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Annual Energy Outlook 2014 with projections to 2040

Independent Statistics & Analysis
U.S. Energy Information Administration

For further information . . .

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AEO2014 is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the AEO2014 during 2014.

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Annual Energy Outlook 2014

With Projections to 2040

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Preface

The *Annual Energy Outlook 2014* (AEO2014), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices focused on the U.S. through 2040, based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2014 focuses on five primary cases: a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections. EIA published an Early Release version of the AEO2014 Reference case in December 2013.

The report begins with an Executive Summary that highlights key implications of the projections, followed by a Legislation and Regulations section that discusses how recently enacted federal and state legislation and regulations were incorporated in AEO2014, such as: the revised carbon dioxide emissions standards and banking provisions announced by the Regional Greenhouse Gas Initiative in February 2013 [*1*]; updated Renewable Fuel Standard target volumes to reflect actions by the U.S. Environmental Protection Agency to lower the target volume of cellulosic biofuel; and incorporation of modifications to existing state renewable portfolio standards or similar laws since the *Annual Energy Outlook 2013* was released. The Legislation and Regulations section also discusses selected legislative and regulatory issues could have major implications for energy markets and may be enacted in the near future.

The Issues in Focus section contains articles on selected energy topics, including a discussion of the results of two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements. Other discussions include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle energy demand
- Effects of lower natural gas prices on projected industrial production
- Implications of accelerated power plant retirements
- Renewable electricity projections under alternative assumptions in AEO2014
- Implications of low electricity demand growth.

The Market Trends section summarizes the AEO2014 projections for energy markets by end-use market sector or energy supply source. In some instances, this section also uses alternative cases to illustrate a range of potential outcomes under difference circumstances, highlighting the uncertainty associated with the projections. Complete tables for the five primary cases are provided in Appendixes A through C, and major results from many of the other alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser.

AEO2014 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2013. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections. In certain situations, however, where it is clear that a law or regulation will take effect shortly after AEO2014 is completed, it may be considered in the projection.

AEO2014 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The AEO2014 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in AEO2014 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the AEO2014 projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Updated *Annual Energy Outlook 2014* Reference case (April 2014)

The AEO2014 Reference case included as part of this complete report, released in April 2014, was updated from the AEO2013 Reference case released in April 2013. The Reference case was updated to reflect new legislation or regulation enacted since that time or to incorporate modeling changes. Major changes made in the Reference case include:

Macroeconomic

- Revised U.S. Census Bureau population projections [*2*]. The population projection for 2040 in the AEO2014 Reference case is almost 6% below the 2040 projection used for the AEO2013 Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available [*3*]. Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector [*4*].
- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use [*5*].
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports [*6, 7*].
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in AEO2014 because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new standards for residential furnaces.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS) [*8*].
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries, such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks [*9*].
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to vehicle miles traveled (VMT) projections for light-duty vehicles (LDVs), based on an analysis of VMT by age groups and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with AEO2013. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in AEO2014, compared with 41% growth in AEO2013.
- Added liquefied natural gas (LNG) as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phaseout of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles, including: (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, using flow decisions based on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices [*10*].

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data [11].
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling [12].
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners [13].
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis [14]—with lower production levels than in AEO2013, as more recent experience with these emerging technologies indicates higher costs than previously assumed [15].
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules [16].

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/ Independent System Operator requirements [17], and to capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly, depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirements of nuclear capacity in several regions to better reflect the impacts of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS) [18] covering the electric power sector, to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013 [19]—including revision of PTC expiration dates for each PTC-eligible technology, to reflect the concept of projects being declared "under construction" as opposed to being placed "in service," and extension of the expiration date of the PTC for wind generation projects by one year.

Future analyses using the AEO2014 Reference case will start from the version of the Reference case released with this complete report.

Endnotes

Links current as of April 2014

1. Regional Greenhouse Gas Initiative, "Program Review" (New York, New York: February 7, 2013), http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
2. The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), https://www.census.gov/newsroom/releases/archives/population/cb12-243.html.
3. U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.
4. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
5. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
6. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.
7. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.
8. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.
9. Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (*natural gas plant liquids* [*NGPL*] + *liquefied refinery gases* [*LRG*]) and market (*NGL + refinery olefins*) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in AEO2014 have been relabeled to conform to this newly adopted definition.
10. Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.
11. After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in sweet spots are developed earlier than lower quality resources, based on net present value.
12. High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.
13. Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.
14. Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.
15. EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.
16. When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at those facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

17. North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/ Reliability%20Assessments%20DL/2013SRA_Final.pdf (password required).
18. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.
19. U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

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Executive summary

Introduction

The "Issues in focus" section of the *Annual Energy Outlook* (AEO) provides in-depth discussions on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected topics from recent AEOs are listed in Table IF-1.

Selected quantitative results from the issues discussed in AEO2014 are available in Appendix D. The first topic updates a discussion included in a number of previous AEOs, comparing the Reference case projections with two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements.

Other topics discussed in this section include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle (LDV) energy demand
- Impacts of lower natural gas prices on industrial production
- Implications of accelerated power plant retirements
- Variations in renewable electricity projections in AEO2014 cases
- Implications of lower growth in electricity demand.

Table IF-1. Key analyses from "Issues in focus" in recent AEOs

AEO2013	AEO2012	AEO2011
U.S. reliance on imported liquid fuels in alternative scenarios	Potential efficiency improvements and their impacts on end-use energy demand	Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025
Competition between coal and natural gas in the electric power sector	Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025	Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles
Nuclear power in AEO2013	Impacts of a breakthrough in battery vehicle technology	Potential efficiency improvements in alternative cases for appliance standards and building codes
Effect of natural gas liquids growth	Heavy-duty natural gas vehicles	Potential of offshore crude oil and natural gas resources
	Changing structure of the refining industry	Prospects for shale gas
	Changing environment for fuel use in electricity generation	Cost uncertainties for new electric power plants
	Nuclear power in AEO2012	Carbon capture and storage: Economics and issues
		Power sector environmental regulations on the horizon

Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2013*, DOE/EIA-0383(2013) (Washington, DC: April 2013); U.S. Energy Information Administration, *Annual Energy Outlook 2012*, DOE/EIA-0383(2012) (Washington, DC: June 2012); and U.S. Energy Information Administration, *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC: April 2011).

IF1. No Sunset and Extended Policies cases

Two alternative cases are discussed in this section to provide insight into the sensitivity of the Reference case to scenarios, in which existing tax credits that have sunset dates are assumed not to sunset (No Sunset case), or other policies (i.e., CAFE standards, appliance standards, and building codes) are expanded beyond current provisions in combination with the elimination of the sunset dates on existing tax credits (Extended Policies case). 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 are likely to, or should, be changed. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

The No Sunset and Extended Polices cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), reduced energy-related carbon dioxide (CO_2) emissions, lower energy prices, and lower government tax revenues.

Background

The AEO2014 Reference case is best described as a current laws and regulations case, because it generally assumes that existing laws and regulations remain unchanged throughout the projection period unless the legislation establishing the regulations sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for analysis of proposed changes in legislation or regulations. While this definition of the Reference case supports a variety of further analysis, there may be interest in alternative cases that reflect updates or extensions of current laws and regulations that the AEO2014 Reference case excludes. Areas of particular interest 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 periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the AEO2014 Reference case, except as identified below.

No Sunset case

The sunset provisions for tax credits are eliminated for renewable energy sources in the utility, industrial, and buildings sectors and for energy-efficient equipment in the buildings sector, including the following:

- The production tax credit (PTC) of 1.1 or 2.3 cents/kilowatthour (kWh), depending on the technology, and the 30% investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources are extended indefinitely as opposed to expiring at the end of 2013.
- For solar power investments, a 30% ITC that is scheduled to revert to a 10% credit in 2016 is assumed to be extended indefinitely at 30%.
- In the buildings sector, personal tax credits for the purchase of energy-efficient and renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2013 or in 2016, respectively, as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016. The business ITC for solar systems is assumed to remain at 30% instead of reverting to 10%.
- In the industrial sector, the 10% ITC for combined heat and power (CHP), which is assumed to end in 2016 in the AEO2014 Reference case [*1*], is assumed in the No Sunset case to be preserved through 2040.
- The $1.01/gallon (nominal) subsidy for cellulosic ethanol and $1.00/gallon (nominal) biodiesel subsidy are assumed to be extended at those levels from their recent expiration at the end of 2013 through the end of the projection period [*2*].

Extended Policies case

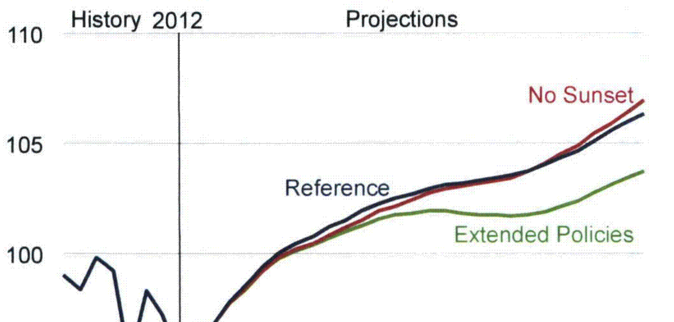
The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or the No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, in addition to the following:

- Federal equipment efficiency standards are assumed to be updated at periodic intervals, consistent with the provisions in existing law, at levels based on ENERGY STAR specifications or on the Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards also are introduced for products that are not currently subject to federal efficiency standards.
- Federal energy codes for residential and commercial buildings are assumed to be updated periodically, providing additional improvement to new construction. The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of those policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed the "maximum technologically feasible" levels described in DOE's technical support documents.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the joint attribute-based CAFE and vehicle GHG emissions standards for model year (MY) 2012 to MY 2025 for light-duty vehicles (LDVs). The Reference and No Sunset cases assume that the CAFE standards are then held constant at MY 2025 levels in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time. The Extended Policies case modifies the assumption in the Reference and No Sunset cases, assuming continued increases in CAFE standards at an annual average rate of 1.3% for new LDVs after MY 2025.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards for MY 2014 to MY 2018. The Reference and No Sunset cases assume that the standards are held constant at MY 2018 levels in subsequent model years, although the fuel economy of HDVs rises modestly thereafter. The Extended Policies case includes an increase in fuel consumption and GHG emissions standards for 13 vehicle size classes.
- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (which may include multiple units), instead of being limited to properties with systems smaller than 50 megawatts (MW) as in the Reference case [*3*]. Also, the ITC is modified to increase the eligible CHP unit cap from 15 MW to 25 MW. These extensions are consistent with previously proposed legislation.
- The extension of ethanol and biodiesel subsidies assumed in the No Sunset case is not included in the Extended Policies case, because the renewable fuel standard (RFS) program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use.

Analysis results

The changes made to the Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), and reduced energy-related carbon dioxide (CO_2) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the effects of the Extended Policies case tend to be greater than those of the No Sunset case (with some exceptions discussed below). Both cases result in lower energy prices, because the assumed tax credits and end-use efficiency standards lead to lower energy demand (except in the No Sunset case after 2034, as discussed below) and lower costs for renewable technologies. Appliance purchase costs are also affected. In addition, the government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Figure IF1-1. Total energy consumption in three cases, 2005-40 (quadrillion Btu)



Energy consumption

Total energy consumption in the No Sunset case is slightly lower than in the Reference case before 2034 and slightly higher than in the Reference case in the later years of the projection (Figure IF1-1). Improvements in energy efficiency lead to reduced consumption in the No Sunset case, but the demand-increasing effect of lower energy prices fully offsets the efficiency impacts by the end of the projection period. In 2040, total energy consumption in the Extended Policies case is 2% below the Reference case projection, as the combination of tax and other policy extensions reduces overall demand even after taking price declines into account.

Buildings energy consumption

Renewable distributed generation (DG) technologies (photovoltaic systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. The continuation of tax credits in the No Sunset case spurs increased adoption of DG systems, leading to 59 billion kWh of onsite electricity generation from renewable DG in 2025, compared with 25 billion kWh in the Reference case. In 2040, onsite electricity generation from renewable sources increases to 145 billion kWh in the No Sunset case—almost three times the amount of onsite electricity generated in the Reference case in that year.

Similar adoption of renewable DG occurs in the Extended Policies case, while efficiency gains from assumed future standards and more stringent building codes further reduce delivered energy use in the buildings sectors. Delivered energy use for buildings in the Extended Policies case is 1.5%, or 0.3 quadrillion British thermal units (Btu), lower than in the Reference case in 2025 and 5.4%, or 1.1 quadrillion Btu, lower than in the Reference case in 2040. In the No Sunset case, in contrast, delivered energy consumption is only 1.0% (0.2 quadrillion Btu) and 1.8% (0.4 quadrillion Btu) lower than in the Reference case projections for 2025 and 2040, respectively.

Electricity use shows the largest reduction in the two alternative cases relative to the Reference case. Building electricity purchases in 2025 are 1.4% and 1.9% lower in the No Sunset and Extended Policies cases, respectively, and 2.8% and 6.9% lower, respectively, in 2040, when compared with the Reference case. Increased onsite generation decreases electricity purchases in both cases. Additional reductions in electricity purchases occur in the Extended Policies case, as assumed standards increase the market penetration of efficient equipment and building construction. Energy use for water heating in the Extended Policies case shows the largest drop relative to the Reference case, at 16% (0.4 quadrillion Btu) below the Reference case level in 2040. Space heating and cooling also are affected by the assumed standards for equipment and building codes in the Extended Policies case, and energy consumption for those uses is reduced by a combined 6.7% (0.5 quadrillion Btu) from the Reference case level in 2040. In 2040, natural gas use in the buildings sectors is 0.9% and 4.1% below the Reference case level in the No Sunset and Extended Policies cases, respectively.

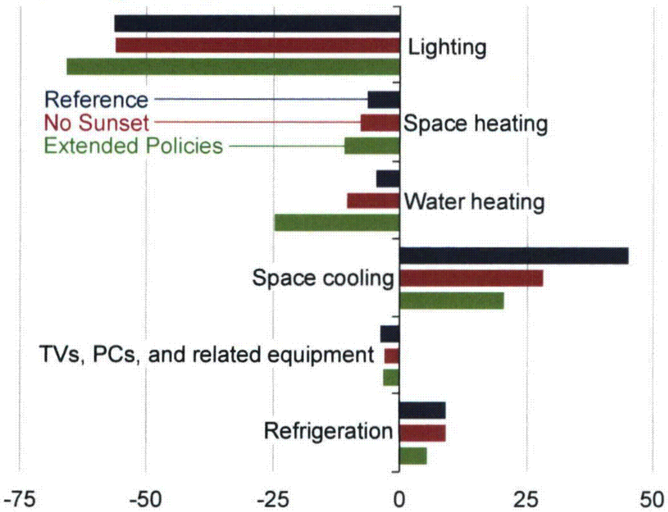
Residential energy consumption for most end uses moves in the same direction in all three cases, but at different rates (Figure IF1-2). For example, energy use for lighting, which declines in the Reference case, declines further in the Extended Policies case with additional standards; and space cooling, which increases in the Reference case, increases more slowly in the No Sunset case, which assumes the continuation of tax credits for efficient equipment and building shell thermal integrity improvement.

Industrial energy consumption

The No Sunset case modifies the Reference case assumptions by extending the existing ITC for industrial CHP through 2040. The Extended Policies case starts from the No Sunset case and expands the credit to include industrial CHP systems of all sizes, while raising the system size limit for the maximum credit that can be claimed, from 15 MW of installed capacity to 25 MW. The changes result in 1.2 gigawatts (GW) of additional industrial CHP capacity in the Extended Policies case compared with the Reference case in 2025 and 3 GW of additional capacity in 2040.

From 2025 through 2040, more CHP capacity is installed in the Extended Policies case than in the No Sunset case, but the differences narrow over time. CHP capacity is 0.3 GW higher in the Extended Policies case than in the No Sunset case in 2025, but only 0.1 GW higher in 2040. The Extended Policies case includes a tax benefit that applies to more CHP units than in the No Sunset case, which by itself provides greater incentive to build CHP capacity. However, electricity prices are slightly lower in the Extended Policies case than in the No Sunset case starting around 2024, and the difference grows over time, which reduces the economic attractiveness of CHP. These opposite effects explain why CHP capacity in the Extended Policies case is only slightly higher than in the No Sunset case, and why the difference decreases over time. Also, the median size of the nameplate capacity of industrial CHP units is 10 MW [4], and most CHP systems are well within the 50-MW total system size, which means that relaxing the size constraint is not as strong an incentive for investment as is allowing the current tax credit for new CHP investments to continue after 2016.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40 (percent)



Natural gas consumption in the industrial sector averages 10.4 quadrillion Btu per year from 2012 to 2040 in all three cases. However, the pattern of use varies, with the No Sunset and Extended Policies cases showing higher levels of consumption than the Reference case at the end of the projection period.

Transportation energy consumption

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the joint CAFE and greenhouse gas emissions standards promulgated by EPA and NHTSA for model years 2012 through 2025 are extended through 2040, with an assumed average annual increase of 1.3%. Sales of vehicles that do not rely solely on gasoline internal combustion engines for power (including those that use

Effects of proposed energy provisions in the Energy Savings and Industrial Competitiveness Act of 2013

Senate bill S. 1392, The Energy Savings and Industrial Competitiveness Act of 2013 (ESICA) [5], introduced in July 2013, contains provisions for building energy codes, industrial energy efficiency, federal agencies, and budget offsets. Assuming appropriation of the funding authorized in the bill, EIA examined two key provisions of the proposed legislation: the adoption of updated building energy codes for residential and commercial buildings, and a rebate program for energy-efficient electric motors [6]. Other provisions require further specification by federal agencies or Congress, or they address levels of detail beyond that modeled in the National Energy Modeling System. Amendments have been introduced that may have energy impacts, but they are not part of the bill as of this writing and are not considered in this analysis. Of the two provisions analyzed for AEO2014, the updated building codes have a small effect on energy consumption and CO_2 emissions, and the industrial motors rebate program has virtually no effect. The analysis assumes that states will take advantage of incentives offered to implement the updated codes, and that once in place the codes will be effective over time.

Compared with the AEO2014 Reference case, the proposed building codes in ESICA reduce buildings delivered energy consumption by 0.7% in 2025 and 1.1% in 2040. Natural gas shows the largest reduction in buildings' energy use relative to the Reference case, as improved building shells lessen space heating requirements. Lower energy use in the ESICA case leads to lower levels of CO_2 emissions than in the Reference case. From 2014 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 307 million metric tons (an annual average of about 12 million metric tons) relative to the Reference case projection.

Residential and commercial consumers save $9.2 billion (2012 dollars) on energy purchases in 2040 in the ESICA case relative to the Reference case, as a result of lower energy demand. From 2014 to 2040, the cumulative reduction in residential and commercial energy purchases in the ESICA case totals $96.9 billion. Some of those savings are assumed to be offset by additional costs to the buildings sectors in meeting more stringent building codes, but such costs are not comprehensively modeled by EIA. The electric motor rebate program has a minimal impact on energy use, because the proposed program is limited in terms of both authorized funding and the two-year time frame for eligible installations.

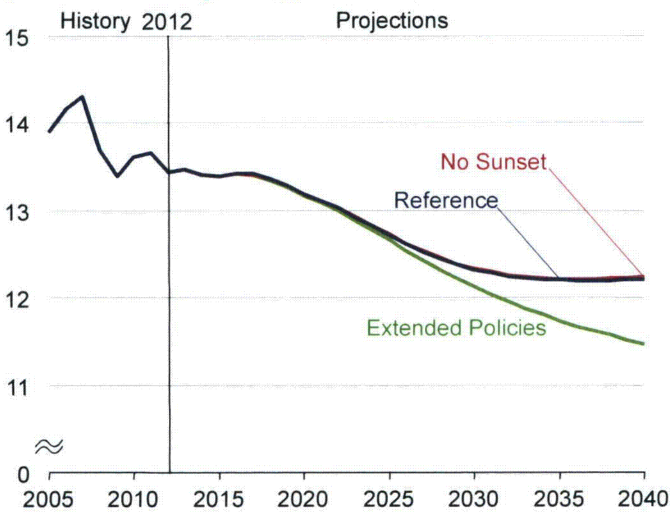
diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to 76% of new light-duty vehicle (LDV) sales in 2040, compared with 55% in the Reference case.

LDV energy consumption declines from 16.0 quadrillion Btu (8.7 million barrels per day [MMBbl/d] of oil equivalent) in 2012 to 13.5 quadrillion Btu (7.4 million barrels per day (MMBbl/d) of oil equivalent) in 2025 in the Reference case as a result of the increase in CAFE standards. Extension of the increases in CAFE standards in the Extended Policies case further reduces LDV energy consumption to 11.1 quadrillion Btu (6.1 MMBbl/d of oil equivalent) in 2040, which is 9% lower than in the Reference case.

The Extended Policies case differs from the Reference and No Sunset cases by extending the standards for heavy-duty vehicle (HDV) fuel consumption and GHG emissions after MY 2018. New HDV fuel economy increases from 7.7 mpg in 2018 to 8.0 mpg in 2040 in the Extended Policies case. HDV annual energy consumption still rises from 5.3 quadrillion Btu (2.5 MMBbl/d of oil equivalent) in 2012 to 6.0 quadrillion Btu (2.9 MMBbl/d of oil equivalent) in 2018 and continues to grow to 7.3 quadrillion Btu (3.5 MMBbl/d of oil equivalent) in 2040 in the Extended Policies case. However, the total is lower than the 7.5 quadrillion Btu (3.6 MMBbl/d of oil equivalent) in the Reference case in 2040.

Consumption of petroleum and other liquids in the transportation sector is nearly the same through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 12.7 MMBbl/d of oil equivalent in 2025 to 11.5 MMBbl/d of oil equivalent in 2040, as compared with 12.2 MMBbl/d of oil equivalent in 2040 in the Reference case (Figure IF1-3).

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40 (million barrels per day)



Renewable electricity generation

The No Sunset and Extended Policies cases assume that tax credits for renewable electricity generation sources are extended through 2040, resulting in significantly more renewable generation—primarily from wind and solar—than in the Reference case in 2040 (Figure IF1-4). In general, renewable generation in the No Sunset case is slightly higher than in the Extended Policies case, which includes energy efficiency measures that result in slower load growth and lower demand for new generation capacity.

In the Extended Policies case, wind generation more than triples from 2012 to 2040, compared with a 76% increase in the Reference case. However, the short-term growth of wind generation in the Reference case exceeds that in the Extended Polices case, as qualification for the current production tax credit (PTC) requires that new wind capacity be under construction by 2013 and generally in service before 2016, resulting in a near-term surge in wind capacity additions.

Minimal demand for new capacity and competitive natural gas prices limit mid-term (approximately 2015 to 2025) wind growth in all the cases, but long-term sustained growth of wind generation capacity begins earlier (in the early 2020s) and proceeds at more rapid rate in the Extended Policies case as a result of relative attractiveness of wind projects under the continued support of the PTC.

Solar generation grows at a uniformly higher rate in the Extended Policies case than in the Reference case, in response to the assumed extension of the solar investment tax credits (ITC) in the Extended Policies case that either expire or are significantly reduced after 2016 in the Reference case. In both the No Sunset and Extended Polices cases, total U.S. solar generation increases by an average of about 12% per year from 2012 to 2040, compared with 7% per year in the Reference case. In general, the relatively higher growth benefits both utility-scale PV installations in the electric power sector and customer-sited rooftop PV applications in the residential and commercial sectors. The effects of tax credit extensions on other renewable generation technologies, such as hydropower, biomass, and geothermal, are minimal in comparison.

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall fossil energy use leads to lower levels of energy-related CO_2 emissions than in the Reference case. In the Extended Policies case, the emissions reduction is larger than in the No Sunset case. From 2012 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 2.6 billion metric tons (a 1.7% reduction over the period) in the Extended Policies case relative to the Reference case, as compared with 1.2 billion metric tons (a 0.7% reduction over the period) in the No Sunset case (Figure IF1-5). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4% of the total cumulative reduction in CO_2 emissions from 2012 to 2040 in comparison with the Reference case. The balance of the reduction in CO_2 emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Most of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon absorption when the plant feedstock is grown. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In the Extended Policies case, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels in the buildings sector. In the industrial sector, the Extended Policies case shows reduced emissions as a result of lower petroleum use.

Energy prices and tax credit payments

With lower natural gas use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, natural gas and electricity prices are lower than in the Reference case. In 2040, the average delivered price for natural gas is \$0.44/thousand cubic feet (Mcf), or 4.2%, lower in the No Sunset case and \$0.48/Mcf, or 4.5%, lower in the Extended Policies case than in the Reference case (Figure IF1-6). Similarly, average end-use electricity prices are 0.46 cents/kWh

Figure IF1-4. Renewable electricity generation in three cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

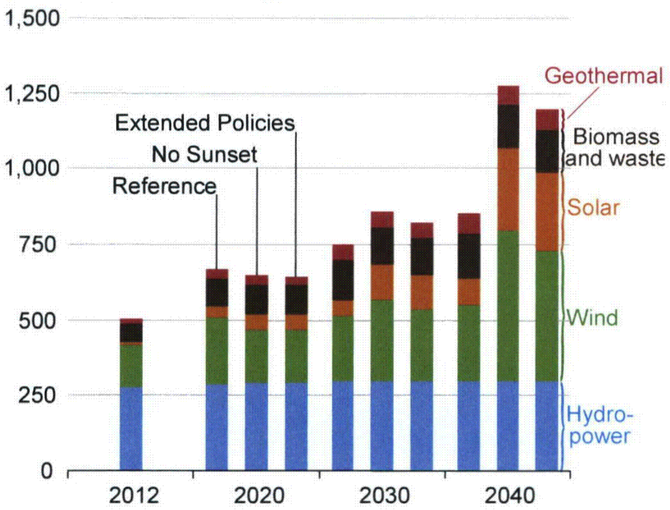
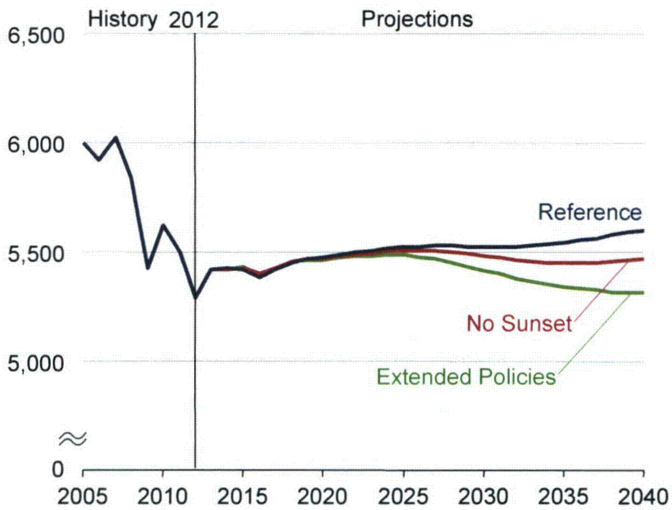


Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40 (million metric tons)



(4.1%) lower in the No Sunset case and 0.55 cents/kWh (5.0%) lower in the Extended Policies cases than in the Reference case (Figure IF1-7).

The reductions in delivered energy consumption and CO_2 emissions in the No Sunset and Extended Policies cases are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. Compared to the Reference case, residential and commercial consumers in the No Sunset case, on average, pay an extra $1.7 billion/year (2012 dollars) for end-use equipment, residential building shell improvements, and additional distributed generation systems between 2014 and 2040. The government, on average, pays an extra $7.7 billion/year in tax credits to consumers in the buildings sector (or, from the government's perspective, receives that amount of reduced revenue). In the Extended Policies case, consumers and the government pay, on average, an additional $14.5 billion and $5.1 billion/year, respectively, over the amounts in the Reference case between 2014 and 2040.

