Issues in Focus

Introduction

Each year, the Issues in Focus section of the *AEO* provides an in-depth discussion on topics of special interest, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. The first section compares the results of two cases that adopt different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies. The other case assumes the extension of a selected group of existing policies—CAFE standards, appliance standards, and PTCs—in addition to the elimination of sunset provisions.

Other sections include a discussion of end-use energy efficiency trends in *AEO2010*; an analysis of the impact of incentives on the use of natural gas in heavy freight trucks; factors affecting the relationship between crude oil and natural gas prices; the sensitivity of the projection results to variations in assumptions about the availability of U.S. shale gas resources; the implications of retiring nuclear plants after 60 years of operation; and issues related to accounting for CO_2 emissions from biomass energy combustion.

The topics explored in this section represent current, emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years also remain relevant today. Table 3 provides a list of titles from the 2009, 2008, and 2007 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyses.html.

No Sunset and Extended Policies cases

Background

The *AEO2010* Reference case is best described as a "current laws and regulations" case, because it generally assumes that existing laws and fully promulgated regulations will remain unchanged throughout the projection period, unless the legislation establishing them specifically calls for them to end or change. The Reference case often serves as a starting point for the analysis of proposed legislative or regulatory changes, a task that would be difficult if the Reference case included "projected" legislative or regulatory changes.

As might be expected, it is sometimes difficult to draw a line between what should be included or excluded from the Reference case. Areas of particular uncertainty include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.
- Laws or regulations that call for the periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. DOE and CAFE standards for vehicles issued by NHTSA.
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions.

Table 3. Key analyses from "Issues in Focus" in recent *AEO*s

AEO2009	*AEO2008*	*AEO2007*
Economics of Plug-In Hybrid Electric Vehicles	Impacts of Uncertainty in Energy Project Costs	Impacts of Rising Construction and Equipment Costs on Energy Industries
Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf	Limited Electricity Generation Supply and Limited Natural Gas Supply Cases	Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors
Expectations for Oil Shale Production	Trends in Heating and Cooling Degree-Days: Implications for Energy Demand	Miscellaneous Electricity Services in the Buildings Sector
Bringing Alaska North Slope Natural Gas to Market	Liquefied Natural Gas: Global Challenges	Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing
Natural Gas and Crude Oil Prices in *AEO2009*	World Oil Prices and Production Trends in *AEO2008*	World Oil Prices in *AEO2007*
Electricity Plant Cost Uncertainties		Biofuels in the U.S. Transportation Sector
Greenhouse Gas Concerns and Power Sector Planning		Loan Guarantees and the Economies of Electricity Generating Technologies
Tax Credits and Renewable Generation		Alaska Natural Gas Pipeline Developments
		Coal Transportation Issues

Examples include the numerous provisions of the CAA that require the EPA to issue or revise regulations if they find that some type of emission is harmful to the public health, or that standards are not being met.

To provide some insight into the sensitivity of results to different characterizations of "current laws and regulations," two alternative cases are discussed in this section. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed.

Analysis cases

The two cases prepared—the No Sunset case and Extended Policies case—incorporate all the assumptions from the *AEO2010* Reference case, except as identified below. Changes from the Reference case assumptions in these cases include the following.

No Sunset case

- Extension of renewable PTCs, ITCs, and tax credits for energy-efficient equipment in the buildings sector through 2035, including:
  - The PTC of 2.1 cents per kilowatthour or the 30-percent ITC available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, currently set to expire at the end of 2012 for wind and 2013 for the other eligible resources.
  - For solar power investment, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
  - In the buildings sector, tax credits for the purchase of energy-efficient equipment, including PV in new houses, are assumed to be extended indefinitely, as opposed to ending in 2010 or 2016 as prescribed by current law. The business ITC for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent.
  - In the industrial sector, the ITC for CHP that ends in 2016 in the *AEO2010* Reference case is assumed to be extended through 2035.
- Extension of the $0.45 per gallon blender's tax credit for ethanol through 2035; it is set to expire at the end of 2010.
- Continued implementation of the RFS after the 2022 date currently specified in EISA2007 until the renewable fuels target of 36 billion gallons is met. After the 36 billion gallon level is met, the mandate is assumed to continue increasing production in proportion to growth in overall transportation fuel use.
- Extension of the $1.00 per gallon biodiesel excise tax credit through 2035; rather than expiring on December 31, 2009.
- Extension of the $0.54 per gallon tariff on imported ethanol through 2035; it is set to expire at the end of 2010.
- Extension of the $1.01 per gallon cellulosic biofuels PTC through 2035; rather than expiring at the end of 2012.

Extended Policies case

With the exception of the blender's and other biofuel tax credits, the Extended Policies case adopts the same assumptions as in the No Sunset case, plus the following:

- Federal appliance efficiency standards are updated at particular intervals consistent with the provisions in the existing law, with the levels determined by the consumer impact tests under DOE testing procedures, or under Federal Energy Management Program (FEMP) purchasing guidelines.

  The efficiency levels chosen for the updated residential standards are based on the technology menu from the *AEO2010* Reference case, and whether or not the efficiency level passed the consumer impact test prescribed in DOE's standards-setting process. The efficiency levels chosen for the updated commercial equipment standards are based on the technology menu from the *AEO2010* Reference case and FEMP-designated purchasing specifications for Federal agencies.
- The implementation of rules proposed by NHTSA and the EPA for national tailpipe CO_2-equivalent emission and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, has been harmonized.

  In the *AEO2010* Reference case, which applies the NHTSA and EPA rules, the new CAFE standards lead to an increase in fleet-wide LDV standards from 27.1 mpg in MY 2011 to 34.0 mpg in MY 2016, based on projected sales of vehicles by type and footprint. As required by EISA2007, the fuel economy standards increase to 35 mpg in 2020. The Extended Policies case assumes further increases in the standards, so that the minimum fuel economy standard for LDVs increases to 45.6 mpg in 2035. In actual practice, the new CAFE would need to meet a test of economic practicality.

- The extension of the blender's and all biofuels excise tax credits through 2035 adopted in the No Sunset case are *not* included in the Extended Policies case. The RFS enacted in EISA2007 is an alternative instrument for stimulating demand for biofuels, it already is represented in the *AEO-2010* Reference case, and it tends to be the binding driver on biofuels rather than the tax credits.

Analysis results

The assumption changes made in the Extended Policies case generally lead to lower overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced energy-related GHG emissions. While this case shows lower energy prices because the impacts of the tax credits and end-use efficiency standards lead to lower energy demand and reduce the cost of renewable fuels, consumers spend more on appliances that are more efficient in order to comply with the tighter appliance standards, and the Government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 7). Lower energy prices in the No Sunset case lead to slightly higher energy consumption, but the difference never reaches as much as 1 percent in any year of the projections.

Total energy consumption in the Extended Policies case, which assumes the issuance of more stringent efficiency standards for end-use appliances and LDVs in the future, is lower than in the Reference case. In 2035, total energy consumption in the Extended Policies case is nearly 3 percent below the projection in the Reference case. As an example of individual end uses, the assumed future standard for residential electric water heating, which requires installation of heat pumps starting in 2013, has the potential to reduce their electricity use by 60 percent from the Reference case level in 2035. Overall, delivered energy use in the buildings sector in 2035 is 5 percent lower in the Extended Policies case.

The impact on LDV energy use in the transportation sector in the Extended Policies case is similar. In 2035, total LDV energy use in the Extended Policies case is nearly 6 percent lower than in the Reference case (Figure 8) and less than 0.5 percent above the 2007 level. Relative to the *AEO2010* Reference case, the efficiency standard for new LDVs in 2035 is 10 mpg higher in the Extended Policies case—46 mpg versus 36 mpg (Figure 9); however, higher fuel prices in the Reference case improve the cost competitiveness of advanced technologies, leading to improvements in fuel economy that are above the minimum requirements (Figure 10). As a result, the average fuel economy of new LDVs in the Reference case increases to 40 mpg in 2035 [Reference (achieved)], which is 4 mpg above the required minimum. In the Extended Policies case, the fuel economy standards are binding [Extended Policies (achieved)], because increases in fuel economy above the standards

Figure 7. Total energy consumption in three cases, 2005-2035 (quadrillion Btu)

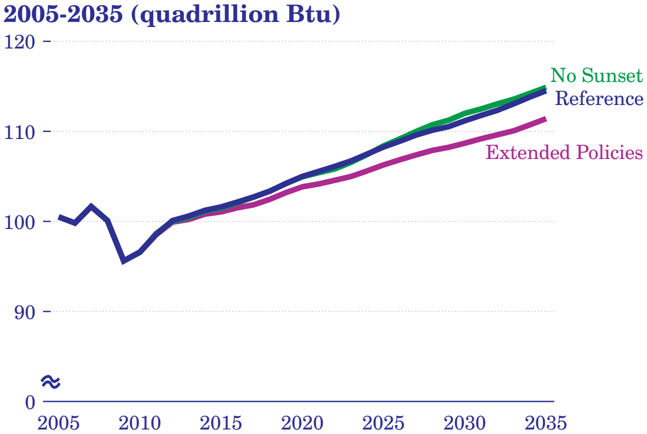
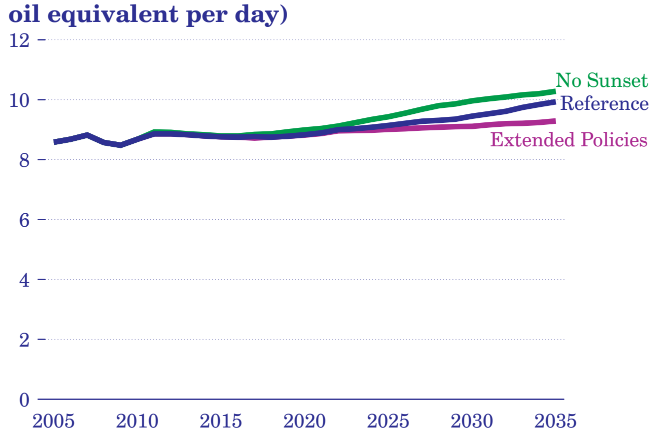


Figure 8. Light-duty vehicle energy consumption in three cases, 2005-2035 (million barrels oil equivalent per day)



require advanced technologies that are not cost-effective given the projected fuel prices.

Renewable electricity generation

The extension of tax credits for renewables through 2035 would lead to more rapid growth in renewable generation than projected in the Reference case, particularly over the longer run. When the renewable tax credits are extended without extending energy efficiency standards, as is assumed in the No Sunset case, there is significant growth in renewable generation throughout the projection period relative to the Reference case projection (Figure 11). Extending both renewable tax credits *and* energy efficiency standards results in more modest growth in renewable generation, because renewable generation in the near term is the primary source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

Figure 9. New light-duty vehicle fuel efficiency standards in two cases, 2005-2035 (miles per gallon)

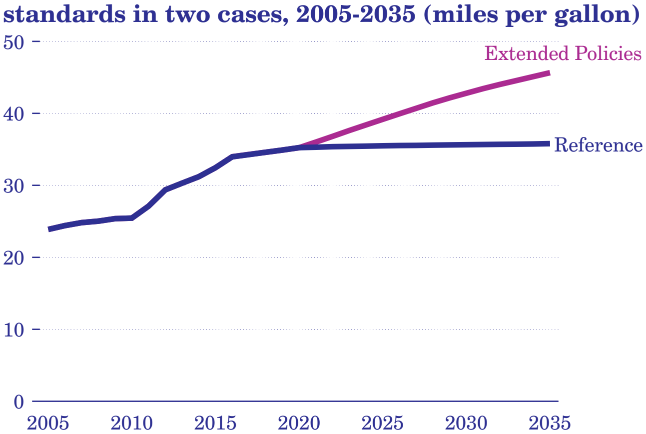
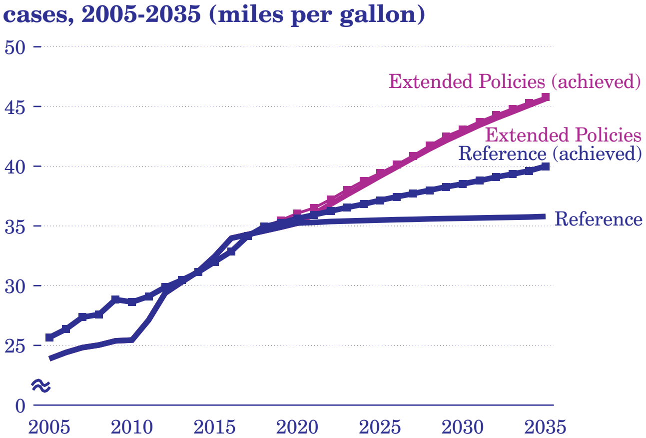


Figure 10. New light-duty vehicle fuel efficiency standards and fuel efficiency achieved in two cases, 2005-2035 (miles per gallon)

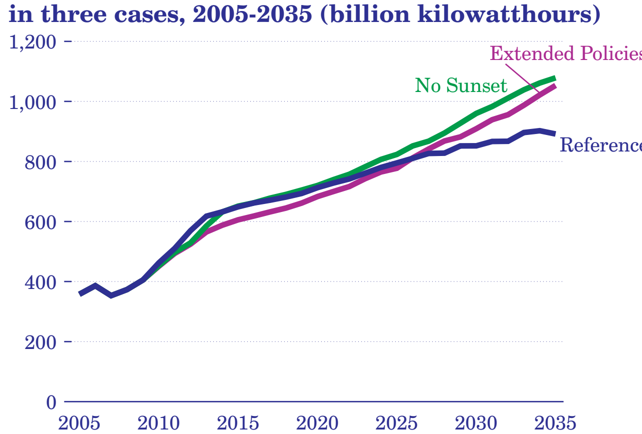


In the Reference case, growth in renewable generation accounts for 45 percent of total generation growth from 2008 to 2035. In the No Sunset and Extended Policies cases, growth in renewable generation accounts for 61 to 65 percent of total generation growth. In 2035, the share of total electricity sales accounted for by nonhydroelectric renewables is 13 percent in the Reference case, as compared with 17 percent in the No Sunset and Extended Policies cases.

