Natural Gas Prices Rise As More Expensive Resources Are Produced

Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)

Average lower 48 wellhead prices for natural gas generally increase in the reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operation in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 64).

Henry Hub spot market prices and delivered end-use natural gas prices generally follow the trend in lower 48 wellhead prices; however, delivered prices also are subject to variation in average transmission and distribution rates and resulting margins, as reflected in the difference between the average delivered price and the average supply price for natural gas. Some new pipelines are built to bring supplies to market and to reach new customers, but the bulk of the pipeline system is already in place, and revenue requirements for those segments decline as capital is depreciated. Consequently, transmission and distribution margins for natural gas delivered to the industrial and electric power sectors either remain flat or decline.

Natural gas distribution rates are determined in large part by consumption levels per customer, which decline in the residential and commercial sectors over the projection period. As a result, fixed costs are distributed over a smaller customer base, leading to slight increases in transmission and distribution margins in those sectors. In the transportation sector, transmission and distribution margins for natural gas used as fuel in CNG vehicles decline in real terms, as motor fuels taxes remain constant in nominal terms.

Prices Vary With Economic Growth and Technology Progress Assumptions

Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)

The extent to which natural gas prices increase in the AEO2009 reference and alternative cases depends on assumptions about economic growth rates and the rate of improvement in natural gas exploration and production technologies. Technology improvements reduce drilling and operating costs and expand the economically recoverable resource base.

Technology improvement is particularly important in the context of growing investment in production of natural gas from shale formations, which generally can be produced more efficiently than the natural gas contained in conventional formations, but which 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 allows for more growth in production. More rapid technology improvement puts downward pressure on natural gas prices, mitigated somewhat by higher levels of consumption than in the reference case. In the slow technology case, slower declines in exploration and development costs lead to higher natural gas prices than in the reference case.

In the AEO2009 high economic growth case, natural gas consumption grows more rapidly, and natural gas prices rise more sharply, than in the reference case. In the low economic growth case, natural gas consumption grows more slowly, and natural gas prices are lower, than in the reference case (Figure 65).
Largest Source of U.S. Natural Gas Supply Is Unconventional Production

From 2007 to 2030, total natural gas production in the reference case increases by more than 4 trillion cubic feet, even as onshore lower 48 conventional production (from smaller and deeper deposits) continues to taper off. Unconventional natural gas is the largest contributor to the growth in U.S. natural gas production, as rising prices and improvements in drilling technology provide the economic incentives necessary for exploitation of more costly resources. Unconventional natural gas production increases from 47 percent of the U.S. total in 2007 to 56 percent in 2030 (Figure 66).

Natural gas in tight sand formations is the largest source of unconventional production, accounting for 30 percent of total U.S. production in 2030, but production from shale formations is the fastest growing source. With an assumed 267 trillion cubic feet of undiscovered technically recoverable resources, production of natural gas from shale formations increases from 1.2 trillion cubic feet in 2007 to 4.2 trillion cubic feet, or 18 percent of total U.S. production, in 2030. The expected growth in natural gas production from shale formations is far from certain, however, and continued exploration is needed to provide additional information on the resource potential.

Offshore production also makes up a significant portion of domestic natural gas supply, accounting for 15 percent of total domestic production in 2007 and 21 percent in 2030. The increase in offshore production is largely from deepwater formations and OCS areas recently released from Congressional moratoria.

World Oil Prices and Technology Progress Affect Natural Gas Supply

Improvements in natural gas exploration and development technologies reduce drilling costs, increase production capacity, and ultimately lower wellhead prices, increasing both production levels and end-use consumption. More rapid technology improvement raises the potential level of natural gas production and offsets the effects of depletion of the resource base, particularly for onshore conventional resources. In the rapid technology case, natural gas production in 2030 is 1.4 trillion cubic feet higher than in the reference case; in the slow technology case, it is 1.5 trillion cubic feet lower than in the reference case.

The impact of world oil prices on domestic natural gas production is indirect, affecting natural gas consumption and, to a lesser degree, LNG imports. In the high oil price case, natural gas production in 2030 is 1.7 trillion cubic feet higher than in the reference case (Figure 67), with most of the additional supply, 1.2 trillion cubic feet, being used for GTL production. In addition, higher oil prices reduce liquids consumption, leading to a decline in crude oil processing at refineries, so that more natural gas is consumed at refineries to replace still gas that otherwise would be available for refinery use. Higher levels of natural gas consumption for CTL production and refinery use in the high price case are offset to some extent by a decline in natural gas use for electricity generation.

