in deeper waters rises to 3.0 trillion cubic feet in 2019 and then declines through 2030.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production declines in the *AEO2008* reference case from 6.6 trillion cubic feet in 2006 to 4.4 trillion cubic feet in 2030 (Figure 80). Incremental production of lower 48 onshore natural gas comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2020. As a result, Alaska's natural gas production increases from 0.4 trillion cubic feet in 2006 to 2.0 trillion cubic feet in 2030 in the reference case.

Natural Gas Supply Projections Reflect Rates of Technology Progress

Figure 81. Total U.S. natural gas production, 1990-2030 (trillion cubic feet)



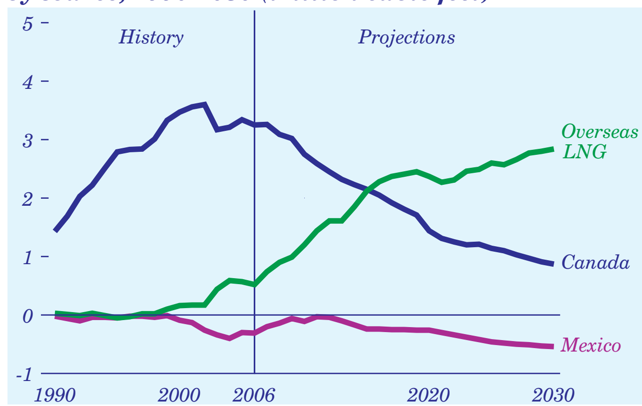
Exploration for and production of natural gas becomes more profitable when prices increase and when exploration and development costs decline. The rapid and slow technology cases show the effects of different assumed rates of technology improvement in the oil and natural gas industries, which directly affect exploration and development costs. The high and low price cases show the effects of different assumptions about oil price levels and the availability of unproved oil and natural gas resources.

Technological progress generally reduces the cost of natural gas production, leading to lower wellhead prices, more end-use consumption, and more production. More rapid progress works to increase domestic natural gas production and slower progress works to reduce production in the technology cases. U.S. natural gas production in 2030 is 6.4 percent higher in the rapid technology case and 4.8 percent lower in the slow technology case than in the reference case (Figure 81).

The high and low price cases show smaller effects on total production than do the technology cases. The high and low price cases include higher and lower oil prices and assume an unproven natural gas resource base that is 15 percent smaller (in the high price case) or 15 percent larger (in the low price case) than assumed in the reference case. In the high price case, the stimulative effect that higher natural gas prices normally would have on natural gas production is offset by an increase in E&P costs as a result of the smaller resource base.

Net Imports of Liquefied Natural Gas Grow in the Projection

Figure 82. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)

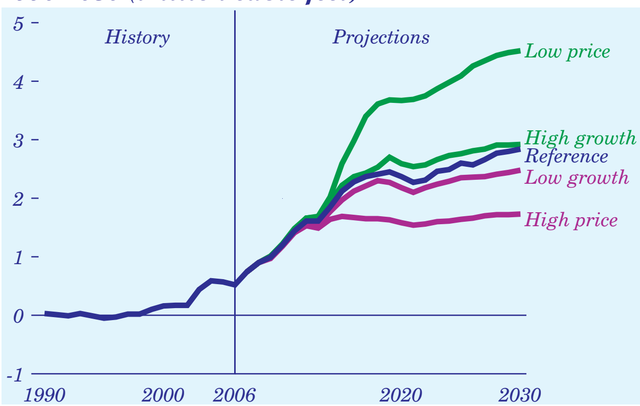


Net U.S. imports of natural gas from Canada are projected to decline, and net imports of LNG are projected to grow, from 2006 through 2030. Most of the expected growth in U.S. natural gas imports is in the form of LNG. The total capacity of U.S. LNG receiving terminals increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the reference case (with no further increase through 2030), and net LNG imports grow from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030 (Figure 82). The U.S. market is expected to be tight throughout the projection because of competition for LNG supplies across the world. Although U.S. imports rise over time, they are expected to vary significantly from year to year, depending on domestic and worldwide natural gas prices. When international natural gas prices are higher than U.S. prices, LNG imports are expected to be lower, and vice versa. Thus, LNG imports in the *AEO2008* cases reflect the expected long-term trend rather than actual import levels in any particular year.