In all three cases, the most rapid growth in renewable capacity occurs in the near term, then slows through 2020, before picking up again. Before 2015, ample supplies of renewable energy in relatively favorable resource areas (windy lands, accessible geothermal sites, and low-cost biomass), combined with the Federal incentives, make renewable generation competitive with conventional sources. If the rapid growth in renewables is dampened because of the economic downturn, more natural gas generation would be expected. With slow growth in electricity demand and the addition of capacity stimulated by renewable incentives before 2015, little new capacity is needed between 2015 and 2020. In addition, in many regions, most attractive low-cost renewable resources already have been exploited, leaving less-favorable sites that may require significant investment in transmission as well as other additional infrastructure costs. New sources of renewable generation also appear on the market as a result of cogeneration at biorefineries built primarily to produce renewable liquid fuels to meet the Federal RFS, where combustion of waste products to produce electricity is an economically attractive option.

After 2020, renewable generation in the No Sunset and Extended Policies cases increases more rapidly than in the Reference case, and as a result

Figure 11. Renewable electricity generation in three cases, 2005-2035 (billion kilowatthours)



generation from fossil fuels—particularly natural gas—is reduced from the levels projected in the Reference case (Figure 12). In 2035, electricity generation from natural gas in the No Sunset and Extended Policies cases is 13 percent and 16 percent lower, respectively, than in the Reference case.

Greenhouse gas emissions

In the No Sunset and Extended Policies cases, the combination of lower overall energy demand and greater use of renewable fuels leads to lower levels of energy-related CO_2 emissions than projected in the Reference case. The difference grows over time, to 146 million metric tons (2 percent) in the No Sunset case and 200 million metric tons (3 percent) in the Extended Policies case in 2035 (Figure 13). From 2012 to 2035, energy-related CO_2 emissions are reduced by a cumulative total of more than 1.9 billion metric tons in the Extended Policies case relative to the Reference case.

Energy prices and tax credit payments

With lower levels of overall energy use and more consumption of renewable fuels in the No Sunset and Extended Policies cases, energy prices are lower than projected in the Reference case. In 2035, natural gas wellhead prices are $0.56 per thousand cubic feet (7 percent) and $0.70 per thousand cubic feet (9 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 14), and electricity prices are 5 percent and 6 percent lower than projected in the Reference case (Figure 15).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case require additional equipment costs to consumers and revenue reductions for the Government. From 2010 to 2035, residential and commercial consumers spend an additional $16 billion (real 2008 dollars) per year on average for newly purchased end-use equipment, distributed generation systems, and residential shell

Figure 12. Electricity generation from natural gas in three cases, 2005-2035 (billion kilowatthours)

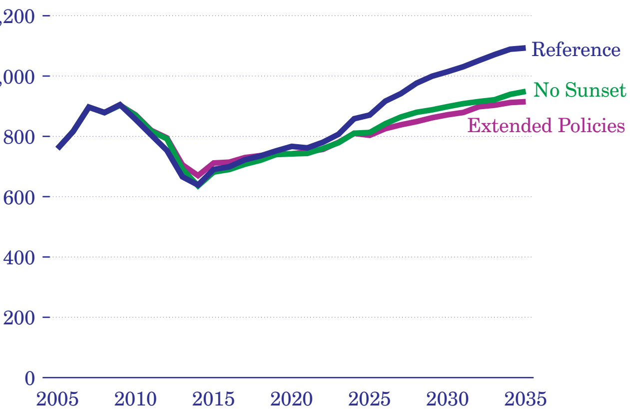


Figure 13. Energy-related carbon dioxide emissions in three cases, 2005-2035 (million metric tons)

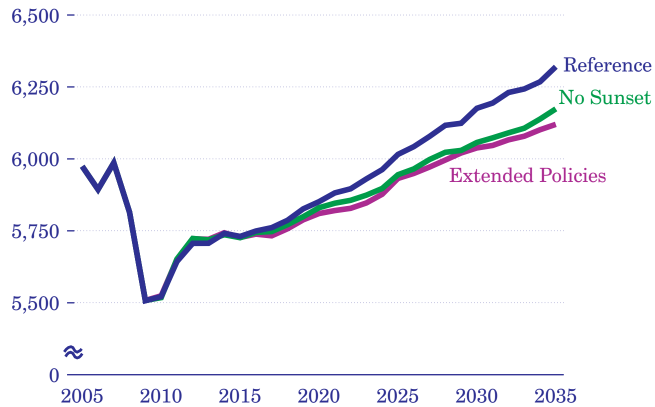


Figure 14. Natural gas wellhead prices in three cases, 2005-2035 (2008 dollars per thousand cubic feet)

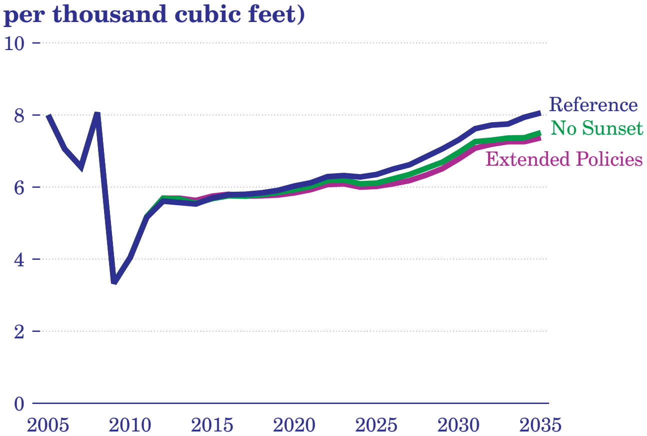
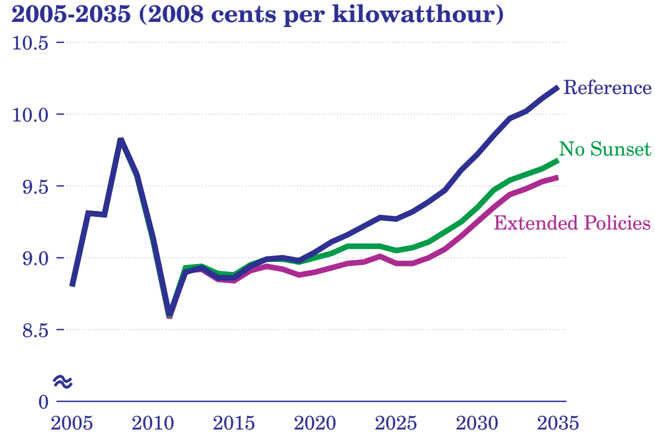


Figure 15. Average electricity prices in three cases, 2005-2035 (2008 cents per kilowatthour)



improvements in the Extended Policies case than in the Reference case.

Tax credits paid to consumers in the buildings sector in the Extended Policies case average $10.5 billion more per year than in the Reference case, reaching a cumulative total of $300 billion in revenue reductions to the Government over the period from 2010 to 2035. In comparison, cumulative revenue reductions as a result of tax credits in the buildings sector total $27 billion over the same period in the Reference case. The largest response to Federal PTC incentives for new central-station renewable generation is seen in the No Sunset case, with extension of the PTC resulting in cumulative reductions in Government tax revenues that total approximately $45 billion from 2010 to 2035, as compared with $24 billion in the Reference case. Additional reductions in Government tax revenue in the No Sunset case result from extension of the blenders tax credit, the biodiesel blenders tax credit, and the cellulosic biofuels PTC, with cumulative total tax revenue reductions from 2010 to 2035 of $156 billion, $32 billion, and $168 billion (all in 2008 dollars), respectively, compared to the Reference case.

World oil prices and production trends in *AEO2010*

In *AEO2010*, the price of light, low-sulfur (or "sweet") crude oil delivered at Cushing, Oklahoma, is tracked to represent movements in world oil prices. EIA makes projections of future supply and demand for "total liquids," which includes conventional petroleum liquids—such as conventional crude oil, natural gas plant liquids, and refinery gain—in addition to unconventional liquids, which include biofuels, bitumen, coal-to-liquids (CTL), gas-to-liquids (GTL), extra-heavy oils, and shale oil.

World oil prices can be influenced by a multitude of factors. Some tend to be short term, such as movements in exchange rates, financial markets, and weather, and some are longer term, such as expectations concerning future demand and production decisions by the Organization of the Petroleum Exporting Countries (OPEC). In 2009, the interaction of market factors led prompt month contracts (contracts for the nearest traded month) for crude oil to rise relatively steadily from a January average of $41.68 per barrel to a December average of $74.47 per barrel [*38*].

Changes in the world oil market over the course of 2009 served to highlight the myriad factors driving future liquids demand and supply and how a change in these factors can reverberate through the world liquids market. Over the long term, world oil prices in EIA's outlook are determined by four broad factors: non-OPEC conventional liquids supply, OPEC investment and production decisions, unconventional liquids supply, and world liquids demand. Uncertainty in long-term projections of world oil prices can be explained largely by uncertainty about one or more of these four broad factors.

Recent market trends

In 2009, world oil prices were especially sensitive to demand expectations, with producers, consumers, and traders constantly looking for any indication of a possible recovery in the world's economy and a likely corresponding increase in oil demand.

On the supply side, OPEC demonstrated greater dedication to supporting prices in 2009 than it had in other recent periods where it adopted restraints on production. From February to June 2008, OPEC maintained 70 percent or greater compliance as measured by the actual aggregate production cuts achieved by quota-restricted members as a percentage of the group's agreed-upon production cut, before falling to average levels of just above 60 percent after September [*39*]. The above-average compliance increased the group's spare capacity to roughly 5 million barrels per day in December 2009, and helped boost prices to a range of $70 to $80 per barrel [*40*].

Since June 2009, Iraq has held two rounds of bidding for development of its oil resources. The sum of the targeted production increase from the awarded fields is about 9.5 million barrels per day, or almost four times the country's current production. Although most industry analysts do not expect Iraq to achieve those production targets in full, the likely increase may cause changes in OPEC quota allocations and long-term production decisions.

There were also significant developments for non-OPEC supply in 2009, some with potentially long-lasting implications. Although oil prices rose throughout 2009, many of the projects delayed during the price slump that started in August 2008 have not yet been revived. The time required for project development creates a lag between investment decisions and increased oil deliveries, indicating that medium-term supply growth may be constrained if delayed projects are not restarted in the short term.

A related trend, which began in 2008 and continued in 2009, was a decline in factor input costs—i.e., the costs of the materials, labor, and equipment necessary to develop liquids projects. The decline in construction material costs and rig rates may have encouraged the delay of some projects, as investors played a wait-and-see game in order to secure contracts at the lowest possible cost. That trend appears to have bottomed out at the end of 2009, however, after producing only a slight overall reduction in costs [*41*]. Before the recent reduction in production costs, an industry research group estimated that costs had approximately doubled since 2000 [*42*].

Severe problems in the global credit market that began in 2008 and continued through 2009 have made it difficult to finance some exploration and production (E&P) projects. The full effect of limits on credit availability for oil supply projects will not be realized for some time, as the projects stalled due to a lack of financing, particularly exploration projects, would not have brought supply to the market for several years. In addition to its impact on individual E&P projects, the recent credit crisis may also have led to an overall and possibly lasting change in risk tolerance on the part of both lenders and investors. Still, while credit terms were being tightened and financial risk was being trimmed, ongoing exploration efforts in Africa resulted in a wave of discoveries and new hope for unexplored and under-explored non-OPEC resources.

Long-term prospects

Developments in 2008 and 2009 have demonstrated the range of the uncertainties that underlie the four broad factors underlying long-term world oil prices, as described above. It remains unclear how the world's economy and the demand for liquids will recover, what non-OPEC resources will be brought to market, what production targets OPEC will set or meet, and whether or when individual unconventional liquids projects will come online. The price path assumptions in *AEO2010* encompass a broad range of possible production levels and world oil price paths, with a range of $160 per barrel (in real terms) between the High Oil Price and Low Oil Price cases in 2035 (Figure 16). Consideration of Low and High Oil Price cases allows EIA and others to analyze a variety of future oil and energy market conditions in comparison with the Reference case.

Reference case oil prices

The global oil market projections in the *AEO2010* Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term, whereas long-term developments will be determined largely by economics. The Reference case assumes that the world economy— and liquids demand—experience significant recovery in 2010, with total liquids consumption returning to the 2008 level of just under 86 million barrels per day.

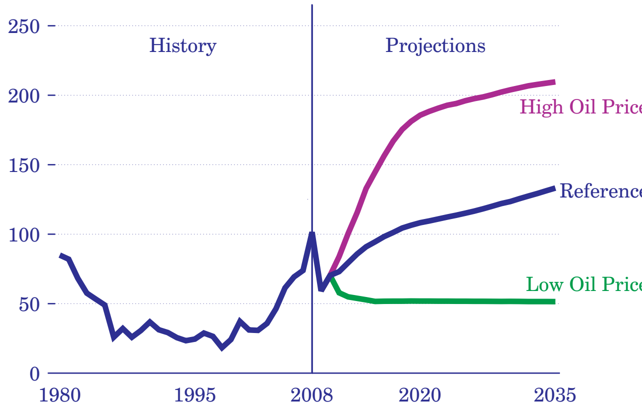
Satisfying the growing world demand for liquids in the next decade will require accessing higher cost supplies, particularly from non-OPEC producers. In the Reference case, the higher cost of non-OPEC supply supports average annual increases in real world oil prices of approximately 0.7 percent from 2008 to 2020 and 1.4 percent from 2020 to 2035. Oil prices, in real terms, rebound following the global recession, to $95 per barrel in 2015 and $133 per barrel in 2035 (real 2008 dollars). Although increases in OPEC production will meet a portion of the growing world demand, the Reference case assumes that OPEC's limits on production growth will maintain its share of total world liquids supply at approximately 40 percent, where it has roughly been over the past 15 years.

Growth in non-OPEC production will come primarily from high-cost conventional projects in regions with unstable fiscal or political regimes and from relatively expensive unconventional liquids projects. The return to higher price levels in the Reference case results from limited access to prospective areas for foreign investors, less attractive fiscal terms, and higher exploration and production costs than have been seen in the past.

Low Oil Price case

The *AEO2010* Low Oil Price case assumes that greater competition and international cooperation will guide the development of political and fiscal

Figure 16. Average annual world oil prices in three cases, 1980-2035 (2008 dollars per barrel)



regimes in both consuming and producing nations, facilitating coordination and cooperation among them. Non-OPEC producing countries are assumed to develop fiscal policies and investment regimes that encourage private-sector participation in the development of their domestic resources; and OPEC is assumed to increase its production levels, providing 50 percent of the world's liquids supply by 2035. The availability of low-cost resources in both non-OPEC and OPEC countries allows for prices to stabilize at relatively low levels, $51 per barrel in real 2008 dollars, thereby reducing the incentive for consuming nations to invest in unconventional liquids production as heavily as they do in the Reference case.