The additional costs to the buildings sectors in the No Sunset and Extended Policies cases are more than offset by savings on energy purchases as a result of efficiency improvements and increased distributed generation. Compared to the Reference case, residential and commercial consumers save an average of $11.9 billion (2012 dollars) in annual energy costs from 2014 to 2040 in the No Sunset case and an average of $20.4 billion annually in the Extended Policies case.

The largest response to federal tax incentives for new renewable generation in the power sector is seen in the No Sunset case, where the extension of the PTC and the 30% ITC reduces government tax revenues by approximately $4.5 billion/year from 2014 to 2040, as compared with $483 million/year in the Reference case. In the Extended Policies case, the reduction in government tax revenues is similar to, but somewhat less than, that in the No Sunset case because of the lower levels of demand. From 2014 to 2040, annual government tax revenues in the Extended Policies case will be approximately $3.3 billion/year lower than in the Reference case.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40 (2012 dollars per thousand cubic feet)

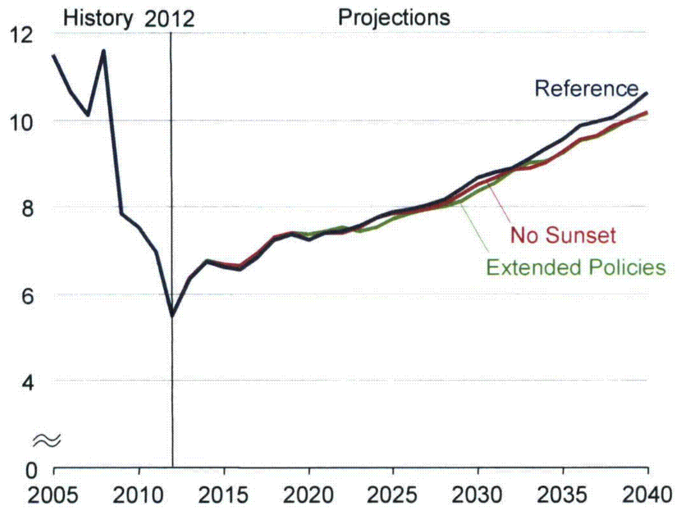
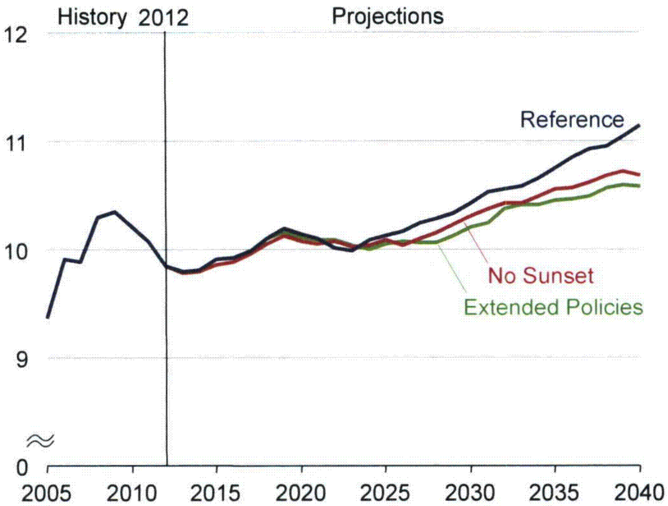


Figure IF1-7. Average electricity prices in three cases, 2005-40 (2012 cents per kilowatthour)



Endnotes for IF1

Links current as of April 2014

1. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
2. A tax extenders package that includes a two-year extension of the biodiesel credit (retroactive to January 1, 2014) was passed by the Senate Finance Committee on April 3, 2014, but still must be passed by the House and the full Senate to become law. R. Kotrba, "Senate Finance Committee passes tax package with biodiesel credit," *Biodiesel Magazine* (April 3, 2014), http://biodieselmagazine.com/articles/41973/senate-finance-committee-passes-tax-package-with-biodiesel-credit.
3. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
4. Calculations based on U.S. Energy Information Administration, Form EIA-860, Schedule 3, 2011 data (Washington, DC, January 9, 2013), http://www.eia.gov/electricity/data/eia860/index.html.
5. U.S. Congress, "S. 1392 - Energy Savings and Industrial Competitiveness Act of 2013," http://beta.congress.gov/bill/113th-congress/senate-bill/1392?q={%22search%22:[%22S.%201392%22]}.
6. Modeled provisions based on S. 1392, Sections 101 and 221, as brought to the Senate floor in September 2013. An updated version of the bill was reintroduced on February 27, 2014, http://beta.congress.gov/bill/113th-congress/senate-bill/2074/text. As of this writing, time had not been scheduled for Senate floor discussion.

Figure sources for IF1

Links current as of April 2014

Figure IF1-1. Total energy consumption in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-4. Renewable electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-7. Average electricity prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

IF2. U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level

U.S. production of tight oil has increased dramatically in the past few years, from less than 1 million barrels per day (MMbbl/d) in 2010 to more than 3 MMbbl/d in the second half of 2013 [*1*]. The *Annual Energy Outlook 2014* (AEO2014) Reference case reflects continued growth in tight oil production. However, growth potential and sustainability of domestic crude oil production hinge around uncertainties in key assumptions, such as well production decline, lifespan, drainage areas, geologic extent, and technological improvement—both in areas currently being drilled and in those yet to be drilled. As a result, High and Low Oil and Gas Resource cases were developed to examine the effects of alternate resource and technology assumptions on production, imports, and prices.

The projected trends in oil production vary tremendously in the alternative cases, and those trends hold important implications for the United States. In the High Oil and Gas Resource case, growth in tight oil production continues for a longer period of time than projected in the Reference case. Domestic crude oil production increases to nearly 13 MMbbl/d before 2035 in the High Oil and Gas Resource case, and net U.S. oil imports decline through 2036 and remain at or near zero from 2037 through 2040. The Low Oil and Gas Resource case reflects uncertainty about tight oil and shale crude oil and natural gas resources that leads to lower domestic production than in the Reference case. In this case, production reaches 9.1 MMbbl/d in 2017 before falling to 6.6 MMbbl/d in 2040, leading to higher projected dependence on net imports of petroleum and other liquids than in the Reference case. The range of production and imports in these alternative cases, as shown in Figures IF2-1 and IF2-2, illustrates the importance of uncertainty in the resource and technology assumptions.

Policymakers, industry, markets, and the public have great interest in the outlook for future domestic oil production and its key drivers. EIA continues to advance both the quality and transparency of its work in this area. Improvements made to the National Energy Modeling System (NEMS) Oil and Gas Supply Module for AEO2014 enhance its ability to capture rapid growth in tight oil production. Specifically, EIA has implemented a more disaggregated representation of estimated ultimate recovery (EUR) that uses well-level data aggregated to the county level within key producing regions to track the combined effect of technology advances and the changing quality of resources being targeted on production per well, which in turn drives an analysis of EUR for wells in each region. There is still a great deal of uncertainty in the projections of U.S. tight oil production. EIA's analysis reflects those uncertainties by varying key assumptions regarding the resource base and the rate of technology advances that lower drilling cost or raise its productivity across alternative cases. As new information is gained through drilling, production, and technology experimentation, NEMS projections for tight oil production will continue to evolve.

Improvements in data collection and projections

The domestic oil supply outlook in AEO2014 is based on data derived from measurements at production sites that are available for analysis. Those data provide a basis for improved understanding of the key factors that have contributed to the growth of tight oil production, which has improved the analysis in AEO2014; however, limitations about the use of the data should be taken into account when the Reference case results are examined.

As individual production profiles of wells drilled in tight oil formations are developed and analyzed, they provide a basis for the calculation of a production decline curve and EUR for each well. The results can be used to project potential future production from existing wells and from new wells drilled in the same plays [*2*].

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)

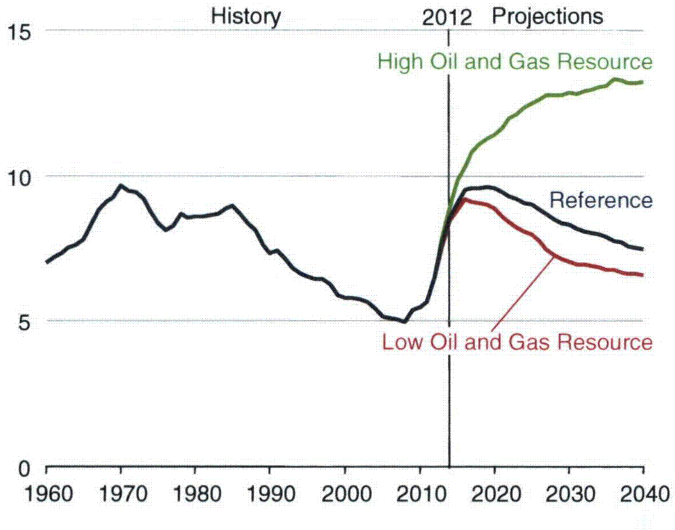
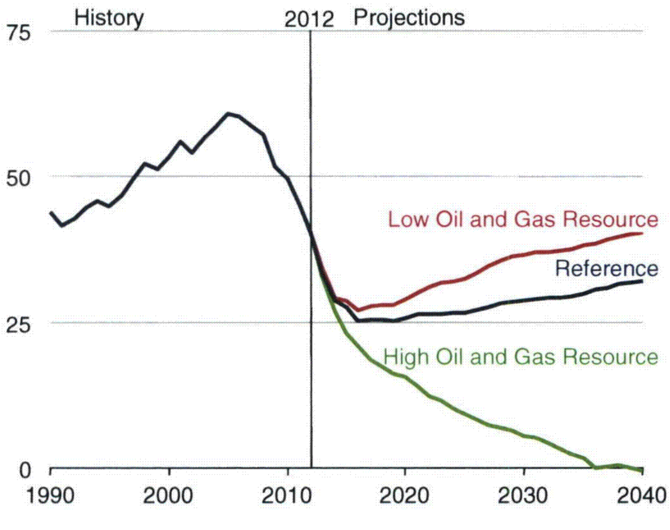


Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)



Production decline curves and the associated EURs for individual wells vary widely across plays, within single plays, and even within discrete sections (counties) of a single play. Using the Eagle Ford formation in Texas as an example, the discussion below examines the methods used to estimate EURs for tight oil wells, the distribution of EURs, the factors that contribute to variations in EURs, and the implications of using county-level representations as the basis for projections of overall production totals both for oil and for natural gas, which is often a coproduct of tight oil production. Uncertainties related to EUR estimation and advances in tight oil production technologies, and their effects on projections of domestic tight oil production in the AEO2014 High and Low Oil and Gas Resource cases, are explored by scaling production decline curves.

Estimating ultimate recovery per well

For each tight well or shale well with initial production in 2008 or later, and with at least four months of production data available, the U.S. Energy Information Administration (EIA) fits monthly production to a decline curve. The mathematical form of the curve is initially hyperbolic [*3*], but it shifts to exponential when the annual decline rate reaches 10% [*4*]. The EUR is the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime.

The actual production curve and the resulting actual ultimate recovery are highly uncertain and cannot be known until the well is plugged and abandoned, which may occur sooner or later than 30 years. Estimates of future production based on the first few months of initial production can differ significantly from later estimates for the same well.

As more months of production are added, the shape of the production curve and the resulting EUR for a given well can change. For example, for one well drilled in Live Oak County in the Eagle Ford formation in Texas, fitting a curve to the first year of monthly production data gave a EUR of 574,000 barrels; using four years of production data gave a EUR of 189,000 barrels for the same well. Conversely, another well in the same county had a EUR of 105,000 barrels based on the first 12 months of production data but 224,000 barrels based on four years of monthly production data. For the wells in the Eagle Ford formation with at least four years of production, EURs based on only the first year of monthly production ranged from as much as 385,000 barrels higher to 173,000 barrels lower than the EURs based on four years of production. Generally, the EUR stabilizes after three years of production, because for many wells in tight formations nearly 50% of the EUR has been produced during that period. EURs based on three years of data differ from EURs based on four years of data by 6,000 barrels on average, with a range of 65,000 barrels higher to 98,000 barrels lower. Because most Eagle Ford wells have been producing for less than three years (Table IF2-1), their EURs are likely to change as more production history is added.

County-level representation

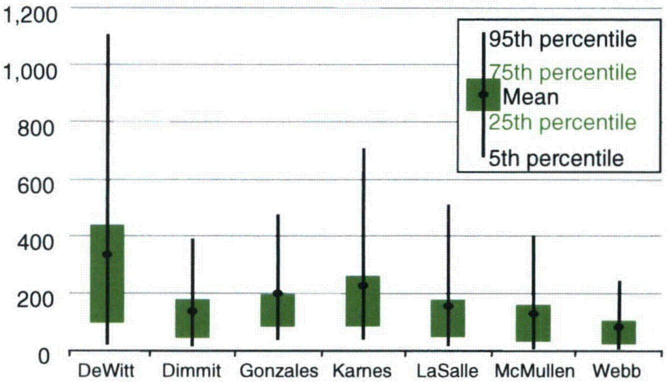
The decline curves from all wells in each county, averaged by production month, are used to generate a representative production curve that provides a basis for estimating production from future wells in that county. Wells that are newly drilled, with fewer data points and therefore greater uncertainty in the fit of their decline curves, have a tendency to inflate the average EUR. Older wells, which may have been drilled and completed using technologies and practices that are no longer representative of future practices, tend to pull the average down.

The range of EURs within a given county can be large, as shown in Figure IF2-3 for the seven counties in the Eagle Ford formation that have more than 400 oil and natural gas wells. Some wells have high initial production, but because they have been producing for less than a year, their EURs are highly uncertain. These few high-performing wells raise the county mean EUR above the county median EUR, generally skewing the mean toward the 75th percentile.

Table IF2-1. Average estimated ultimate recovery for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production

Vintage year	Number of wells	Average EUR (thousand barrels)
2008	33	36
2009	75	57
2010	514	117
2011	1,627	153
2012	2,717	191
2013	418	169
All years	**5,384**	**168**

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013 (thousand barrels)



	DeWitt	Dimmit	Gonzales	Karnes	LaSalle	McMullen	Webb
Mean EUR	334	137	198	226	153	127	80
Number of wells	453	820	486	975	755	455	593

The Eagle Ford formation covers 32 counties in Texas. In 14 of those counties, fewer than 10 wells had been drilled as reported through June 2013. The EUR for counties with little or no drilling is assumed to be equal to the average of the mean estimates from adjacent counties [5]. The Eagle Ford county-level EURs range from more than 300,000 barrels per well (DeWitt county) to less than 25,000 barrels per well (Burleson and Maverick counties), with a mean average of roughly 170,000 barrels per well and a median of 103,000 barrels per well across all the Eagle Ford counties.

The county-level representation derived from well-level data implemented in AEO2014 allows the model to reflect rapid growth in production for plays in the early years of development, when producers focus on developing the most productive wells in the formation's sweet spots [6], the plateau in production as new drilling offsets the decline in production from older wells, and an eventual decline in production as development moves to less-productive areas (Figure IF2-4). However, there is still a great deal of uncertainty underlying the recovery of tight oil in known plays, as well as the potential for production from additional plays or other layers within a currently productive formation that has not been tested. The application of refinements to current technologies, as well as new technology advances, can also have significant (but uncertain) impacts on the recoverability of tight and shale crude oil.

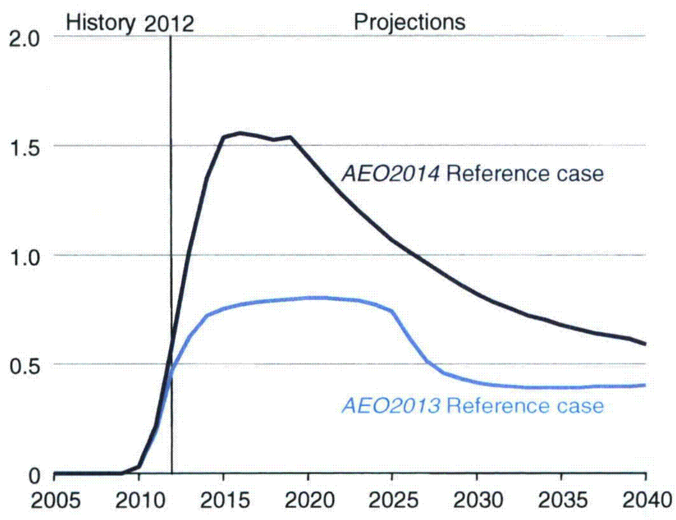
High and Low Resource cases

The High and Low Oil and Gas Resource cases in AEO2014 were developed using assumptions that result in higher and lower estimates of technically recoverable crude oil and natural gas resources than those in the Reference case [7]. These cases allow for an examination of the potential impacts of higher and lower domestic supply on energy demand, imports, and prices, but they do not represent upper and lower bounds for future domestic oil and natural gas supply. The two cases are not symmetric; currently, there is more uncertainty about the potential for greater gains in production than about the potential for lower production levels.

The High Oil and Gas Resource case assumes a broad-based future increase in crude oil and natural gas resources, not limited to production of oil and natural gas in tight sands and shales. However, optimism about increased supply has been buoyed by recent advances in the production of crude oil and natural gas from tight and shale formations. With the adjusted resource and technology advance assumptions in the High Oil and Gas Resource case, domestic crude oil production continues to increase to more than 13 MMbbl/d before 2035. Specific assumptions for the High Oil and Gas Resource case, as compared with the Reference Case, include:

- EURs for tight oil, tight gas, and shale gas wells are 50% higher [8]
- Additional tight oil resources as well as 50% lower well spacing (i.e., wells are closer together), with a downward limit of 40 acres per well for existing and potential future tight oil resources, to capture the possibility that additional layers or new areas of low-permeability zones will be identified and developed
- Diminishing returns on the EUR when drilling in a county exceeds the number of potential wells assumed in the Reference case [9], to capture the probability that greater drilling density will cause wells to interfere with each other (i.e., production from one well might reduce production from a nearby well)
- Long-term technology improvements beyond those assumed in the Reference case, represented as a 1% annual increase in the EURs for tight oil, tight gas, and shale gas wells

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40 (million barrels per day)



- More resources in Alaska and in the lower 48 offshore, including the development of tight oil in Alaska and 50% higher technically recoverable undiscovered resources for other Alaska crude oil and the lower 48 offshore (which reflects more favorable resolution of the uncertainty surrounding undeveloped areas where there has been little or no exploration and development activity, and where modern seismic survey data are lacking)
- The development of lower 48 onshore oil shale (kerogen), with production reaching 135,000 barrels per day by 2025.

The High Oil and Gas Resource case does not include exploration or production activity in the Arctic National Wildlife Refuge.

The Low Oil and Gas Resource case reflects only the uncertainty around tight and shale crude oil and natural gas resources—specifically, whether the performance of current and future wells drilled will actually be less than estimated. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50% lower than in the AEO2014

Reference case (by scaling all applicable production decline curves). All other resource assumptions are unchanged from the Reference case.

Effects on domestic crude oil production

The difference in overall production across cases mostly reflects differences in tight oil projections. In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, which results in more and earlier development of tight oil resources than in the Reference case. The greater abundance of tight oil resources in the High Oil and Gas Resource case causes tight oil production to peak later in the projections, at 8.5 MMbbl/d in 2035, compared to the Reference case peak production rate of 4.8 MMbbl/d in 2021. From 2012 through 2040, cumulative tight oil production in the High Oil and Gas Resource case amounts to 75 billion barrels, compared with 44 billion barrels in the Reference case.

In the Low Oil and Gas Resource case, lower estimates of tight oil, tight gas, and shale gas resources result in a U.S. production profile that is both slower and lower than in the Reference case, with tight oil production peaking at 4.3 MMbbl/d in 2016 and then declining through 2040. Cumulative tight oil production from 2012 through 2040 amounts to 34 billion barrels in the Low Oil and Gas Resource case, which is 23% less than in the Reference Case.

Effects on U.S. net imports of petroleum and other liquids

The variations in projected domestic petroleum supply between the Reference case and the High and Low Oil and Gas Resource cases result in significant variations in the share of net imports in total U.S. liquid fuels consumption (Figure IF2-2). The net import share of petroleum and other liquids consumption, which increased steadily from 27% in 1985 to about 60% in 2005, has fallen since 2005, to roughly 40% in 2012. In the Reference case, the share of U.S. petroleum and other liquids consumption met by imports continues declining to 25% in 2016, and then begins a gradual increase starting in 2020, reaching 32% in 2040. The net import share follows a similar trend in the Low Oil and Gas Resource case, falling to 27% in 2016 and then rising to 40% in 2040. In contrast, net import dependence continues to decline through 2036, and it is at or near zero from that point until 2040 in the High Oil and Gas Resource case.

Effects on prices

As a result of higher levels of U.S. crude oil production in the High Oil and Gas Resource case, North Sea Brent crude oil prices are lower than in the Reference case: $125 per barrel (2012 dollars) in 2040, compared with $141 per barrel in 2040 in the Reference case. Lower motor gasoline and diesel prices in the transportation sector encourage more consumption.

In the Low Oil and Gas Resource case, lower levels of domestic crude oil production result in a slightly higher Brent crude oil price than in the Reference case—$145 per barrel (2012 dollars) in 2040. As noted above, because the uncertainty around production increases is greater than the uncertainty around production decreases, assumptions in the Low Oil and Gas Resource case are closer to the assumptions in the Reference case than are the assumptions in the High Oil and Gas Resource case.

Endnotes for IF2

Links current as of April 2014

1. The term tight oil does not have a specific technical, scientific, or geologic definition. Tight oil is an industry convention that generally refers to oil produced from very low permeability shale, sandstone, and carbonate formations, with permeability being a laboratory measure of the ability of a fluid to flow through the rock. In limited areas of some very low permeability formations, small volumes of oil have been produced for many decades.
2. A play is defined as a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
3. The hyperbolic decline curve is given by $Q_t = Q_i / [(1 + bD_i t)^{1/b}]$, where Q_t is the production volume in time t (in months), Q_i is the initial volume at time 0 (the 30-day initial production rate or IP is Q_1), D_i is the initial decline rate, and b is the hyperbolic parameter (b of 0.001 is basically an exponential decline). Because the reported production in the first month could include 1 to 31 days of actual production, the first-month data are excluded from the fitting routine.
4. Of the 6,594 Eagle Ford wells included in the Drillinginfo database, 927 were excluded because they had less than four months of production data—leaving 5,667 to be evaluated through the automated fitting routine. For 95% of the wells, monthly production was fitted successfully to a hyperbolic decline curve.
5. Planned future enhancements to this methodology include taking into account any available geologic information (i.e., porosity, depth, thickness, total organic carbon, thermal maturity, and natural fracture density and location) to provide appropriate weights for the adjacent county EURs.
6. Sweet spot is an industry term for those selected and limited areas within a play where the well EURs are significantly higher than those for the rest of the play—sometimes as much as 10 times higher than those for the lower production areas within the play.
7. The total unproved technically recoverable crude oil resources are 401 billion barrels in the High Oil and Gas Resource case and 180 billion barrels in the Low Oil and Gas Resource case, compared to 209 billion barrels in the Reference case. Total unproved technically recoverable dry natural gas resources are 3,349 trillion cubic feet (Tcf) in the High Oil and Gas Resource case and 1,480 Tcf in the Low Oil and Gas Resource case, compared to 1,932 Tcf in the Reference case.
8. This is achieved by scaling the applicable production decline curves upward.
9. For this assumption, the initial production rate is increased by 20%, but the decline curve is shifted so that the overall EUR is reduced by 20%.

Figure and table sources for IF2

Links current as of April 2014

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Table IF2-1. Average EUR for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production: U.S. Energy Information Administration.

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013: U.S. Energy Information Administration.

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40: History: U.S. Energy Information Administration. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A, and AEO2013 National Energy Modeling System, run REF2013.D102312A.

IF3. Potential of liquefied natural gas as a freight locomotive fuel

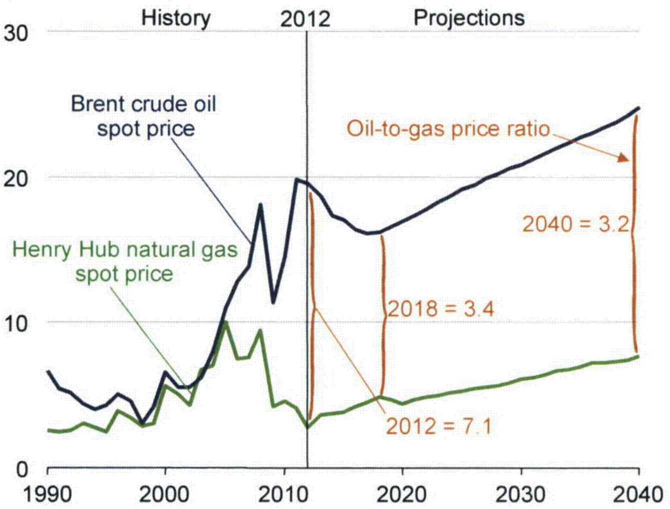
Continued growth in domestic natural gas production, along with substantially lower natural gas spot prices compared to crude oil, is reshaping the U.S. energy economy and attracting considerable interest in the potential for fueling freight locomotives with liquefied natural gas (LNG). While there is significant appeal for major U.S. railroads to use LNG as a fuel for locomotives because of its potentially favorable economics compared with diesel fuel, there are also key uncertainties as to whether, and to what extent, the railroads can take advantage of this relatively cheap and abundant fuel.

Freight railroads and the basic economics of fuel choice

Major U.S. railroads, known commonly as Class 1 railroads, are defined as line-haul freight railroads with certain minimum annual operating revenue. Currently, that classification is based on 2011 operating revenue of $433.2 million or more [1]. While there are 561 freight railroads operating in the United States, only seven are defined as Class 1 railroads. The Class 1 railroads account for 94% of total freight rail revenue [2]. They haul large amounts of tonnage over long distances, and in the process they consume significant quantities of diesel fuel. In 2012, the seven Class 1 railroads consumed more than 3.6 billion gallons (gal) of diesel fuel [3], amounting to 10 million gal/day and representing 7% of all diesel fuel consumed in the United States. The two largest consumers of diesel fuel among the Class 1 railroads—Burlington Northern Santa Fe (BNSF) and Union Pacific—consumed more than 1 billion gal each in 2012. The cost to Class 1 railroads of consuming such large quantities of diesel fuel was more than $11 billion in 2012, representing 23% of their total operating expense (Table IF3-1).

Class 1 railroads are considering the use of LNG to fuel locomotives because of the potential for significant cost savings. Following years of tight price linkage, spot prices for crude oil (North Sea Brent) and natural gas (Henry Hub) diverged around 2005. In 2012, the Brent spot price was about seven times the Henry Hub spot price on an energy equivalent basis. That differential is projected to narrow in the midterm, but a persistent gap is expected to continue, with crude oil prices more than three times higher than natural gas per million British thermal units (MMBtu) throughout the Reference case projection period, going out to 2040 (Figure IF3-1).

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040 (2012 dollars per million Btu)



The large differential between crude oil and natural gas commodity prices translates directly into a significant disparity between projected LNG and diesel fuel prices, even after accounting for natural gas liquefaction costs that exceed refining costs. In the AEO2014 Reference case, the long-run price difference between locomotive diesel fuel and LNG in rail applications increases from $1.48/gal of diesel equivalent in 2014 to $1.77 in 2040 (Figure IF3-2).

Given the difference between LNG and diesel fuel prices in the Reference case, railroads that switch locomotive fuels could accrue significant fuel cost savings. Locomotives are used intensively, consume large amounts of fuel, and are kept in service for relatively long periods of time. The net present value of future fuel savings across the Reference case projection for an LNG locomotive compared to a diesel counterpart is well above the roughly $1 million higher cost of the LNG locomotive and tender (Figure IF3-3).