Over the past year, reported costs for development of the Mackenzie Delta natural gas pipeline, including development costs for the three anchor natural gas fields, have increased substantially [*87*]. Therefore, the pipeline is not expected to be built with natural gas prices at the levels projected in the *AEO2008* reference case. Canada still is expected to export natural gas to the United States in the reference case, however, with U.S. net imports from Canada declining from 3.2 trillion cubic feet in 2006 to 0.9 trillion cubic feet in 2030. Natural gas prices in the reference case are adequate to support that level of imports despite the absence of the Mackenzie Delta pipeline.

LNG Imports Are the Source of Supply Most Affected in the Price Cases

Figure 83. Net U.S. imports of liquefied natural gas, 1990-2030 (trillion cubic feet)



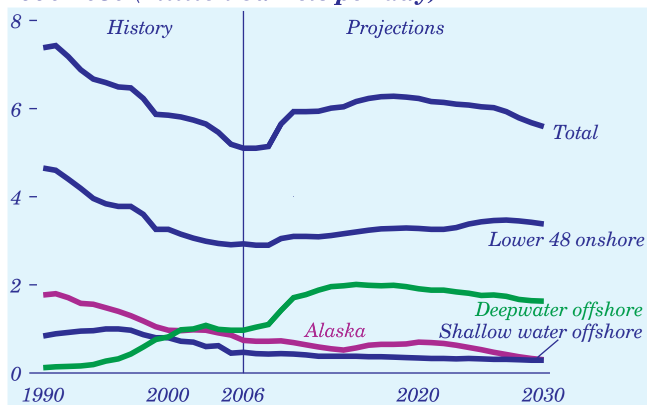
Net U.S. imports of LNG are expected to vary considerably from year to year, depending on both the level of U.S. natural gas prices and whether those prices are higher or lower than prices elsewhere in the world. Higher prices overseas are expected to reduce U.S. LNG imports, and lower prices overseas are expected to increase U.S. imports. U.S. LNG imports are much less sensitive to economic growth rates, which determine the level of domestic natural gas consumption. Given the uncertainty in future domestic and overseas natural gas prices, the level of future U.S. LNG imports is highly uncertain.

In the high price case, the higher world crude oil price is expected to result in increased natural gas consumption in overseas energy markets, exerting upward pressure on LNG prices. In addition, some LNG contract prices are tied directly to crude oil prices. Higher crude oil prices will also spur greater GTL production, placing additional pressure on world natural gas supplies. Collectively, these activities are expected to increase overseas wellhead natural gas prices and worldwide LNG prices, reducing both domestic natural gas consumption and LNG imports in the United States.

Net U.S. imports of LNG in 2030 are projected to total 2.8 trillion cubic feet in the reference case, 4.5 trillion cubic feet in the low price case, 1.7 trillion cubic feet in the high price case, 2.9 trillion cubic feet in the high economic growth case, and 2.5 trillion cubic feet in the low economic growth case (Figure 83).

U.S. Crude Oil Production Increases Slightly Through 2030

Figure 84. Domestic crude oil production by source, 1990-2030 (million barrels per day)