High Oil Price case

The *AEO2010* High Oil Price case assumes not only a rebound in world oil prices with the return of world economic growth, but also a continued rapid escalation in prices as a result of long-term restrictions on conventional liquids production. The restrictions result from both political decisions and resource characteristics: the major OPEC and non-OPEC producing countries use quotas, fiscal regimes, and varying degrees of nationalization to further increase revenues from oil production, and the consuming countries turn to domestic production of high-cost unconventional liquids to satisfy demand. As a result, in the High Oil Price case, world oil prices rise throughout the projection period, to $210 per barrel in 2035. Liquids demand is dampened by the high prices, but is overshadowed by the severity of limitations on access to and availability of lower cost conventional resources. OPEC's share of production falls to 35 percent.

Components of liquid fuels supply

In the *AEO2010* Reference case, total world liquid fuels consumption in 2035 is 112 million barrels per day, or 26 million barrels per day higher than in 2008, with production increases from OPEC and non-OPEC conventional sources totaling 15.5 million barrels per day. As a result, the conventional liquids share of world liquids supply drops from 95 percent in 2008 to 87 percent in 2035.

Production of unconventional crude oils in the *AEO2010* Reference case is 4.0 million barrels per day higher in 2035 than in 2008 and represents 5.6 percent of global liquid fuels supply in 2035. Production increases from Venezuela's Orinoco belt and Canada's oil sands are limited by access restrictions in Venezuela and environmental concerns in Canada. The relatively high world oil prices in the Reference case encourage U.S. production of oil shale, with volumes reaching 0.4 million barrels per day in 2035. Relatively high prices also encourage growth in global CTL, GTL, and biofuel production, from a combined total of 1.8 million barrels per day in 2008 to 8.4 million barrels per day in 2035, or 8 percent of total liquids supplied.

In the *AEO2010* Low Oil Price case, oil prices are on average more than 50 percent lower than in the Reference case from 2015 to 2035. In this case, conventional crude oil accounts for the largest share of total liquids production in any of the three price cases in 2035, at about 90 percent. Production of conventional crude oil totals 100.5 million barrels per day in 2035, higher than the total for all conventional liquids in the Reference case. Total conventional liquids production reaches 114.8 million barrels per day, and total liquids production reaches 127 million barrels per day, in the Low Oil Price case in 2035.

Despite their generally higher costs, production of unconventional crude oils is also higher in the Low Oil Price case than in the Reference case, as a result of changes in economic access to resources. In the Low Oil Price case, Venezuela's production of extra-heavy oil in 2035 increases from the Reference case projection of 1.3 million barrels per day to 3.4 million barrels per day—a 160-percent increase that more than compensates for lower production of Canada's oil sands (0.6 million barrels per day in 2035) due to reduced profitability. Total production of unconventional crude oil in the Low Oil Price case is 1.0 million barrels per day higher in 2035 than projected in the Reference case. Production of other unconventional liquids (CTL, GTL, and biofuels) in 2035, primarily in the United States, China, and Brazil, is 3.2 million barrels per day lower than projected in the Reference case, again due to reduced profitability.

In the High Oil Price case, oil prices from 2015 to 2035 are on average 66 percent higher than in the Reference case. The higher prices are caused by restrictions on economic access to non-OPEC conventional resources in countries such as Russia, Kazakhstan, and Brazil, combined with reductions in OPEC production. Conventional liquids production in the High Oil Price case totals 71.8 million barrels per day in 2035, 9.8 million barrels per day lower than the 2008 total; total liquids production reaches only 91 million barrels per day in 2035.

Access restrictions also limit the production of Venezuela's extra-heavy oil from the Orinoco belt, which totals 0.8 million barrels per day in 2035, as compared with 1.3 million barrels per day in the Reference case. Higher world oil prices support increased production from Canada's oil sands, which totals 5.5 million barrels per day in 2035, as compared with 4.5 million barrels per day in the Reference case. Production of shale oil, predominantly in the United States, does not change appreciably from the Reference case level in the High Oil Price case, because the projects are economically viable in the Reference case, and even a 66-percent increase in prices does not stimulate additional production growth. With the increase in oil sands production outweighing the decrease in extra-heavy oil production through 2035, production of unconventional crude oil from all sources is higher in the High Oil Price case than in the Reference case.

Production of liquids from other unconventional sources, including CTL, GTL, and biofuels, is almost 50 percent (3.9 million barrels per day) higher in the High Oil Price case than in the Reference case in 2035. The increase results primarily from higher CTL production in China (approximately 1.3 million barrels per day above the Reference case projection in 2035) and higher biofuels production in the United States (0.9 million barrels per day above the Reference case in 2035). U.S. GTL production in the High Oil Price case is notably different from the Reference case projection, with production beginning in 2017 and reaching 0.5 million barrels per day in 2035.

Energy intensity trends in *AEO2010*

Energy intensity—energy consumption per dollar of real GDP—indicates how much energy a country uses to produce its goods and services. From the early 1950s to the early 1970s, U.S. total primary energy consumption and real GDP increased at nearly the same annual rate (Figure 17). During that period, real oil prices remained virtually flat. In contrast, from the mid-1970s to 2008, the relationship between energy consumption and real GDP growth changed, with primary energy consumption growing at less than one-third the previous average rate and real GDP growth continuing to grow at its historical rate. The decoupling of real GDP growth from energy consumption growth led to a decline in energy intensity that averaged 2.8 percent per year from 1973 to 2008. In the *AEO2010* Reference case, energy intensity continues to decline, at an average annual rate of 1.9 percent from 2008 to 2035.

Definitions and classifications

Energy efficiency is defined as the ratio of the amount of energy services provided to the amount of energy consumed [*43*]. Familiar examples of energy services are the heat supplied by a furnace and the light output of a lamp.

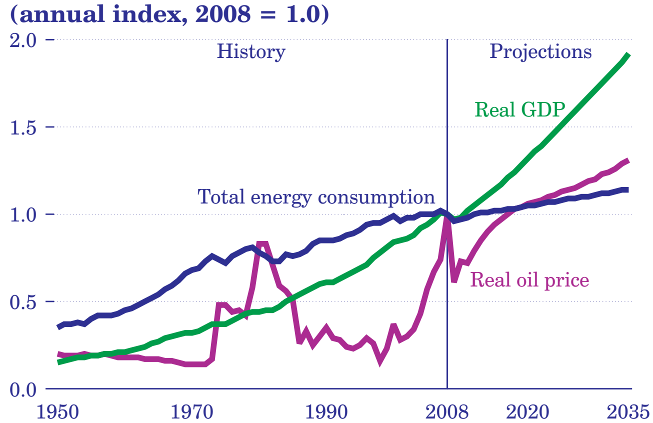
Energy conservation is defined as the lowering of energy consumption by reducing energy services. For example, lowering a thermostat's setting during the heating season is classified as energy conservation, because less heating is provided. Because the ratio of energy services to energy consumption is unchanged, energy efficiency does not change in this example.

As indicated above, *energy intensity* is defined as energy consumption per dollar of real GDP. Any change in energy intensity that does not result from a change in efficiency is referred to as a *structural change* [*44*]. Examples of structural change include energy conservation, a change in the mix of economic activity among the sectors of the economy, a change in the mix of activities within a sector, and a geographical change in population density. Energy use is affected in these examples of structural change, but not because of changes in energy efficiency.

CO_2 emissions associated with energy production and consumption are a growing concern. *Carbon intensity* is the ratio of CO_2 emissions to real GDP. The type of fuel used to provide energy services—or in the case of electricity, the fuel used to generate it—affects carbon intensity.

As defined here, efficiency and intensity are inversely related: increases in energy efficiency reduce energy intensity. To facilitate comparisons among them, the

Figure 17. Trends in U.S. oil prices, energy consumption, and economic output, 1950-2035 (annual index, 2008 = 1.0)

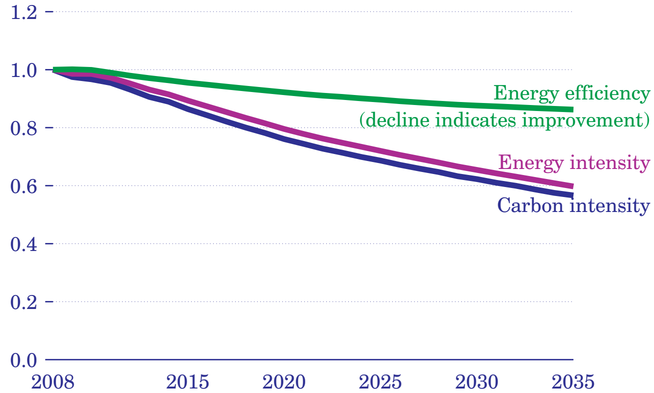


efficiency index discussed below is calculated as the inverse of the usual efficiency concept: energy consumption per unit of service demand. In this way, both improvements in efficiency and improvements in intensity are shown as decreases.

Results for the Reference case

Because the available data are limited, it is difficult to determine the amount of historical decoupling of energy consumption growth from real GDP growth that was attributable to improvements in energy efficiency [*45*]. With the wealth of technology detail on energy-using equipment in NEMS, efficiency can be characterized readily [*46*]. Figure 18 compares indexes of the Reference case projections for energy efficiency, energy intensity, and carbon intensity. The average rate of decline in the index for energy intensity from 2008 to 2035 is almost quadruple the rate of decline in the index for energy efficiency, reflecting the dominant role of structural change. The

Figure 18. Projected changes in indexes of energy efficiency, energy intensity, and carbon intensity in the *AEO2010* Reference case, 2008-2035 (index, 2008 = 1.0)



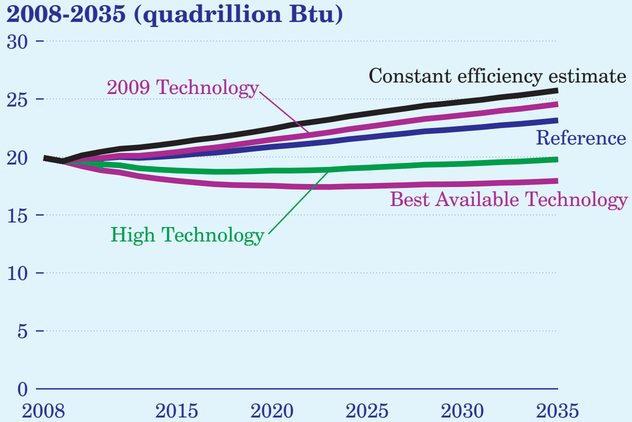
Comparing efficiency projections

Realized improvements in energy efficiency generally rely on a combination of technology and economics [*47*]. The figure below illustrates the role of technology assumptions in the *AEO2010* projections for energy efficiency in the residential and commercial buildings sector. Projected energy consumption in the Reference case is compared with projections in the Best Available Technology, High Technology, and 2009 Technology cases and an estimate based on an assumption of no change in efficiency for building shells and equipment (the cases are defined in Appendix E).

With the exception of the constant efficiency estimate, the rate at which existing equipment stocks are replaced in each of the cases is governed by the rate of stock turnover. The constant efficiency estimate assumes no stock turnover and no change in efficiency from the 2009 existing stock. The 2009 Technology case assumes a normal rate of stock turnover, but limits new equipment choices to what is available in 2009. Comparing the two projections, energy consumption in 2035 is 1.2 quadrillion Btu lower in the 2009 Technology case. The difference—about 4.5 percent—shows the effect of stock turnover even absent any technology improvements.

In the Best Available Technology case, with new construction materials and replacement equipment limited to the most energy-efficient available, energy consumption in the buildings sector in 2035 is 8.6 percent lower than the 2009 level and 23 percent lower than in the Reference case, even though total floorspace grows by more than 50 percent. Even in 2035, however, not every piece of equipment or every building shell reaches the maximum efficiency that could be achieved as a result of technology improvements, because some long-lived equipment and building shells installed before 2009 still have not been replaced at that point. Surpassing the efficiency levels projected in the Best Available Technology case would require policies designed to increase the rate of stock turnover—for example, by incentivizing or mandating retrofits of existing buildings and replacement of equipment with the most efficient models available.

Delivered energy consumption in the residential and commercial buildings sector in five scenarios, 2008-2035 (quadrillion Btu)



larger reduction in the index for carbon intensity reflects a shift toward less carbon-intensive energy sources in the Reference case, especially wind, biofuels, and solar. In the Reference case, the ratio of carbon emissions to energy consumption in 2035 is 5 percent lower than its 2008 value.

Energy consumption increases at an average annual rate of 0.5 percent from 2008 to 2035 in the *AEO2010* Reference case. The portion of the energy intensity decline projected in the Reference case that can be attributed to structural changes and the portion that can be attributed to changes in energy efficiency is illustrated by comparing the growth of primary energy use in the Reference case with estimates of constant energy efficiency and constant energy intensity, calculated from the *AEO2010* Reference case (Figure 19).

Assuming no improvement in energy intensity beyond 2008, energy consumption would grow in the Reference case at the rate of real GDP, 2.4 percent annually, to 192 quadrillion Btu in 2035—77.6 quadrillion Btu (68 percent) higher than in the Reference case. Similarly, assuming no change in energy efficiency beyond its 2008 level, energy consumption would increase to 132.8 quadrillion Btu in 2035, or 18.3 quadrillion Btu (16 percent) higher than in the Reference case. The intensity decline from structural change in the Reference case, 59.2 quadrillion Btu, is the difference between the projection for energy consumption in 2035 when no change in energy intensity is assumed and the same projection when no change in energy efficiency is assumed. Thus, structural change accounts for 76 percent of the decline in energy intensity in the Reference case, and efficiency improvement accounts for 24 percent.

Figure 19. Structural and efficiency effects on primary energy consumption in the *AEO2010* Reference case (quadrillion Btu)

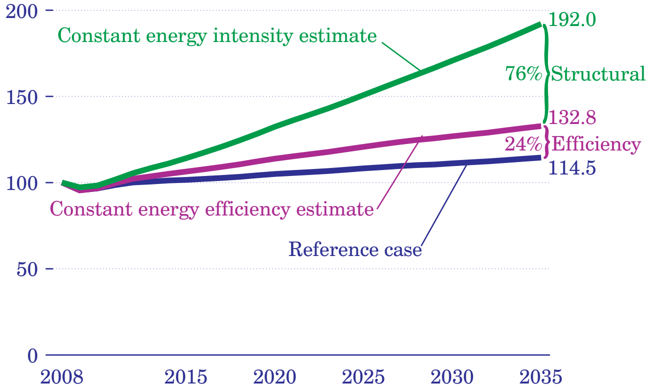


Table 4 shows average annual growth rates from 2008 to 2035 for real GDP, population, and major indicators for energy consumption in the end-use sectors in the Reference case. Because the growth rate for real GDP is higher than any of the other growth rates, energy consumption in each sector would be expected to grow more slowly than real GDP, and energy intensity would be expected to decline, even in the absence of efficiency gains.