Relatively large changes in assumptions used to evaluate investments in LNG locomotives (such as a significantly shorter payback period or much higher discount rate) or in

Table IF3-1. Class 1 railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012

Class 1 railroad (2012)	Diesel fuel consumption (gallons)	Fuel cost (thousand 2012 dollars)	Fuel cost share of total operating expense
Burlington Northern Santa Fe	1,335,417,552	$4,273,779	29%
Union Pacific	1,108,029,359	$3,505,671	24%
CSX Transportation	490,902,017	$1,542,747	18%
Norfolk Southern	462,466,433	$1,437,178	18%
Canadian National Grand Trunk	101,555,124	$326,303	16%
Canadian Pacific Soo	71,575,774	$231,211	16%
Kansas City Southern	64,078,412	$195,428	22%
Total	**3,634,024,671**	**$11,512,317**	**23%**

fuel prices would be required to change LNG fuel economics for railroad use from favorable to unfavorable. Starting from the Reference case, the economics for switching to LNG locomotives remain favorable unless the payback period is reduced by eight years or the discount rate applied is raised by nine percentage points (Figure IF3-4). However, in the Low Oil Price case, the net present value of fuel cost savings associated with LNG use are not large enough to offset the higher additional upfront cost of LNG locomotives and tenders (Figure IF3-5). The shortfall in the value of fuel savings relative to upfront investment increases over the projection period in this case, making investments in LNG fueling less attractive over time. Clearly, uncertainty about future fuel prices suggests that there is some risk for companies in making such a fundamental change in freight rail operations.

Challenges for liquefied natural gas as a freight rail fuel

While simple economic calculations involving the comparison of fuel cost savings to additional upfront cost are relatively straightforward, other factors, including operational, financial, regulatory, and mechanical challenges, also affect fuel choices by railroads. One of the most challenging factors raised by the switch to LNG locomotives by Class 1 railroads is the effect on operations. Switching from diesel fuel to LNG would require a new delivery infrastructure for locomotive fuel. Natural gas would need to be delivered to fuel depots, either by truck in smaller quantities, as LNG [*4*], or perhaps by pipeline. Larger quantities of

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40 (2012 dollars per gallon diesel equivalent)

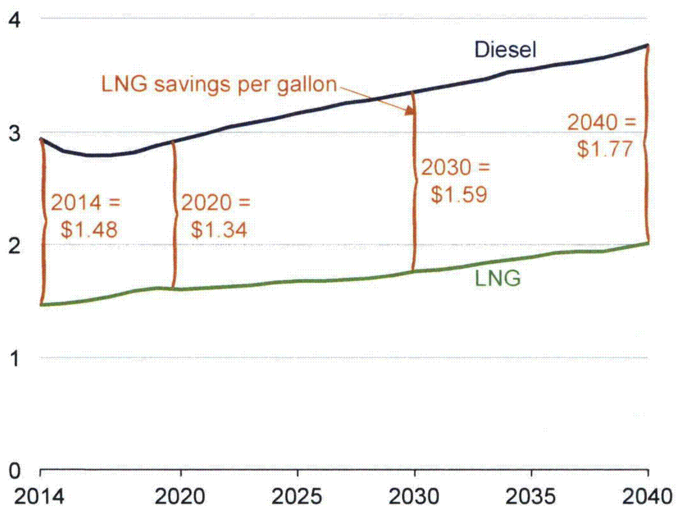


Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40 (million 2012 dollars, net present value)

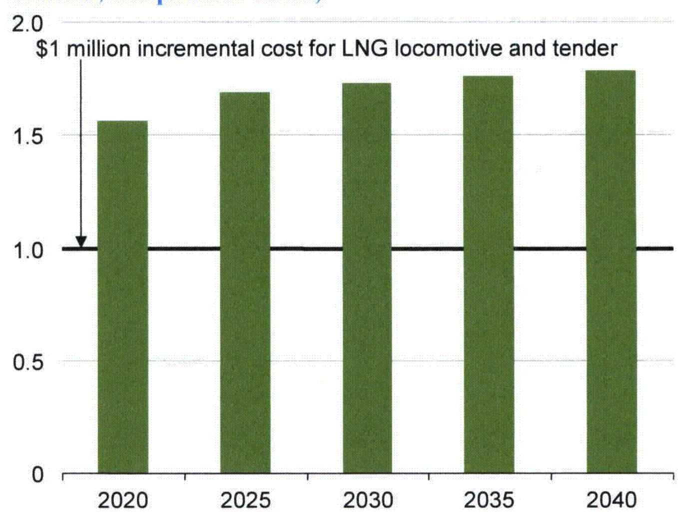


Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices (payback years and discount rate)

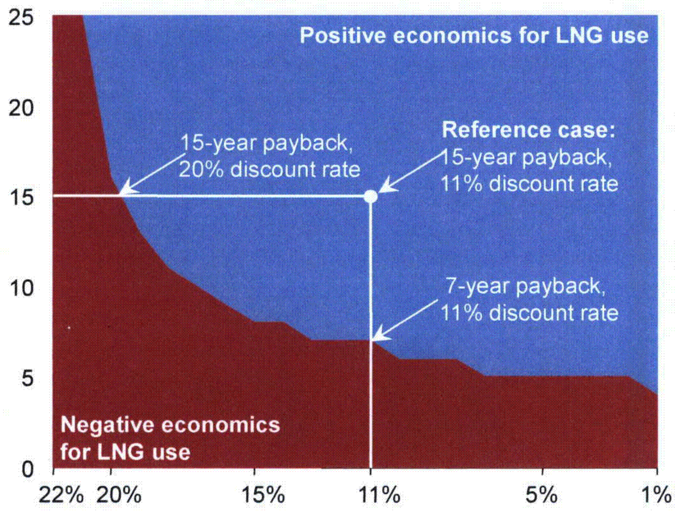
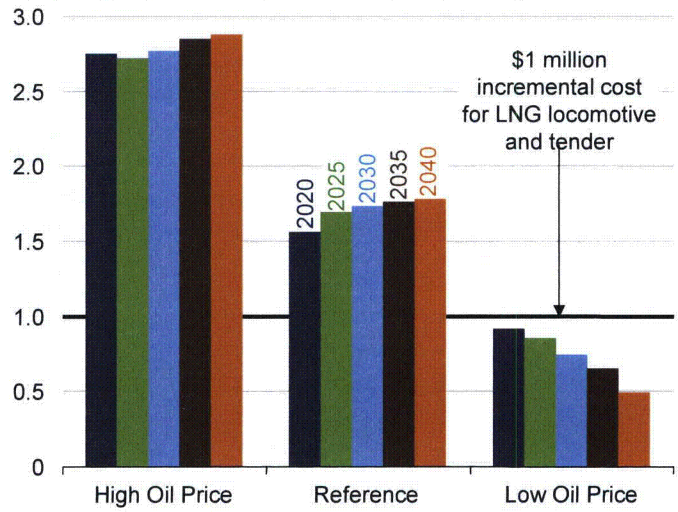


Figure IF3-5. Discounted average fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40 (net present value, million 2012 dollars)



natural gas would require liquefaction before delivery to tender cars for use in locomotives. Building the new infrastructure would require a large financial investment in addition to the large investments made in locomotives and tender cars.

The building of LNG refueling infrastructure could also complicate the inter-operability of the rail network, depending on how quickly modifications could be made to accommodate refueling at multiple points around the nation. Impeding the ability of the rail network system to move goods because of a lack of fuel availability could drive up costs and lead to reductions in network flexibility and operational efficiency [*5*]. In addition, operations could be further affected by fuel switching because of the cost of training staff at refueling depots and in maintenance shops, updating maintenance facilities to handle LNG locomotives and tenders, and managing more extensive logistics [*6*]. Further, LNG locomotives and tender cars could require more maintenance than their diesel counterparts. All of these operational changes would create a duplicative infrastructure [*7*], because many diesel-fueled locomotives still would be in service at least for some significant period, and compression-ignited LNG locomotives still require at least some diesel fuel for combustion ignition.

Replacing the current stock of diesel locomotives with LNG locomotives and tender cars would represent a significant financial investment by Class 1 railroads. In 2012, there were 25,174 locomotives in the service of Class 1 railroads, the vast majority of which were line-haul locomotives [*8*]. A new diesel line-haul locomotive costs about $2 million [*9*], and rebuilt locomotives cost about half that amount. With a new LNG locomotive and tender costing about $1 million more than a diesel counterpart, the cost to replace the entire diesel locomotive stock with LNG locomotives and tenders would be tens of billions of dollars, not including additional infrastructure, training, logistics, and a potential increase in maintenance costs. Moreover, much of the cost of the transition, such as purchases of locomotives and tender cars, potentially would occur over a much shorter time period than a fuel payback period.

The financing requirement of large capital expenditures complicates the rather straightforward calculation of locomotive fuel economics. The amount of capital available to Class 1 railroads, either on hand or raised in capital markets, is an important factor in determining whether, or to what extent, railroads can take advantage of fuel cost savings over time. The decision to switch from diesel fuel to LNG is also influenced by the facts that railroads are a highly capital-intensive industry [*10*] with complete responsibility for maintaining the physical rail network, that they face many competing needs for financial investment, and that they must ensure adequate return on investment for their shareholders.

On the regulatory side, LNG rail cargos currently are not permitted without a waiver from the Federal Railroad Administration (FRA) under Federal Emergency Management Agency (FEMA) rules. The development of standard LNG tenders and regulations is underway, with issues related to safety, crashworthiness, and environmental impact, including methane leakage, under consideration [*11*].

Finally, LNG locomotives currently are undergoing extensive testing and demonstration to determine their fuel consumption, emissions, operational performance, and range under real-world conditions. Locomotives and tenders will be evaluated to ensure mechanical performance of such components as connections between tender and locomotive. Several Class 1 railroads are planning to start LNG locomotive demonstration projects to provide better understanding of the obstacles to an LNG fuel switch.

The future of liquefied natural gas in freight rail: lessons from history

The large potential fuel cost savings from the switch to LNG locomotives from diesel has resulted in great interest on the part of the freight rail industry, observers, and analysts. The companies have discussed the potential of LNG as comparable with the switch from steam propulsion to diesel in the 1940s and 50s [*12*], a revolution in freight rail known simply as "dieselization." Other industry experts have responded with more caution, likening the switch to the more evolutionary transformation of diesel-electric freight rail locomotives from direct current (DC) to alternating current (AC) propulsion that has been occurring since the early 1990s [*13*].

The diesel revolution in rail began in yard-switching operations during the mid-1920s, followed by passenger rail in the mid-1930s. After an initial period of hesitation, mainly because of the vast amount of capital already invested in steam locomotives and their refueling and watering infrastructure, diesel freight locomotives first appeared in 1941. They then captured the market at an extraordinary rate, with the last steam locomotive mustered out of service in 1961 [*14*].

The advantages of using diesel locomotives over steam were numerous. While diesel locomotive costs were about double per horsepower compared to steam, diesel locomotives proved superior in almost every other way. Steam locomotives had to slow or stop to take on water, requiring extensive watering infrastructure, and they needed nearly constant cleaning, maintenance, and repair, with annual costs reaching 25% of the initial cost of the locomotive. The switch to diesel allowed the railroads to avoid costly watering time and infrastructure and dramatically reduced maintenance and repair. As a result, diesel engines could travel faster and thus double the annual mileage of steam locomotives. Diesel engines, unlike steam engines, could be turned on and off with relative ease; a lead diesel locomotive could control other locomotives on a unit train; the costs of rail line maintenance were reduced because diesel locomotives were lighter and did not "pound the tracks"; and maintenance costs were lowered by the use of standardized parts and design [*15*].

Although diesel freight locomotives took over the market in 20 years, freight locomotives with AC traction motors, which began service in Class 1 railroads in the early 1990s, represent about 17% of the locomotive stock today [*16*]. AC locomotives have the major advantage of greater adhesion levels than their counterparts equipped with DC motors, allowing fewer locomotives to pull the same load. The ability to reduce the number of locomotives pulling a unit train represents a significant improvement in fuel efficiency, but it has not been adopted to the same extent as dieselization. Class 1 railroads have gradually adopted or decided against AC traction for a variety of reasons related to operations, upfront incremental costs, and the ability to take advantage of increased adhesion levels. For example, in recent years Union Pacific, Canadian Pacific, and CSX have chosen AC traction locomotives because of locomotive unit reductions, reliability, interoperability, and life-cycle costs. Canadian National Grand Trunk and Norfolk Southern have stayed with DC traction because of incremental cost and the inability to apply unit train reductions. BNSF has chosen AC locomotives for coal runs, where they can take advantage of unit locomotive reductions, and DC locomotives for intermodal runs, where they cannot [17].

These historical examples of the impacts of new technologies and fuels may offer insights into the future potential for LNG locomotives. As happened during the diesel revolution, freight railroads may adopt a completely new locomotive fuel and infrastructure over two decades if there is a compelling business case. However, many cost and operational efficiencies made diesel locomotives superior to steam locomotives, and the same dynamic may not be seen with LNG. Moreover, investment in existing capital stock and relevant equipment may be an impediment early in a transformation process.

The ongoing evolution of AC traction locomotives shows that Class 1 railroads will invest in a new locomotive technology, at least gradually, if there is significant reason to do so. The decision may balance factors such as cost with operational efficacy.

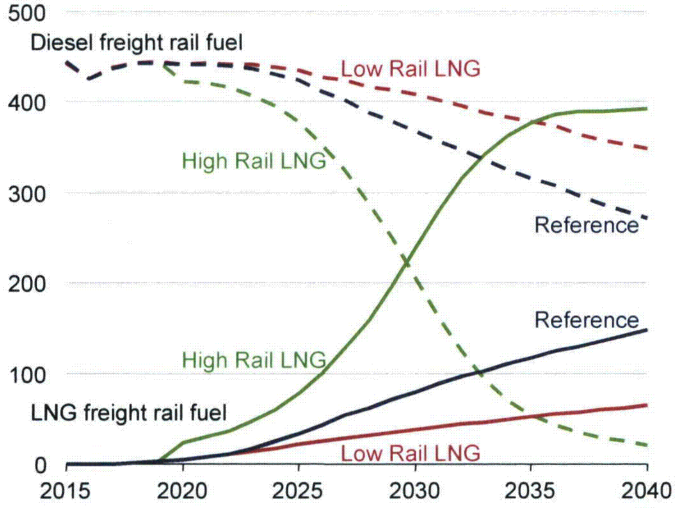
Liquefied natural gas in freight rail—revolution and evolution cases

AEO2014 includes two alternative cases that examine the potential impact of LNG in freight rail, based on the diesel revolution and AC traction evolution. The cases also look at the impact of a specific LNG engine technology. The High Rail LNG case represents a revolution in freight rail locomotive fueling similar to that of dieselization in the 1940s and 1950s. After an initial trial period starting in 2017 through 2020, Class 1 railroads take advantage of the favorable economics of LNG locomotive fuel such that after a 20-year period, all freight rail motive stock is converted to LNG capability. The new locomotives are assumed to use high-pressure direct injection (HPDI) LNG engine technology, which uses natural gas as the primary fuel and relies on a small amount of diesel fuel for ignition. HPDI engines use fuel at a ratio of about 95% LNG to 5% diesel. LNG-only engines are not expected to be adopted for locomotives.

The Low Rail LNG case represents an evolution in freight rail locomotive fueling similar to the ongoing penetration of AC traction locomotives. After an initial trial period from 2017 through 2020, Class 1 railroads take advantage of the favorable LNG locomotive fuel economics by turning over their engine stocks at an average rate of 1% per year. The new LNG locomotives are assumed to use a dynamic gas blending engine, which uses diesel fuel for combustion until intake temperature rises, at which point natural gas is used. The engines are LNG-capable up to a fuel consumption ratio of 80% LNG and 20% diesel and have the added advantage of being dual-fuel compatible, with the ability to switch back to 100% diesel fuel as needed. The Reference case does not make any assumption about the type of LNG engine used but instead allows LNG to penetrate into freight rail at the average annual turnover rate of new and rebuilt stock experienced over the last decade.

The High and Low Rail LNG cases show a dramatic change in the fuel mix used by freight rail. In the Reference case, LNG fuel use increases from 0.5 trillion Btu in 2017 to 148 trillion Btu in 2040, or 35% of total freight rail energy consumption (Figure IF3-6). In the High Rail LNG case, LNG fuel consumption increases to 392 trillion Btu in 2040, or 95% of freight rail energy consumption. LNG consumption in the Low Rail LNG case increases to just 64 trillion Btu, or 16% of total freight energy consumption.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40 (trillion Btu)



While the impacts are dramatic in the freight rail sector, it is important to note that the impacts on total energy use in the U.S. transportation system and on the nation's total energy consumption are relatively small. In the Reference case, transportation diesel consumption increases from about 6 quadrillion Btu in 2012 to 6.5 quadrillion Btu in 2017 and 7.5 quadrillion Btu in 2040, with railroad diesel use of 0.5 quadrillion Btu in 2012 decreasing to 0.4 quadrillion Btu in 2017 and 0.3 quadrillion Btu in 2040, when LNG accounts for 35% of projected energy use by freight rail in the Reference case. Most transportation diesel fuel consumption—more than 80%—occurs in heavy-duty vehicles. Because freight rail accounts for only a small share of transportation diesel use, projected total transportation diesel fuel use in 2040 varies only modestly across cases with different levels of LNG use in freight rail, ranging from 7.3 quadrillion Btu in the High Rail LNG case to 7.6 quadrillion Btu in the Low Rail LNG case.

Projected natural gas consumption for transportation (excluding pipeline transportation) is sensitive to variation in freight rail use of LNG, because relatively small amounts of natural gas currently are consumed in mobile applications either as compressed or liquefied natural gas. Natural gas consumption in the transportation sector (including pipeline transportation) increases from 0.9 quadrillion Btu in 2040 in the Reference case to 1.1 quadrillion Btu in the High Rail LNG case and to 0.8 quadrillion Btu in the Low Rail LNG case. The projected changes in use of LNG in rail have marginal impacts on retail natural gas prices in the transportation sector, which impact natural gas demand in other transportation uses. As a result of these price changes, heavy-duty truck natural gas demand partially offsets the consumption impacts occurring in rail.

Because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption. Total U.S. natural gas energy consumption varies from 32.3 quadrillion Btu in 2040 in the Reference case to 32.4 quadrillion Btu in the High Rail LNG case and 32.1 quadrillion Btu in the Low Rail LNG case.

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3. U.S. Department of Transportation, Surface Transportation Board, *Annual Reports Financial Data,* http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
4. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
5. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
6. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
7. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
8. U.S. Department of Transportation, Surface Transportation Board, *Annual Report Financial Data* (2012 and various years), http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
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Table IF3-1. Class 1 Railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012: U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data," http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-5. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, RLNGLOW20.D012914C, and RLNGHIGH20.D012914C.

IF4. Light-duty vehicle energy demand: demographics and travel behavior

In 2012, energy consumption by light-duty vehicles (LDVs) accounted for 61% of all transportation energy consumption in the United States, or 8.4 million barrels of oil equivalent per day, and represented nearly 10% of world petroleum liquids consumption. LDV energy use is driven by both LDV fuel economy and travel behavior, as measured by LDV vehicle miles traveled (VMT). LDV VMT per licensed driver peaked in 2007 at 12,900 miles per year and decreased to 12, 500 miles in 2012.

The shift in VMT highlights the importance of travel behavior and its influence on LDV energy consumption. Before the 2007 peak, travel behavior in the United States tracked closely with economic growth. Since 2007, trends in U.S. LDV travel have not followed the trends in economic indicators such as income and employment as closely (Figure IF4-1). Although economic factors continue to influence travel demand, demographic, technological, social, and environmental factors also have shown the potential to affect LDV travel.

The AEO2014 Low and High VMT cases examine variations in travel demand as compared with the Reference case. In the Reference case, VMT per licensed driver begin to increase after 2018. The compound annual rate of growth in total VMT for LDVs from 2012 to 2040 in the AEO2014 Reference case is 0.9%—below the 1.7% rate from 1995 to 2005 but higher than the 0.7% average annual growth rate from 2005 through 2012. The Low VMT case assumes an environment in which travel choices made by drivers result in lower demand for personal vehicle travel, consistent with recent trends in VMT per licensed driver. In the Low VMT case, total U.S. LDV travel demand in 2040 is 19% lower than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 0.2%. The High VMT case assumes changes in travel behavior that result in an increase in VMT per licensed driver compared with the Reference case. In the High VMT case, total U.S. LDV travel demand in 2040 is nearly 6% higher than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 1.1% (Figure IF4-2).

The alternative VMT cases have direct implications for both projected energy use by LDVs and associated carbon dioxide emissions. In the Low VMT case, U.S. LDVs consume 5.3 million barrels of oil equivalent per day in 2040, 18% less than in the Reference case, resulting in total transportation sector CO_2 emissions roughly 9% lower than in the Reference case. In the High VMT case, LDVs consume 6.7 million barrels of oil equivalent per day in 2040, or 5% more than in the Reference case, resulting in total transportation sector CO_2 emissions more than 2% higher than in the Reference case (Figures IF4-3 and IF4-4).

Influential travel demand factors

Fuel use by LDVs is directly related to travel demand, which in turn depends on economic, demographic, technological, social, and environmental factors. In general, the demand for LDV travel is likely to decline when licensing rates fall [*1*], use of telework increases, or fuel prices are relatively high. Fuel use by LDVs is likely to rise when the driving-age population grows, during periods of expanding economic activity, or when fuel prices are relatively low.

Economic factors

Although recent U.S. travel indicators have started to decouple from economic indicators, economic indicators still are a dominant influence on levels of personal travel. There are strong links between economic activity and employment and commuting. Employment rates (Figure IF4-5) largely determine the ability of individuals to travel. When people are not employed and have less income, their daily travel is likely to be much lower than when they are commuting to and from work.

The labor force participation rate, defined as the percentage of the total population ages 16 years and older that is employed or looking for work, has declined since the early 2000s [*2*]. Reasons for the decline include increasing retirements and lack of

Figure IF4-1. Economic indicators of travel, 1975-2012 (index, 1995 = 1.0)

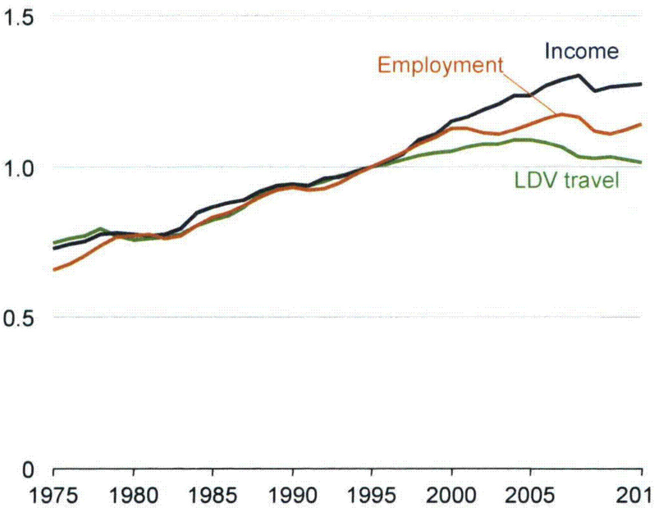
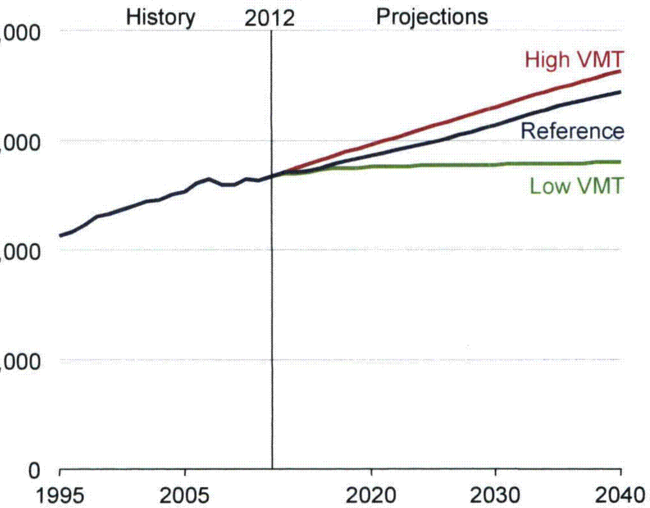


Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040 (billion miles)



opportunities in the job market (which cause those without jobs to give up on job searches). When the labor force participation rate declines, the unemployment rate may also decline as people are removed from the labor pool, even if overall employment is stable. If the trend continues, retirees and people having difficulty finding jobs may reduce their travel as compared with people who have similar demographic profiles and are employed. When labor force participation rates rise, VMT per driver is likely to increase, particularly for millennials (those born between the early 1980s and early 2000s).

Other macroeconomic factors also influence travel behavior. Income, fuel prices, the costs of purchasing a vehicle, and other vehicle operating costs all influence the extent to which an individual can afford LDV travel. Households with vehicle ownership rates that equal or exceed the number of licensed drivers in the household have maximum non-overlapping access to vehicles. More recently, a business model that provides drivers with access to a shared-pool of vehicles has developed, particularly in urban areas. Because users of shared pool vehicles incur charges for time of use as well as fuel, this model discourages vehicle use for low-value trips. Income provides the financial means to own and operate a vehicle and, therefore, to travel; but operating costs can affect vehicle utilization rates. When fuel prices increase, the cost of driving increases, and many licensed drivers may choose to drive fewer miles, particularly if their personal incomes do not increase at the same rate as fuel prices.

Economic growth and higher employment rates are correlated with increased travel; however, it is unclear to what extent those economic effects may be offset or reinforced by other factors, such as aging of the population, driver licensing rates, telecommuting rates, and access to alternative travel options. The AEO2014 High and Low VMT cases illustrate potential impacts on overall VMT under plausible combinations of factors that could raise or lower VMT.

Demographic factors

Although economic factors play a significant role, demographic factors such as population, age distribution, and licensing rates also are important determinants of LDV travel demand. Population age groups have different gender distributions, licensing rates, and travel behaviors. As the age groups change over time, long-term effects on VMT will become apparent, particularly for the age groups that have the greatest influence on VMT.