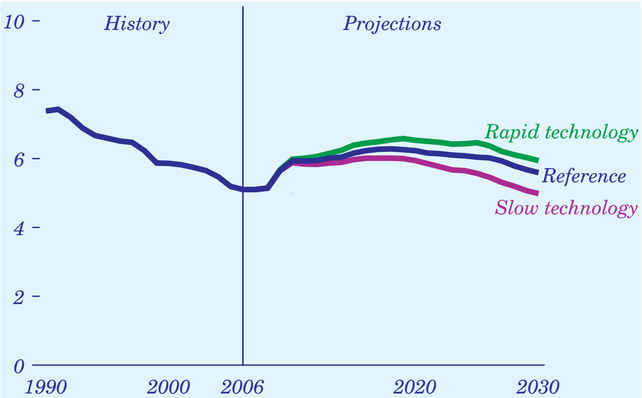


In the reference case, U.S. conventional oil production grows from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, then declines to 5.6 million barrels per day in 2030 (Figure 84). The shape of the U.S. production profile is determined largely by lower 48 offshore oil production, which rises from 1.4 million barrels per day in 2006 to 2.4 million barrels per day in 2015 and then falls to 1.9 million barrels per day in 2030. Deepwater oil production in the Gulf of Mexico increases from 970,000 barrels per day in 2006 to a peak of 2.0 million barrels per day between 2013 through 2019, which is followed by a decline to 1.6 million barrels per day in 2030. Production in the shallower Gulf waters (at depths less than 1,000 feet) declines from 350,000 barrels per day in 2006 to 230,000 barrels per day in 2030. The decline in total offshore oil production during the later years of the reference case reflects depletion of the largest offshore oil fields and the fact that the remaining offshore oil resource base is composed of smaller and smaller fields.

Because a large portion of the U.S. onshore conventional oil resource base already has been produced, newly discovered oil reservoirs are expected to be smaller, more remote (e.g., Alaska), and more costly to exploit. Onshore oil production in the lower 48 States increases slightly, however, as higher crude oil prices stimulate production by EOR techniques using CO_2 injection, which increases from 350,000 barrels per day in 2006 to 1.3 million barrels per day in 2030. Excluding the increase in EOR production, lower 48 onshore oil production declines slowly, from 2.6 million barrels per day in 2006 to 2.1 million barrels per day in 2030.

More Rapid Technology Advances Could Raise U.S. Oil Production

Figure 85. Total U.S. crude oil production, 1990-2030 (million barrels per day)



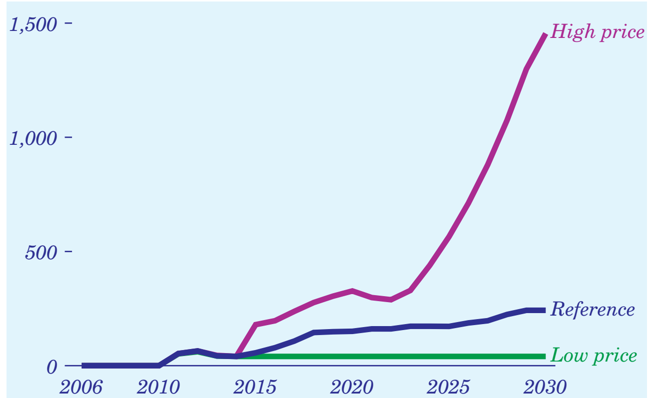
The rapid and slow oil and gas technology cases assume rates of technological progress in the petroleum industry that are 50 percent higher and 50 percent lower than in the reference case. The rate of technological progress determines the cost of developing and producing the remaining domestic oil resource base. Higher (or lower) rates of technological progress result in lower (or higher) oil development and production costs, which in turn allow more (or less) oil production. In 2030, domestic crude oil production is 5.6 million barrels per day in the reference case, 5.9 million barrels per day in the rapid technology case, and 5.0 million barrels per day in the slow technology case (Figure 85).

Domestic oil consumption, which is determined largely by oil prices and economic growth rates, does not vary significantly across the technology cases; however, imports of crude oil and petroleum products do vary, depending on domestic oil production levels. In 2030, net imports of crude oil and liquid fuels total 12.4 million barrels per day in the reference case, as compared with 12.0 million barrels per day in the rapid technology case and 13.0 million barrels per day in the slow technology case.