In each of the end-use sectors, most of the improvement (decline) in energy intensity results from structural change: 82 percent in the buildings sectors, where average annual increases in residential and commercial floorspace are only about one-half the average increase in real GDP; 82 percent in the industrial sector, where output from non-energy-intensive manufacturing grows at twice the rate of output from energy-intensive manufacturing; and 53 percent in the transportation sector, where structural change is slower and improvements in fuel efficiency as a result of tightening fuel economy standards account for 47 percent of the decline in energy intensity. (For further discussion of efficiency in the *AEO2010* buildings cases, see box on page 31.)

Results for the Integrated Technology cases

The *AEO2010* Low Technology case assumes that the efficiency of newly purchased equipment does not improve beyond what is currently available (although end-use or process efficiency does improve to some extent as a result of stock turnover, because replacement equipment nearly always is more efficient than the equipment it replaces). The High Technology case

Table 4. Average annual increases in economic output, population, and energy consumption indicators in the buildings, industrial, and transportation sectors, 2008-2035 (percent per year)

Real GDP	**2.4**
Population	**0.9**
Buildings sector	
Number of households	1.0
Commercial floorspace	1.3
Industrial sector	
Real value of industrial shipments	
Nonmanufacturing	0.9
Energy-intensive manufacturing	0.8
Non-energy-intensive manufacturing	1.8
Transportation sector	
Vehicle miles traveled	
Light-duty vehicles	1.7
Freight trucks	1.7
Air seat-miles	1.3
Rail ton-miles	0.8

assumes earlier availability of high-efficiency technologies and lower technology costs than in the Reference case. Also, in a departure from previous *AEO*s, the *AEO2010* High Technology case assumes that consumers are more likely to choose advanced technologies, because they evaluate efficiency investments at a 7-percent real discount rate, which is generally lower than assumed in the Reference case.

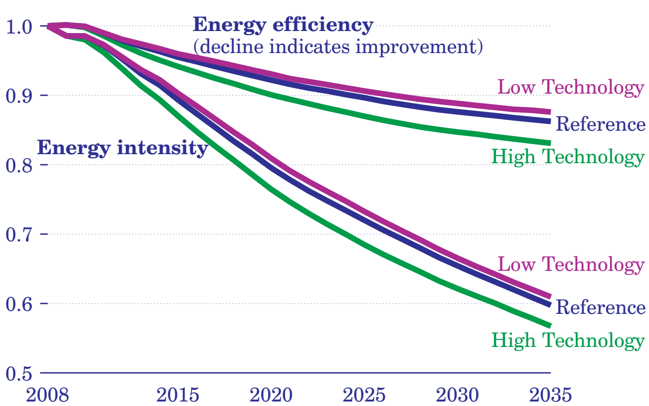
In the Low Technology and High Technology cases, projections for energy consumption in 2035 are 2.4 quadrillion Btu (2 percent) higher and 5.7 quadrillion Btu (5 percent) lower, respectively, than in the Reference case. Energy efficiency and intensity trends in the Reference, Low Technology, and High Technology cases are shown in Figure 20. From 2008 to 2035, there is a 12- to 17-percent improvement in energy efficiency across the three cases and a 39- to 43-percent reduction in intensity.

The relatively narrow range of projections in Figure 20 indicates that, although technology advances play a role in reducing energy intensity and carbon intensity, structural components are much more significant. Population shifts to more moderate climates, smaller households, less energy-intensive manufacturing, and more fuel-efficient LDVs and high-speed rail could further reduce energy intensity. Policies governing future CO_2 emissions and deployment of low- and no-carbon technologies will be the main determinant of future carbon intensity.

Natural gas as a fuel for heavy trucks: Issues and incentives

Environmental and energy security concerns related to petroleum use for transportation fuels, together with recent growth in U.S. proved reserves and technically recoverable natural gas resources, including

Figure 20. Energy efficiency and energy intensity in three cases, 2008-2035 (index, 2008 = 1.0)



shale gas, have sparked interest in policy proposals aimed at stimulating increased use of natural gas as a vehicle fuel, particularly for heavy trucks. In 2008, U.S. freight trucks used more than 2 million barrels of petroleum-based diesel fuel per day. In the *AEO2010* Reference case, they are projected to use 2.7 million barrels per day in 2035. Petroleum-based diesel use by freight trucks in 2008 accounted for 15 percent of total petroleum consumption (excluding biofuels and other non-petroleum-based products) in the transportation sector (13.2 million barrels per day) and 12 percent of the U.S. total for all sectors (18.7 million barrels per day). In the Reference case, oil use by freight trucks grows to 20 percent of total transportation use (13.7 million barrels per day) and 14 percent of the U.S. total (19.0 million barrels per day) by 2035. The following analysis examines the potential impacts of policies aimed at increasing sales of heavy-duty natural gas vehicles (HDNGVs) and the use of natural gas fuels, and key factors that lead to uncertainty in these estimates.

Historically, natural gas has played a limited role as a transportation fuel in the United States. In 2008, natural gas accounted for 0.2 percent of the fuel used by all highway vehicles and 0.2 percent of the fuel used by heavy trucks—the market that many observers believe to be the most attractive for increasing the use of natural gas. Because there are relatively few heavy vehicles that use natural gas for fuel currently, there has been very little development of natural gas fueling infrastructure. Currently there are 827 fueling stations for CNG and 38 fuel stations for LNG in the United States. Most are privately owned and are used for central refueling [*48*]. Further, they are not distributed evenly: 24 percent (201) of the CNG facilities and 71 percent (27) of the LNG facilities are in California. Unless more natural gas vehicles enter the market, there will be little incentive to build more natural gas fueling infrastructure nationally or in local or regional corridors.

Despite the price advantage that natural gas has had over diesel fuel in recent years (an advantage that is projected to increase over time in the Reference case), other factors—including higher vehicle costs, lower operating range, and limited fueling infrastructure—have severely limited market acceptance and penetration of natural gas vehicles. As of 2008, trucks powered by natural gas made up only 0.3 percent of the heavy truck fleet, or about 27,000 of the 8.7 million registered heavy trucks. Although their share grows in the Reference case projections, high incremental costs keep the fleet of HDNGVs relatively small, at 1.7 percent (260,000 vehicles) of the total stock of 15 million heavy trucks on the road in 2035.

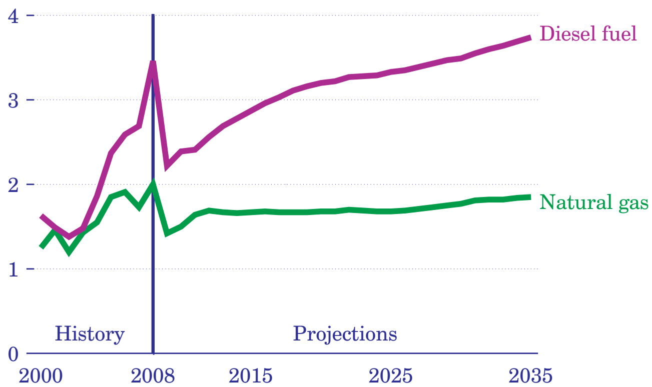
Characteristics and usage of heavy-duty natural gas vehicles

HDNGVs have significant incremental costs relative to their diesel-powered counterparts in the *AEO2010* Reference case: $17,000 for light-heavy (class 3, GVWR of 10,000 to 14,000 pounds), $40,000 for medium-heavy (classes 4 through 6, GVWR of 14,001 to 26,000 pounds), and $60,000 for heavy trucks (classes 7 and 8, GVWR of 26,001 pounds and greater). By far the largest component of incremental cost is the fuel storage system, which consists either of cylindrical tanks to hold CNG at high pressure or of highly insulated tanks to hold LNG. Because tank technology is fairly mature and, in the case of cylindrical tanks to hold gases at high pressure, is already widely deployed, the Reference case does not assume significant reductions in incremental vehicle costs over time.

Natural gas for use in transport vehicles currently costs 42 percent less than diesel fuel (on an energy-equivalent basis and considering only existing taxes), and with oil prices rising at a significantly faster rate than U.S. natural gas prices, the gap is projected to widen to 50 percent in 2035 in the *AEO2010* Reference case (Figure 21). Consequently, the payback period for incremental vehicle costs becomes shorter when natural gas trucks are used more intensively.

The Department of Transportation's Vehicle Inventory and Use Survey (VIUS), last completed in 2002, suggests a wide range for the intensity of heavy truck use. Notably, in the 2002 VIUS, trucks reporting a primary range of operation that extended more than 500 miles from their base averaged 91,000 vehicle-miles traveled (VMT), or more than 5 times the average of 17,000 VMT for trucks reporting a primary range of operation range within 100 miles of their base.

Figure 21. Delivered energy prices for diesel and natural gas transportation fuels in the Reference case, 2000-2035 (2008 dollars per gallon of diesel equivalent)



Although long-distance trucking offers a potentially faster payback of the incremental capital costs for HDNGVs, their penetration and acceptance in the long-distance freight market faces two significant barriers: limited driving range without refueling and a lack of available fueling infrastructure. A diesel truck with one 150-gallon diesel tank and a fuel economy of 6 to 7 mpg can drive approximately 1,000 miles without refueling, which can be extended readily with an auxiliary fuel tank. In contrast, a CNG-fueled truck with a frame-rail-mounted storage tank can drive only about 150 miles without refueling, while one with a back-of-cab frame-mounted storage tank can drive about 400 miles without refueling, similar to an LNG-fueled truck with frame-rail-mounted tanks. In addition, regardless of fuel type, long-distance trucks are less likely to be fueled at central bases, which makes them more dependent on fueling infrastructure that is open to the public.

In addition to concerns about driving range and refueling, the residual value of HDNGVs in the secondary market is likely to be an important consideration for buyers. Also, purchase decisions can be influenced by other factors, such as weight limits on highways and bridges, which can make the considerable additional weight of CNG or LNG tanks a significant drawback in some market segments.

The importance of range and refueling infrastructure barriers suggests that the best near-term market penetration opportunity for HDNGVs, some of whose incremental costs are already covered by tax credits, could be in the market for centrally fueled fleets that operate primarily within a limited distance from their base. The 2002 VIUS reported a total of 145 billion truck VMT (not counting light trucks used primarily for personal transportation), of which about 50 percent was made up by trucks with a primary operating range of 200 miles or less and about one-third by trucks fueled at private facilities (presumably, with considerable overlap between the two groups). Accordingly, the following analysis focuses on "fleet vehicles" in the short-range (less than 200 miles), centrally fueled segment of the heavy truck market.

Sensitivity cases with incentives for heavy-duty natural gas vehicles

Policies that provide economic incentives—such as tax credits for vehicles, fuel, and fueling infrastructure—could stimulate sales of HDNGVs and the development of additional natural gas fueling infrastructure. *AEO2010* includes several sensitivity cases that examine the potential impacts of such incentives.

The **Reference Case 2019 Phaseout With Base Market Potential** is a modified Reference case that incorporates lower incremental costs for all classes of HDNGVs (zero incremental cost relative to their diesel-powered counterparts after accounting for incentives) and tax incentives for natural gas refueling stations ($100,000 per new facility) and for natural gas fuel ($0.50 per gallon of gasoline equivalent) that begin in 2011 and are phased out by 2019.

The **Reference Case 2027 Phaseout With Expanded Market Potential** is another modified Reference case with the same added assumptions of lower incremental costs for HDNGVs and subsidies for fueling stations and natural gas fuel as in the first modified Reference case, but with the subsidies extended to 2027 before phaseout. In addition, it assumes increases in the potential market for natural gas vehicles, for both "fleet vehicles" and "nonfleet vehicles" (see Table 5).

In the following text and data presentations, the cases above are referred to more briefly as the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case.

HDNGVs cannot gain a major share of the heavy truck market in the absence of major investments in natural gas fueling infrastructure. The assumed $100,000 tax credit per filling station is a relatively small percentage of the estimated $1 million to $4 million cost for such facilities. Assuming an initial cost of $2 million per station, Table 6 shows the levelized capital cost of the station per gallon of diesel equivalent refueling capacity with and without the $100,000 tax credit, for station fuel throughput capacities of 1,250, 5,000, and 12,500 gallons per day [*49*].

As indicated in Table 6, increasing the throughput capacity of a fueling station from 1,250 to 5,000 gallons diesel equivalent per day lowers the capital cost recovery component of supplying natural gas fuel to HDNGVs by more than $1.00 per gallon of diesel equivalent. The infrastructure tax credit lowers the capital cost recovery component by only an additional 8 cents per gallon for the smallest facility size shown in the table and by only 1 cent per gallon for the largest facility size. This suggests that throughput capacity (demand) is a far more important consideration for decisions about investment in natural gas fueling stations than are potential tax credits on the order of about $100,000.

Impacts of incentives in the Base Market and Expanded Market cases with Reference case world oil price assumptions

In the 2019 Phaseout Base Market and 2027 Phaseout Expanded Market cases, both of which use oil price assumptions from the *AEO2010* Reference case, HDNGV sales increase with the availability of incentives. Assuming a 2019 phaseout date for tax credits and the base characterization of maximum penetration of the new truck market, sales of new HDNGVs in the 2019 Phaseout Base Market case increase from about 500 in 2008 to 32,500 in 2035, versus 22,000 in the Reference case (Figure 22). Assuming a 2027 phaseout of tax credits and the expanded characterization of maximum market penetration, HDNGV sales in the 2027 Phaseout Expanded Market case increase to 270,000 in 2035, or roughly 35 percent of

Table 5. Maximum market potential for natural gas heavy-duty vehicles in Base Market and Expanded Market cases (percent of total heavy-duty vehicle fleet)

Vehicle type and class	Base Market	Expanded Market
Fleet vehicles		
Class 3	10	35
Classes 4-6	10	45
Classes 7-8	10	60
Nonfleet vehicles		
Class 3	3	10
Classes 4-6	3	25
Classes 7-8	3	25

Table 6. Levelized capital costs for natural gas fueling stations with and without assumed tax credits (2008 dollars per gallon of diesel equivalent refueling capacity)

Station capacity (gallons equivalent per day)	Cost without credits	Cost with credits
1,250	1.47	1.39
5,000	0.37	0.35
12,500	0.15	0.14

all new heavy truck sales. The HDNGV share of the total U.S. heavy truck stock in 2035 is 2.8 percent in the 2019 Phaseout Base Market case and 23.3 percent in the 2027 Phaseout Expanded Market case (versus 1.7 percent in the Reference case).