A key factor in the recent shift of personal travel demand is specific travel behavior in age and gender groups. In this analysis, the driving population is divided into five age groups (Table IF4-1), and each age group is further divided into males and females (not shown in the table). Licensing rates differ across age and gender groups. Since 1990, licensing rates generally have been declining for the two youngest age groups and increasing for the two oldest groups (Figure IF4-6). For males, most age groups have seen declining or stagnant

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)

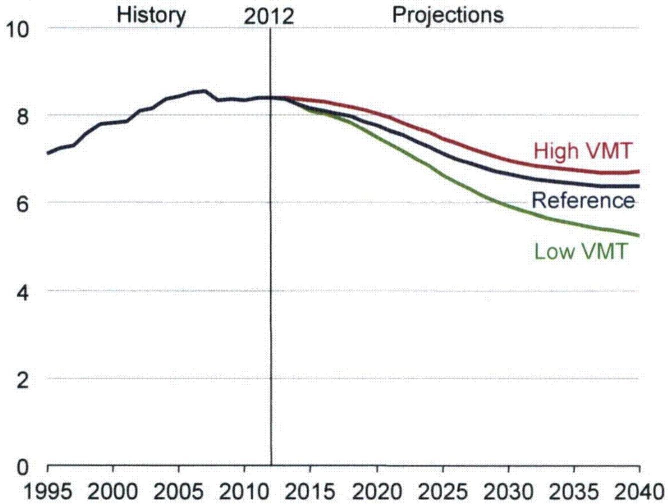


Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040 (million metric tons)

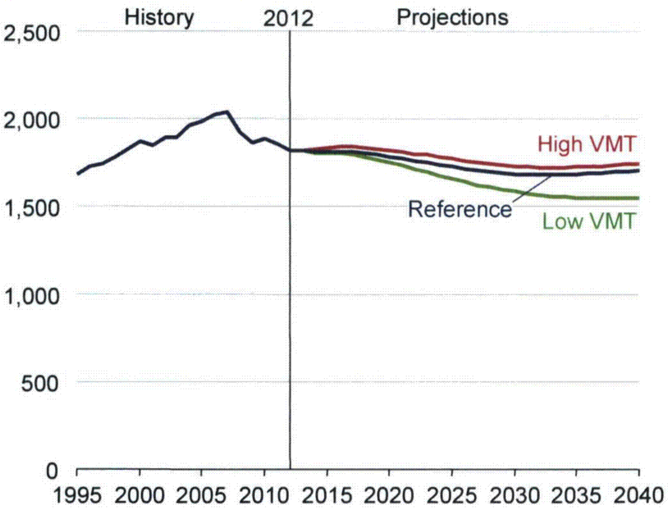
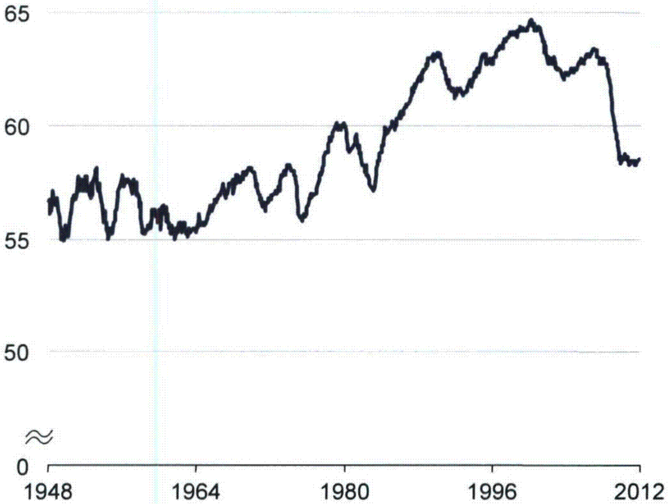


Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012 (percent)



licensing rates, with the only exception being males 65 years and older. The female age groups have seen similar stagnation for most of the younger age groups and an increase for females 65 years and older.

Since about 1990, the average age of males who are licensed drivers has been higher than the average age of the male population 16 years and older (the male driving population). That trend is projected to continue as fewer young males obtain licenses or delay obtaining licenses until later in life. Conversely, the average age of female licensed drivers has been lower than the average age of the female driving population, but it is projected to be higher than the average age before 2020 and to continue rising through 2040 (Figure IF4-7). For both males and females, the average age of the driving population and average age of licensed drivers increase in the Reference case, with fewer younger individuals obtaining licenses and more choosing to wait until later in life to become licensed drivers.

The population age 34 years and below has seen a decrease in both licensing rates and VMT per licensed driver, with the licensing rate for the group falling by 5% over the past decade [3]. Some of the decline is a result of increased state restrictions on licenses. For example, for individuals under 18, states almost universally issue provisional licenses with restrictions on driving hours and passengers and do not allow full driving privileges until 18 years of age [4]. Since 2000, VMT per licensed driver for the population under 20 has dropped by 13%. In 1990, 52% of eligible individuals under 20, and 92% of those between 20 and 34 years of age, obtained their licenses. In 2010, those shares were 43% and 86%, respectively [5]. If the trend persists, licensing rates could continue to decline or flatten out for the youngest driving populations, further reducing VMT per capita. If the licensing rate returns to historic levels, total VMT will increase. Technological factors may also play a role for younger age groups, as discussed below.

The peak driving age group, between 35 and 54 years of age, has experienced a small decline in licensing, from 95% in 1990 to an estimated 92% in 2010. Drivers in this age group traveled an average of almost 15,000 miles annually in 2012, the highest rate of VMT per licensed driver for any age group. This relatively large age group, accounting for 34% of the population in 2012, has a limited influence on changes in total VMT, because neither the licensing rate nor the share of the population has changed drastically through history or is projected to change significantly in the future. Much of that stability results from high employment rates for this age group, as a result of the interaction between economic and demographic factors.

The overall population share in the oldest age group, 65 years and older, has grown steadily since 2000 and is expected to reach 24% of the total population ages 16 and above in 2025, up from a 17% share in 2012. Although the size of this segment of the population has grown since 2000, personal travel (VMT per capita) by the oldest age group dropped by 7% between 2008 and 2009, and its total VMT dropped by 10%. More members of the older population are obtaining their licenses than in the past, but they also have altered their travel behavior, increasing their use of public transportation by 40% during the period from 2001 to 2009 [6]. As the aging of the U.S. population continues, long-term effects on VMT will be apparent, particularly as seen in older driver behavior versus younger driver behavior, as well as gender and regional differences in driver behavior.

Table IF4-1. Historic and projected distribution of age groups

	Percent of population ages 16 and above		
Age (years)	2012	2025	2040
16-19	6.9	6.1	6.0
20-34	26.1	24.4	22.8
35-54	34.1	30.9	30.9
55-64	15.5	15.0	13.5
65+	17.4	23.7	26.8

Figure IF4-6. Driver licensing rates by age group, 1990-2010 (percent of total age group)

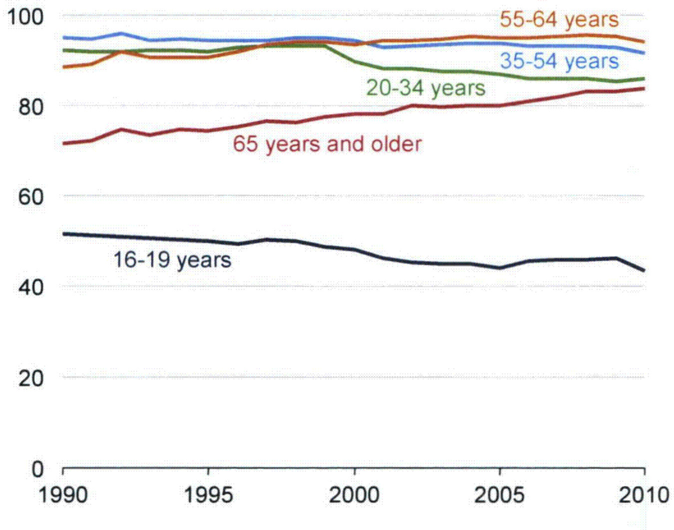
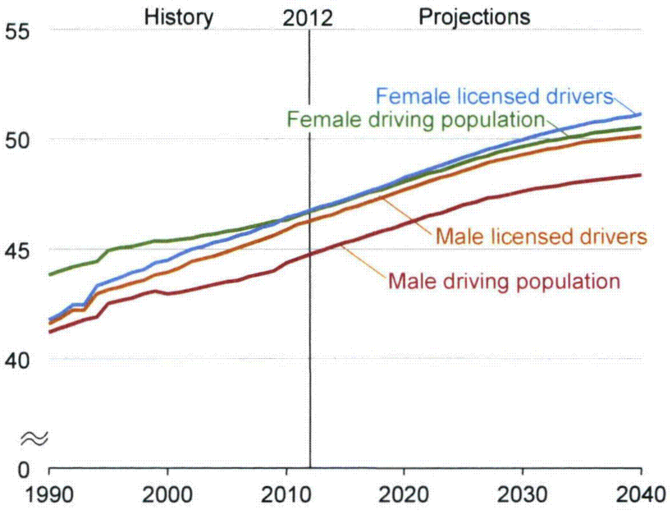


Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040 (years)



Demographic changes can also interact with other factors to influence VMT. Historically, shifts in demographics coupled with economic changes have had major impacts on total travel. For example, the increasing number of women who entered the work force beginning in the 1970s—and added secondary incomes for their families—led to a rise in VMT that combined both economic activity and demographic changes. In the future, factors that influence VMT may merge in various ways that change long-term trends in U.S. travel demand.

Technological, social, and environmental factors

Technological, social, and environmental factors also can influence VMT. Alternative modes of travel affect VMT to the degree that the population has access to substitutes for personal LDVs. The decision to choose a substitute travel option depends on cost in comparison to personal LDVs, convenience, personal preferences, and the availability of mass transit, rail, biking, and pedestrian travel service options. Other opportunities may also affect personal travel, including car-sharing services, car rental and taxi services, and carpooling.

Technological changes and improvements can also affect VMT. The increasing fuel efficiency of LDVs can influence personal travel by lowering the marginal cost of driving per mile. As vehicle efficiency improves, individuals can drive the same distance with less fuel and therefore at a lower cost, which may result in an increase in VMT. In recent analyses supporting the promulgation of new final fuel economy and greenhouse gas emissions standards for LDVs in model years 2017 through 2025, the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) applied a 10% rebound in VMT to reflect the lower fueling costs of more efficient vehicles [7].

Other types of technological and environmental changes also can affect personal travel. Telecommuting, e-commerce, urbanization, and social media can supplant or complement personal vehicle use. Telecommuting, or working from home, can influence personal VMT. From 1997 to 2010, the share of the workforce working at least one day of the week from home increased from 7% to 9.5%. As that trend grows, so does the likelihood that individuals will reduce their total miles driven. The share of the working population that works exclusively from home also has increased, from 4.8% in 1997 to 6.6% in 2010 [8]. Although telecommuting can have an impact on reducing VMT, work-related travel in 2009 was only 25% of total personal travel [9].

Technological advances have increased access to and the availability of electronic devices and other opportunities that can influence VMT—including, but not limited to, social media, GPS applications, and electronic devices. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth obtain driver licenses. Others suggest that access to social media actually increases opportunity and desire for travel. Mobile technology and changing preferences of the younger generations will play a significant part in determining the future of LDV travel.

Finally, spatial development patterns may begin to play a different role in determining VMT than is suggested by history, as suburban sprawl gives way to other development patterns. Urbanization generally results in increases in, and greater access to, public transportation and would be likely to support other forms of transportation, including biking, car sharing, and carpooling. Land use changes and related policies, mainly at the local level but supported or incentivized by state and federal policies, have had only localized impacts on VMT to date. However, the tradeoff between suburban and exurban development and urban infill development is likely to change over the coming decades, and those changes could affect VMT.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040 (VMT per licensed driver per year)

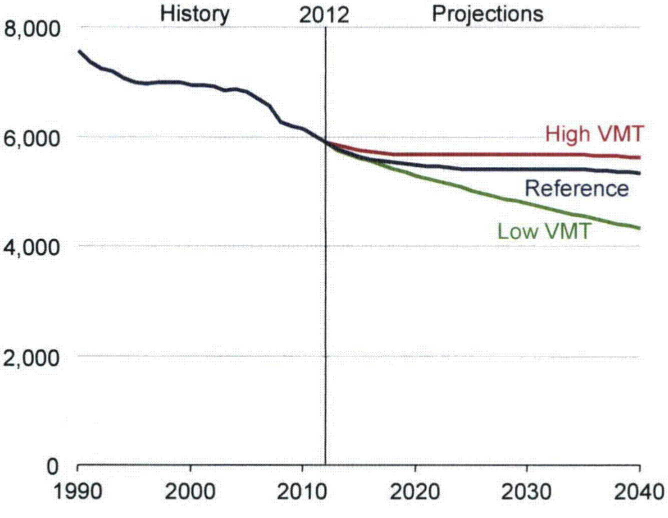
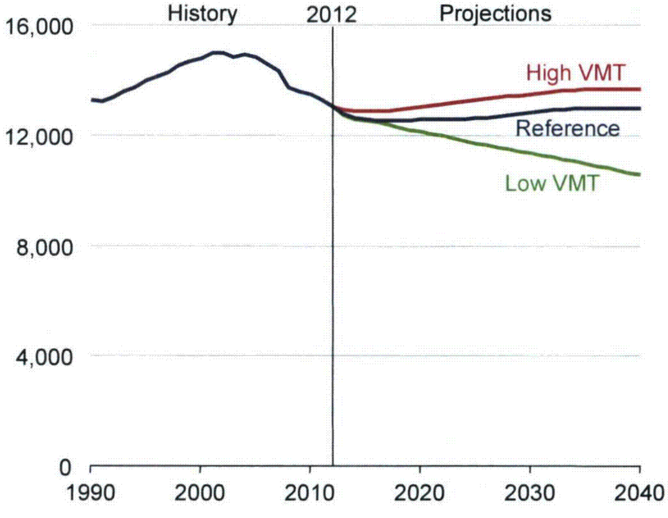


Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040 (VMT per licensed driver per year)



VMT sensitivity analysis

The High and Low VMT cases suggest possible future changes in travel behavior and their potential impacts on VMT and on LDV energy demand. The Low VMT case assumes a 0.5% annual decrease in VMT per licensed driver from 2013 to 2040 for each age and gender group. The High VMT case assumes a pattern of annual increases in VMT per licensed driver: 0.3% starting in 2013, 0.4% starting in 2016, 0.5% starting in 2019, and 0.6% starting in 2023, slowing to 0.5% starting in 2027, 0.4% starting in 2032, and 0.3% from 2036 through 2040. Figures IF4-8 through IF4-12 show VMT per licensed driver in each case for five age groups.

In the Low VMT case, VMT per licensed driver for all drivers decline throughout the projection, to about 10,400 miles per year in 2040—a 19% decrease from 12,800 miles per year in 2040 in the Reference case. In the High VMT case, VMT per licensed driver for all drivers rise to 13,500 miles per year in 2040—nearly 6% higher than in the Reference case (Figure IF4-13). In the Low VMT case, VMT per licensed driver across all age groups decline by an average of 0.7% per year from 2012 to 2040, compared with an average increase of 0.1% per year in the Reference case. The High VMT case projects 0.3% average annual growth in VMT per licensed driver from 2012 through 2040.

Total LDV VMT increase only slightly in the Low VMT case, to almost 2.8 trillion miles in 2040, as compared with 3.6 trillion miles in 2040 in the High VMT case. Annual increases in total LDV VMT from 2012 to 2040 average 0.2% in the Low VMT case and 1.1% in the High VMT case.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040 (VMT per licensed driver per year)

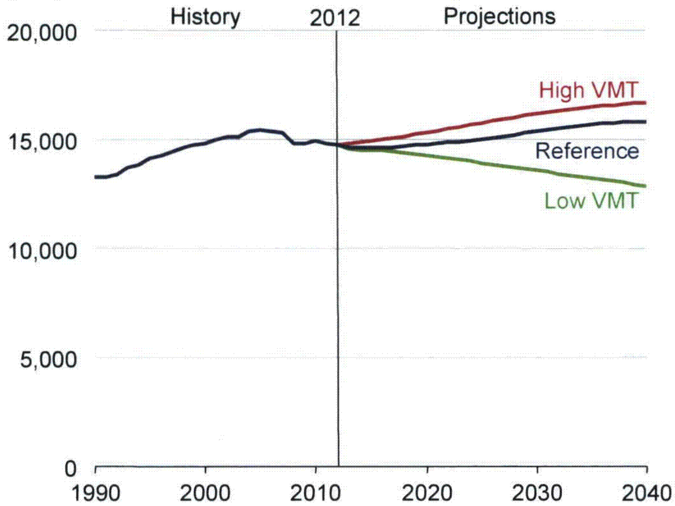


Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040 (VMT per licensed driver per year)

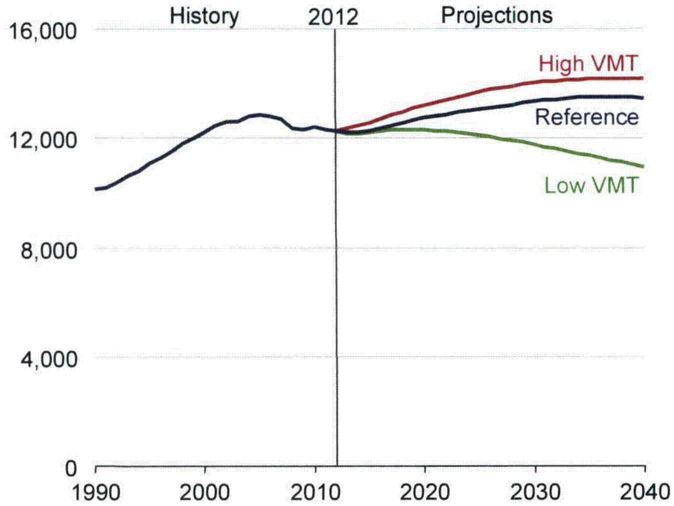


Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040 (VMT per licensed driver per year)

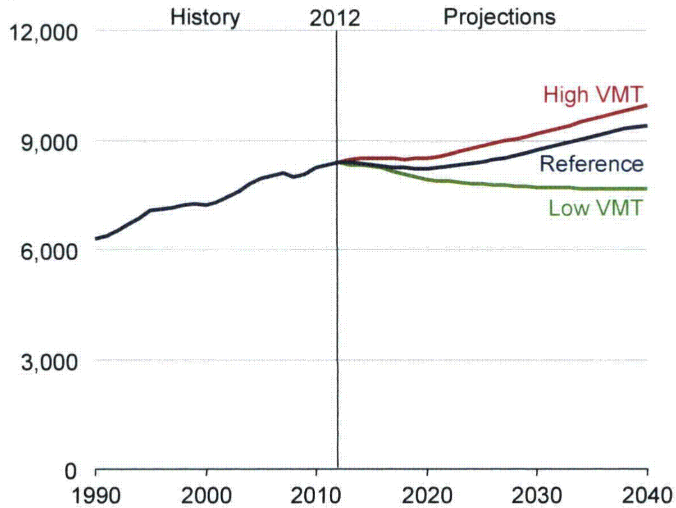
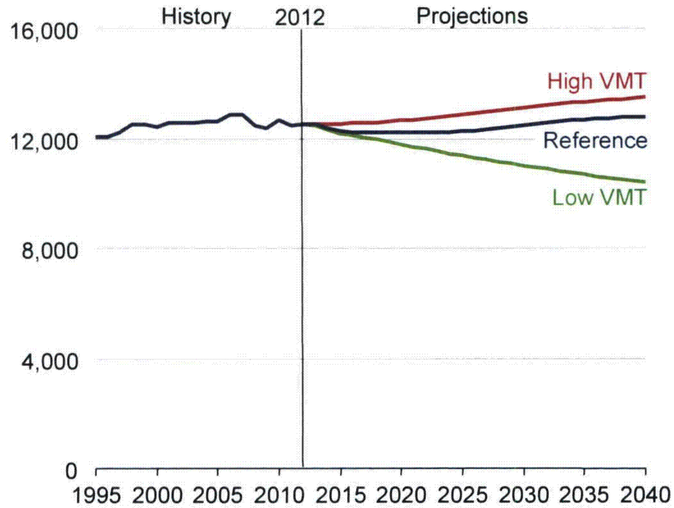


Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040 (VMT per licensed driver per year)



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1. The licensing rate is the share of a population or group 16 years old or older that have driver's licenses.
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Figure and table sources for IF4

Links current as of April 2014

Figure IF4-1. Economic indicators of travel, 1975-2012: Income: U.S. Bureau of Economic Analysis, "GDP and Personal Income" *National Data,* http://www.bea.gov/iTable/index_nipa.cfm. **Employment:** U.S. Department of Labor, Bureau of Labor Statistics, *Current Employment Statistics,* http://www.bls.gov/ces/#data. **LDV Travel:** U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," Highway Statistics Series 2011 (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040: History: S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book,* Edition 31 (July 2012), http://info.ornl.gov/sites/publications/files/Pub37730.pdf. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012: U.S. Department of Labor, Bureau of Labor Statistics, Current Employment Statistics, http://www.bls.gov/ces/#data.

Table IF4-1. Historic and projected distribution of age groups: U.S. Department of Commerce, U.S. Census Bureau, 2010 Census Data, https://www.census.gov/2010census/data/.

Figure IF4-6. Driver licensing rates by age group, 1990-2010: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/; and U.S. Department of Commerce, U.S. Census Bureau, *2010 Census Data,* https://www.census.gov/2010census/data/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

IF5. Effects of lower natural gas prices on projected industrial production

This analysis focuses on variation in industrial output in the Low and High Oil Price cases and Low and High Oil and Gas Resource cases compared to the *Annual Energy Outlook 2014* (AEO2014) Reference case. Energy-intensive industries, including food, paper, bulk chemicals, glass, cement, iron and steel, and aluminum, are the industries that use the largest amount of energy per unit of output and are the most sensitive to natural gas prices. Of these, the most natural gas-intensive industries are food, paper, bulk chemicals, and glass [*1*].

Analysis of the industrial sector as a whole reveals strong links between natural gas prices and industrial production [*2*]. Further analyses reveal important data issues and indicate some basic sensitivity to natural gas prices for the most energy-intensive industries, subject to trade competition, when they are disaggregated [*3, 4*]. Those studies show evidence of a straightforward production decline when natural gas prices to the bulk chemicals industry increase, but the relationship does not appear to apply to the less natural gas-intensive cement industry. The same studies point to an important role for demand, both foreign and domestic, for all industries, including the energy-intensive industries. The National Energy Modeling System used to produce AEO2014 includes sufficient disaggregation to support analysis of the influence of natural gas prices on industrial output.

Demand categories

Expenditure categories, such as personal consumption, investment, government spending, and trade, measure underlying demand in the U.S. economy. Each category includes more detailed disaggregation, such as durable and nondurable goods. The AEO2014 industrial output projections use 59 different categories of final demand, with the effects of each category on industrial production differing across industries. The most important final demand categories for the industries analyzed here, according to input-output tables from the Commerce Department's Bureau of Economic Analysis (BEA) [*5*], are consumer spending, trade, and investment (see box below). In addition to demand from domestic consumers and trade, interindustry demand also affects the industrial sector.

Impact of Bureau of Economic Analysis revisions on the National Income and Product Accounts

BEA performs comprehensive National Income and Product Accounts (NIPA) revisions approximately every five years. The 2013 release was its 14th comprehensive revision. The previous release was in July 2009. The BEA comprehensive revisions incorporate changes in the methods used to measure the U.S. economy as well as the most up-to-date, most complete, and most accurate source data available. Changes in NIPA definitions, classifications, and presentations as a result of the 2013 comprehensive revision include:

- Capitalization of expenditures on research and development (R&D)
- Capitalization of expenditures on entertainment, literary, and artistic originals
- Addition of intellectual property products to the fixed investment tables, including R&D; entertainment, literary, and artistic originals; and software
- Accrual treatment of defined benefit pension plan transactions, recognizing the costs of unfunded liabilities
- Expanded set of ownership transfer costs for residential fixed assets
- Change of the reference year for price indexes and inflation-adjusted series.

The AEO2014 Reference case and High and Low Economic Growth cases started with the IHS Global Insight U.S. long-term model simulations available in March and June 2013, which do not reflect the latest comprehensive NIPA revisions for two reasons. First, the July 2013 NIPA revisions were issued late in the AEO preparation cycle. The late issuance of the NIPA revisions delayed the September and October releases of the IHS Global Insight U.S. long-term model simulations, normally used in preparation of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO). Second, EIA uses the economic forecast together with interindustry data describing how each industry uses other industries' output, and how each industry satisfies its final demand components [*6*]. BEA released the updated interindustry tables in December 2013, much too late for the AEO. While the comprehensive NIPA revisions affect past and projected estimates of GDP, they are not expected to materially affect projected energy use. The results of the 2013 NIPA comprehensive revisions will be included in EIA's *Annual Energy Outlook 2015*.

Although the 2013 comprehensive NIPA revision did not lead to changes in broad economic trends or in the general patterns of past business cycles, it did increase gross domestic product (GDP) in every year back to 1929. The average annual growth rate of real GDP from 1929 to 2012 was revised upward to 3.3%, as compared with the previous estimate of 3.2%. More recently, the annual growth rate from 2002 to 2012 was revised upward to 1.8%, as compared with the previous estimate of 1.6%. The economic recession of 2007-09 (December 2007 to June 2009) now looks less severe than previously reported—with GDP contracting by 2.9% over that period after the comprehensive revision, compared with 3.2% before the revision. In addition, the current recovery is stronger than first reported—a 2.2% average annual expansion from the second quarter of 2009 through the first quarter of 2013, compared with 2.1% before the revision. The revised data also indicate that the economy shrank at an average annual rate of 1.3% in the first quarter of 2011, compared with 0.1% growth before the revision.

(continued on next page)

Changes in 2012 nominal GDP as a result of the comprehensive revision total $559.8 billion, including $526 billion (94%) attributable to changes in definitions and $33.8 billion (6%) resulting from statistical changes. Research and development capitalization accounts for 75% of definitional changes, or $396.7 billion. Two-thirds of R&D expenditures are made by the private sector and one-third by government. The remaining changes to definitions include capitalization of entertainment, literary, and artistic originals ($74.3 billion, or 14%); an expanded set of ownership transfer costs for residential fixed assets ($42.3 billion, or 8%); and accrual accounting for defined benefit pension programs ($12.6 billion, or 2%).

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12 (billion dollars)

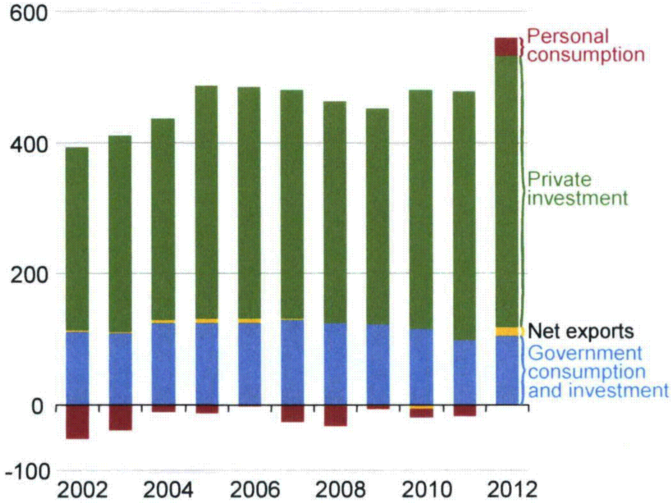


Figure IF5-1 shows the annual impacts of the NIPA revisions on the major components of GDP from 2002 to 2012. Private investment and government expenditures accounted for 92% of the $560 billion upward revision in 2012, primarily as a result of the capitalization of R&D expenditures. Revisions to gross private domestic investment contributed $413 billion, or 74% of the total; revisions to government expenditures contributed $104 billion, or 19% of the total; and revisions to personal consumption and net exports contributed $43 billion, or 7% of the total upward revision to 2012 GDP.

The increase in private and government investment spending is primarily the result of BEA's continued work to broaden the definition of GDP. With this comprehensive revision, NIPA now includes capitalization of spending on R&D and on long-lived artwork produced by artists, studios, and publishers—intangible assets that previously were considered intermediate inputs to the production of other goods or services. Although the inclusion of intangible assets does raise the measured level of overall economic activity, it has only a modest impact on economic growth rates.