In the low oil price case, refineries use less natural gas. Also, with less expensive crude oil taking a larger share in world energy markets, more natural gas is available for export to the United States as LNG. Domestic natural gas production is therefore lower, and LNG imports are higher, than in the reference case.
U.S. Net Imports of Natural Gas Decline in the Projection

U.S. net imports of natural gas decline in the AEO-2009 reference case from 16 percent of supply in 2007 to 3 percent in 2030. The reduction is a result primarily of lower imports from Canada and higher exports to Mexico because of growing demand for natural gas in each of those countries. In addition, with relatively high prices and advances in technology, the potential for U.S. domestic natural gas production (particularly from unconventional sources) increases, providing a competitive alternative to imports of LNG.

Conventional natural gas production from Canada’s Western Sedimentary Basin has been declining in recent years. In the reference case, Canada’s unconventional production does not increase rapidly enough to keep up with domestic demand growth while maintaining current export levels. For Mexico, U.S. pipeline exports are needed to meet the country’s growth in demand for natural gas, which is not matched by increases in domestic production and LNG imports.

In the United States, LNG imports peak at 1.5 trillion cubic feet in 2018 before declining to 0.8 trillion cubic feet in 2030 (Figure 68), despite projected U.S. regasification capacity of 5.2 trillion cubic feet. The near-term increase is the result of growth in world liquefaction capacity, which temporarily exceeds world demand, making LNG available to the U.S. market—particularly in the summer to fill storage facilities. In the longer term, high LNG prices (which are tied to oil prices in many markets) and ample domestic natural gas supplies reduce U.S. demand for LNG imports; however, the amount of LNG available to U.S. markets could change if world natural gas consumption differs from the levels projected in the reference case.

With No Alaska Pipeline, Lower 48 Prices for Natural Gas Are Higher

The AEO2009 reference case assumes that a proposed pipeline to transport natural gas from Alaska’s North Slope to Alberta, Canada, and ultimately to the lower 48 States will be built in 2020, and that Alaska’s natural gas production will increase by 1.6 trillion cubic feet as a result. The no Alaska pipeline case assumes that the pipeline will not be built, leading to higher prices in lower 48 natural gas markets, more lower 48 production and imports of natural gas, and lower consumption.

The largest impact on natural gas prices in the no Alaska pipeline case occurs when the pipeline reaches full capacity in 2022, two years after the pipeline begins operating in the reference case. In 2022, Henry Hub spot market prices for natural gas (in 2007 dollars) are higher by $0.63 per thousand cubic feet in the no Alaska pipeline case than in the reference case. After 2022 the price impact lessens gradually, to $0.13 per thousand cubic feet in 2030 (Figure 69). In 2026, total natural gas consumption is 0.8 trillion cubic feet lower in the no pipeline case than in the reference case, and consumption for electricity generation is 0.3 trillion cubic feet lower.

Higher natural gas prices and reduced supply in the no pipeline case lead to more unconventional production and LNG imports in the lower 48 States. Pipeline imports from Canada, which in the no pipeline case do not compete with Alaska natural gas in lower 48 markets, are 0.5 trillion cubic feet above the reference case level in 2028. LNG imports are only slightly higher in the no pipeline case, as a result of increased competition in world markets and the availability of domestic natural supplies at competitive prices.
U.S. Crude Oil Production Increases With Rising Oil Prices

The long-term decline in total U.S. crude production has slowed over the past few years, as higher world oil prices have spurred drilling. In the projections, total U.S. domestic crude oil production, which has been falling for many years, begins to increase in 2009. Most of the near-term increase is from the deepwater offshore. Growth is limited after 2010, however, because newer discoveries are smaller, and capital expenditures rise as development moves into deeper waters.

A number of deepwater discoveries in the Gulf of Mexico have begun to ramp up production recently or are expected to begin production by the end of 2009. The largest include Shenzi, Atlantis, Blind Faith, and Thunder Horse. Expiration of the Congressional moratoria on the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the OCS also allow crude oil production to increase in the Atlantic and Pacific OCS after 2014 and in the Eastern Gulf of Mexico OCS after 2025. Total offshore production increases at an average annual rate of 2.8 percent, from 1.4 million barrels per day in 2007 to 2.7 million barrels per day in 2030.