As a result of the projected increases in new HDNGV sales, natural gas demand in the heavy truck sector increases from about 0.01 trillion cubic feet in 2008 to 0.15 trillion cubic feet in 2035 in the 2019 Phaseout Base Market case and to 1.6 trillion cubic feet in 2035 in the 2027 Phaseout Expanded Market case (Figure 23). In the Reference case, the natural gas share of total fuel consumption by heavy trucks increases from 0.2 percent in 2008 to 1.8 percent in 2035; in the 2019 Phaseout Base Market and 2027 Phaseout Expanded Market cases, it increases to 3.3 percent and 40.0 percent, respectively.

Figure 22. Sales of new heavy-duty natural gas vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (thousands of vehicles)

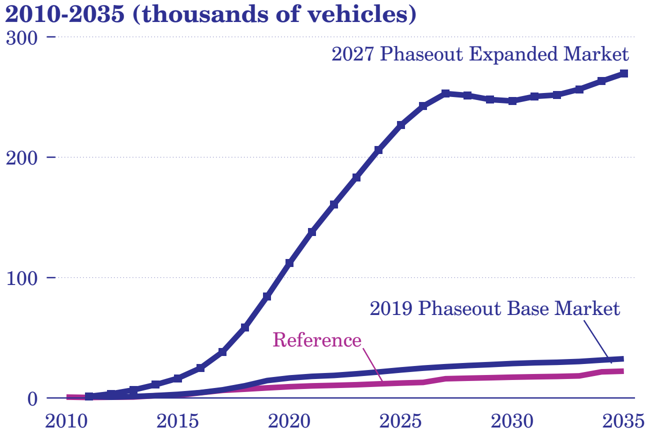
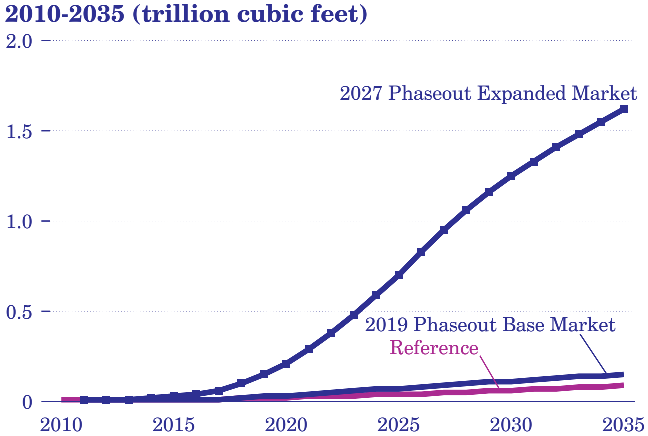


Figure 23. Natural gas fuel use by heavy-duty natural gas vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (trillion cubic feet)

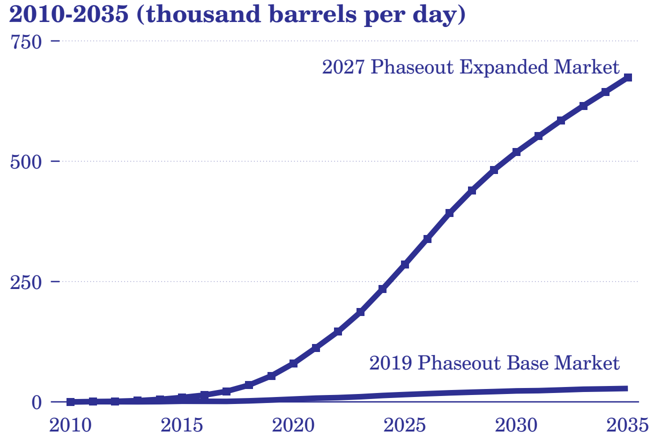


Roughly speaking, 1 trillion cubic feet of natural gas replaces 0.5 million barrels per day of petroleum (predominantly, diesel fuel). Thus, natural gas consumption by HDNGVs in the 2027 Phaseout Expanded Market case displaces about 0.67 million barrels per day of petroleum product consumption in 2035 (Figure 24). Without a major impact on world oil prices, which is not expected to result from the significant but gradual adoption of natural gas as a fuel for U.S. heavy-duty vehicles, nearly all (more than four-fifths) of the reduction in U.S. oil consumption would result in a decline in oil imports.

In the longer term, increased demand for natural gas in the transportation sector would tend to stimulate increases in U.S. natural gas production and imports, as well as higher natural gas prices in all the end-use sectors. As a result, natural gas demand in the other sectors would decrease—particularly in the electric power sector, where some generators would switch to coal—and expenditures for natural gas would increase. In the *AEO2010* Reference case, total U.S. natural gas consumption increases from 23.3 trillion cubic feet in 2008 to 24.9 trillion cubic feet in 2035. In the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case, total natural gas consumption increases by 0.4 percent, to 25.0 trillion cubic feet, and by 4.8 percent, to 26.1 trillion cubic feet, respectively, in 2035.

In the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case, more than two-thirds of the additional natural gas used by HDNGVs is produced domestically, and less than one-third is provided by increases in pipeline imports from Canada and LNG imports. U.S. natural gas prices rise modestly in both cases.

Figure 24. Reductions in petroleum product use by heavy-duty vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (thousand barrels per day)



Impacts of incentives in the Base Market and Expanded Market cases with low world oil price assumptions

Lower oil prices tend to make HDNGVs a less attractive option, and higher oil prices tend to make them more attractive. In the two sensitivity cases discussed above, which assumed Reference case world oil prices, market penetration by HDNGVs reaches or nearly reaches its assumed maximum market potential. As a result, higher oil prices would not lead to further increases in HDNGV sales, unless the large price advantage of natural gas were sufficient to open additional segments of the heavy truck transportation market to the use of natural-gas-fueled vehicles.

On the other hand, if oil prices were lower than projected in the Reference case, there would be less incentive to switch from diesel to natural gas fuel in heavy trucks. With no tax incentives or assumed market expansion for HDNGVs, there are almost no sales of new HDNGVs in 2035 in the *AEO2010* Low Oil Price case. To analyze the impact of lower oil prices, EIA ran two sensitivity cases that were identical to those discussed earlier but instead used the Low Oil Price case. In the 2019 Phaseout Base Market Low Price case, sales of new HDNGVs total about 17,000 in 2035. In the 2027 Phaseout Expanded Market Low Price case, sales of new HDNGVs total about 205,000 in 2035. Similarly, natural gas consumption by HDNGVs increases to 0.1 trillion cubic feet in 2035 in the 2019 Phaseout Base Market Low Price case and to 1.2 trillion cubic feet in the 2027 Phaseout Expanded Market Low Price case, as compared with almost no demand for natural gas in the heavy vehicle sector in 2035 in the *AEO2010* Low Oil Price case.

Incentive costs and impacts on energy expenditures

Increased use of natural gas as a transportation fuel changes the levels of demand for, and consequently the prices of natural gas and other fuels used in transportation and other sectors of the economy. Depending on the amount of natural gas used in the transportation sector, the sum of incentive payments to the transportation sector plus higher energy costs to other sectors may be more than offset by savings in the transportation sector from fuel switching from diesel to natural gas. Figure 25 shows annual vehicle and fuel tax incentive payments and net changes in economy-wide energy expenditures for the 2027 Phaseout Expanded Market case [*50*]. The graph shows how changes in transportation demand for natural gas and petroleum products may affect energy expenditures throughout the economy while the incentives are in effect. The significant increase in transportation natural gas use and associated reductions in petroleum product use result in increases in economy-wide natural gas prices and expenditures that are more than offset by economy-wide decreases in petroleum product prices and expenditures.

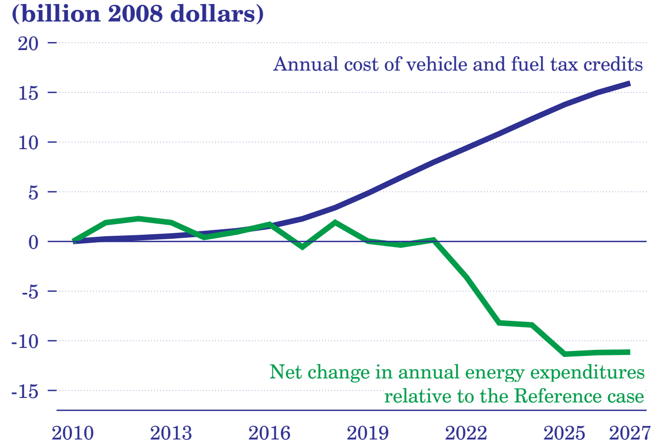
The projections in Figure 25 do not reflect many of the factors that could be important for policymakers' evaluations of incentives for HDNGVs, such as the cost of infrastructure tax credits, productivity losses resulting from more frequent refueling, impacts on net energy costs, incremental vehicle costs beyond the period when incentives are provided, or environmental benefits of reducing emissions of conventional pollutants and GHGs. Also, they do not consider potential effects on royalty and severance payments as a result of changes in domestic natural gas production or oil imports, or effects on GDP and other relevant indicators of economic welfare and energy security.

Factors affecting the relationship between crude oil and natural gas prices

Background

Over the 1995-2005 period, crude oil prices and U.S. natural gas prices tended to move together, which

Figure 25. Annual cost of vehicle and fuel tax credits and net change in annual economy-wide energy expenditures for the 2027 Phaseout Expanded Market case, 2010-2027 (billion 2008 dollars)



supported the conclusion that the markets for the two commodities were connected. Figure 26 illustrates the fairly stable ratio over that period between the price of low-sulfur light crude oil at Cushing, Oklahoma, and the price of natural gas at the Henry Hub on an energy-equivalent basis.

The *AEO2010* Reference and High Oil Price cases, however, project a significantly longer and persistent disparity between the relative prices of low-sulfur light crude oil and natural gas on an energy-equivalent basis [*51*]. The apparent disconnect in prices between seemingly similar commodities varies over a wide range between 2010 and 2035 [*52*]. Over much of the projection period in the Reference case, the crude oil price is about 2.8 times the natural gas price on an energy equivalent basis—115 percent higher than the historical average price ratio of 1.3 from 1995 to 2005. In the High Oil Price case, the ratio widens to as much as 4.8; in the Low Oil Price case, it narrows from nearly 3.0 in 2009 to 1.1 in 2035.

Such an apparent lack of responsiveness of natural gas prices to changes in crude oil prices in all cases reflects the changes that have occurred in the underlying uses of the two commodities. The divergence of crude oil and natural gas markets also reflects the fact that opportunities for the substitution of natural gas for crude oil products are limited by the large infrastructure investments that would be required to allow substitution on a significant scale and bring the prices of the two commodities closer together in the U.S. market in the Reference and High Oil Price cases. In the absence of such investments, EIA expects the gap between oil and natural gas prices in U.S. energy markets to remain wide.

Opportunities to substitute natural gas for petroleum

In the United States, the capability to substitute natural gas supplies directly for petroleum, particularly in the electric power sector, has eroded over time. In 1978, 4.0 quadrillion Btu of petroleum was consumed to produce electricity, representing nearly 17 percent of total energy use for U.S. electricity generation, as compared with 14 percent for natural gas [*53*]. In 2008, only 0.5 quadrillion Btu of petroleum was consumed for electricity generation, representing 1.2 percent of total energy use for generation [*54*, *55*], while natural gas has grown to 17 percent of generation. The trend has been similar in the commercial and industrial sectors where there are a declining number of opportunities to substitute natural gas for petroleum.

Still, there are potential opportunities for natural gas to displace petroleum. First, direct use of natural gas in the U.S. transportation sector could provide an opportunity for substitution. Second, natural gas could be exported to countries where petroleum is widely used for thermal applications. Third, natural gas can be converted directly to petroleum-like liquid fuels that could be substituted for diesel and gasoline in the existing vehicle fleet using the existing distribution infrastructure.

The physical properties of natural gas are such that it is more difficult and costly than liquid fuels to transport and consume. As shown in Figure 27, the energy density of natural gas is much lower than that of most liquid fuels. To match the energy equivalent of a 1-gallon container of diesel fuel, a balloon of natural gas at atmospheric pressure would have to be nearly a thousand times larger than the gallon container. At a

Figure 26. Ratio of low-sulfur light crude oil prices to natural gas prices on an energy-equivalent basis, 1995-2035

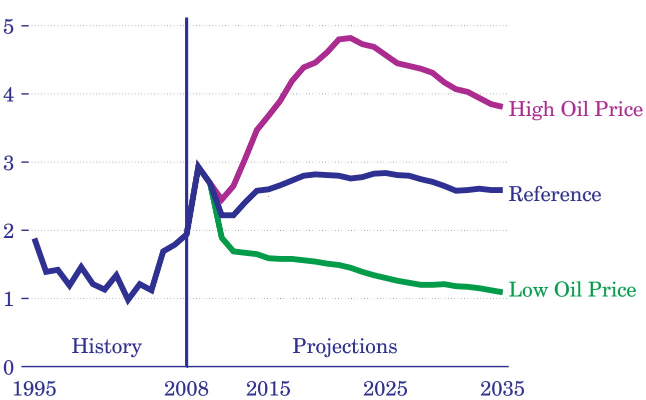
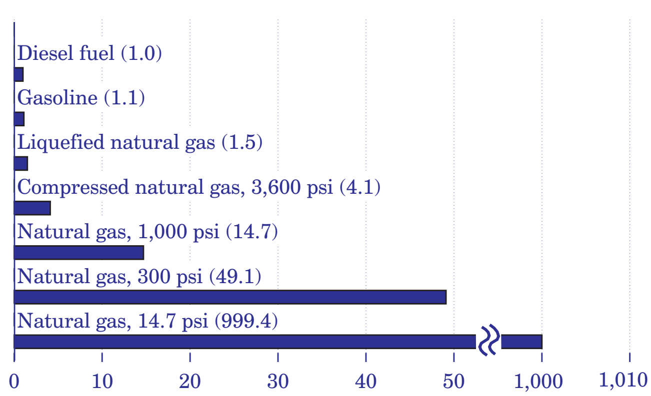


Figure 27. Ratio of natural gas volume to diesel fuel volume needed to provide the same energy content



pressure of 3,600 pounds per square inch (psi), however, which is the pressure rating for the fuel tanks used in CNG vehicles, only 4 times as much space is required to match the energy equivalent of 1 gallon of diesel fuel. And when the gas is converted to LNG by chilling to about -260 degrees Fahrenheit, its energy density increases to the point where it requires only 50 percent more volume to match the energy content of diesel fuel. However, the materials used for the handling and storage of LNG differ significantly from those used for CNG or petroleum-like liquid fuels.