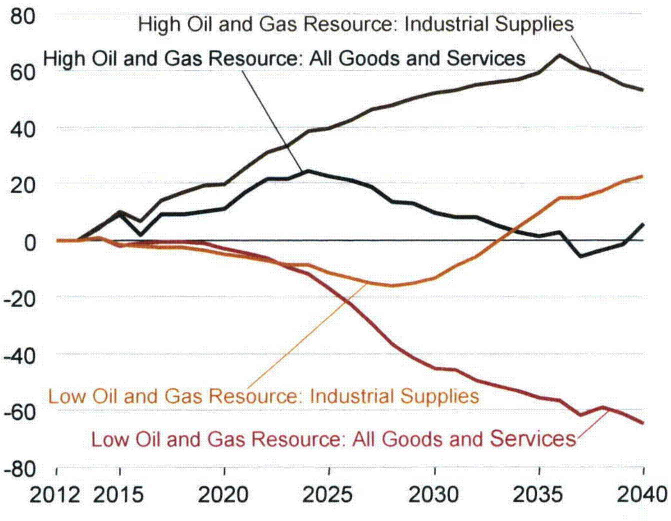
Alternative cases

Results

Oil and Gas Resource cases

Changes in the assumed size of the U.S. oil and natural gas resource base and the rate of technology advance within the sector can affect the nation's economy. In general, increases in oil and natural gas resources result in lower prices and higher industrial output, and a smaller oil and natural gas resource base results in higher prices and lower industrial output. However, the cases are not symmetric. In the High Oil and Gas Resource case, GDP is 1.2% higher in 2040 than projected in the Reference case, total industrial output is 5.1% higher in 2040, and bulk chemicals and paper industries output is 11.5% higher in 2040, as a result of improved trade advantages resulting from lower prices. The changes tend to be smaller in the Low Oil and Gas Resource case. GDP is 0.4% lower in 2040 than projected in the Reference case, total industrial output is 2.3% lower in 2040, and bulk chemicals and paper industries output is 5.0% lower in 2040, as a result of lower oil and natural gas production and higher prices in the Low Oil and Gas Resource case.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)



Among the final demand categories, trade of industrial supplies (Figure IF5-2) and consumer goods (Figure IF5-3) show the largest differences across the Oil and Gas Resource cases. Energy trade is a major component of industrial supplies. Trade of industrial supplies and consumer goods drives production in the bulk chemicals industry (Figure IF5-4). The price advantage of natural gas-based feedstock varies widely in the High Oil and Gas Resource case (Figure IF5-5), with corresponding impacts on the bulk chemicals industry. Differences in production of bulk chemicals account for a large portion of the differences in fuel consumption results, particularly for petroleum and other liquids and for natural gas, both of which are used as feedstocks in the bulk chemicals industry.

In the High Oil and Gas Resource case, exports of all goods and services from 2012 to 2025 grow faster than imports, as a result of lower U.S. producer prices [7] that are attributable in part to lower natural gas prices (see Figure IF5-2). After 2025, the growth rate of imports begins to increase. Net exports of industrial supplies continue to grow throughout the projection in the High Oil and Gas Resource case, because energy imports are low. In the Low Oil and Gas Resource case, net exports of all goods and services decline through 2040, primarily as a result of slow export growth when U.S. producer prices are higher than those in the Reference case. Net exports of industrial supplies in the Low Oil and Gas Resource case are lower than in the Reference case until 2034, when nonenergy imports drop below Reference case levels as U.S. producer price inflation slows.

Oil Price cases

In comparison with the Reference case, the Low Oil Price case shows lower natural gas prices and production, and the High Oil price case shows higher natural gas prices and production. However, the magnitude of the changes in the Oil Price cases is smaller than in the Oil and Gas Resource cases. The changes in natural gas prices in the Low Oil Price case affect the economy earlier in the projection, leading to changes in inflation, unemployment, and interest rates. In the High Oil Price case, the economy shows larger losses beginning earlier than in the Low Oil and Gas Resource case but recovers as natural gas production expands.

In both the Low and High Oil Price cases, the largest changes from the Reference case are for trade in industrial supplies (Figure IF5-6) and consumer goods (Figure IF5-7), which primarily affect the bulk chemicals, glass, and paper industries. Differences

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)

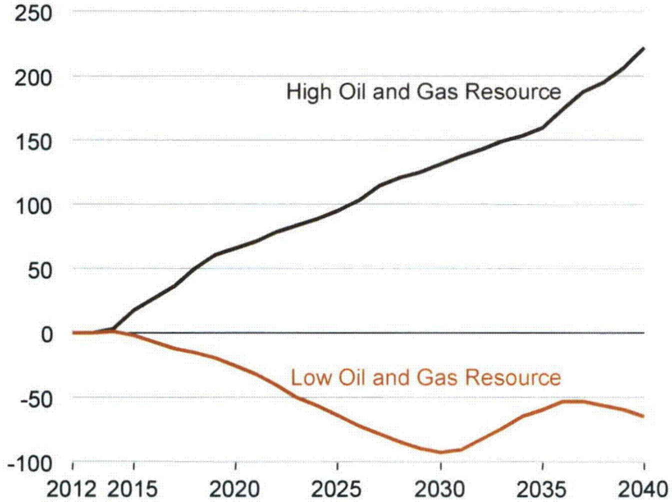


Figure IF5-4. Bulk chemicals value of shipments in three cases, 2012-40 (billion 2005 dollars)

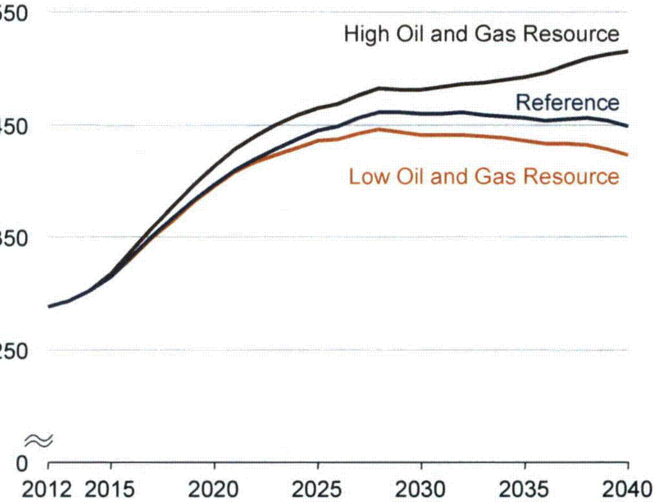


Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40

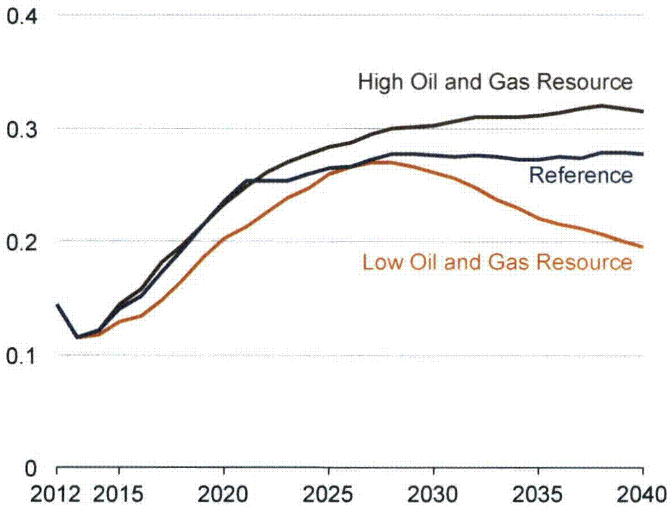


Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)

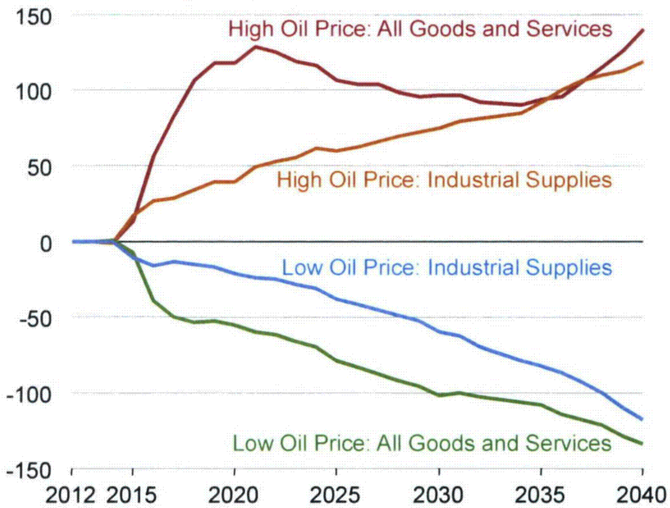
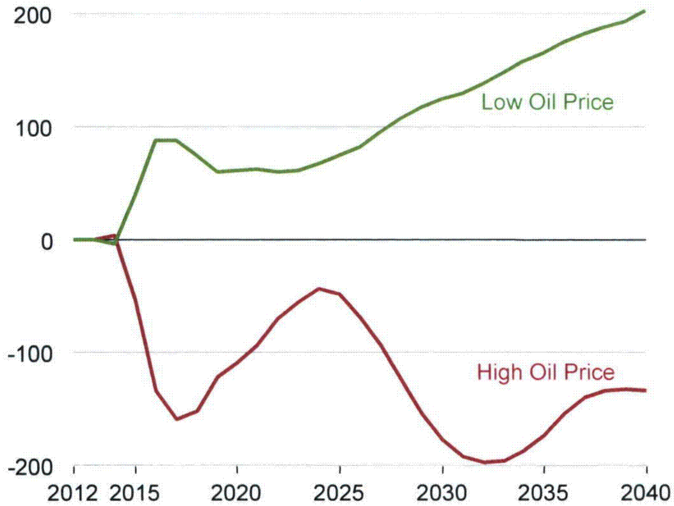


Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)



in consumer spending affect output in the glass and paper industries, which are tightly linked to consumer goods and more closely tied to demand for capital goods than is the bulk chemicals industry. Fuel consumption trends in the Low and High Oil Price cases differ from those in the Low and High Oil and Gas Resource cases, primarily because of the bulk chemicals industry. The initial response of the bulk chemicals industry to higher oil prices compared with the Reference case is a decrease in output (Figure IF5-8), and the initial response to lower oil prices is an increase in output, which does not occur in the High and Low Oil and Gas Resource cases (see Figure IF5-4). In the High Oil Price case, oil prices grow faster than the prices of natural gas-based feedstocks, leading to a price advantage for natural gas feedstocks (Figure IF5-9). As a result, bulk chemicals output in the High Oil Price case in 2040 is higher than in the Reference case. In the Low Oil Price case, with natural gas prices increasing more than oil prices, bulk chemicals output remains below the Reference case level in 2040.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)

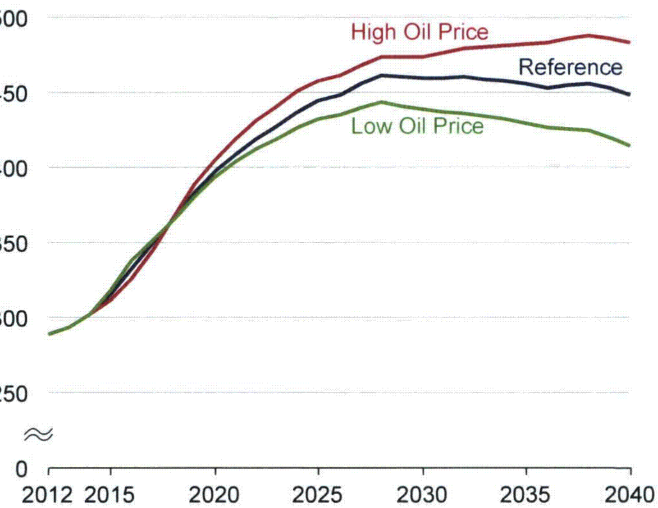
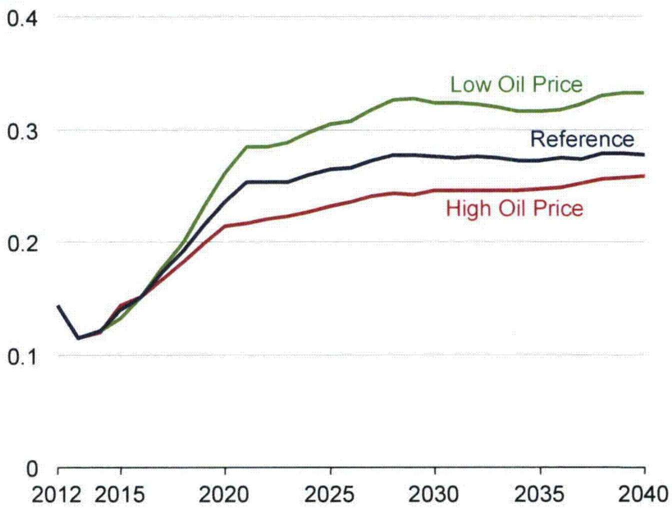


Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40



Endnotes for IF5

Links current as of April 2014

1. U.S. Energy Information Administration, 2010 Manufacturing Energy Consumption Survey (MECS), http://www.eia.gov/consumption/manufacturing/index.cfm.
2. V. Arora and J. Lieskovsky, "Natural gas and U.S. economic activity," *The Energy Journal* (forthcoming, 2014).
3. E. Sendich, "The importance of natural gas in the industrial sector with a focus on energy-intensive industries," EIA Discussion Paper (February 28, 2014), http://www.eia.gov/discussionpapers/?src=bookshelf.
4. V. Arora and E. Sendich, "Natural gas and U.S. industrial production: a closer look at four industries" (unpublished).
5. Bureau of Economic Analysis, Industry Accounts, http://bea.gov/industry/index.htm#annual.
6. For a more detailed description of the interindustry data changes, see "Benchmark input-output account of the U.S. economy, 2007" (December 18, 2013), http://www.bea.gov/newsreleases/industry/io/ionewsrelease.htm.
7. The producer price index, used to capture the selling prices received by domestic producers for their output, represents the price paid by industrial sector purchasers for inputs.

Figure sources for IF5

Links current as of April 2014

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12: History: U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, First Quarter Third Release (Washington, DC, June 26, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp1q13_3rd.htm; and U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, Second Quarter Advanced Release (Washington, DC, July 31, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp2q13_adv.htm.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-4. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

IF6. Implications of accelerated power plant retirements

In 2012, coal-fired and nuclear power plants together provided 56% of the electricity generated in the United States. The role of these technologies in the U.S. generation mix has been changing since 2009, as both low natural gas prices and slower growth of electricity demand have altered their competitiveness relative to other fuels. Many coal-fired plants also must comply with requirements of the Mercury and Air Toxics Standards (MATS) and other environmental regulations. Some of the challenges faced by coal-fired and nuclear generators, and the implications for electricity markets if the plants are retired in significant numbers, are analyzed in this discussion.

Of the total installed 310 gigawatts (GW) of coal-fired generating capacity available at the end of 2012, 50 GW, or 16%, is projected to be retired by 2020 in the AEO2014 Reference case. Despite those projected retirements, coal continues to account for the largest share of the electricity generation mix through 2034, after which it is overtaken by natural gas. However, throughout the projection the coal share of total generation remains significantly below its 49% share in 2007, when coal set its annual generation record.

In 2012 and 2013, operators of five nuclear power reactors representing 4.2 GW of capacity announced plans to retire the reactors by 2015. Four of the reactors—San Onofre 2 and 3, Kewaunee, and Crystal River—already have ended nuclear power production, and the fifth, Vermont Yankee, is expected to end generation by the end of 2014 [*1*]. In addition, the Oyster Creek plant is expected to conclude operation in 2019 [*2*]. These are the first retirements of U.S. nuclear power plants since Millstone Unit 1 was retired in 1998. Retirements often are the result of unique circumstances, but some owners of nuclear power plants have voiced concerns about the profitability of their units, sparking discussion of possible additional nuclear retirements [*3*]. In order to evaluate the impacts of potential retirements beyond those in the Reference case, AEO2014 includes several alternative cases with economic assumptions that make it less likely that existing coal and nuclear power plants will be used for generation.

Factors that lead to power plant retirements

Power plant owners generally make the decision to retire plants when their expected costs exceed their expected revenues over the future life of the plants [*4*]. Costs incurred by power plants can include large capital projects, such as installation of flue gas desulfurization (FGD) systems or scrubbers on coal plants, increased operating costs, or higher fuel costs. Revenues are received from energy sales or capacity payments in wholesale electricity markets in regions of the country with competitive wholesale markets, or from cost-recovery mechanisms in regions with vertically integrated utilities subject to rate regulations [*5*].

Recent trends in the electric power industry have resulted in both declining revenues and increased operating costs for coal plants. Because natural gas often is the marginal fuel and thus sets prices in Regional Transmission Organization (RTO) markets, and natural gas influences wholesale electricity prices in non-RTO markets, the decline in natural gas prices beginning in 2008 tends to reduce electricity prices and the payments received by all generators for the electricity they produce. Lower natural gas prices also improve the competitiveness of natural gas combined-cycle (NGCC) power plants relative to coal-fired plants. When lower natural gas prices drive the cost of generating electricity from an NGCC plant below that of a nearby coal-fired plant, the coal plant is dispatched, or operated, less often and earns less revenue [*6*].

Slow growth of electricity demand in recent years has resulted in fewer high-cost marginal generators being dispatched. In regions with excess generating capacity, plants with relatively high variable operating costs may not be dispatched frequently enough to produce the revenue needed to cover their costs [*7*], making them candidates for retirement. Although the average price of coal delivered to the electric power sector declined in both 2012 and 2013, it rose by more than 4% per year from 2007 to 2011, and the resulting increase in operational costs for coal-fired power plants reinforced the impacts of lower demand and more competitive natural gas prices.

When faced with declining profitability, plant owners may choose to retire their units rather than make additional investments to keep them operating. In the AEO2014 Reference case, all coal-fired plants are required to have either a scrubber or a dry sorbent injection (DSI) system combined with a fabric filter in order to continue operating in 2016 [*8*] and later years. As of the end of 2012, 64% of the U.S. fleet of coal-fired generators was compliant with this requirement. The remaining plant owners are in the process of deciding whether to retrofit or retire their plants [*9*].

The outlook for nuclear power also has been altered by the changing conditions in U.S. electricity markets. Nuclear power plants have lower fuel costs than either coal- or natural gas-fired plants, translating to lower variable operating costs and ensuring that they are dispatched when available. The spread between the price of electricity and the fuel cost for nuclear plants is often referred to as the quark spread. Nuclear power plant owners in wholesale markets rely on sufficient quark spreads to cover nonfuel operations, maintenance, and any new capital expenses associated with the plants to provide a return on their investment. Lower wholesale electricity prices have reduced quark spreads for all nuclear power plants, especially those with increasing operations and maintenance (O&M) costs or capital addition costs.

The AEO2014 Reference case assumes an additional 6 GW of generic nuclear retirements from 2012 to 2019, beyond the six reactor retirements already announced (a total that includes the Oyster Creek plant), as higher-cost units face continued economic challenges. Those projected retirements are represented by derating of existing capacity for plants in vulnerable regions, not by retiring any specific plants. Higher natural gas prices in the Reference case after 2020 support the continued operation of the U.S. nuclear fleet and limit retirements from 2020 through 2040.

Accelerated retirement cases

AEO2014 includes several cases designed to explore the effects of alternative assumptions that change projected natural gas prices or electricity demand, or assigns a value to carbon dioxide (CO_2) emissions as a proxy for possible future policies to mitigate greenhouse gas emissions. However, those cases have impacts throughout the energy system and the economy, which makes it difficult to measure the independent effects of significant coal and nuclear capacity retirements. In order to isolate the effects of additional retirements on the energy system, several cases were developed by incorporating assumptions that directly accelerate retirements of coal-fired and nuclear power plants.

Accelerated Coal Retirements case

The AEO2014 High Coal Cost case assumes a decrease in coal mine productivity and an increase in coal transportation costs, causing coal prices to rise to a level 68% above those in the Reference case in 2040. In the Reference and High Coal Cost cases, real O&M costs are flat, which is consistent with long-term historical trends. However, as coal plants age, higher O&M costs may also become a concern because replacement parts and upgrades to plant equipment could be required to keep them operating effectively. In the Accelerated Coal Retirements case, the assumptions of the High Coal Cost case are combined with an assumed 3% annual increase in real O&M costs for coal-fired power plants from 2012 through 2040, with the increase intended to represent the high end of potential future O&M costs. The higher fuel prices and O&M costs in the Accelerated Coal Retirements case serve as proxies for any combination of factors that would produce a higher rate of coal plant retirements.

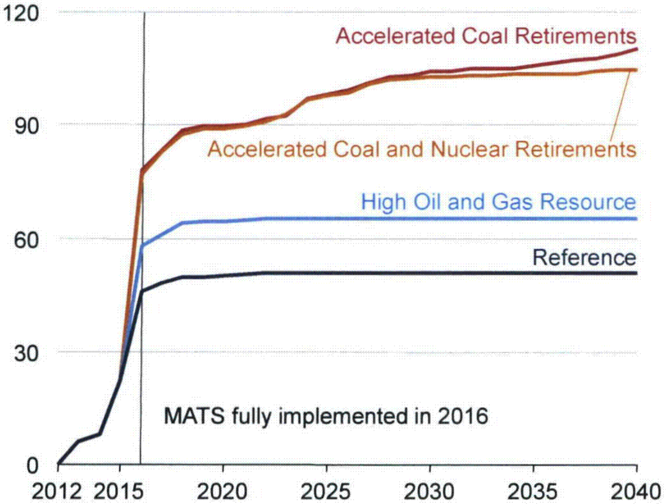
Accelerated Nuclear Retirements case

The Nuclear Regulatory Commission (NRC) has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years and then to extend them in 20-year increments. The NRC has already approved initial 20-year license extensions for more than 70% of the nuclear fleet, and the AEO2014 Reference case assumes that each plant will receive a first license extension unless its planned retirement has specifically been reported. The nuclear power industry currently is developing strategies to submit license applications for additional 20-year life extensions that would allow plants to continue operating beyond 60 years. The AEO2014 Reference case assumes that plants reaching 60 years of age between 2030 and 2040 will be granted a second life extension.

Nuclear power plants operate as baseload capacity. Although they are expensive to build and maintain, they have relatively low variable operating costs, which ensures that they are dispatched when available. While not affecting their dispatch order, increases in nonfuel O&M costs can have negative effects on the economics of nuclear power plants through lower profit margins. To avoid retirement for economic reasons, a plant must maintain a positive net present value over its operating lifetime. As with coal plants, annual O&M costs for nuclear power plants remain flat in the AEO2014 Reference case. However, recent data suggest that O&M costs for nuclear plants rose at an average annual rate of 4% over the 2008-12 period [*10*].

The Accelerated Nuclear Retirements case assumes that O&M costs for nuclear power plants grow by 3% per year through 2040; that all nuclear plants not retired for economic reasons are retired after 60 years of operation; and that no additional nuclear power plants are built after the 5.5 GW of capacity currently under construction is completed. This case reflects uncertainty regarding actions and costs associated with continued operation of the existing nuclear fleet.

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40 (gigawatts)



Accelerated Coal and Nuclear Retirements case

Large-scale simultaneous retirements of both coal-fired and nuclear capacity could have a significant effect on the electric power system. In order to assess that potential effect, the AEO2014 Accelerated Coal and Nuclear Retirements case combines the assumptions of the Accelerated Coal Retirements case and the Accelerated Nuclear Retirements case.

Results

Retirements

In the Accelerated Coal Retirements case, 110 GW of capacity, or 117% more than in the Reference case, is retired by 2040 (Figure IF6-1). In the Accelerated Coal and Nuclear Retirements case, coal retirement levels are similar to those in the Accelerated Coal Retirements case through 2030, with a slight leveling off toward the end of the projection, when some coal-fired capacity is needed to make up for the lost nuclear capacity.

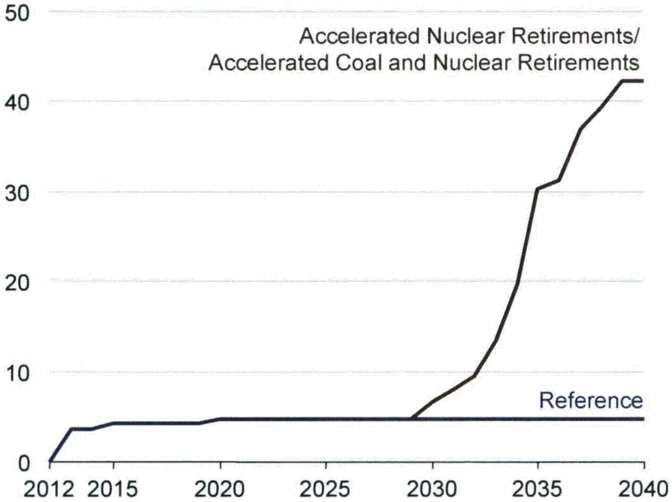
In the Accelerated Nuclear Retirements case, 42 GW of nuclear capacity is retired through 2040 (Figure IF6-2). However, other than retirements early in the projection, there is no significant reduction in nuclear capacity before the plants begin to reach their 60th year of operation, in 2029. The same retirement trajectory is repeated in the Accelerated Coal and Nuclear Retirements case.

There is no incremental increase in nuclear retirements in the Accelerated Nuclear Retirements, despite higher O&M costs. However, incremental retirements do occur in the Low Nuclear case, discussed in the Market Trends section of the AEO2014. The Low Nuclear case uses the same assumptions as the Accelerated Nuclear Retirements case, but also includes the resource assumptions from the High Oil and Gas Resource case that result in lower natural gas prices than in the Reference case. As a result, economic retirements of nuclear power plants that have not operated for 60 years do occur in the last decade of the projection in the Low Nuclear case, with nuclear capacity falling to 35 GW below the levels in the Accelerated Coal and Nuclear Retirements case.

Capacity additions

In order to replace capacity that is retired in the accelerated retirement cases, more total capacity (including capacity in the electric power sector, combined heat and power, and capacity in the end-use sectors) is added than in the Reference case. The new capacity mix consists almost entirely of natural gas and renewable energy sources (Figure IF6-3). Natural gas-fired combined-cycle units are favored because of their low fuel prices and relatively moderate capital costs.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40 (gigawatts)



Generation fuel mix

As existing coal and nuclear plants are retired, natural gas and renewables gain increasing shares of the generation mix (Figure IF6-4). The strength of this trend depends on how much nuclear and coal-fired capacity is retired.

Coal-fired generation in 2040 is lowest in the Accelerated Coal Retirements case, which results in the greatest total loss of coal-fired capacity. In all AEO2014 cases, including the Reference case, available coal-fired capacity operates as baseload generation throughout the projection. Therefore, removing coal capacity results in lower overall levels of generation. Coal-fired electricity generation in 2040 is 1% higher in the Accelerated Nuclear Retirements case than in the Reference case as a result of a small increase in coal-fired capacity installed at the end of the projection period.

Nuclear power plants also consistently operate as baseload generation, and their total generation varies with changes in capacity. In the Accelerated Nuclear Retirements and Accelerated Coal and Nuclear Retirements cases, nuclear

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40 (gigawatts)

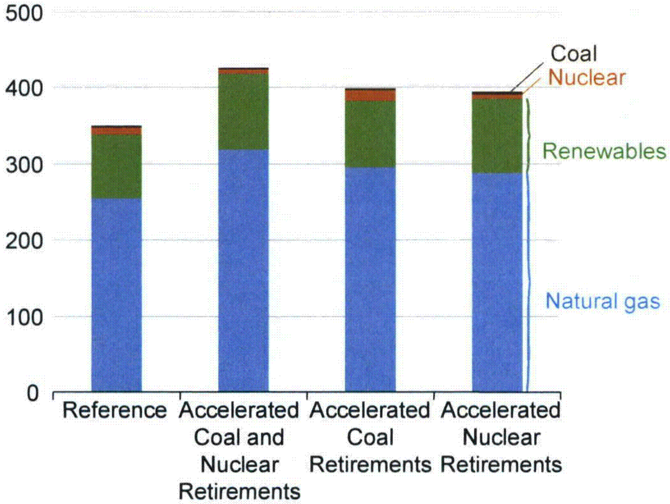
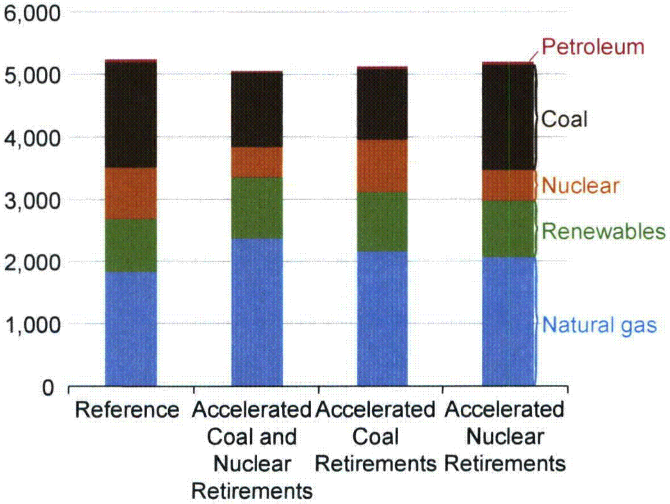


Figure IF6-4. Electricity generation by fuel in four cases, 2040 (billion kilowatthours)



generation in 2040 is 40% lower than in the Reference case. In the Accelerated Coal Retirements case, nuclear electricity generation is 2% above the Reference case level in 2040.