U.S. onshore crude oil production also increases throughout the projection, primarily as a result of increased application of CO₂-enhanced oil recovery techniques, exploitation of oil from the Bakken shale formation [98], and the startup of liquids production from oil shale, which is supported by favorable world oil prices and continued advances in oil shale extraction technology. Total onshore production of crude oil increases from 2.9 million barrels per day in 2007 to 4.1 million barrels per day in 2030 (Figure 70).

U.S. Oil Production Depends on Prices, Access, and Technology

U.S. crude oil production is highly sensitive to world crude oil prices, because the remaining domestic resource base generally requires more costly secondary or tertiary recovery techniques, which are likely to be uneconomical when world oil prices are low. Even when prices are higher, however, high-cost projects typically involve long lead times from discovery to production, which limit their impact on total production levels. In the high oil price case, U.S. crude oil production in 2030 is 1.1 million barrels per day higher than in the reference case, mostly as a result of increased production from onshore CO₂-enhanced recovery projects and offshore deepwater projects. In the low oil price case, crude oil production in 2030 is 2.0 million barrels per day lower than in the reference case, primarily because of lower production from CO₂-enhanced recovery projects, and because fewer projects in the lower 48 offshore and Alaska’s North Slope are economical when world oil prices are relatively low.

Both onshore and offshore production generally increase as technology advances reduce the costs of exploration and development. In the rapid technology case, U.S. crude oil production in 2030 is 0.3 million barrels per day higher than in the reference case, with most of the increase coming from resources in the lower 48 offshore. In the slow technology case, crude oil production in 2030 is 0.7 million barrels per day lower than in the reference case (Figure 71). Most of the difference between the 2030 production levels in the reference and slow technology cases results from lower levels of production from CO₂-enhanced oil recovery in the slow technology case.
Liquid Fuels Consumption

BTL, CTL, and Oil Shale Production Grows With Technology Improvement

Production of liquid fuels from oil shale, coal, natural gas, and biomass becomes viable over time in the reference case as a result of continued technology improvements and rising oil prices. Growth in their production can be moderated, however, by rising capital costs and by the enactment of more stringent environmental regulations affecting water and land use—which increase production costs—and GHG emissions. Consequently, penetration rates vary for the different production processes.

BTL production begins in 2012 in the reference case and grows by an average of 29 percent per year through 2030 (Figure 72). CTL production begins in 2011 and grows by an average of 19 percent per year. The increase in CTL production would be larger if it were not constrained by the reference case assumption that growing concern about GHG emissions will limit investment in the carbon-intensive CTL technology.

Oil shale production begins later, in 2023, but increases rapidly, averaging 35 percent per year from 2023 to 2030. Research and development efforts are expected to provide the necessary technology improvements to yield commercial quantities of liquids from oil shale production that, over time, can be further increased in scale. Although no GTL production is expected before 2030 in the reference case, GTL production in Alaska begins in 2017 in the high oil price case and then grows by an average of 21 percent per year from 2017 to 2030.

Transportation Sector Dominates Liquid Fuels Consumption

The transportation sector continues to dominate liquid fuels consumption in the projections (Figure 73), with large increases in the use of diesel fuel and biofuels. In the reference case, total consumption of petroleum-based motor gasoline in 2030, including E10 but excluding E85, is 1.3 million barrels per day below the 2007 total, whereas both consumption of diesel fuel and consumption of E85 increase, by about 1.5 million barrels per day each. Biofuel consumption grows with the EISA2007 mandates, and diesel fuel consumption expands as more light-duty diesel vehicles are produced by automotive manufacturers seeking to comply with new CAFE standards. Diesel fuel use for freight trucks also increases as industrial output expands.

In the other sectors, liquid fuels consumption declines through 2030. Industrial use of liquids drops by 19 percent, despite a 47-percent increase in industrial shipments. Much of the decline from 2007 to 2030 results from changes in the chemical industry, where there is a shift in the production mix, and energy efficiency improves. Liquid fuels consumption in the buildings sector continues to fall, as fewer buildings use oil for heating, and efficiency improves as older systems are replaced with more efficient equipment.

Liquid fuels consumption in the electric power sector declines as a result of slowing growth in demand for electricity from 2007 to 2030. With Federal and State efficiency standards minimizing the need for new generating capacity, little new oil-fired capacity is installed, and generation from older oil-fired capacity is offset by production from new capacity using coal, natural gas, nuclear, and renewable fuels.
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 AEO2009 reference case, the credit requirement for conventional biofuels is met in 2022, but the requirement for advanced fuels is not. In that event, EISA2007 provides for both the application of waivers and modification of applicable credit volumes. The RFS mandates are achieved in 2027 in the reference case, and as BTL production grows, the overall target of 36 billion gallons is exceeded in 2030 (Figure 74).