An expanded market for CNG or LNG would require additional investment in vehicles and infrastructure for compression and storage of CNG or for liquefaction and storage of LNG. Some of the issues, challenges, and opportunities surrounding the use of natural gas as a substitute for diesel fuel are described in the Issues in Focus section, "Natural gas as a fuel for heavy trucks: Issues and incentives."

Barriers to U.S. exports of LNG

World crude oil and natural gas prices could converge if barriers to the flow of natural gas between U.S. and world markets were eliminated through the combined use of the existing pipeline network, existing LNG terminals, and investment in new U.S. LNG liquefaction capacity (and possibly LNG tankers) to allow exports of U.S. natural gas when it is economical. Currently, there is one liquefaction facility in Alaska that exports LNG from the United States. Investment in new U.S. liquefaction capacity would face significant risk, however, because there are large quantities of "stranded gas" in remote regions of the world that can be priced well below the expected cost of resources in the lower 48 States.

Potential for production of liquid fuels from natural gas

Another opportunity to substitute natural gas for crude oil would be to convert it to petroleum-like liquid products similar to gasoline and diesel fuel, for use in the liquid fuel infrastructure and end-use equipment. Such a transformation is possible through use of the GTL process.

There are several GTL processes, the best known using a Fischer-Tropsch reactor. The reactor produces a paraffin wax that is hydrocracked to form liquid products that resemble petroleum liquids. Distillates, including diesel, heating oil, and jet fuel, are the primary products, making up 50 to 70 percent of the total volume produced, and naphtha usually represents about 25 percent of the volume. The process efficiency is about 57 percent (43 percent of the energy content of the natural gas is lost in the process) [*56*]. Thus, the price ratio of liquid products to natural gas would have to exceed about 1.8 to justify operation of the plant, excluding consideration of other operating costs and the cost of capital investment. To appreciate the price risk faced by investors, one can consider the effects of recent fluctuations in energy prices on investments in U.S. natural gas turbine and combined-cycle generating units and ethanol production facilities [*57*]. Indeed, *AEO2010* examines the potential impacts of lower energy prices in the Low Oil Price case, which shows the ratio of crude oil prices to natural gas prices declining to 1.1 in 2035, indicating that if any GTL plants were built they would not be operated under those price conditions.

The technologies and equipment used in the best-known GTL technology are similar to those that have been employed for decades in methanol and ammonia plants, and most are relatively mature; however, the scale on which previous GTL plants have been implemented is relatively small. The newest GTL plants have been expanded to much larger sizes, including one in excess of 100,000 barrels per day, to take advantage of economies of scale, but recent attempts to build projects at those larger sizes have encountered technology or project execution risks [*58*]. Currently, there are four GTL plants in operation worldwide, with 96,200 barrels per day of total capacity [*59*]. In addition, two projects with 174,000 barrels per day of capacity are under construction or ready for startup [*60*]. However, the construction of GTL plants at sites with available stranded gas reserves has been limited, indicating investor reluctance to pursue this option fervently, especially when investments in less capital-intensive LNG capacity are possible. Indeed, some GTL projects have been canceled or deferred in the past few years [*61*].

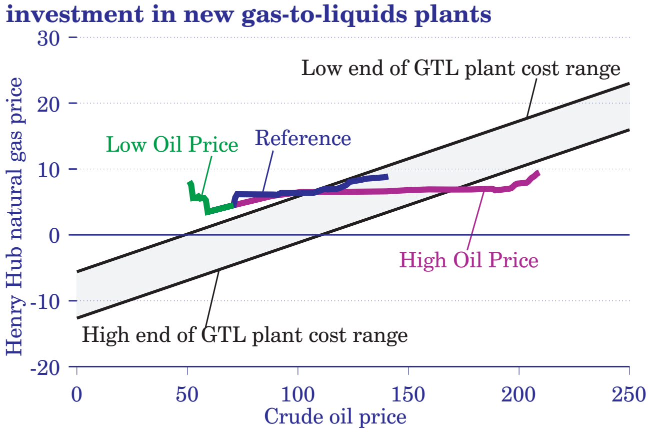
The overnight capital costs for a new GTL plant situated on the U.S. Gulf Coast would range from $50,000 per barrel-stream day of capacity [*62*] to an estimated $104,000 per barrel-stream day [*63*]. Accordingly, a relatively modest unit with a capacity of 34,000 barrels per day represents an estimated overnight capital cost [*64*] of $1.7 billion to $3.5 billion. With financing included, the estimated total investment would be $2.2 billion to $4.4 billion. In addition, construction of the facility would take 4 years or more, imposing further market risk. The risk-adjusted discount factor used by investors will be critical to determining whether investors would proceed with GTL investments.

Figure 28 shows the maximum "breakeven" average price of natural gas that could be tolerated over a 10-year plant operating period [*65*] in order to justify the risk associated with investing in a GTL facility, based on the range of capital costs discussed above and a 10-percent hurdle rate [*66*]. Profitable cases lie below the line. At $100 per barrel for crude oil, the breakeven price for natural gas that would justify investment in a GTL facility is -$1.20 to $5.80 per million Btu. At higher crude oil prices, the range of the breakeven natural gas price also rises. At a crude oil price of $200 per barrel, the breakeven price for natural gas is $10.20 to $17.30 per million Btu. At a crude oil price of $60 per barrel, the breakeven natural gas price ranges from -$5.80 to $1.30 per million Btu, illustrating the substantial impact of oil price uncertainty on the profitability of investment in a GTL facility.

Figure 28 also shows how investment in a GTL facility would fare with the natural gas and crude oil price projections in the *AEO2010* Reference, Low Oil Price, and High Oil Price cases. With the prices in the Low Oil Price case, GTL is a poor investment. With the prices in the Reference case, GTL is a marginal investment. Only with the highest prices in the Reference case and the low end of GTL plant costs do the breakeven economics favor the project. In the High Oil Price case, however, the combination of higher crude oil prices and lower natural gas prices implies that investment in a GTL plant on the U.S. Gulf Coast could be profitable.

A large investment in GTL would be needed in order to produce an appreciable effect on worldwide prices for crude oil and U.S. natural gas. Construction of sufficient new GTL capacity to affect world crude oil prices, about 1 million barrels per day, would require a total investment between $50 billion and $135 billion. That level of capacity would still represent only 1.2 percent of the 85.9 million barrels per day of the world's estimated total liquids production in 2007 [*67*], and less than 1 percent of projected 2035 production in the Reference case [*68*].

Figure 28. Breakeven natural gas price (2008 dollars per million Btu) relative to crude oil price (2008 dollars per barrel) required for investment in new gas-to-liquids plants



Another option is the potential use of stranded natural gas in Alaska to produce GTL. Because of Alaska's severe weather conditions, construction of GTL (or any other) facilities is likely to be much more expensive than the construction of GTL plants on the U.S. Gulf Coast or in the Middle East. Some estimates suggest that doubling the construction costs and extending the construction period by at least 2 years would be reasonable assumptions. Construction of GTL facilities in Alaska, therefore, seems unlikely given the cost uncertainties mentioned above and the crude oil price projections in the *AEO2010* Reference case.

Looking forward

A large disparity between crude oil and natural gas prices, as projected in the *AEO2010* Reference and High Oil Price cases, will provide incentives for innovators and entrepreneurs to pursue opportunities that, in the longer term, could increase domestic or international markets for U.S. natural gas. For example, a scenario with relatively high oil prices would tend to increase the value of CO_2 used for EOR as well as GTL production. Because GTL processing plants can accommodate natural gas feedstocks with relatively high CO_2 content and can target fields smaller than those required for LNG production, such circumstances would provide incentives for the development of smaller GTL systems that produce both liquid products and a valuable CO_2 co-product. Because EIA cannot predict whether or when such innovations might arise, they are not included in the *AEO2010* analysis cases.

Importance of low-permeability natural gas reservoirs

Introduction

Production from low-permeability reservoirs, including shale gas and tight gas, has become a major source of domestic natural gas supply. In 2008, low-permeability reservoirs accounted for about 40 percent of natural gas production and about 35 percent of natural gas consumption in the United States. Permeability is a measure of the rate at which liquids and gases can move through rock. Low-permeability natural gas reservoirs encompass the shale, sandstone, and carbonate formations whose natural permeability is roughly 0.1 millidarcies or below. (Permeability is measured in "darcies.")

The use of hydraulic fracturing in conjunction with horizontal drilling in shale gas formations and the use of hydraulic fracturing in tight gas formations has opened up natural gas resources that would not be commercially viable without these technologies. As shale gas production has expanded into more basins and recovery technology has improved, the size of the shale gas resource base in the *AEO* has increased markedly. Because the exploitation of shale gas resources is still in its initial stages, and because many shale beds have not yet been tested, there is a great deal of uncertainty over the size of the recoverable shale gas resource base. Low-permeability gas wells typically produce at high initial flow rates, which decline rapidly and then stabilize at relatively low levels for the remaining life of the wells.

To illustrate the importance of low-permeability natural gas reservoirs for future U.S. natural gas supply, consumption, and prices, three alternative cases were developed for *AEO2010*: a No Shale Gas Drilling case, a No Low-Permeability Gas Drilling case, and a High Shale Gas Resource case. The No Shale Gas Drilling and No Low-Permeability Gas Drilling cases examine the implications of no new drilling in low-permeability formations. The High Shale Resource case examines the possibility that shale gas resources could be considerably greater than those represented in the Reference case. The three alternative cases are *not* intended to represent any expected future reality. Rather, they are intended to illustrate the importance of low-permeability formations for EIA's projections of future U.S. natural gas supply and are likely to be extremes. All the cases assume no change from the Reference case assumptions about the size of, and access to, Canadian and other international natural gas resources. Specific assumptions in the three cases are as follows.

No Shale Gas Drilling case. Starting in 2010, in this case no new onshore lower 48 shale gas production wells are drilled. Natural gas production from shale gas wells drilled before 2010 declines continuously through 2035.

No Low-Permeability Gas Drilling case. Starting in 2010, in this case no new onshore lower 48 low-permeability natural gas production wells are drilled, including shale gas wells and "tight" sandstone and carbonate gas wells. Natural gas production from low-permeability wells drilled before 2010 declines continuously through 2035.

High Shale Gas Resource case. In this case, the unexploited portion of each shale formation supports twice as many new wells as in the Reference case. The lower 48 shale gas resource base increases by 88 percent, from 347 trillion cubic feet in the Reference case to 652 trillion cubic feet in the High Shale Gas Resource case. The estimated recovery per well in each formation is the same as in the Reference case.

Natural gas supply, consumption, and prices

Low-permeability natural gas resources are more abundant and less expensive than other domestic natural gas supply alternatives that could replace them, and they are expected to play a significant role in future domestic natural gas markets. Consequently, their future absence or presence is expected to have a significant impact on the average cost of natural gas production and prices, which in turn would affect natural gas imports and consumption. In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, lower 48 onshore natural gas productive capacity is less than in the Reference case, and as a result average U.S. natural gas prices are higher, more natural gas is imported, and natural gas consumption is reduced (Table 7). Conversely, in the High Shale Gas Resource case, natural gas productive capacity is higher, natural gas prices and imports are lower, and consumption is higher than projected in the Reference case.

No Shale Gas Drilling and No Low-Permeability Gas Drilling cases

In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, total domestic natural gas production in 2035 is 18 percent and 25 percent lower, respectively, and onshore lower 48 production is 27 percent and 39 percent lower, respectively, than in the Reference case. The loss of onshore lower 48 productive capacity leads to higher natural gas prices and lower consumption levels. In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, the Henry Hub spot price for natural gas in 2035 is \$1.49 and \$2.00 per million Btu higher, respectively, than the Reference case price of \$8.88 per million Btu. The significantly higher natural gas prices are a result of the removal of considerable low-cost natural gas resources, leaving a smaller natural gas resource base that is more expensive to produce.

Because higher domestic natural gas prices make other supply sources more competitive, both offshore Gulf of Mexico production and net natural gas imports increase in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases. Offshore natural gas production levels in 2035 are 7 percent and 18 percent (0.3 trillion cubic feet and 0.8 trillion cubic feet) higher, respectively, than in the Reference case, and net imports are 154 percent and 207 percent higher (2.2 trillion cubic feet and 3.0 trillion cubic feet). In 2035, net imports make up 6 percent of total U.S. natural gas supply in the Reference case, 16 percent in the No Shale Gas Drilling case, and 20 percent in the No Low-Permeability Gas Drilling case. The higher levels of net imports in the two alternative cases are the result of increases in LNG imports and imports from Canada, as well as a reduction in exports to Mexico.

In 2035, net LNG imports in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases are more than double those in the Reference case (1.8, 2.4, and 0.8 trillion cubic feet, respectively), and net natural gas imports from Canada are 52 percent and 59 percent greater, respectively, in the two alternative cases than in the Reference case. Because the assumptions in these cases are not applied to the Canadian natural gas resource base, higher U.S. prices lead to more natural gas production in Canada (including Canadian shale gas). In addition, Canada's Mackenzie Delta natural gas pipeline begins operating before 2035 in the two alternative cases, which does not occur in the Reference case. Net natural gas exports to Mexico in 2035 are 35 percent and 47 percent lower in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, respectively, than in the Reference case.

The impact on natural gas consumption of restricted drilling in low-permeability reservoirs is less pronounced than the impact on domestic supply, for two reasons. First, the increase in net imports partially offsets the reduction in domestic natural gas productive capacity. Second, long-lived natural gas consumption equipment responds more slowly to changes in natural gas prices than does natural gas supply—although the electric power sector, where natural gas consumption responds relatively quickly to changes in natural gas prices, is an exception. In 2035, natural gas consumption in the electric power sector is 1.3 trillion cubic feet (17 percent) lower in the No Shale Gas Drilling case and 1.9 trillion cubic feet (26 percent) lower in the No Low-Permeability Gas Drilling case than the Reference case level of 7.4 trillion cubic feet.