Natural gas prices

In all the AEO2014 accelerated retirement cases, natural gas prices are higher in most years than in the Reference case as retirements of existing coal and nuclear capacity lead to both increased use of existing natural gas-fired plants and the development of new plants. The alternative cases with the largest increases in natural gas-fired generation also have the largest price increases. For example, the price of natural gas delivered to the electric power sector in 2040 in the Accelerated Coal and Nuclear Retirements case is 11% higher than the Reference case price (Figure IF6-5) [*11*].

Carbon dioxide emissions in the electric power sector

Coal and natural gas are the primary sources of CO_2 emissions from the electric power sector. Coal is the most significant contributor, emitting more than twice as much CO_2 per megawatthour (mWh) as a combined-cycle plant fueled by natural gas. Generation using nuclear power and renewables does not emit CO_2.

Because of the high CO_2 intensity of coal, scenarios that result in less coal-fired electricity generation also result in the most significant emissions reductions. Total electric power sector CO_2 emissions in the Accelerated Coal Retirements case are 20% below those in the Reference case in 2040 (Figure IF6-6). Emissions are slightly higher in the Accelerated Coal and Nuclear Retirements case, because some nuclear power generation is replaced by gas-fired generation; however, the effect of the coal-fired capacity retirements still keeps emissions 14% below the Reference case level in 2040. In the Accelerated Nuclear Retirements case, nuclear generation is 328 mWh below the Reference case level in 2040, while electric power sector CO_2 emissions are 85 million metric tons higher, reflecting an average increase of 0.26 metric tons CO_2 per mWh reduction in nuclear generation across the two scenarios. The estimated increase in CO_2 emissions per mWh of nuclear generation reduced, which is slightly below the estimated increase in CO_2 emissions per additional mWh of generation from advanced combined-cycle plants burning natural gas, reflects replacement generation from natural gas and renewables, together with some reduction in overall electricity demand as a result of higher end-user prices.

Retail electricity prices

Retail electricity prices vary in the accelerated retirement cases, because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices (Figure IF6-7). In 2040, real retail electricity prices in the Accelerated Coal and Nuclear Retirements case are 12% higher than those in the Reference case.

Conclusions

Accelerated retirements of coal-fired and nuclear electricity generation capacity would cause natural gas and renewables to gain an increased share in the nation's electricity generation mix. Natural gas is most often the lowest-cost option for replacement capacity, while renewable generation grows, spurred by the increased economic competitiveness of solar and wind technologies toward the end of the projection period. The rising use of natural gas in the electric power sector results in price increases for both natural gas and electricity in all sectors relative to the Reference case (Table IF6-1).

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040 (2012 dollars per thousand cubic feet)

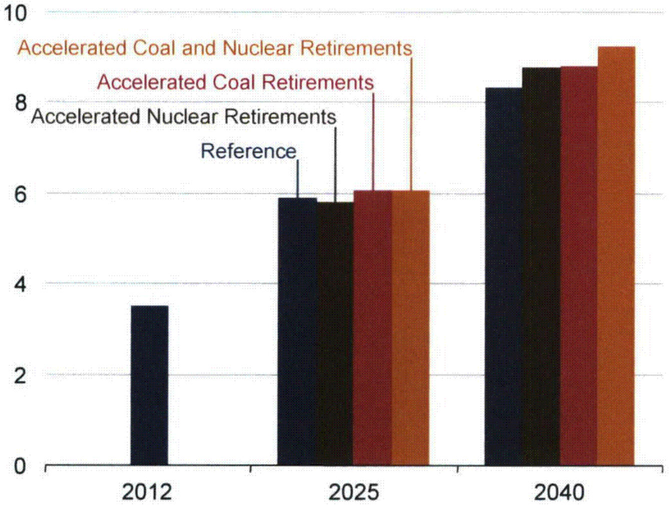


Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40 (million metric tons per year)

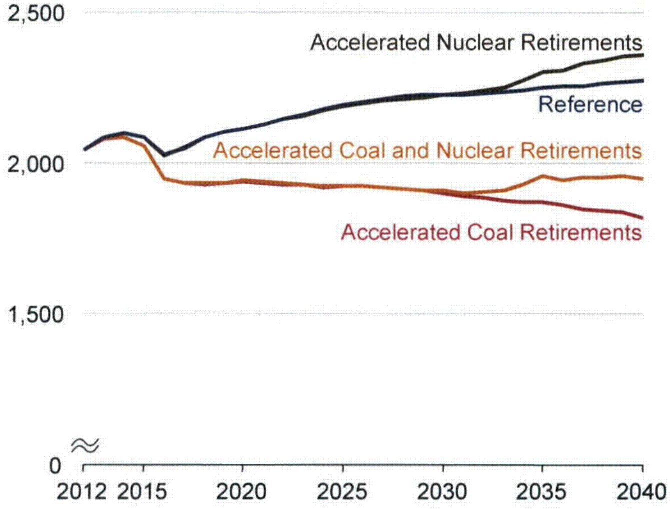
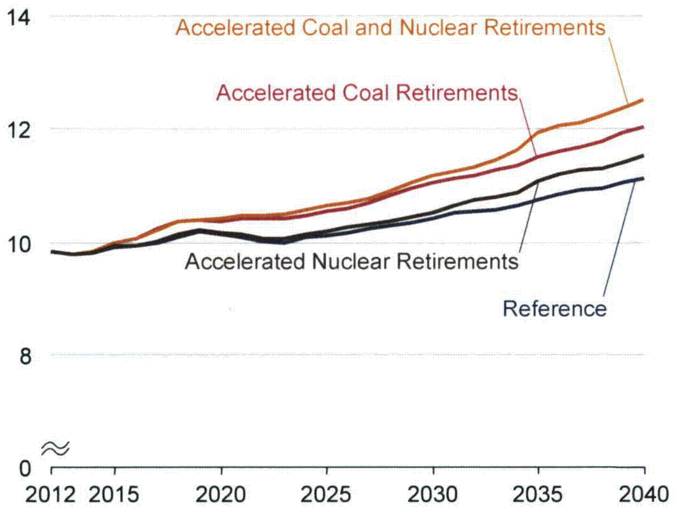


Figure IF6-7. Average retail electricity prices in four cases, 2012-40 (2012 cents per kilowatthour)



Effects on CO_2 emissions depend on the technology retired. Because a natural gas-fired combined-cycle plant emits less than half as much CO_2 as a plant fueled with pulverized coal, accelerated retirements of coal-fired plants result in lower CO_2 emissions compared with the Reference case. In contrast, because nuclear power plants emit no CO_2, accelerated retirements of nuclear power plants raise CO_2 emissions compared with the Reference case.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040

Year and case	Average delivered natural gas price to power sector (2012 dollars per million Btu)	Retail electricity price (2012 cents per kilowatthour)	Electric power sector carbon dioxide emissions (million metric tons)
2012	3.44	9.8	2,039
2025			
Reference	5.76	10.1	2,194
Accelerated Coal Retirements	5.91	10.5	1,925
Accelerated Nuclear Retirements	5.69	10.2	2,188
Accelerated Coal and Nuclear Retirements	5.92	10.6	1,923
2040			
Reference	8.16	11.1	2,271
Accelerated Coal Retirements	8.60	12.0	1,821
Accelerated Nuclear Retirements	8.57	11.5	2,356
Accelerated Coal and Nuclear Retirements	9.03	12.5	1,946

Endnotes for IF6

Links current as of April 2014

1. Entergy, "Entergy to close, decommission Vermont Yankee" (Press Release, August 27, 2013; accessed March 25, 2014), http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.
2. Exelon Corporation, "Exelon to retire Oyster Creek generating station in 2019" (Press Release, December 8, 2010; accessed March 25, 2014), http://www.exeloncorp.com/newsroom/pr_20101208_Nuclear_OysterCreekRetirement.aspx.
3. M. Wallace and G.D. Banks, *Restoring U.S. Leadership in Nuclear Energy* (Center for Strategic & International Studies, Washington, DC, June 2013), http://csis.org/publication/restoring-us-leadership-nuclear-energy.
4. The U.S. Energy Information Administration analysis assumes competitive economics for electric power capacity, in which variable costs determine dispatch, and fixed costs must also be paid by electric sales revenue to continue operation over the long term.
5. Capacity payments provide units with revenue for being available to run in order to ensure reliability. Capacity payments can account for a significant portion of revenue for peak load plants, which do not run often and require financial incentives to remain available for dispatch.
6. U.S. Energy Information Administration, "Dark spreads measure returns over fuel costs of coal-fired generation," *Today In Energy* (February 20, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=10051.
7. U.S. Energy Information Administration, "Electric generator dispatch depends on system demand and the relative cost of operation," *Today In Energy* (August 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590.
8. U.S. Energy Information Administration, "Assumptions to AEO2014: Electricity Market Module" (forthcoming), http://www.eia.gov/forecasts/aeo/assumptions/.
9. S. Ferris, "Hatfield's Ferry Power Station quietly closes for good," *Herald Standard* (Uniontown, PA, October 20, 2013), http://www.heraldstandard.com/new_today/hatfield-s-ferry-power-station-quietly-closes-for-good/article_cd0133e1-9adb-58c2-8f8d-66769de34835.html. Installing control equipment does not guarantee that a plant will remain economical to continue operating. Retirement of the Hatsfield's Ferry power station in Pennsylvania was announced after installation of a $650 million FGD scrubber system in 2009. However, in the AEO2014 Reference case most coal-fired power plants continue operating despite the regulatory hurdle of MATS in 2016.
10. Electric Utility Cost Group (EUCG), via Nuclear Energy Institute, "Annual briefing for the financial community" (February 13, 2014), http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/Nuclear-Energy-in-2014-Status-and-Outlook.
11. The 2025 average price of natural gas price delivered to the electric power sector in the Accelerated Nuclear Retirements case is slightly lower than the price in the Reference case due to a decline in LNG export capacity additions. The retirement of nuclear capacity in the Accelerated Nuclear Retirements case after 2030 causes an increase in demand from the electric power sector, resulting in higher natural gas prices, and the anticipation of higher prices reduces the economic competitiveness of LNG export facilities, lowering LNG export projections. This results in lower natural gas prices in the Accelerated Nuclear Retirements case between 2022 and 2032, because less natural gas is exported. Demand from the power sector does not change significantly from the Reference case until significant amounts of nuclear capacity are retired.

Figure and table sources for IF6

Links current as of April 2014

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCCSTOM.D012314A, HCLONUC.D012314A, and HIGHRESOURCE. D112913B.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWNUC14.D012314B, and HCLONUC.D012314A.

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14. D012314B.

Figure IF6-4. Electricity generation by fuel in four cases, 2040. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM. D012314A, and LOWNUC14.D012314B.

Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-7. Average retail electricity prices in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

IF7. Renewable electricity projections show growth under alternative assumptions in AEO2014

In the AEO2014 Reference case, renewable electricity generation grows by 69% from 2012 to 2040, including an increase of more than 140% in generation from nonhydropower renewable energy sources. Renewables are collectively the fastest-growing source of electricity generation in the projection, with annual growth rates that exceed the growth rate for natural gas-fired generation. However, because renewables start from a relatively low 12% market share of total generation, their contribution to U.S. total electricity generation is just 16% in 2040 in the Reference case, well below the natural gas and coal shares of 35% and 32%, respectively (Figure IF7-1).

The AEO2014 Reference case is based on current laws and policies, as well as on known technology and demographic trends. Projections of nonhydropower [1] renewable electricity generation are sensitive to assumptions about government policies and external market factors. Key uncertainties affecting projected growth include expiration of policies that affect financial incentives for deployment or operation of particular technologies, the costs and performance of the technologies, the costs of competing generation sources, and macroeconomic conditions that affect growth in electricity demand (including GDP growth).

The renewable energy policy landscape is particularly dynamic compared to that of more-established energy sources, as new and existing policies continue to be created and adjusted at the federal, state, and local levels. In addition, policies that affect competing sources of generation, such as natural gas and coal, can have significant impacts on renewable generation projects. For example, placing an explicit or implicit value on carbon dioxide (CO_2) emissions would make the cost of operating fossil-fueled capacity higher, improving the relative economics of renewables.

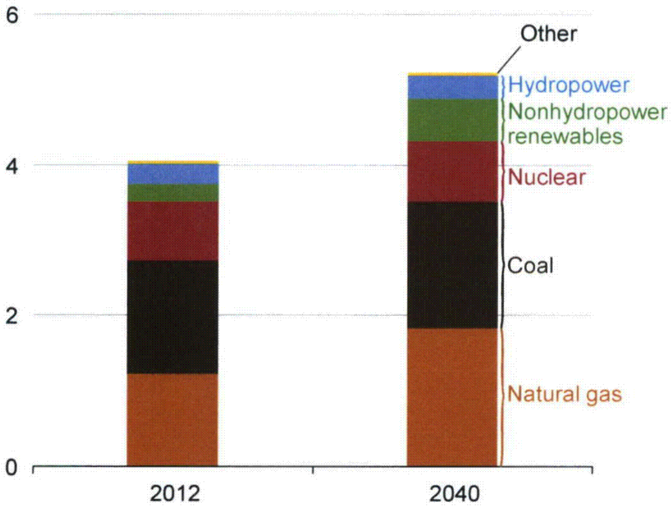
From 2005 to 2012, nonhydropower renewable generation more than doubled, encouraged by policies such as federal tax credits and grants, state renewable portfolio standards (RPS), and a variety of other state and local policies such as rebates, tax incentives, financing assistance, net metering, and interconnection standards. For example, the federal production tax credit (PTC), which most recently applied to wind, geothermal, biomass, hydro, certain waste technologies, and marine energy projects under construction by the end of 2013, was first established by the Energy Policy Act of 1992. Since that time, the tax credit has been revised periodically—expiring several times and then subsequently being renewed. Most recently, the credit expired at the end of 2013 and has not been extended as of early 2014. Trade groups and renewable supporters continue to advocate for an extension to the 2013 deadline, but the AEO2014 Reference case assumes no such extension.

Assumptions about the cost and performance of renewable technologies also affect the projections, particularly as some renewable technologies become more economically competitive in some regions. Determination of future or even current technology costs can be a challenge. For example, in the case of solar photovoltaic (PV) technologies, there is enough variation among current projects in terms of geographic locations, technologies, developer experience, and regulatory frameworks that even the most carefully developed estimates will overstate actual costs for some projects and understate costs for others. While PV capital costs have declined over the past decade, there is continuing uncertainty about both the degree and pace of future cost declines.

Projections for generation with renewables are sensitive to the prices of competing generation sources and other market factors, particularly in later years of the projection period, when the projected trends in renewable generation are increasingly influenced by economic rather than policy factors. In some regions and projection years, renewable resources like wind or solar may represent the marginal source of capacity growth, which makes renewables sensitive to price swings in competing resources as well as to broader economic or market fluctuations. In order to address such uncertainties, AEO2014 includes alternative cases to provide insight regarding the direction and magnitude of sensitivities in the projections. Table IF7-1 shows key technology, policy, economic, and market uncertainties and shows how they are addressed in a selected group of AEO2014 alternative cases (described in more detail in Appendix E).

The Low Renewable Technology Cost case assumes that renewable technology capital costs are 20% lower than in the Reference case. The No Sunset case assumes the extension of existing federal energy policies that contain sunset provisions—in particular the production and investment tax credits for certain renewable electricity generation technologies. The GHG25 case assumes a policy that applies a fee on carbon dioxide emissions (in 2012 dollars) starting at $25 per metric ton in 2015 and escalating by 5% per year to about $85 per metric ton in 2040. The High Oil and Gas Resource case adjusts oil and gas resource and productivity assumptions that result in natural gas prices to the electric power sector in 2040 that are 37% lower than in the Reference case. The Low Oil and Gas Resource case adjusts assumptions about oil and gas resources that result in natural gas prices to the electric power sector in 2040 that are 33%

Figure IF7-1. Total U.S. electricity generation by energy source, 2012 and 2040 (billion kilowatthours)



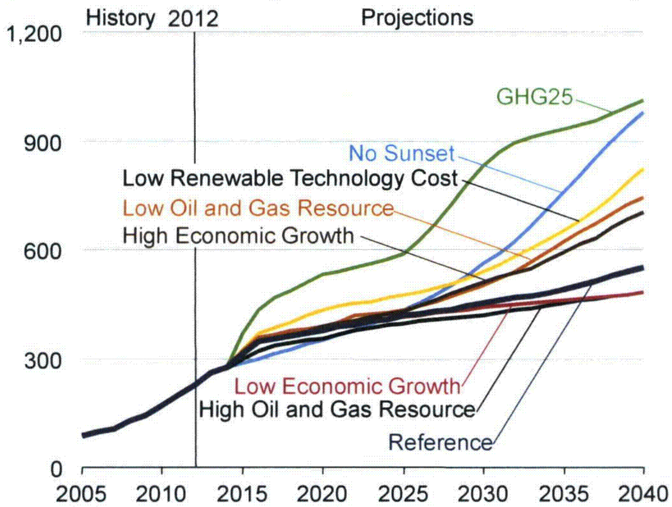
higher than in the Reference case. The High Economic Growth and Low Economic Growth cases assume higher and lower levels of real GDP growth from 2012 to 2040 than in the Reference case.

Figure IF7-2 shows projected total nonhydropower renewable generation from 2012 to 2040 in the selected alternative cases. The results vary significantly, particularly in the later years of the projection. For example, in the GHG25 case total nonhydropower renewable generation in 2040 is 83% higher than in the Reference case, and in the High Oil and Gas Resource case total nonhydropower renewable generation in 2040 is 12% lower than in the Reference case.

Some of the assumptions used in the AEO2014 alternative cases can lead to significant increases in long-term growth of renewable electricity generation. However, alternative cases with assumptions that are less favorable to renewables growth, such as the Low Economic Growth case (with slower electricity demand growth) and the High Oil and Gas Resource case (with lower natural gas prices) are unlikely to result in renewable projections that fall drastically below those in the Reference case—in large part because state renewable portfolio standards (RPS) effectively establish a floor for generation with renewables. RPS policies generally require that a minimum share of generation must come from renewable sources, and even with slow load growth or competition from low-cost alternative generation resources, renewable generation must be sufficient to meet the RPS target. On the other hand, as renewable generation sources become increasingly competitive after 2025, a favorable shift in assumptions may result in an impact that does not have a limit on the upper bound, allowing for stronger growth in renewable generation than is projected in the Reference case.

In addition, long-term projections are more sensitive to changes in assumptions than are near-term projections. Although the range of renewable generation in 2040 across the alternative cases is large, the 2025 projections for total renewable generation are within 15% of the Reference case in all the alternative cases except for the GHG25 case. Near-term growth in renewable generation is constrained by a combination of factors that generally hold across most sensitivity analyses: growth in electricity demand continues at a relatively low annual rate (less than 1% per year in the Reference case) compared with historical levels, and generating capacity required to meet demand and reserve requirements in many regions already exceeds near-term requirements at the start of the projection period. As a result, demand for new generating capacity of any type in the first decade of the projection is minimal in most regions. From 2012 to 2025, total generating capacity—including renewables, fossil fuels, and nuclear—increases by only 4%. However, as renewable technologies become more economically competitive, they capture a larger share of the growing market. In addition, even with low rates of electricity demand growth, the presence of a significant and growing fee on CO_2 emissions creates enough pressure early in the projection period to spur significant growth of renewable generation in the near term.

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)



Alternative assumptions that lead to greater penetration of electricity markets by renewable energy sources—namely, those in the No Sunset, Low Renewable Technology Cost, GHG25, Low Oil and Gas Resource, and High Economic

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation

Key uncertainties	Selected AEO2014 alternative cases	Uncertainties not addressed in AEO2014 alternative cases
Technology: Cost assumptions for renewable technologies.	Low Renewable Technology Cost	Breakthroughs in new or emerging renewable (e.g., wave/tide/ocean) or complementary (e.g., storage) technologies
Policy: Current policies may not expire as scheduled; future policies may impose direct or indirect fees on carbon dioxide emissions.	No Sunset GHG25 (carbon dioxide fee case)	Existing policies not explicitly modeled in AEO2014 that are more specific or geographically specialized (e.g., net metering, local rebate programs, and technology-specific set-asides in state RPS programs); other new policies that could be introduced
Macroeconomics and prices: Macroeconomic growth rates and natural gas prices.	High Oil and Gas Resource Low Oil and Gas Resource High Economic Growth Low Economic Growth	Competition from other fuels; sector- or region-specific economic factors; unexpected shifts in demand

Growth cases—do not have proportionate effects on all renewable technologies (Figures IF7-3 through IF7-6). Generation from solar and wind installations generally increases by more compared with the Reference case than does generation from biomass, waste, and geothermal sources. Solar generation in 2040 in most of the alternative cases is more than double the Reference case level. Wind starts from a much larger installed capacity base, so the percentage growth in wind generation is lower than for solar, but in all five alternative cases wind generation in 2040 is at least 20% higher than projected in the Reference case.

Solar and wind energy are expected to remain the primary sources of renewable capacity growth. Although geothermal, waste, and biomass resources have some favorable characteristics compared to wind and solar, such as the ability to provide operator-dispatched power, each has significant limitations. The limitations include a limited resource base (geothermal, waste) or relatively high capital and/or fuel costs (biomass). Although wind and solar will continue to be capital-intensive technologies, they are expected to achieve cost reductions that—along with a larger resource base—result in higher growth than other renewables under favorable conditions (such as placement of an explicit or implicit value on CO_2 emissions, or high natural gas prices). However, solar and wind resources also vary in availability and quality by region, and generation facilities are likely to be concentrated in the more favorable regions.

Even in the alternative cases that result in higher levels of market penetration for renewable generation technologies, the results are limited by the selection of technologies currently modeled by the U.S. Energy Information Administration. The AEO2014 alternative cases cannot be used to evaluate potential technologies that are not characterized in the National Energy Modeling

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

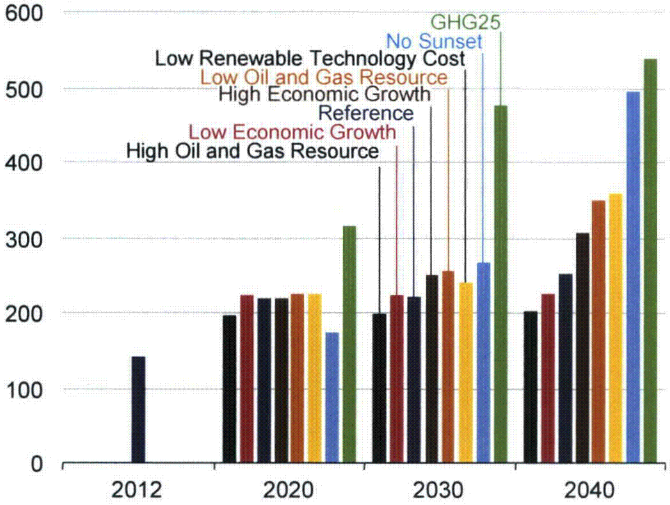


Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

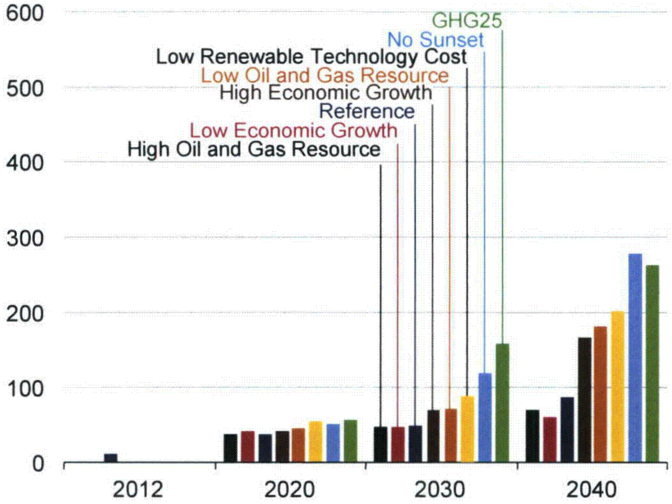


Figure IF7-5. Electricity generation from geothermal power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

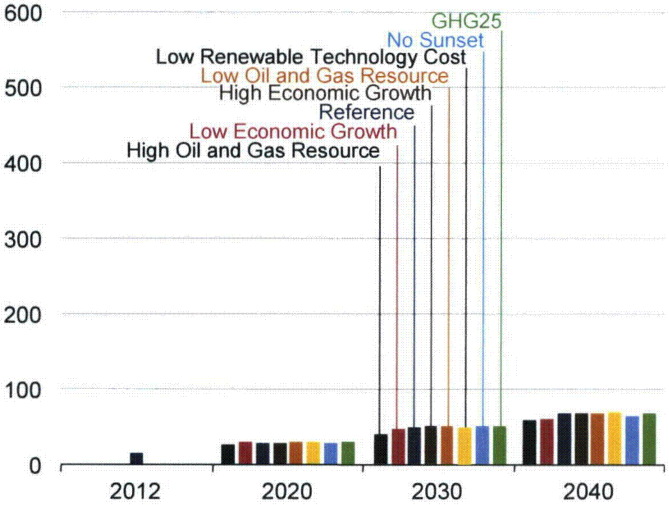
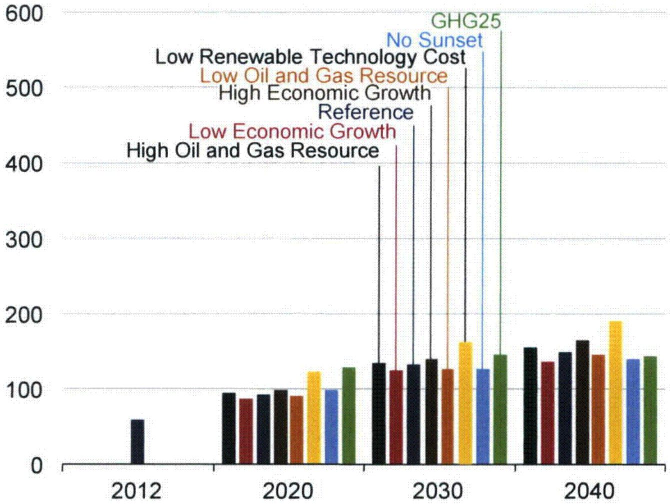


Figure IF7-6. Electricity generation from biomass and waste power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)



System. Some emerging renewable technologies not included in AEO2014 include engineered geothermal systems, marine hydrokinetics (such as wave energy), in-stream hydroelectric, and hybrid solar thermal combined cycle.

Similarly, no new electricity storage technologies are included in the projections. Electricity storage represents one of several options for accommodating high levels of intermittent generation from wind and solar resources. Because such technologies, other than pumped hydro storage, generally are either in early stages of development or not yet commercially established, impacts on electricity markets in the near- to mid-term period are difficult to model.

The AEO2014 alternative cases typically examine the effects of changing single assumptions within a moderate range of uncertainty, and they are not intended to be interpreted as bounding cases. For example, a compound case incorporating high natural gas prices, low renewable technology costs, and an explicit or implicit value for CO_2 emissions could be expected to result in additional renewable generation growth, although the impact would not necessarily be the sum of the results of the individual cases. The same could be true if any of the individual alternative cases were examined using different assumptions—for example, if renewable technology costs were assumed to be 50%, rather than 20%, below the costs used in the Reference case.