Progress toward meeting the RFS is complicated by slowing growth in U.S. petroleum use through 2030. The push for more fuel-efficient automobiles, which slows the increase in motor gasoline consumption in the reference case, also slows progress toward meeting the RFS, because more efficient gasoline engines and growing penetration of hybrids reduce the demand for ethanol in gasoline fuel blends. A 10-percent limit on ethanol in gasoline for most of the current fleet of passenger vehicles delays further market penetration until more E85-compatible vehicles are in use and the market infrastructure for E85 and other biofuels is expanded to accommodate the distribution and sale of growing volumes.

As a result of the RFS in EISA2007, CAFE standards, and higher liquid prices, biofuels in the form of ethanol and biodiesel displace a growing portion of the fossil fuel component of transportation fuel use in the reference case (Figure 75). With biofuels representing all the growth in motor fuel supply, there is virtually no growth in petroleum consumption through 2030, as demand for petroleum-based gasoline declines and demand for petroleum-based diesel grows modestly. The growing share for diesel fuel is similar to recent trends in Europe, where increases in diesel use have outpaced the growth in gasoline use for some time, causing European refineries to be reconfigured for more diesel production.

U.S. production of biofuels grows from less than 0.5 million barrels per day in 2007 to 2.3 million barrels per day in 2030. Ethanol production provides the largest share of that growth, as ethanol use for gasoline blending grows to more than 0.8 million barrels per day and ethanol consumption in E85 increases to 1.1 million barrels per day in 2030. Much of the growth in demand for E85 occurs after 2015, when the market for E10 blending is saturated. Although most of the ethanol consumed is produced domestically, net imports of ethanol also increase, to 0.5 million barrels per day in 2030.

To meet RFS and CAFE standards, the vehicle fleet changes dramatically in the reference case. In 2030, 60 percent of the new LDVs sold are E85, flex-fuel, conventional hybrid, or PHEVs.
Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

With crude oil prices rising in the reference case, prices for both gasoline and diesel fuel increase by an average of 1.4 percent per year, to about $4 per gallon (2007 dollars) in 2030 (Figure 76). The average increase in E85 prices is 0.5 percent per year over the same period, and the E85 price in 2030 is less than $3 per gallon. As a result, the difference between gasoline and E85 prices increases from roughly 30 cents per gallon in 2007 to more than a dollar per gallon in 2030.

In the reference case, ethanol is used initially as a blending component with gasoline, but the U.S. market for ethanol blending with gasoline to make E10 is near saturation by 2012. Meeting the EISA2007 RFS after 2012 therefore requires increased consumption of E85. To encourage the use of E85, its price (in terms of energy content) must be equivalent to or below the price of motor gasoline. E85 prices increase only moderately in the reference case, to $2.72 per gallon in 2012 and $2.79 in 2022, on the path to achieving the sales volume needed to meet the RFS mandate.

The increase in ethanol sales requires construction of a sufficient base of E85 fueling stations and distribution infrastructure to ensure the commercial viability of a growing fleet of E85 vehicles. AEO2009 assumes that the average cost to modify an existing service station for E85 sales will be about $46,000. Assuming no intermediate ethanol blends, E85 prices must be subsidized by refiners and marketers through high prices for gasoline and diesel fuel in order to meet the mandated ethanol level in the RFS once the E10 market is saturated and E85 is the primary contributor.

Imports of Liquid Fuels Vary With World Oil Price Assumptions

U.S. imports of liquid fuels, which grew steadily from the mid-1980s to 2005, decline sharply from 2007 to 2030 in the reference and low oil price cases, even as they continue to provide a major part of total U.S. liquids supply. Increasing use of biofuels, much of which are domestically produced, tighter CAFE standards, and higher energy prices moderate the growth in demand for liquids. A combination of higher prices and mandates leads to increased domestic production of oil and biofuels. In the reference case, there is essentially no growth in the use of liquid fuels from 2007 to 2030.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 58 percent in 2007. That trend continues in the reference case, with a net import share of 41 percent in 2030, and in the high oil price case, with a 30-percent share in 2030. In the low price case, the net import share falls in the near term before rising to 57 percent in 2030. With lower prices for liquid fuels, demand increases while domestic production decreases, and more imports are needed to meet demand. With higher prices, the need for imports is smaller but still substantial (Figure 77). Increased penetration of biofuels in the liquids market reduces the need for imports of crude oil and petroleum products in the high price case.