Table 7. Natural gas prices, supply, and consumption in four cases, 2035

Projection	Reference	No Shale Gas Drilling	No Low-Permeability Gas Drilling	High Shale Gas Resource
Henry Hub spot price (2008 dollars per million Btu)	8.88	10.37	10.88	7.62
Total U.S. natural gas production (trillion cubic feet)	**23.3**	**19.1**	**17.4**	**25.9**
Onshore Lower 48	17.1	12.5	10.4	20.0
Offshore Lower 48	4.3	4.7	5.1	4.0
Alaska	1.9	1.9	1.9	1.9
First year of operation for the Alaska natural gas pipeline	2023	2020	2020	2030
Total net U.S. imports of natural gas (trillion cubic feet)	**1.5**	**3.7**	**4.5**	**0.8**
Canada	1.7	2.5	2.7	1.4
Mexico	-1.0	-0.7	-0.5	-1.3
Liquefied natural gas	0.8	1.8	2.4	0.8
Total U.S. natural gas consumption (trillion cubic feet)	**24.9**	**22.9**	**22.0**	**26.8**
Electric power	7.4	6.1	5.5	8.7
Residential sector	4.9	4.8	4.7	5.0
Commercial sector	3.7	3.6	3.5	3.8
Industrial sector	6.7	6.5	6.4	7.0
Other	2.2	1.9	1.8	2.3

High Shale Gas Resource case

Relative to the Reference case, both natural gas production costs and prices are reduced in the High Shale Gas Resource case. Consequently, domestic natural gas production is more competitive, and U.S. natural gas consumption is higher. In 2035, onshore lower 48 and total natural gas production are 17 percent and 11 percent higher, respectively, in the High Shale Gas Resource case than in the Reference case, and Henry Hub spot prices are $1.26 per million Btu lower than in the Reference case. Increased domestic production and lower natural gas prices reduce net imports in 2035 by 44 percent from their level in the Reference case, to 0.8 trillion cubic feet, and offshore natural gas production in 2035 is reduced by 7 percent, to 4.0 trillion cubic feet. The decline in net imports results from a 19-percent reduction in net imports from Canada, an 8-percent reduction in net LNG imports, and a 25-percent increase in net exports to Mexico in the High Shale Gas Resource case, relative to the Reference case.

Because of the lower natural gas prices in the High Shale Gas Resource case, U.S. natural gas use in 2035 is 2.0 trillion cubic feet (8 percent) higher than in the Reference case. The majority of the increase is in the electric power sector, which accounts for 1.3 trillion cubic feet (18 percent) of the total increase.

U.S. nuclear power plants: Continued life or replacement after 60?

Background

Nuclear power plants generate approximately 20 percent of U.S. electricity, and the plants in operation today are often seen as attractive assets in the current environment of uncertainty about future fossil fuel prices, high construction costs for new power plants (particularly nuclear plants), and the potential enactment of GHG regulations. Existing nuclear power plants have low fuel costs and relatively high power output. However, there is uncertainty about how long they will be allowed to continue operating.

The nuclear industry has expressed strong interest in continuing the operation of existing nuclear facilities, and no particular technical issues have been identified that would impede their continued operation. Recent *AEO*s had assumed that existing nuclear units would be retired after 60 years of operation (the initial 40-year license plus one 20-year license renewal). Maintaining the same assumption in *AEO2010*, with the projection horizon extended to 2035, would result in the retirement of more than one-third of existing U.S. nuclear capacity between 2029 and 2035. Given the uncertainty about when existing nuclear capacity actually will be retired, EIA revisited the assumption for the development of *AEO2010* and modified it to allow the continued operation of all existing U.S. nuclear power plants through 2035 in the Reference case.

The modified assumption in the Reference case implies that the operating lives of some nuclear plants will be more than 60 years. To address the uncertainty about whether such life extensions will be allowed, an alternative Nuclear 60-Year Life case was developed, assuming that all the existing U.S. nuclear power plants will be retired after 60 years of operation.

Discussion

The Atomic Energy Act of 1954 authorized the U.S. Nuclear Regulatory Commission (NRC) to issue operating licenses for commercial nuclear power plants for a period of 40 years. The 40-year time frame was derived from accounting and anti-trust concerns, not technical limitations [*69*]. The law allows the NRC to issue operating license renewals in 20-year increments, provided that reactor owners demonstrate that continued operations can be conducted safely. As of July 2009, the NRC had granted license renewals to 50 of the 104 operating reactors in the United States, allowing them to operate for 60 years. Fifteen additional applications are under review, and the owners of 21 other units have announced that they intend to file for 20-year license extensions. The NRC has yet to deny an application for a 20-year extension [*70*]. Previous *AEO*s assumed that all of the 104 existing units would operate for a total of 60 years, provided that they remained economical.

In December 2009, the Oyster Creek Generating Station in Lacey Township, New Jersey, became the first nuclear power plant in the United States to begin its 40th year of operation. With Oyster Creek and other nuclear plants of similar vintage just beginning to enter their first period of license renewal, it probably will be at least 5 to 10 years before there is any clear indication as to whether plant operators will be likely to seek further extensions of their plants' operating lives.

For the *AEO2010* Reference case, EIA assumed that the operating lives of existing nuclear power plants would be extended at least through 2035. Assuming that the NRC continues to approve license extensions, the decision to operate a facility is an economic one made by plant owners. Aging plants may face increased operation and maintenance (O&M) costs and capital expenditures, which generally decrease their profitability. Revenue projections are dependent on electricity prices, which are uncertain due to variations in fossil fuel prices, regional economic growth, and environmental regulations. Thus, even if the costs of operating nuclear plants do not change, changes in electricity prices can affect their profitability when their generation is sold at market-based rates.

Between 1974 and 1998, 14 commercial nuclear reactors in the United States were retired. The circumstances of each retirement were unique to the particular plant, but the common thread was that the expected cost of continued operation was higher than expected revenues, and there were less costly generating options available. Highly competitive natural-gas-fired generation could have been a factor in those retirements. Natural-gas-fired combined-cycle plants were the favored option for new capacity during the 1990s, when natural gas prices were relatively low and it was widely believed that they would remain low for the foreseeable future. In contrast, real O&M costs for nuclear power plants had increased by 77 percent during the 1980s [*71*], owners faced the risk that new NRC regulations might require prohibitively expensive retrofits, and there was widespread concern State public utility commissions would not allow full cost recovery for expenditures on nuclear plants.

The economics of existing nuclear power plants are more favorable today, because natural gas prices are higher, the nuclear plants are performing well, and the potential enactment of GHG regulations increases uncertainty about fuel and operating costs for power plants that burn coal and natural gas. To date, there have been no announced plans to retire any of the 104 operating U.S. commercial nuclear reactors. To the contrary, the NRC and the nuclear power industry are preparing applications for license renewals that would allow continued operation beyond 60 years, the first of which is scheduled to be submitted by 2013. In February 2008, DOE and the NRC hosted a joint workshop titled "Life Beyond 60," with a broad group of nuclear industry stakeholders meeting to discuss this issue [*72*]. The workshop's summary report outlined many of the technical research needs that participants agreed were important to extending the life of the existing fleet of U.S. nuclear plants.

Several concerns were expressed at the DOE/NRC workshop. Because heat, water, and radiation can have long-term effects on the materials they are in contact with in nuclear power plants, more effective monitoring may be needed as the systems age, which could require updates to instruments and controls. Over the next several years, research is being focused on identifying problems that aging facilities might encounter and formulating potential solutions. Until that research has been completed, it will be difficult to estimate any cost increases that may result from extending the age of reactors.

Future cost increases may reflect only routine expenditures, or they could involve major capital projects, such as the replacement of reactor vessels, containment structures, or buried piping and cables. To date, no plans or cost estimates for such potential modifications have been made public; however, they have the potential to be very expensive, and they could require extended plant shutdowns. While a plant is out of operation, the generation lost will have to be replaced, probably with expensive power purchased on the spot electricity market.

For most existing nuclear plants, decisions about retirement or life extension ultimately will be based on the cost and feasibility of all the measures needed for a plant to continue to operate safely and economically. It is difficult to anticipate future operating costs, but it can be helpful to compare current operating costs with the total levelized costs of new nuclear power plants in order to gauge the magnitude of increases in O&M costs that would make retirement an option from an economic standpoint. For instance, with current O&M costs at the most expensive nuclear units in operation averaging approximately 3.5 cents per kilowatthour [*73*] and total levelized costs for new baseload capacity ranging from 8 cents to 11 cents per kilowatthour, the operating costs of existing nuclear power plants would have to increase substantially before it would be economical to retire even the most expensive units.

Nuclear plant owners also face the risk of future regulations that could require expensive upgrades. Such a rule was recently the subject of the Supreme Court case *Entergy Corp v. Riverkeeper* [*74*], which focused on whether or not the EPA could conduct cost-benefit analyses to determine whether a plant needed to replace open-cycle cooling water systems with closed-cycle systems. A retrofit of such magnitude would be costly and thus could alter the relicensing decision for a particular facility.

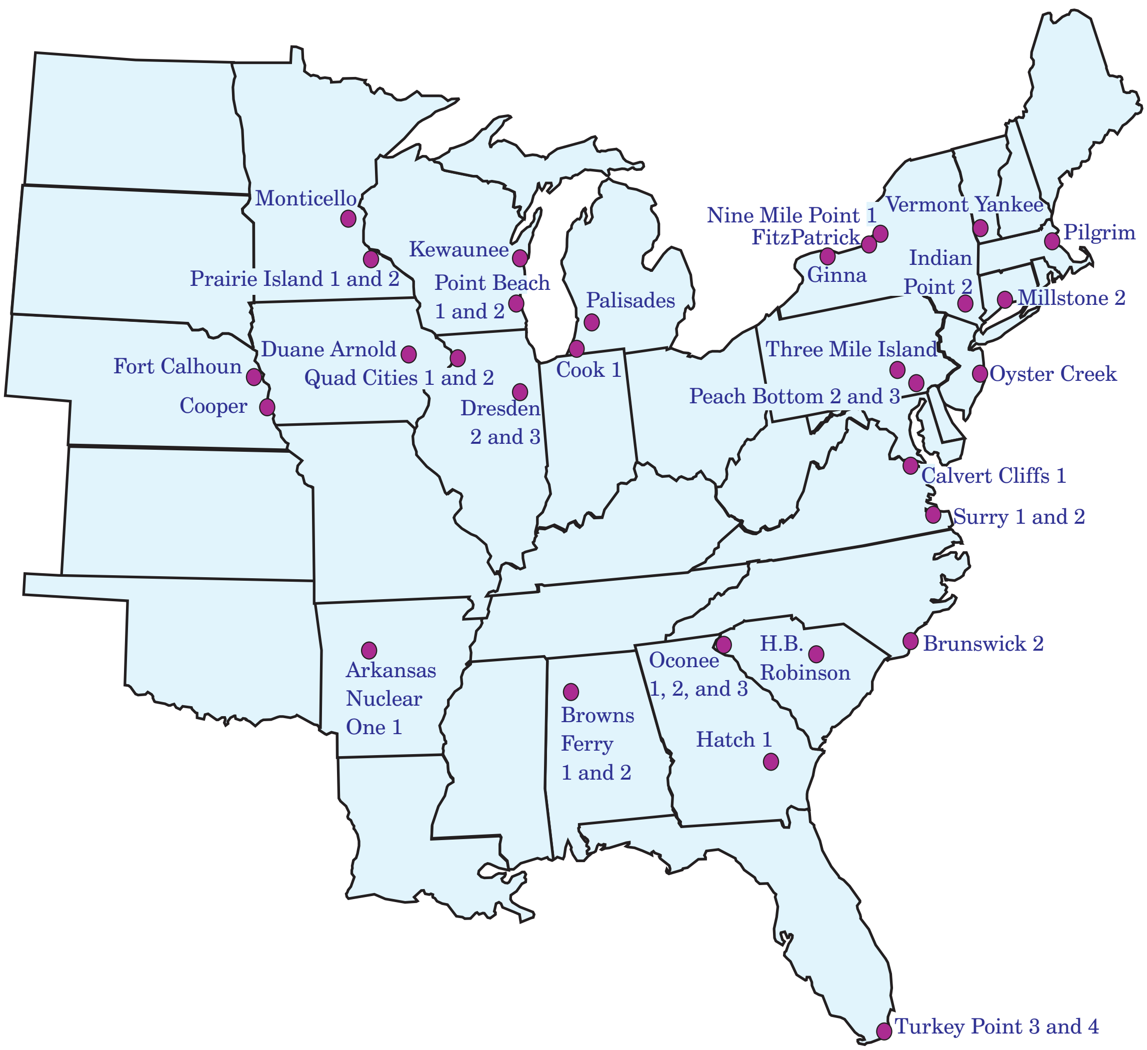
The *AEO2010* Reference case assumes an additional O&M cost of $30 per kilowatt for nuclear power capacity after 30 years of operation, which is meant to represent the various programs that must be undertaken in order to ensure continued safety. Even with this added cost, no retirements of existing nuclear power plants are projected by 2035 in the Reference case.

Alternative case

If all the existing nuclear power plants in the United States were retired after 60 years of operation, the impacts on electricity markets, fuel use, and GHG emissions would be substantial. Therefore, *AEO2010* includes an alternative Nuclear 60-Year Life case, which assumes that no existing nuclear power plant will receive a second license extension, and all of them will be retired after 60 years. The 60-year retirement assumption is not meant as a hard-and-fast rule but as a possibility that allows examination of the impact of retiring existing nuclear capacity from the generation mix.

A total of 30.8 gigawatts of capacity at operating U.S. nuclear power plants—or approximately one-third of the existing fleet—will have been in operation for at least 60 years by 2035. The Nuclear 60-Year Life case assumes that all of that capacity will be retired between 2029 and 2035. Figure 29 shows the locations of the plants that would be retired, which are spread fairly evenly across the regions where nuclear power capacity is prominent.