Higher rates of technological progress result in higher oil production rates and more rapid depletion of the domestic resource base. Cumulative U.S. crude oil production from 2006 through 2030 is 2.0 billion barrels (3.9 percent) higher in the rapid technology case and 2.6 billion barrels (4.9 percent) lower in the slow technology case than in the reference case.

Unconventional Liquids Production Increases With Higher Oil Prices

Figure 86. Total U.S. unconventional crude oil production, 2006-2030 (thousand barrels per day)

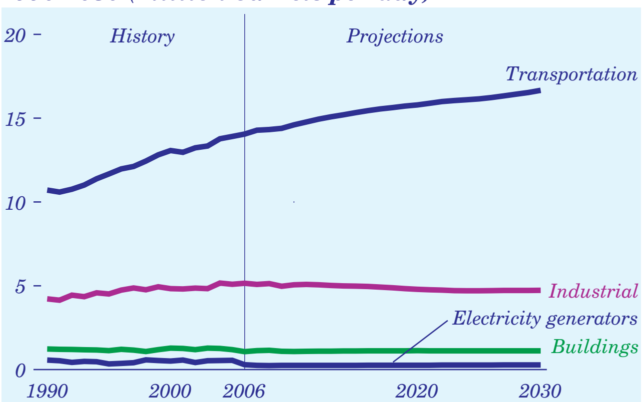


Crude oil prices are the primary determining factor for future levels of domestic unconventional oil production (such as oil shale, CTL, and GTL). In the *AEO2008* low price case, CTL production begins in 2011, using only U.S. facilities now under construction, and remains at 40,000 barrels per day through 2030. With the higher oil price in the reference case, CTL production starts in 2011 at about 50,000 barrels per day and increases to about 240,000 barrels per day in 2030 (Figure 86). In the high price case, both GTL and oil shale production become economical, and total domestic unconventional oil production increases to 1.5 million barrels per day in 2030—1.2 million barrels per day from CTL, 130,000 barrels per day from GTL, and 140,000 barrels per day from oil shale. In the high price case, both oil and natural gas prices are sufficiently high to encourage both the construction of an Alaska natural gas pipeline and GTL production on Alaska's North Slope.

There is considerable uncertainty surrounding the future of unconventional crude oil production in the United States. Environmental regulations could either preclude unconventional production or raise its cost significantly. If future U.S. laws limited and/or taxed greenhouse gas emissions, they could lead to substantial increases in the costs of unconventional production, which emits significant volumes of CO_2. Restrictions on access to water also could prove costly, especially in the arid West. In addition, environmental restrictions on land use could preclude unconventional oil production in some areas of the United States.

Transportation Uses Lead Growth in Liquid Fuels Consumption

Figure 87. Liquid fuels consumption by sector, 1990-2030 (million barrels per day)



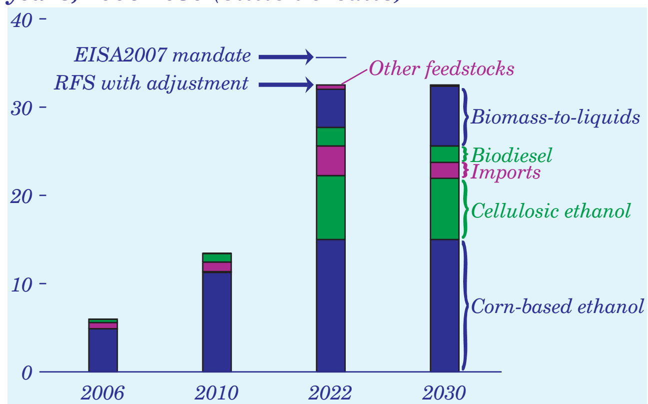
U.S. consumption of liquid fuels—including fuels from petroleum-based sources and, increasingly, those derived from nonpetroleum primary fuels such as coal, biomass, and natural gas—totals 22.8 million barrels per day in 2030 in the reference case, an increase of 2.1 million barrels per day over the 2006 total (Figure 87). All of the increase is in the transportation sector, which accounts for 73 percent of total liquid fuels consumption in 2030, up from 68 percent in 2006.