Endnotes for IF7

Links current as of April 2014

1. Hydropower has resource-specific characteristics that separate it from other renewable energy sources. It is projected to remain close to current capacity and generation levels in the cases considered here.

Figure and table sources for IF7

Links current as of April 2014

Figure IF7-1. Total U.S. electricity generation by fuel, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation: U.S. Energy Information Administration.

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-5. Electricity generation from geothermal power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-6. Electricity generation from biomass and waste power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

IF8. Implications of low electricity demand growth

Although electricity demand fell in only three years between 1950 and 2007, it declined in four of the five years between 2008 and 2012. The largest drop occurred in 2009 (Figure IF8-1). One contributing factor was the steep economic downturn from late 2007 through 2009, which led to a large drop in electricity sales in the industrial sector. Other factors, such as efficiency improvements associated with new appliance standards in the buildings sectors and overall improvement in the efficiency of technologies powered by electricity, have slowed electricity demand growth and may contribute to slower growth in the future, even as the U.S. economy continues its recovery.

In the Reference case, which assumes no new efficiency standards beyond those already in place or announced as final for future implementation as of 2012, total electricity use grows by an average of less than 1% per year from 2012 to 2040. Demand grows across all sectors, with average annual increases in the industrial sector (0.9% per year) slightly higher than those in the residential and commercial sectors (0.7% and 0.8% per year, respectively). As a result of rising demand, 351 gigawatts (GW) of new electricity generating capacity is added from 2012 to 2040, electricity generation increases by 29%, and carbon dioxide (CO_2) emissions from the electric power sector increase by 11%.

To examine the energy implications of slower growth of electricity demand, AEO2014 includes a Low Electricity Demand case, in which annual electricity demand in 2040 is only slightly higher than the 2012 level of 3.8 trillion kilowatthours (kWh).

Low Electricity Demand case

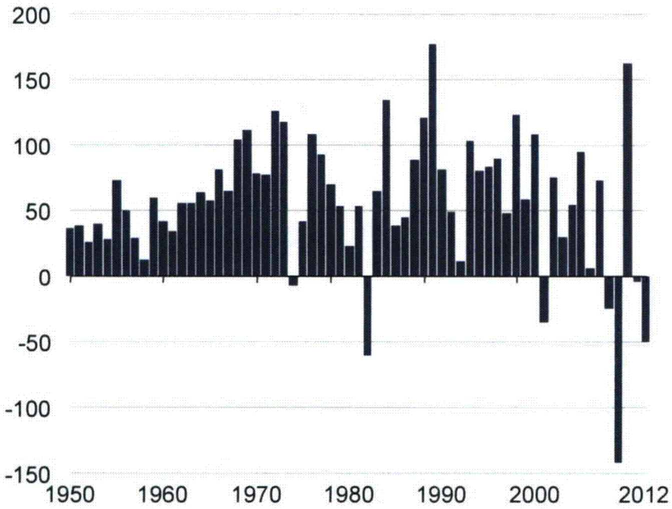
Electricity demand growth depends on economic growth, relative energy prices, and technology choices in the end-use sector, among other factors. Changes in electricity demand result in corresponding changes in electricity generation and the mix of technologies used to meet demand.

The Low Electricity Demand case was developed by assuming changes in technology choices and higher efficiency in the end-use sectors. To limit the number of competing influences, macroeconomic and fuel supply assumptions were unchanged from those in the Reference case. The goals for the Low Electricity Demand case were to identify a combination of technologies that would result in flat demand, and to examine the impacts of stagnant demand on future needs for electricity generation and supply.

The Low Electricity Demand case uses the assumptions incorporated in the Best Available Demand Technology case for both the residential and the commercial sectors, as described in Appendix E and the Market Trends section of this report. The Best Available Demand Technology case assumes that all future equipment purchases in the residential and commercial sectors will be made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiencies also are assumed to improve relative to the Reference case, and distributed generation costs are assumed to decline much faster than in the Reference case. In addition to those assumptions, the Low Electricity Demand case assumes higher energy savings for electric motors in pumps, fans, and air compressors used in the industrial sector compared with the Reference case. Those adjustments reduce total electric power consumption by electric motors slightly less than 20% over the course of the projection. Although technically plausible, such a drop in electric motor energy usage may not represent a likely path for motor development.

As a result of changes across all end-use sectors in the Low Electricity Demand case, retail electricity sales in 2040 are roughly the same as in 2012. Industrial sales grow slightly from 2012 levels, but a decline in residential sales offsets that growth. Because the distributed generation assumptions in the buildings sector result in higher investment in end-use renewable capacity and generation relative to the Reference case, direct-use generation increases, and there is a 7% increase in total electricity consumption from 2012 to 2040, as compared with 29% in the Reference case (Figure IF8-2).

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012 (billion kilowatthours)



Analysis results

Electricity generation capacity

In the Low Electricity Demand case, little new capacity is added in the power sector after planned capacity additions are completed (Figure IF8-3). A significant amount of renewable capacity is added in the end-use sectors as a result of the lower cost assumptions for distributed solar photovoltaics, and a smaller amount of renewable capacity (19% of total renewable additions) is added in the power sector to meet renewable portfolio standards. Total natural gas capacity added is only one-quarter of the amount in the AEO2014 Reference case. Even more so than in the Reference case, there are few new additions of coal or nuclear capacity beyond those already under construction.

With lower demand for electricity, a total of 110 GW of older coal-fired generating capacity is retired between 2013 and 2040 in the Low Electricity Demand case, more than double the 51 GW retired in the Reference case (Figure IF8-4). Most of the retirements occur early in the projection, due to the timing of the Mercury and Air Toxics Standards (MATS), which require a decision to retire or retrofit coal plants to meet environmental standards by 2016. A total of 100 GW of oil- and gas-fired capacity is retired between 2013 and 2040 in the Low Electricity Demand case, compared with 40 GW in the Reference case.

Electricity generation

Electricity generation in 2040 is 17% lower in the Low Electricity Demand case than in the Reference case, with natural gas-fired generation 472 billion kWh lower and coal-fired generation 343 billion kWh lower. Figure IF8-5 shows total electricity generation from the electric power sector and the end-use sectors, with the contributions broken out for natural gas and renewable generation to display the relative levels of generation from the end-use sectors. As in the Reference case, natural gas-fired generation overtakes coal-fired generation by the end of the projection period, but overall shares for both fuels are lower than in the Reference case. In 2040, the coal share of total generation drops from 37% in 2012 to 32% in the Reference case, and to 31% in the Low Electricity Demand case. The natural gas share, which increases from 30% in 2012 to 35% in 2040 in the Reference case, grows to only 32% in 2040 in the Low Electricity Demand case. Because there is less need for new generating capacity, there is less opportunity for growth in natural gas-fired generation from new plants.

Nuclear electricity generation is slightly lower in the Low Electricity Demand case than in the Reference case, as a result of fewer new builds, but it provides a slightly higher share of total generation than in the Reference case. Renewable generation grows by 60% from 2012 to 2040 in the Low Electricity Demand case, slightly less than the 69% growth in the Reference case, as a large

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040 (billion kilowatthours)

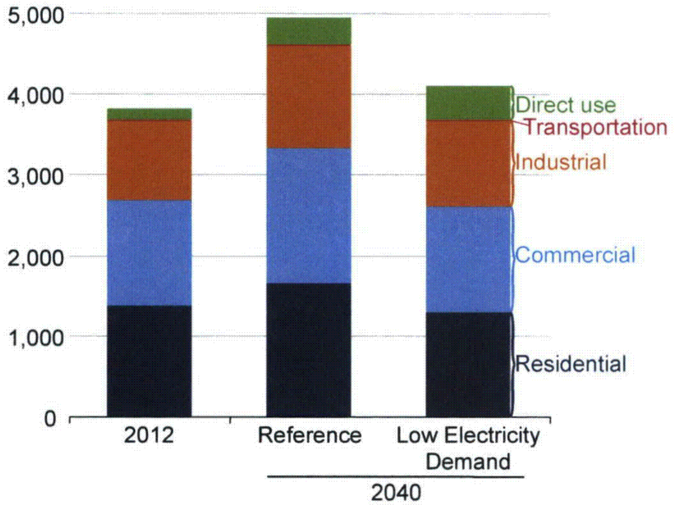


Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40 (gigawatts)

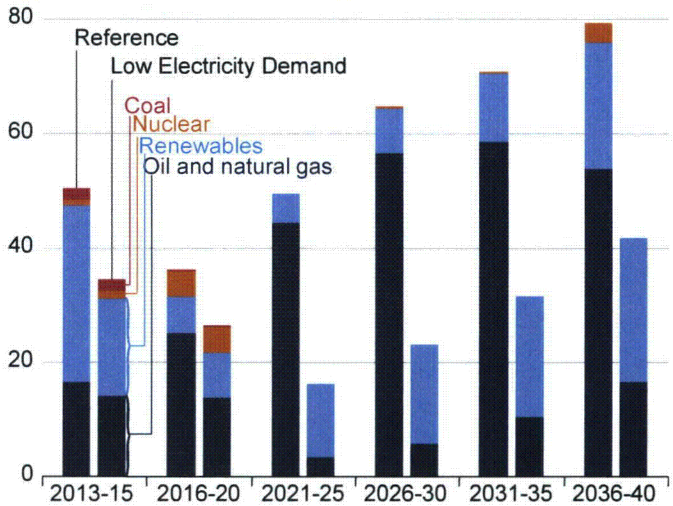


Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40 (gigawatts)

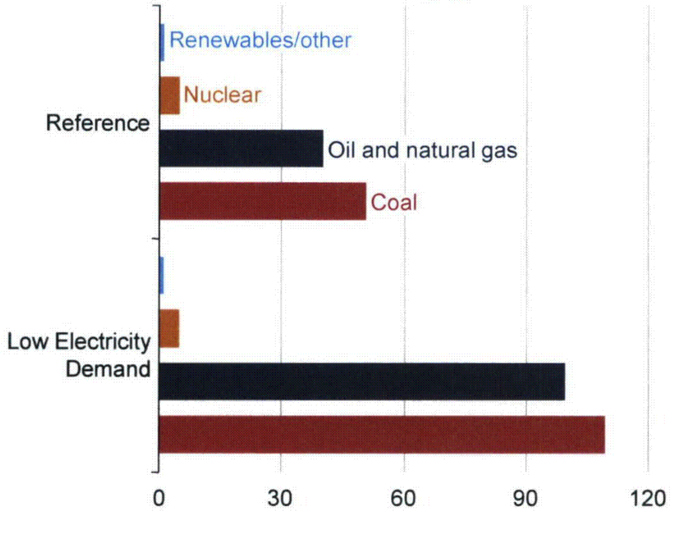
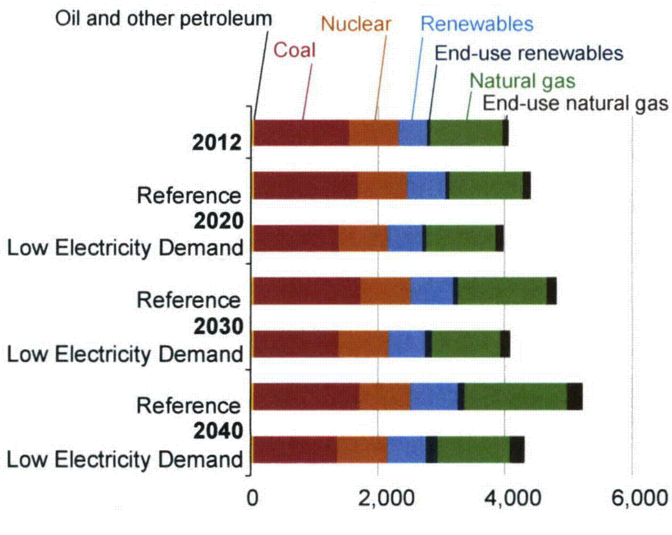


Figure IF8-5. Electricity generation in two cases, 2012-40 (billion kilowatthours)



increase in end-use sector renewable generation offsets much of the decline in renewable generation in the electric power sector compared with the Reference case.

Emissions

The lower level of generation from fossil fuels in the Low Electricity Demand case results in lower greenhouse gas emissions. In 2020, power sector CO_2 emissions are 16% lower than in the Reference case, and in 2040 they are 22% lower (Figure IF8-6). Emissions of other pollutants (sulfur dioxide, nitrogen oxides, and mercury) are also lower than in the Reference case, in proportion to coal-fired generation. The additional retirements of coal-fired capacity in the Low Electricity Demand case begin to occur in 2016, when MATS takes effect. With lower demand and prices for electricity than in the Reference case, it is less economical to install retrofits to comply with the MATS standards. As a result, fewer environmental controls are added.

Regional impacts

The mix of fuels used to meet U.S. demand for electricity varies across the country, and the initial mix can affect regional projections in the different cases. In general, the West is more reliant on natural gas and renewable generation, the upper Midwest and Central parts of the country are more reliant on coal, the Northeast is more reliant on natural gas and nuclear power, and in the Mid-Atlantic and Southeast there is a mix of generation from coal, nuclear power, and natural gas.

Currently, most coal-fired capacity is installed in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC) region, which includes most of the Mid-Atlantic and Ohio Valley region [7] (Figure IF8-7). Most of the coal retirements in both the Reference case and the Low Electricity Demand case occur in those regions.

In the RFC region, retirements of coal-fired capacity in the Low Electricity Demand case are double those in the Reference case, and in the SERC region they are nearly triple those in the Reference case. The RFC and SERC regions also contain 67% of the country's current nuclear capacity. However, as in other regions, there are no additional retirements of nuclear capacity in the Low Electricity Demand case relative to the Reference case. As a result, nuclear generation levels are similar in the two cases, and they make up a higher share of the total generation when electricity demand is lower. In SERC, the coal share of total generation in 2040 declines from 38% in the Reference case to 34% in the Low Electricity Demand case, and the nuclear share grows from 23% in the Reference case to 28%. Similarly in the RFC region, the 2040 coal share drops from 44% in the Reference case to 40% in the Low Electricity Demand case, and the 2040 nuclear share rises from 21% to 26%. In both regions the natural gas share also declines slightly in the Low Electricity Demand case relative to the Reference case, because fewer new natural gas-fired power plants are built. Additional retirements of older oil and gas units have less effect on generation than do retirements of coal units, because the oil and gas units typically operate less frequently throughout the year.

In contrast, in regions where there may not be more economical baseload technologies available, coal continues to provide most of the generation needs in 2040, even when electricity demand is assumed to be flat. In the Midwest Reliability Organization (MRO) region, coal-fired plants provided 60% of total generation in 2012, and they still provide 52% in the Reference case and 55% in the Low Electricity Demand case in 2040. With few new natural gas-fired additions projected in the Low Electricity Demand case, coal-fired power plants continue to provide a large portion of the region's total electricity generation.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40 (million metric tons carbon dioxide)

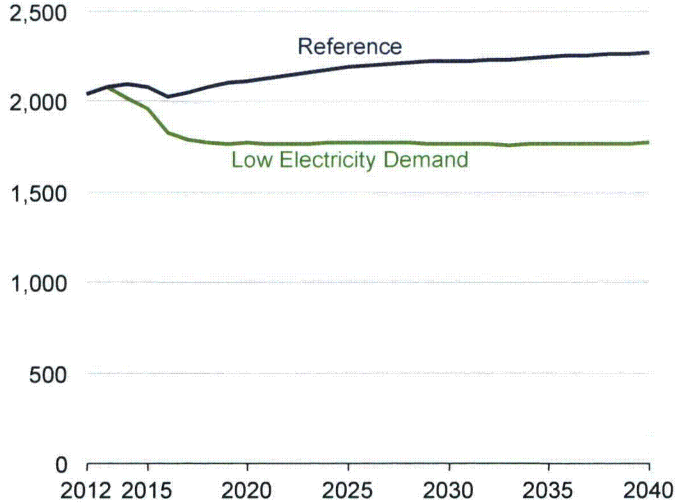
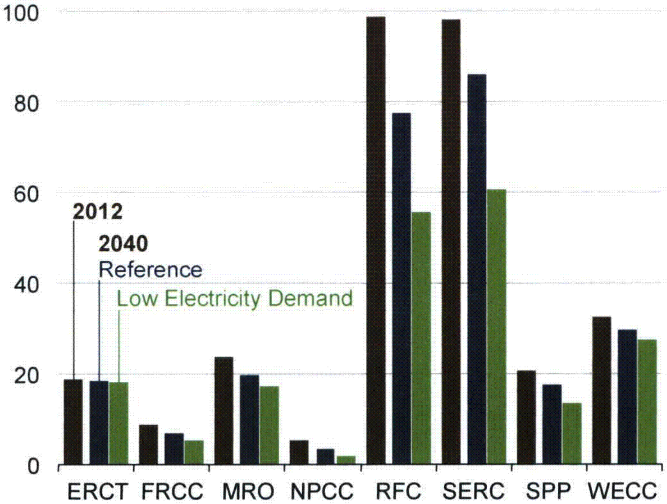


Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040 (gigawatts)



Endnotes for IF8

Links current as of April 2014

1. See Appendix F for a map of the Electricity Market Model (EMM) regions. For this discussion, results at the EMM level have been aggregated to the larger NERC regions on which they are based.

Figure sources for IF8

Links current as of April 2014

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013).

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

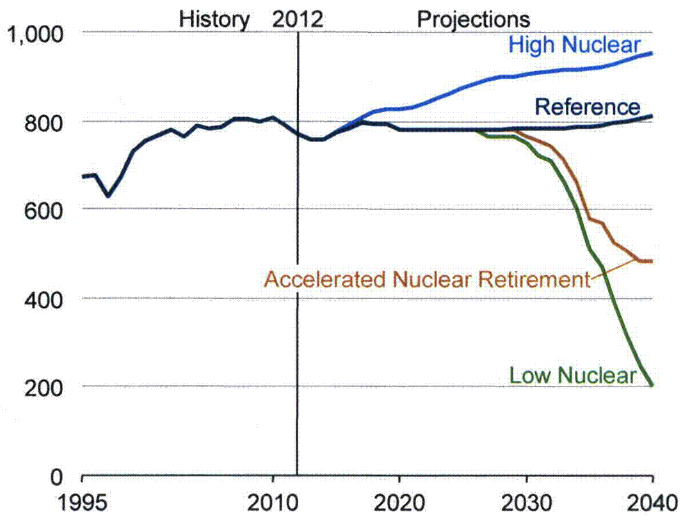
Figure IF8-5. Electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040: History: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Nuclear electricity generation varies with license renewals, uprates, and operating costs

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040 (billion kilowatthours)



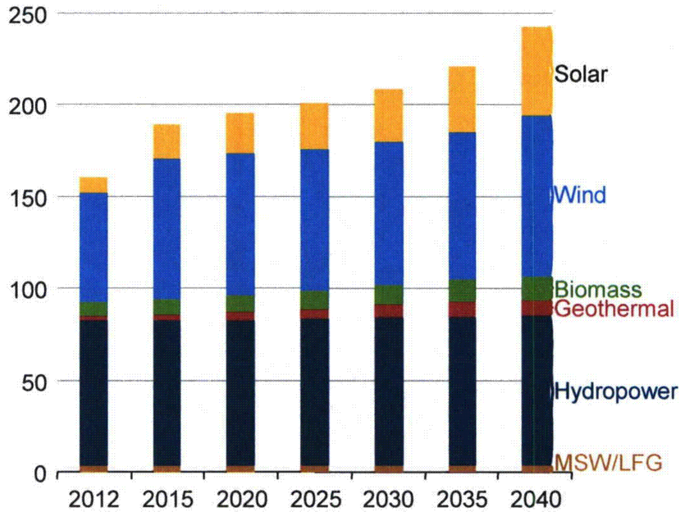
Projections of nuclear capacity and generation are influenced by assumptions about the potential for capacity uprates, new licensing requirements, future operating costs, and outside influences such as natural gas prices and incentives for other generating technologies. In the Reference case, nuclear capacity and generation remain relatively flat, with early retirements offset by new additions (Figure MT-35).

As discussed in AEO2014 Issues in focus, the Accelerated Nuclear Retirement case assumes no new nuclear builds beyond those currently under construction; that all existing units are retired by 60 years of age; and that nonfuel operating costs at existing nuclear plants increase by 3% annually, similar to recent rates. In this case, 42 gigawatts (GW) of nuclear capacity is retired, mostly from 2030 to 2040. The Low Nuclear case combines those assumptions with the High Oil and Gas Resource case and the No Sunset case. Lower natural gas prices make existing and new natural gas units more economical, and together with tax credits for newly added renewable capacity, they lower electricity market prices. With rising operating costs for nuclear plants and lower electricity prices, 77 GW of nuclear capacity is retired before 60 years of life. The retired nuclear capacity is replaced primarily by natural gas capacity, leading to a 6% increase in CO_2 emissions in the electric power sector in 2040.

The High Nuclear case assumes more uprates of existing units, adding 6.0 GW of capacity, and the addition of 12.6 GW of planned capacity through 2027. As a result, total nuclear generation in 2040 is 17% higher than in the Reference case, reducing the need for additional natural gas-fired generation.

Solar photovoltaics and wind dominate renewable capacity growth

Figure MT-36. Renewable electricity generating capacity by energy source, including end-use capacity in the Reference case, 2012-40 (gigawatts)



Total renewable generating capacity grows by 52% from 2012 to 2040 in the AEO2014 Reference case. Nonhydropower renewable capacity, particularly wind and solar, nearly doubles (Figure MT-36) and accounts for almost all of the growth in renewable capacity.

Solar power leads the growth in renewable capacity, increasing from less than 8 GW in 2012 to more than 48 GW in 2040. Wind capacity increases from less than 60 GW in 2012 to 87 GW in 2040, the second-largest amount of new renewable capacity. Although geothermal capacity more than triples and biomass capacity nearly doubles in the projection, combined they account for less than 15% of renewable capacity additions. Wind is the top source of nonhydropower renewable capacity in the projection, surpassing the hydropower share in 2036.

Renewable capacity growth is supported by a variety of federal and state policies, particularly state renewable portfolio standards (RPS) and federal tax credits. However, the impact of those policies is limited later in the projection period, because individual state renewable targets stop increasing by 2025, and projects must generally be online by 2016 to qualify for currently available federal tax credits. In addition, growth in electricity demand is modest and natural gas prices are relatively low after 2025. Renewable capacity grows by an average of 0.7%/year from 2020 to 2030, compared with 3.8%/year from 2010 to 2020. However, as natural gas prices rise over the projection period, renewable capacity becomes an increasingly cost-competitive option in some regions, and the total grows by an average of 1.5%/year overall from 2030 to 2040.

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Appendix E

NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2014* (AEO2014) are generated using the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook* (AEO) projections, NEMS is used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other federal agencies. NEMS is also used by nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, AEO projections are used by analysts and planners in other government agencies and nongovernmental organizations.

The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition across the various energy fuels and sources. The time horizon of NEMS extends to 2040. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 9 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all activities necessary to produce, import, and transport fuels to end users. The information flows also include such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thereby achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached for each year from 2013 through 2040. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the effects and costs of legislation and environmental regulations that affect each sector. NEMS accounts for all energy-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury from the electricity generation sector.

The version of NEMS used for AEO2014 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of October 31, 2013, as discussed in the Legislation and Regulations section of the AEO. The potential effects of proposed federal and state legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. Many of the pending provisions are examined, however, in alternative cases included in AEO2014 or in other analysis completed by EIA.

In general, the historical data presented with AEO2014 projections are based on various EIA publications [*2*]; however, data were taken from multiple sources. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to AEO2014 appendix tables indicate the definitions and sources of historical data.

Where possible AEO2014, which was developed during the summer of 2013, presents information for 2013 and 2014 that is consistent with the short-term projections from EIA's September 2013 *Short-Term Energy Outlook* (STEO) [*3*]. EIA's views regarding energy use over the 2013 through 2015 period are reported in monthly STEO updates [*4*], which should be considered to supersede information reported for those years in AEO2014.

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, values of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and quantities. The MAM uses the following models from IHS

Global Insight: Macroeconomic Model of the U.S. Economy, National Industrial Output model, and National Employment by Industry Model. In addition, EIA has constructed a Regional Economic, Industrial Output and Employment by Industry model to project regional economic drivers, and a Commercial Floorspace model to project 13 floorspace types in the nine Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. This module provides a world crude-like liquids supply curve and generates a worldwide oil supply/demand balance for each year of the projection period. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both petroleum and other liquids supply recovery technologies. The IEM also provides, for each year of the projection period, endogenous assumptions for petroleum products for import and export in the United States. The IEM, through interaction with the rest of NEMS, changes North Sea Brent and West Texas Intermediate (WTI) prices in response to changes in expected production and consumption of crude-like liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, the menu of available equipment, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate projections of heating and cooling degree-days by Census division, based on a 30-year historical trend and on state-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Seven of eight energy-intensive manufacturing industries are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum and other liquids refining (the other energy-intensive manufacturing industry) is modeled in the Liquid Fuels Market Module (LFMM) as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. AEO2014 includes an upgraded representation for the glass industry. Instead of assuming that technological development for a particular process occurs on a predetermined or exogenous path based on engineering judgment, these upgrades allow technological change in the glass industry to be modeled endogenously, using a more detailed process flow representation. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. The combined cement and lime industries and aluminum industry were upgraded to process flow models in previous AEOs. The iron and steel and paper industries will be similarly upgraded in future AEOs.

Model input data associated with energy intensity were aligned with the Manufacturing Energy Consumption Survey 2010 data. In the bulk chemicals model, behavior of naphtha and ethane prices was modified to better respond to oil price cases. The cement model was modified to include multichannel burners that add flexibility for fuel mix, allowing the use of significant amounts of secondary fuels, such as alternative solid fuels including tires, plastics, wood, and waste. The model also includes more rapid penetration of energy-efficient grinding. In the food industry, shipments were categorized in more detail, to grain and oil seed milling, dairy, animal slaughter, and all other. Changes also were made to the nonmanufacturing data approach. Census, U.S. Department of Agriculture, and EIA's Fuel Oil Kerosene Sales data were used to improve projections of petroleum product and natural gas consumption in agriculture, construction, and mining. CHP use is now differentiated by region and industry, based on EIA's updated historical data.

Transportation Demand Module

The Transportation Demand Module projects consumption of energy by mode and fuel—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), liquefied natural gas (LNG), and hydrogen—in the transportation sector, subject to delivered energy prices, macroeconomic variables such as GDP, and other factors such as technology adoption and consumer behavior. The Transportation Demand Module includes legislation and regulations—such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the American Recovery and Reinvestment Act of 2009 (ARRA2009)—which contain tax credits for the purchase of alternatively fueled vehicles. Representations of LDV corporate average fuel economy (CAFE) and greenhouse gas (GHG) emissions standards, heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards, and biofuels consumption reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA), as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use and travel demand for three aircraft types: regional, narrow-body, and wide-body. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

The Transportation Demand Module projects energy consumption for freight and passenger rail and marine vessels by mode and fuel, subject to macroeconomic variables such as the value and type of industrial shipments. Freight ton-miles and efficiency also are projected in the model.

Electricity Market Module

There are three primary submodules of the Electricity Market Module (EMM)—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, known environmental regulations, the expected cost and performance of future generation capacity, expected fuel prices, expected financial parameters, and expected electricity demand to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. This submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several states, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in AEO2014. The AEO2014 Reference case also imposes a limit on CO_2 emissions for specific covered sectors, including the electric power sector in California as represented in California Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32). The AEO2014 Reference case leaves the Clean Air Interstate Rule (CAIR) in effect after the court vacated the Cross-State Air Pollution Rule in August 2012. CAIR incorporates a cap-and-trade program for annual emissions of SO_2 and annual and seasonal emissions of NO_X from fossil fuel power plants. Reductions in hazardous air pollutant emissions from coal- and oil-fired steam electric power plants also are reflected through the inclusion of the Mercury and Air Toxics Standards for power plants, finalized by EPA on December 16, 2011.