Figure 29. U.S. nuclear power plants that will reach 60 years of operation by 2035



In the Nuclear 60-Year Life case, retirement of the plants shown in Figure 29 results in the construction of additional replacement capacity beyond the capacity additions already projected in the Reference case (Table 8). Of the additional capacity built in the Nuclear 60-Year Life case, only about 2 gigawatts is nuclear. Instead, the retired nuclear capacity is replaced almost exclusively with coal and natural gas capacity, which in the absence of policies regulating GHG emissions remains more economical than either nuclear or renewable plants.

Reflecting the different projections for generating capacity additions in the two cases, the projected nuclear share of total generation in 2035 is only 13 percent in the Nuclear 60-Year Life case, compared with 17 percent in the Reference case. Total generation in the Nuclear 60-Year Life case is 1 percent lower than in the Reference case. CO_2 emissions are higher in the Nuclear 60-Year Life case, because nuclear power is replaced with fossil fuels. Again, however, the difference between the projections is less than 1 percent, because most of the capacity replacing the retired nuclear plants is fueled by natural gas.

U.S. electricity prices in 2035 in the Nuclear 60-Year Life case are 4 percent higher than those in the Reference case. In regions where the retirements are scheduled to occur, the price increases are slightly larger: compared to the Reference case, electricity prices in 2035 are 7 percent higher in the North American Electric Reliability Council (NERC) Midwest Reliability region and between 5 and 6 percent higher in the NERC regions in the Northeast, mid-Atlantic, and Southeast. In regions where no retirements occur, there are still small price increases relative to the Reference case, because natural gas prices are higher in the Nuclear 60-Year Life case. Building new capacity to replace the retired nuclear plants is more expensive than allowing their continued operation, and the higher costs are passed on to consumers in the form of higher electricity prices. Natural gas prices also are higher in the alternative case than in the Reference case, by 5.4 percent, because the additional new capacity is predominantly natural-gas-fired, and the increase in demand pushes up the price of natural gas.

Finally, the assumed absence of new Federal policies to limit GHG emissions is crucial to the results of this analysis. In all likelihood, such policies would increase the cost of generating electricity from fossil fuels, improving the relative economics of new nuclear power plants and favoring construction of more nuclear capacity to replace the retired units.

Table 8. Comparison of key projections in the Reference and Nuclear 60-Year Life cases

Projection	Reference	Nuclear 60-Year Life
Generating capacity additions by fuel type, 2008-2035 (gigawatts)		
Coal	11	17
Natural gas	89	102
Nuclear	7	9
Renewable	57	57
Electricity price in 2035 (2008 cents per kilowatthour)	10.2	10.6
Natural gas price in 2035 (2008 dollars per thousand cubic feet)	8.69	9.16

Accounting for carbon dioxide emissions from biomass energy combustion

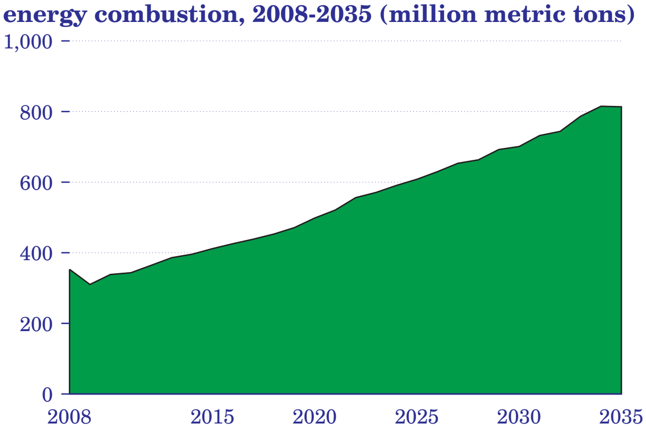
CO_2 emissions from the combustion of biomass [*75*] to produce energy are excluded from the energy-related CO_2 emissions reported in *AEO2010*. According to current international convention [*76*], carbon released through biomass combustion is excluded from reported *energy-related* emissions. The release of carbon from biomass combustion is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time [*77*]. However, analysts have debated whether increased use of biomass energy may result in a decline in terrestrial carbon stocks, leading to a net positive release of carbon rather than the zero net release assumed by its exclusion from reported energy-related emissions.

For example, the clearing of forests for biofuel crops could result in an initial release of carbon that is not fully recaptured in subsequent use of the land for agriculture. To capture the potential net emissions, the international convention for GHG inventories is to report biomass emissions in the category "agriculture, forestry, and other land use," usually based on estimates of net changes in carbon stocks over time.

This indirect accounting of CO_2 emissions from biomass can potentially lead to confusion in accounting for and understanding the flow of CO_2 emissions within energy and non-energy systems. In recognition of this issue, reporting of CO_2 emissions from biomass combustion alongside other energy-related CO_2 emissions offers an alternative accounting treatment. It is important, however, to avoid misinterpreting emissions from fossil energy and biomass energy sources as necessarily additive. Instead, the combined total of direct CO_2 emissions from biomass and energy-related CO_2 emissions implicitly assumes that none of the carbon emitted was previously or subsequently reabsorbed in terrestrial sinks or that other emissions sources offset any such sequestration.

In the future, EIA plans to report CO_2 emissions from biomass combustion alongside other energy-related CO_2 emissions, but to exclude them from the total unless their inclusion is dictated by regulation. As shown in Figure 30, including direct CO_2 emissions from biomass energy combustion would increase the 2008 total for energy-related CO_2 emissions by 353 million metric tons (6.1 percent). In the *AEO2010* Reference case, including emissions from biomass would increase the projected 2035 total for energy-related CO_2 emissions by 813 million metric tons (12.9 percent) [*78*]. If in fact these emissions are all offset by biological sequestration, the net emissions would be zero as assumed in EIA's totals.

Figure 30. Carbon dioxide emissions from biomass energy combustion, 2008-2035 (million metric tons)



Endnotes for Issues in Focus

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39. PFC Energy, "OPEC Output and Quotas—December 2009" (December 7, 2009).
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41. "Upstream Costs Bottoming Out," *UpstreamOnline* (December 8, 2009) (subscription site).
42. "Upstream Players Face More Costs Pain," *UpstreamOnline* (May 14, 2008) (subscription site).
43. For a thorough discussion of the issues involved in measuring efficiency, see U.S. Energy Information Administration, *Measuring Energy Efficiency in the United States' Economy: A Beginning*, DOE/EIA-0555(95)/2 (Washington, DC, October 1995), web site www.eia.doe.gov/emeu/recs/archive/arch_hist_pubs/hp_pdf/DOE%20EIA-0555%2895%29-2.pdf; and S.J. Battles and E.M. Burns, "United States Energy Usage and Efficiency: Measuring Changes Over Time," Presented at the 17th Congress of the World Energy Council, Houston, TX (September 14, 1998), web site www.eia.doe.gov/emeu/efficiency/wec98.htm.
44. Energy efficiency and conservation are sometimes considered closely related aspects of the same concept, but the NEMS framework focuses on energy efficiency and classifies all other sources of intensity reduction as structural elements. The concepts are defined separately in NEMS so as not to overlap. For an alternative view, see K. Gillingham, R. Newell, and K. Palmer, "Energy Efficiency Economics and Policy," *Annual Review of Resource Economics*, Vol. 1 (2009), pp. 597–619.
45. Recent attempts to characterize the efficiency-related factors behind the "California effect" attribute roughly 25 percent of its lower energy consumption per capita to efficiency differences. See A.H. Rosenfeld and D. Poskanzer, "A Graph Is Worth a Thousand Gigawatt-Hours: How California Came to Lead the United States in Energy Efficiency," *Innovations*, Vol. 4, No. 4 (Fall 2009). Another estimate attributes 23 percent of the 2001 difference in California energy intensity to efficiency policies. See A. Sudarshan and J. Sweeney, "Working Paper: Deconstructing the 'Rosenfeld Curve'" (Precourt Energy Efficiency Center, Stanford University, June 2008), web site http://piee.stanford.edu/cgi-bin/htm/Modeling/research/Deconstructing_the_Rosenfeld_Curve.php.
46. S.H. Wade, "Measuring Changes in Energy Efficiency for the *Annual Energy Outlook 2002*," (Washington, DC, 2002), web site www.eia.doe.gov/oiaf/analysispaper/efficiency/index.html.
47. A. Jaffe and R. Stavins, "The Energy-Efficiency Gap," *Energy Policy*, Vol. 22, No. 10 (October 1994), pp. 804-810.
48. U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels and Advanced Vehicles Data Center, "Alternative Fueling Station Total Counts by State and Fuel Type," web site www.afdc.energy.gov/afdc/fuels/stations_counts.html (updated on February 28, 2010).
49. The levelized cost calculation assumes that a 20-percent rate of return over a 5-year payback period would be sufficient to motivate investment in a standalone natural gas fueling station.
50. In the 2019 Phaseout Base Market case, HDNGV sales and consequent fuel switching are small enough to fall within the tolerance of the NEMS model used to produce *AEO2010* and are not reported.

51. Low-sulfur crude oil priced for delivery at Cushing, Oklahoma, and natural gas priced at the Henry Hub.
52. While simple price comparisons assume the same point of sale in retail markets, crude oil and natural gas price comparison reflects unprocessed prices at a supply node. To describe the ratio in terms of the retail market, multiple delivered petroleum product prices would have to be compared to delivered natural gas prices in the same markets. Because making the comparison at the detailed retail level would require a far more complex set of comparisons involving different tax structures and processing costs, the comparison on the supply side is a useful, if somewhat oversimplified, comparison that accounts for most of the price divergence described.
53. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 8.4a, web site www.eia.doe.gov/emeu/aer.
54. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 8.4a, web site www.eia.doe.gov/emeu/aer.
55. Consistent with that reduction has been the abandonment of large-scale storage by electric utilities of petroleum products for generation.
56. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, April 2010), p. 137, web site www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2010).pdf, p. 137.
57. Favorable natural gas prices in the late 1990s led to a surge in investments in turbine and combined-cycle units, to a level that could not be supported when natural gas prices increased. Many of those purchases were resold at discounts, or installation was postponed for years.
58. J. Macharia, "Sasol Oryx GTL Plant Has Problems, Shares Hit," Reuters (May 22, 2007), web site www.reuters.com/article/idUSL2206595120070522.
59. Sasol I (2,500 barrels per day), Mossel Bay (45,000 barrels per day), Bintulu (14,700 barrels per day), and Oryx (34,000 barrels per day).
60. Qatar's Pearl GTL (140,000 barrels per day), which is currently anticipated to begin production in 2011, and Nigeria's Escravos GTL (34,000 barrels per day), which is also slated for a 2011 startup. See "Pearl GTL Sets Milestone as Steam Boilers Start Up," *Gulf Times* (not dated), web site www.gulf-times.com/site/topics/article.asp?cu_no=2&item_no=345533&version=1&template_id=48; and J. Macharia and M. Whittaker, "Update: 2-Sasol's Nigeria Project Costs Up, Loses on Oil Hedge," Reuters (July 29, 2008), web site http://uk.reuters.com/article/idUKL921344320080729.
61. Including Exxon's Palm GTL in Qatar (154,000 barrels per day), which was cancelled in 2007. See National Petroleum Council, "Facing the Hard Truths About Energy, Topic Paper #9, Gas To Liquids (GTL)" (July 18, 2007), page 2, web site www.npchardtruthsreport.org/topic_papers.php.
62. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, April 2010), p. 137, web site www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2010).pdf, p. 137.
63. S. Reed and R. Tuttle, "Shell Aims for 'New Nigeria' as $19 Billion Qatar Plant Starts" *Bloomberg Business Week* (March 3, 2010), web site www.businessweek.com/news/2010-03-03/shell-aims-for-new-nigeria-as-19-billion-qatar-plant-starts.html.
64. Overnight capital costs exclude financing costs during construction.
65. A 10-year operating period is assumed as a maximum private-sector investment horizon for such a project. The 10-year period was chosen based on input from an EIA workshop held in 2007 that looked at capital investment decisionmaking. The papers resulting from that workshop can be found at www.eia.doe.gov/oiaf/emdworkshop/model_development.html. It is possible that a longer operating period would be appropriate with public financing or loan guarentees. This would have the effect of lowering the effective breakeven levels discussed in the article.
66. hydrocarbons-technology.com, "Pearl Gas-to-Liquids Project, Ras Laffan, Qatar" (not dated), web site www.hydrocarbons-technology.com/projects/pearl.
67. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 11.10, web site www.eia.doe.gov/emeu/aer.
68. U.S. Energy Information Administration, *Short Term Energy Outlook* (March 9, 2010 Release), Table 3C, web site www.eia.doe.gov/emeu/steo/pub/contents.html.
69. U.S. Nuclear Regulatory Commission, "Reactor License Renewal Overview" (February 2007), web site www.nrc.gov/reactors/operating/licensing/renewal/overview.html.
70. U.S. Nuclear Regulatory Commission, "Backgrounder on Reactor License Renewal" (November 2009), web site www.nrc.gov/reading-rm/doc-collections/fact-sheets/license-renewal-bg.html.
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72. U.S. Department of Energy and U.S. Nuclear Regulatory Commission, "NRC/DOE Workshop on U.S. Nuclear Power Plant Life Extension Research and Development: *Life Beyond 60*" (February 19-21, 2008), web site http://sites.energetics.com/nrcdoefeb08.
73. Federal Energy Regulatory Commission, "Form 1 – Electric Utility Annual Report: Data (Current and Historical)," web site www.ferc.gov/docs-filing/forms/form-1/data.asp.

74. Supreme Court of the United States, "Entergy Corp. v. Riverkeeper, Inc., et al.," No. 07-588 (October Term, 2008), web site www.supremecourtus.gov/opinions/08pdf/07-588.pdf.
75. "Biomass energy," as used here, includes solid, liquid, and gaseous energy produced from organic nonfossil material of biological origin.
76. Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, web site www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.
77. This is not to say that biomass energy is carbon-neutral. Energy inputs are required in order to grow, fertilize, and harvest the feedstock and to produce and process the biomass into fuels.
78. Emissions estimates are based on biogenic energy consumption (see Appendix A, Table A17, "Renewable Energy by Sector and Source") and CO_2 emissions factors of 88.45 kilograms CO_2 per million Btu for biomass (including wood, wood waste, and biofuels heat and coproducts), 90.65 kilograms CO_2 per million Btu for biogenic municipal solid waste, 65.88 kilograms CO_2 per million Btu for ethanol, 73.84 kilograms CO_2 per million Btu for biodiesel, and 73.15 kilograms CO_2 per million Btu for liquids from biomass and green liquids.