Gasoline, ULSD, and jet fuel are the main transportation fuels. The reference case includes the effects of technology improvements that are expected to increase the efficiency of motor vehicles and aircraft, but the projected growth in demand for each mode outpaces those improvements as the demand for transportation services grows in proportion to increases in population and GDP. With the new CAFE standards in EISA2007, transportation use of liquid fuels increases by 2.6 million barrels per day in the reference case, 3.9 million barrels per day in the high economic growth case, and 1.8 million barrels per day in the high price case from 2006 to 2030.

Consumption of liquid fuels from nonpetroleum sources increases substantially over the projection period. Ethanol, which made up 4 percent of the motor gasoline pool in 2006, increases to 15.8 percent of the total motor gasoline pool in 2030. Total production of liquid fuels from CTL and BTL plants, which are expected to commence operation in 2011, increases in the reference case to 540,000 barrels per day in 2030, equivalent to 9.7 percent of the total pool of distillate fuel.

RFS Is Defined by Multiple Biofuel Categories in EISA2007

Figure 88. EISA2007 RFS credits earned in selected years, 2006-2030 (billion credits)



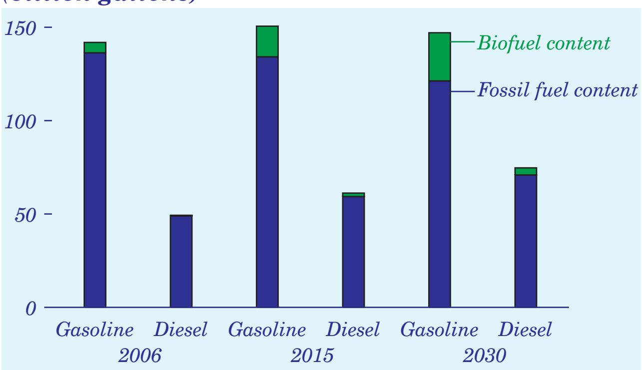
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to gallons produced, except for fatty acid methyl ester biodiesel and BTL diesel, which receive a 1.5-gallon credit for each gallon produced. The renewable fuels can be grouped into two categories: conventional biofuels (ethanol produced from corn starch) and advanced biofuels (including cellulosic ethanol, biodiesel, and BTL diesel). In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels are required in 2022.

In the *AEO2008* reference case, however, only 32.5 billion gallons of RFS credits are generated in 2022, because cellulosic biofuel production is not expected to increase rapidly enough to provide the credits that would be needed to meet the advanced biofuels requirement. If the available quantities of biofuels are inadequate to meet the initial targets, EISA2007 provides for both the application of waivers and modification of applicable credit volumes (Figure 88).

Corn ethanol is projected to make the largest contribution toward the RFS mandate, providing up to 15 billion credits. Cellulosic ethanol contributes 7.2 billion credits to the advanced and cellulosic biofuel requirement in 2022, and BTL diesel contributes 4.3 billion credits. BTL production continues to increase in the later years of the projection, to 6.8 billion gallons in 2030. The remainder of the credits for advanced biofuels in 2022 include credits for approximately 3 billion gallons of ethanol imports, 2 billion gallons of biodiesel, and 0.5 billion gallons of ethanol from wheat and other feedstocks.

EISA2007 Increases U.S. Supply of Renewable Transportation Fuels

Figure 89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030 (billion gallons)

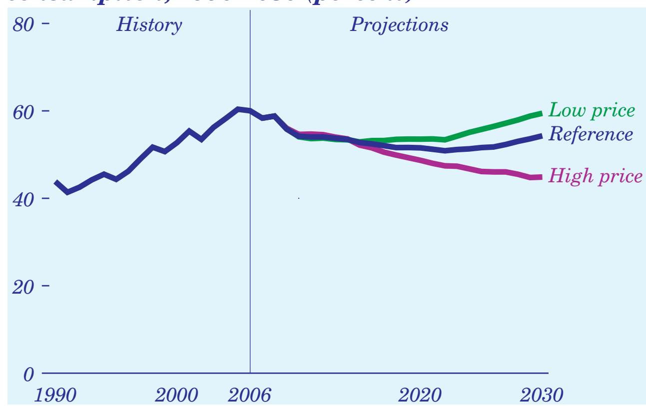


As a result of the EISA2007 RFS, the biofuel component of motor fuels in the transportation sector is projected to grow substantially, as the fossil fuel content of gasoline and diesel declines from 136 billion gallons (96 percent) in 2006 to 125 billion gallons (83 percent) in 2030 (Figure 89). The biofuel content of all gasoline and E85 consumed in the United States, which totaled about 5.6 billion gallons in 2006, increases to 25.8 billion gallons in 2030. In addition, a smaller increase in biofuel content is projected for diesel fuel, from 0.3 billion gallons in 2006 to 3.8 billion gallons in 2030.

Adding to the decline in U.S. consumption of fossil-fuel-based gasoline is a projected increase in diesel fuel use for passenger vehicles—a shift that is likely to require significant adjustments in the refining industry. Crude oil processing typically yields a sizable portion of product in the naphtha range, which frequently is used in motor gasoline. Historically, there has been a mutually beneficial relationship between U.S. and European refiners, with surplus diesel being shipped from the United States to Europe and surplus gasoline shipped from Europe to the United States. A significant increase in U.S. demand for diesel while the demand for gasoline is falling is likely to require significant investment by refiners in both the United States and Europe in order to maximize diesel yields.

Imports of Liquid Fuels Are Expected To Decline

Figure 90. Net import share of U.S. liquid fuels consumption, 1990-2030 (percent)



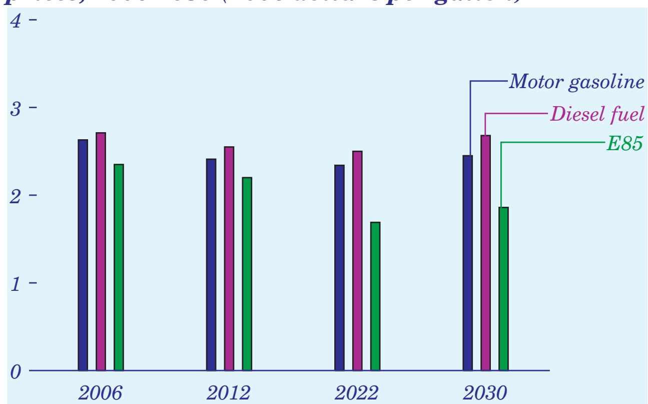
In 2006, net imports of liquid fuels, primarily petroleum, accounted for 60 percent of domestic consumption. In the reference case, U.S. dependence on liquid fuel imports declines to 51 percent in 2022, before climbing to 54 percent in 2030 (Figure 90). In the high price case, net imports as a share of domestic consumption of liquid fuels fall to 45 percent in 2030. In the low price case, dependence on petroleum imports remains roughly constant, with an import share of 59 percent in 2030.

In the reference case, demand for refined products continues to increase more rapidly than refining capacity. Historically, the availability of product imports has been limited by a lack of foreign refineries capable of meeting the stringent U.S. standards for liquids products. One example is provided by the U.S. ban on use of methyl tertiary butyl ether as an oxygenate in RFG. Since the ban took effect in January 2007, U.S. refiners have switched to using ethanol as the oxygenate in RFG, and the New York Mercantile Exchange (NYMEX) market has stopped offering imports of RFG and switched to imports of reformulated blendstock for oxygenate blending.

In recent years, however, liquids demand has grown rapidly in some countries of Eastern Europe and Asia, and those nations are moving to adopt the same fuel quality standards as the developed world. As a result, refineries throughout the world are becoming more sophisticated, and in the future more of them will be able to provide products suitable for the U.S. market, which they may do if it is profitable.

Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

Figure 91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030 (2006 dollars per gallon)

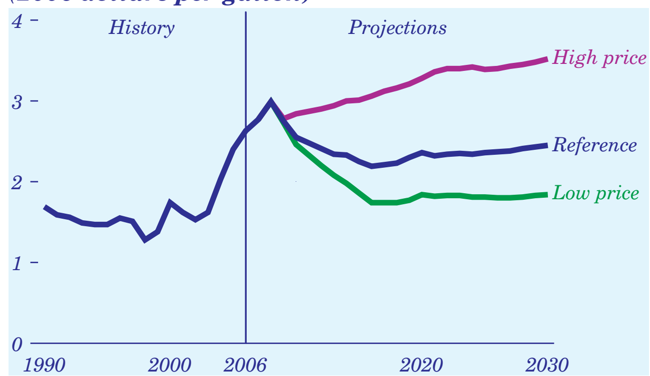


In the *AEO2008* reference case, with the EISA2007 renewable fuels mandate in effect, the U.S. market for E10 is saturated by 2014, after which the ethanol requirement is met by increased consumption of E85. To encourage the use of E85, its price is discounted to make it competitive with motor gasoline on an energy-equivalent basis. The E85 price discounts are funded by premiums placed on the petroleum content of other motor fuels. As E85 consumption increases, the price drops from $2.35 per gallon in 2006 to a low of $1.57 (2006 dollars) in 2017 before rising to $1.86 in 2030. In comparison, the price of motor gasoline is $2.63 per gallon in 2006 and $2.45 in 2030 (Figure 91).

In the low price case, E85 follows the same general price path, falling to $1.44 per gallon in 2030. In contrast, in the high price case, the price of E85 rises to $2.73 per gallon in 2030, although it is still discounted relative to motor gasoline, which increases to $3.52 per gallon in 2030. In the *AEO2008* early release, which excluded the impact of EISA2007, the price of E85 remained closer to the price of motor gasoline throughout the projection period, increasing to $2.29 per gallon in 2030, while the price of gasoline increased to $2.49 in 2030.

U.S. Motor Gasoline Prices Rise and Fall With Changes in World Oil Price

Figure 92. Average U.S. delivered prices for motor gasoline, 1990-2030 (2006 dollars per gallon)



Retail prices for petroleum products largely follow changes in crude oil prices. In the *AEO2008* reference case, the world oil price path reaches a low of $57 per barrel in 2016 and then increases to about $70 in 2030 (2006 dollars). The U.S. average motor gasoline price follows the same trend, falling to $2.19 per gallon in 2016 before rising to $2.45 in 2030.

In the high price case, with the price of imported crude oil rising to $119 per barrel (2006 dollars) in 2030, the average price of U.S. motor gasoline increases rapidly, to $3.06 per gallon in 2016 and $3.52 per gallon in 2030. In the low price case, gasoline prices decline to a low of $1.74 per gallon in 2016, increase slowly through the early 2020s, and level off at about $1.84 per gallon through 2030 (Figure 92).

Because changes from the reference case assumptions for economic growth rates have less pronounced effects on motor gasoline prices than do changes in oil price assumptions, the average prices for U.S. motor gasoline in the high and low economic growth cases are close to those in the reference case. In the high growth case, the average gasoline price falls to a low of $2.24 per gallon in 2016 and then rises to $2.59 per gallon in 2030. In the low growth case, the average price reaches a low of $2.16 per gallon in 2017, followed by an increase to $2.32 per gallon in 2030.

In all the *AEO2008* cases, increases in motor gasoline prices as a result of the EISA2007 biofuel mandates are more than offset by erosion of the real dollar value of the Federal excise taxes. By assumption, the Federal gasoline tax is fixed at its 2007 nominal level of 18.4 cents per gallon.