Although currently there is no federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the AEO2014 Reference case through a 3-percentage-point increase in the cost of capital when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10% ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30% for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.3 cents/kilowatthour (kWh) for electricity produced in the first 10 years of plant operation. For AEO2014, EIA represents the expiration of the PTC that occurred at the end of 2013. However, because the expiration date reflects an under-construction versus in-service deadline, the effective modeled eligibility deadline is extended to new wind and landfill gas plants coming online by the end of 2015, and to other eligible plants coming online by the end of 2016. AEO2014 also accounts for new renewable energy capacity resulting from state renewable portfolio standard programs, mandates, and goals, as described in Assumptions to the Annual Energy Outlook 2014 [5].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability geologic formations. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including six onshore, three offshore, and in three Alaska regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas plays. Crude oil resources include structurally reservoired resources (i.e., conventional) as well as highly fractured continuous zones, such as the Austin Chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production volumes are used as inputs to the LFMM for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module balances natural gas supply and demand, tracks the flows of natural gas, and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting domestic and limited foreign supply sources with 12 lower 48 states regions. The 12 lower 48 states regions align with the nine Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The primary outputs of the module are delivered natural gas prices by region and sector, supply prices, and realized domestic natural gas production. The module also projects natural gas pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

Liquid Fuels Market Module

The LFMM projects prices of petroleum products, crude oil and product import/export activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, environmental regulations, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced liquid fuels technologies [6] are reviewed and updated annually.

The module represents refining activities in eight U.S. regions, and a new Maritime Canada/Caribbean refining region (created to represent short-haul international refineries that predominantly serve U.S. markets). In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are defined by subdividing three of the five U.S. PADDs. All nine refining regions are defined below:

Region 1. PADD I - East Coast
Region 2. PADD II - Interior
Region 3. PADD II - Great Lakes
Region 4. PADD III - Gulf Coast
Region 5. PADD III - Interior
Region 6. PADD IV - Mountain
Region 7. PADD V - California
Region 8. PADD V - Other
Region 9. Maritime Canada/Caribbean.

The LFMM models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the LFMM because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10% by volume (E10), 15% by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85% by volume (E85) for use in flex-fuel vehicles. The module also includes a 16% by volume biobutanol/gasoline blend. Crude oil and refinery product imports are represented by supply curves defined by the NEMS IEM. Products also can be imported from refining region nine (Maritime Canada/Caribbean). Refinery product exports are represented by demand curves, also provided by the IEM.

Capacity expansion of refinery process units and nonpetroleum liquid fuels production facilities is also modeled in the LFMM. The model uses current liquid fuels production capacity, the cost and performance of each production unit, expected fuel and feedstock costs, expected financial parameters, expected liquid fuels demand, and relevant environmental policies to project the optimal mix of new capacity that should be added in the future.

The LFMM includes representation of the renewable fuels standard (RFS) specified in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported biofuels count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 175 are now in operation, with a total maximum sustainable nameplate capacity of more than 13 billion gallons annually), and are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50%—is another new technology modeled in the LFMM. The LFMM also has the capability to produce biobutanol from a retrofitted corn ethanol facility, if economically competitive.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the LFMM, based on their economics compared with competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Two California-specific policies are also represented in the LFMM: the low carbon fuel standard (LCFS) and the AB 32 cap-and-trade program. The LCFS requires the carbon intensity (amount of greenhouse gases/unit of energy) of transportation fuels sold for use in California to decrease according to a schedule published by the California Air Resources Board. California's AB 32 cap-and-trade program is established to help California achieve its goal of reducing CO_2 emissions to 1990 levels by 2020. Working with other NEMS modules (IDM, EMM, and Emissions Policy Module), the LFMM provides emissions allowances and actual emissions of CO_2 from California refineries, and NEMS provides the mechanism (carbon price) to trade allowances such that the total CO_2 emissions cap is met.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to mining capacity, capacity utilization of mines, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector; environmental restrictions; and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in two types of coal (steam and metallurgical) for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2014 cases

Table E1 provides a summary of the cases produced as part of AEO2014. For each case, the table gives the name used in AEO2014, a brief description of the major assumptions underlying the projections, and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases in more detail. The Reference case assumptions for each sector are described in Assumptions to the Annual Energy Outlook 2014 [7]. Regional results and other details of the projections are available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Macroeconomic growth cases

In addition to the AEO2014 Reference case, Low Economic Growth and High Economic Growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- In the Reference case, population grows by 0.7%/year, nonfarm employment by 0.8%/year, and labor productivity by 1.8%/year from 2012 to 2040. Economic output as measured by real GDP increases by 2.4%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.7%/year.

Table E1. Summary of the AEO2014 cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Real GDP grows at an average annual rate of 2.4% from 2012 to 2040. Crude oil prices rise to about $141/barrel (2012 dollars) in 2040. Complete projection tables in Appendix A.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 1.9% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-8
High Economic Growth	Real GDP grows at an average annual rate of 2.8% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-9
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) increases its market share to 51%, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $70/barrel in 2017 and rise slowly to $75/barrel in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
High Oil Price	High prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. OPEC market share averages 37% throughout the projection. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $204/barrel (2012 dollars) in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
No Sunset	Begins with the Reference case and assumes extension of all existing tax credits and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Partial projection tables in Appendix D.	p. IF-3	p. E-10
Extended Policies	Begins with the No Sunset case but excludes extension of the ethanol and biofuel subsidies that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC for CHP and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases LDV and HDV fuel economy standards in the transportation sector. Partial projection tables in Appendix D.	p. IF-3	p. E-10
High Rail LNG	Assumes a higher LNG locomotive penetration rate into motive stock such that 100% of locomotives are LNG capable by 2037. Partial projection tables in Appendix D.	p. IF-18	p. E-11
Low Rail LNG	Assumes a lower LNG locomotive penetration rate into motive stock, at a 1.0 average annual turnover rate for dual-fuel engines that can use up to 80% LNG. Partial projection tables in Appendix D.	p. IF-18	p. E-11
High VMT	Assumes higher licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver in 2012 is 3% higher than in the Reference case, increasing to 7% higher in 2027, and then declining to 3% above the Reference case in 2040. Partial projection tables in Appendix D.	p. IF-22	p. E-11
Low VMT	Assumes lower licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver is 5% lower than in the Reference case for the full projection. Licensing rates stay constant at 2011 levels or decline from 2011 to 2040, specific to gender, age, and census division categories. Partial projection tables in Appendix D.	p. IF-22	p. E-11

Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Accelerated Nuclear Retirements	Assumes that all nuclear plants are limited to a 60-year life, uprates are limited to the 0.7 gigawatts (GW) that have been reported to EIA, and no new additions beyond those planned in the Reference case. Nonfuel operating costs for existing nuclear plants are assumed to increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-11
Accelerated Coal Retirements	Begins with the AEO2014 High Coal Cost case assumptions and also assumes that nonfuel operating costs for existing coal plants increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Accelerated Nuclear and Coal Retirements	Combines the assumptions in the Accelerated Nuclear Retirements and Accelerated Coal Retirements cases. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Electricity: Low Nuclear	Begins with the Accelerated Nuclear Retirements case and combines with assumptions in the High Oil and Gas Resource and the No Sunset cases. Partial projection tables in Appendix D.	p. MT-19	p. E-12
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for 4.8 GW of announced retirement), and a total of 6.0 GW of uprates. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing. Partial projection tables in Appendix D.	p. MT-19	p. E-12
Renewable Fuels: Low Renewable Technology Cost	Capital costs for new nonhydro renewable generating technologies are 20% lower than Reference case levels through 2040, and biomass feedstocks are 20% less expensive for a given resource quantity. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies are 20% lower than Reference case levels through 2040, and the industrial sector assumes a higher rate of recovery for biomass byproducts from industrial processes. Partial projection tables in Appendix D.	p. MT-8	p. E-12
Oil and Gas: Low Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in the Reference case. All other resource assumptions remain the same as in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-12
Oil and Gas: High Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells increases 1%/year to reflect additional technological improvement. Also includes kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in the offshore lower 48 states, Alaska, and shale gas in Canada than in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-13
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year higher than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are lower than in the Reference case, falling to about 25% below the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year lower than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are higher than in the Reference case, ranging between 24% and 31% above the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Integrated 2013 Demand Technology	Referred to in the text as 2013 Demand Technology. Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2013. Commercial and existing residential building shell efficiency is held constant at 2013 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Partial projection tables in Appendix D.	p. MT-6	p. E-9

Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Integrated Best Available Demand Technology	Referred to in the text as Best Available Demand Technology. Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. All residential building shells for new construction are assumed to be code compliant and built to the most efficient specifications after 2013, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50% more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case. Partial projection tables in Appendix D.	p. MT-6	p. E-9
Integrated High Demand Technology	Referred to in the text as High Demand Technology. Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Existing residential building shells exhibit 50% more improvement than in the Reference case after 2013. New and existing commercial building shells are assumed to improve 25% more than in the Reference case by 2040. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, as well as battery electric vehicle costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. MT-6	p. E-9
Energy Savings and Industrial Competitiveness Act	Begins with the Reference case and assumes passage of the energy efficiency provisions in S. 1392, including appropriation of funds at the levels authorized in the bill. Key provisions modeled include improved national building codes for new homes and commercial buildings and a rebate program for advanced industrial motor systems, assuming the bill's passage in 2014. For new residential construction, building shell efficiencies are assumed to improve by 15% relative to IECC2009 by 2020, and building code compliance is assumed to improve. New commercial building shells are assumed to be 30% more efficient than ASHRAE 90.1-2004 by 2020. Partial projection tables in Appendix D.	p. IF-6	--
Low Electricity Demand	This case was developed to explore the effects on the electric power sector if growth in sales to the grid remained relatively low. Begins with the Best Available Demand Technology case, which lowers demand in the building sectors, and also assumes greater improvement in industrial motor efficiency. Partial projection tables in Appendix D.	p. IF-46	p. E-12
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	p. MT-33	p. E-14
GHG10	Applies a price for CO2 emissions throughout the economy, starting at $10/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG25	Applies a price for CO2 emissions throughout the economy, starting at $25/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG10 and Low Gas Prices	Combines GHG10 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. MT-34	p. E-14

- The Low Economic Growth case assumes lower growth rates for population (0.6%/year) and labor productivity (1.4%/year), resulting in lower nonfarm employment (0.7%/year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 1.9%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.3%/year.
- The High Economic Growth case assumes higher growth rates for population (0.8%/year) and labor productivity (2.0%/year), resulting in higher nonfarm employment (1.0%/year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (2.8%/year) than in the Reference case (2.4%). Disposable income per capita grows by 1.7%/year, the same as in the Reference case.

Oil price cases

The benchmark oil price is the price for Brent crude oil, which better reflects the marginal price paid by refineries for imported light, sweet crude oil used to produce petroleum products for consumers. EIA continues to report the WTI price and the Imported Refiner Acquisition Cost.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. AEO2014 considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting primarily from variation in demand for petroleum and other liquid fuels in non-OECD countries due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of OPEC regarding the preferred rate of oil production and about the future finding and development costs and accessibility of non-OPEC oil resources.

- In the Reference case, real oil prices (in 2012 dollars) rise from $112/barrel in 2012 to $141/barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. Compared with AEO2013, EIA sees increasing production from non-OPEC countries, particularly the United States. However, EIA also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC oil production will represent between 39% and 44% of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices fall to $70/barrel (2012 dollars) in 2016, remain below $70/barrel through 2023, and stay below $75/barrel through 2040. The low price results from lower costs of production and lower demand from China and the Middle East compared with the Reference case. Crude oil production from across OPEC rises throughout the projection period in this case, displacing more expensive crude projected in the Reference case (including from the United States). Correspondingly, OPEC's market share of petroleum rises steadily from 40% through 2015 to almost 53% in 2040. In addition, in this case, bitumen production in Canada and renewable fuels from Brazil and the United States see decreases in costs, leading to increased production. This keeps the OPEC market share to between 39% and 50% of the total liquids market. With the exceptions of China and the Middle East, which see reduced economic growth in this case, the lower prices generally lead to higher demand than projected in the Reference case.
- In the High Oil Price case, oil prices reach about $204/barrel (2012 dollars) in 2040. The high prices result primarily from higher costs of petroleum supply. Fewer structurally reservoired crude oil supplies are developed than in the Reference case, leading to increased development of more costly resources, including tight oil and bitumen. Higher prices also lead to significant increases in renewable liquid fuels and coal-to-liquid products as compared with the Reference case. In this case, OPEC's share of world liquids production never exceeds the high of 40% that it reaches in 2013 and drops as low as 37%. The higher supply costs depress demand globally through 2028, but stronger growth in non-OECD countries than is projected in the Reference case leads to higher demand than in the Reference case, starting in these countries in 2029, and starting globally in 2037.

Buildings sector cases

In addition to the AEO2014 Reference case, three technology-focused cases using the NEMS Demand Modules were developed to examine the effects of changes in technology. Residential sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future residential equipment purchases are limited to the range of equipment available in 2013. Existing building shell efficiencies are assumed to be fixed at 2013 levels (no further improvements). For new construction, building shell assumptions are the same as in the Reference case.
- The Integrated High Demand Technology case assumes that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [*8*]. Existing building shell efficiencies exhibit 50% more improvement than in the Reference case after 2013. For new construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Consumers evaluate investments in energy efficiency at a 7% real discount rate.
- The Integrated Best Available Demand Technology case assumes that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class,

regardless of cost. Existing building shell efficiencies have twice the improvement of the Reference case after 2013. For new construction, 100% compliance with building codes is assumed, and building shell efficiencies are assumed to meet the criteria for the most efficient components after 2013. Consumers evaluate investments in energy efficiency at a 7% real discount rate.

Commercial sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future commercial equipment purchases are limited to the range of equipment available in 2013. Building shell efficiencies are assumed to be fixed at 2013 levels.
- The Integrated High Demand Technology case assumes that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case. Energy efficiency investments are evaluated at a 7% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 25% more improvement than in the Reference case.
- The Integrated Best Available Demand Technology case assumes that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Energy efficiency investments are evaluated at a 7% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 50% more improvement than in the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The Low Renewable Technology Cost case assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions for capital cost estimates are 20% below Reference case assumptions from 2014 through 2040.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected federal policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps, as well as tax credits for energy-efficient homes and selected residential appliances. For the commercial sector, business ITC for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30% level without reverting to 10% as scheduled.
- The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. End-use technologies eligible for No Sunset incentives are not subject to new standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the AEO2014 Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The case also adds two additional rounds of improved national building codes with full implementation in 2023 and 2029.

Industrial sector cases

In addition to the AEO2014 Reference case, two technology-focused cases developed using the IDM of NEMS examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the LFMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2013 Demand Technology case and Integrated High Demand Technology case. For the industrial sector, assumptions for the two technology-focused cases are as follows:

- For the Integrated 2013 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing the composition of output within an individual industry. Because all AEO2014 side cases are integrated runs, potential feedback effects from energy market interactions are captured. Therefore, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.
- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [9] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial

processes—i.e., 0.7%/year as compared with 0.4%/year in the Reference case. The same assumption is incorporated in the Low Renewable Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7% annual rate of improvement in byproduct recovery is an assumption in the High Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies selected industrial assumptions as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing ITC for industrial CHP through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts (MW) to 25 MW and eliminating the system-wide cap of 50 MW. These assumptions are based on the proposals made in H.R. 2750 and H.R. 2784 of the 112th Congress.

Transportation sector cases

In addition to the AEO2014 Reference case, the NEMS Transportation Demand Module was used as part of six AEO2014 side cases.

The Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement for technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case. For the Integrated High Demand Technology case, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, including battery electric systems. In the freight truck sector, the Integrated High Demand Technology case assumes more rapid incremental improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The Transportation Demand Module was used to examine the effects of an extension to the LDV GHG Emissions and CAFE Standards beyond 2025 as part of the Extended Policies case. The joint EPA and NHTSA CAFE Standards were increased after 2025, at an average annual rate of 1.3% through 2040, reaching a combined average LDV fuel economy compliance of 55.7 miles/gallon in 2040. As part of the Extended Policies case, the Transportation Demand Module was also used to examine the effects of extending and enhancing the HDV fuel consumption and GHG emissions standards through 2040. The regulations are currently specified for model year (MY) 2014 to MY 2018. The Extended Policies case includes a modest increase in fuel consumption and GHG emissions standards for 13 HDV vehicle size classes.

Assumptions in the NEMS Transportation Demand Module were modified for the High Vehicle Miles Traveled (VMT) and Low VMT cases. These cases examine the effects of changes to licensing rates and VMT on the LDV transportation sector. The High VMT case includes assumptions for increases in VMT per licensed driver for the five VMT age cohorts. VMT per licensed driver is 3% higher than in the Reference case in 2012, increases to 7% above the Reference case in 2027, and decreases back to 3% above the Reference case by 2040. The Low VMT case includes assumptions for a decline in licensed drivers for the 13 gender/age cohorts, as well as decreases in VMT per licensed driver for the five VMT age groups. VMT per licensed driver are 5% lower than in the Reference case for the entire projection, and the licensing rates either stay constant at 2011 levels for all age cohorts or decline as portrayed in the Reference case.

The Transportation Demand Module was also used to examine the effect of varying LNG locomotive penetration in the freight rail sector. The High Rail LNG case allows for LNG locomotives to penetrate the rail sector fully by 2037. The Low Rail LNG case incorporates dual-fuel engines that utilize LNG up to 80%, with an LNG locomotive penetration rate at 1.0% of the average annual stock turnover.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the Market Trends and Issues in Focus sections of AEO2014. Three alternative cases were run to examine the impacts on the electric power sector of potentially large retirements of baseload coal and nuclear plants. In recent years, a combination of low natural gas prices, high retrofit or repair costs, and uncertainty about environmental legislation have led to an increase in announced retirements of coal and nuclear plants. The Issues in Focus article, "Implications of accelerated power plant retirements," discusses the factors influencing those retirement decisions, using the analysis cases to illustrate potential impacts. Two additional cases for nuclear power plants were developed to address uncertainties about the operating lives of existing reactors and the potential for new nuclear capacity and for capacity uprates at existing plants.

A final case combines technology and efficiency improvements across the end-use demand sectors to create a case that projects relatively low growth in total electricity consumption. The Issues in Focus article, "Implications of low electricity demand growth," analyzes the impacts on power sector capacity and generation requirements under a scenario of low demand growth.

Accelerated Retirement cases

- The Accelerated Nuclear Retirement case assumes that reactors will not receive second license renewals, so that all existing nuclear plants are retired within 60 years after beginning operation. The 4.8 GW of announced retirements remain as in the

Reference case, along with the decrease of 5.7 GW of nuclear capacity by 2020 to reflect plants at risk of early closure in specific regions. In the Reference case, after 2020, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will occur for most plants that reach 60 years of operation before 2040. In the Accelerated Nuclear Retirement case, an additional 37 GW of nuclear capacity is retired by 2040. The Accelerated Nuclear Retirement case also assumes that no new nuclear capacity is added throughout the projection, excluding capacity already planned and under construction. It assumes that only those capacity uprates already reported to EIA (0.7 GW) are completed, as in the Reference case, and that nonfuel operating costs at existing nuclear plants increase by 3%/year after 2013.

- The Accelerated Coal Retirement case includes the assumptions used for the High Coal Cost case, including lower productivity and higher costs associated with mining and coal transportation rates. In 2040, delivered coal prices are more than 60% higher in the Accelerated Coal Retirement case than in the Reference case. This case also assumes that non-fuel operating costs at existing coal plants increase by 3%/year after 2013.
- The Accelerated Coal and Nuclear Retirement case combines the assumptions of the Accelerated Coal Retirement and Accelerated Nuclear Retirement cases.

Nuclear cases

- The Low Nuclear case combines the Accelerated Nuclear Retirement case with the High Oil and Gas Resource case and the No Sunset case. This combines more pessimistic assumptions for nuclear costs and lifetimes with more favorable conditions for natural gas-fired and renewable technologies, so that the impacts on the power sector can be viewed under an outlook where output from nuclear power is greatly reduced.
- The High Nuclear case was run to provide a more optimistic outlook, with all nuclear power plant licenses renewed and all plants continuing to operate economically beyond 60 years (excluding the 4.8 GW of announced retirements). The High Nuclear case also assumes that additional planned nuclear capacity is completed, based on combined license applications (COL) issued by the NRC and whether an Atomic Safety and Licensing Board hearing has been scheduled for a COL. The High Nuclear case assumes 12.6 GW of planned capacity additions, as compared with 5.5 GW of planned capacity additions assumed in the Reference case. Finally, the High Nuclear case assumes a total of 6.0 GW of uprates at existing plants, reflecting an assumption that most plants with remaining uprate potential will elect to perform such uprates.

Low Electricity Demand case

- The Low Electricity Demand case uses the assumptions in the Best Available Demand Technology case for the residential and commercial sectors. In addition, input values for the industrial sector motor model are adjusted to increase system savings values for pumps, fans, and air compressors relative to the Reference case. This adjustment lowers total motor electricity consumption by slightly less than 20%. Although technically plausible, this decrease in motor adjustment is not intended to be a likely representation of motor development. As a result of these changes across the end-use sectors, retail sales in 2040 in this case are roughly the same as in 2012.

Renewable fuels cases

In addition to the AEO2014 Reference case, EIA developed a case with alternative assumptions about renewable generation technologies and policies to examine the effects of more aggressive improvement in the costs of renewable technologies.

- In the Low Renewable Technology Cost case, the capital costs of new non-hydro renewable generating technologies are assumed to be 20% below Reference case assumptions from 2014 through 2040. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 20% less expensive than in the Reference case for the same resource quantities. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes also is increased. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies also are 20% lower than Reference case levels through 2040.
- In the No Sunset case and the Extended Policies case, expiring federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.3 cents/kWh (adjusted annually for inflation) available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents/kWh available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.3 cents/kWh. The extension also applies to the 30% ITC for new generators using solar energy, which may also be claimed in lieu of the PTC for eligible technologies.

Oil and natural gas supply cases

The sensitivity of the AEO2014 projections to changes in assumptions regarding technically recoverable domestic crude oil and natural gas resources is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

- In the Low Oil and Gas Resource case, the estimated ultimate recovery per tight oil, tight gas, or shale gas well is assumed to be 50% lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable resource of crude oil is decreased to 180 billion barrels, and the natural gas resource is decreased to 1,480 trillion cubic feet (Tcf), as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas as of January 1, 2012, in the Reference case.
- In the High Oil and Gas Resource case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production, to more than 13 million barrels per day (MMbbl/d) in 2040 compared with 7.5 MMbbl/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, with 50% lower acre spacing (minimum 40 acres) than in the Reference case, as well as additional unidentified tight oil resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed; (2) diminishing returns on the estimated ultimate recovery once drilling levels in a county exceed the number of potential wells assumed in the Reference case to reflect well interference at greater drilling density; (3) additional 1% annual increase in the estimated ultimate recovery for tight oil, tight gas, and shale gas wells due to faster technological improvement; (4) kerogen development reaching 135,000 barrels/day in 2024; (5) tight oil development in Alaska, increasing the total Alaska technically recoverable resource by 1.9 billion barrels; and (6) 50% higher technically recoverable undiscovered resources in Alaska, the offshore lower 48 states, and shale gas in Canada than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and developed earlier than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 401 billion barrels, and the natural gas resource increases to 3,349 Tcf as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas in the Reference case as of the start of 2012.

Liquids market cases

The Liquid Fuels Market Module of NEMS was used (with other NEMS models) to complete the Low Renewable Technology Cost case, which is discussed in more detail in the renewable fuels cases section. In addition to the 20% reduction in nonhydro renewable generating technologies, 20% reduction in biomass feedstock costs, and higher rate of recovery for biomass byproducts from industrial processes, the LFMM assumes capital costs for new ethanol, biodiesel, pyrolysis, and other BTL technologies are 20% lower than reference case levels through 2040.

Some assumptions in the LFMM were changed to support the No Sunset case by extending the ethanol and biodiesel subsidies beyond their current end dates (2013). This assumption was excluded from the Extended Policies case.

Coal market cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, coal transportation rates, and costs of non-U.S. coal supplies to international markets. The alternative productivity and cost assumptions are applied in every year from 2014 through 2040. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.4 percentage points observed since 2000 for mines in Wyoming's Powder River Basin and 2.3 percentage points for other coal-producing regions. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25% change in rates relative to the Reference case in 2040. In both the High and Low Coal Cost cases, price trends for non-U.S. coal export supplies (e.g., coal exported to international markets from ports in Australia or Southern Africa, a NEMS-defined region that includes South Africa, Mozambique, and Botswana) are assumed to be similar, but price changes are approximately 10% less than the price changes projected for U.S. coal exports. The Low and High Coal Cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the Low Coal Cost case, the average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.5% in the Reference case for the years 2014 through 2040 to 0.9% in the Low Coal Cost case. Coal miner wages, mine equipment costs, and other mine supply costs all are assumed to be about 24% lower in 2040 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25% lower in 2040. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.
- In the High Coal Cost case, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal miner wages, mine equipment costs, and other mine supply costs in 2040 are assumed to be about 31% higher than in the Reference case, and coal transportation rates in 2040 are assumed to be 25% higher. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

Additional data on productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are included in Appendix D.

Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in AEO2014 to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the effects of faster and slower technology improvement in the demand sectors (partially described in the sector-specific sections above). In addition, four cases were run with alternative assumptions about expectations for future regulation of GHG emissions.

Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency and/or reduced technology cost. Three alternative demand technology cases—Integrated 2013 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology—are used in AEO2014 to examine the potential effects of variation in the rate of technology improvement in the end-use demand sectors, independent of any offsetting effects of variations in technology improvement in the supply/conversion sectors. Assumptions for each end-use sector are described in the sector-specific sections above.

No Sunset case

In addition to the AEO2014 Reference case, a No Sunset case was run, assuming the extension of all existing tax credits and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. The No Sunset case also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Extended Policies case

The Extended Policies case begins with the No Sunset case described above but excludes extension of the ethanol and biofuel subsidies included in the No Sunset case, because the RFS program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use. The Extended Policies case assumes an increase in the capacity limitations on the ITC and extension of the program. It includes additional rounds of federal efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2029; and increases LDV and HDV fuel economy standards in the transportation sector. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Greenhouse gas cases

Given concerns about climate change and possible future policy actions to limit GHG emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. To reflect the market's current reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power and CTL plants without CCS and for all capital investment projects (excluding CCS) at existing coal-fired power plants in the Reference case and all other AEO2014 cases except the No GHG Concern case, GHG10 case, GHG25 case, and GHG10 and Low Gas Prices case. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The four alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon emissions price, as well as an examination of the impact of a combination of a specific economywide carbon emission price and low natural gas price. AEO2014 includes three economywide CO_2 price cases—two levels of carbon prices and one case combined with an alternative natural gas price projection. In the GHG10 case and the GHG10 and Low Gas Prices case, the price of carbon emissions is set at $10/metric ton of CO_2 in 2015. In the GHG25 case, the price is set at $25/metric ton of CO_2 in 2015. In all cases, the price begins to rise in 2016 at 5%/year. The GHG10 case and the GHG25 case use the Reference case assumptions regarding oil and natural gas resource availability. The GHG10 and Low Gas Prices case uses the assumptions from the High Oil and Gas Resource case, as described above in the Oil and natural gas supply section. The GHG cases are intended to measure the sensitivity of the AEO2014 projections to a range of implicit or explicit valuations of CO_2 emissions. At the time AEO2014 was completed, no legislation including a GHG price was pending; however, the EPA is developing technology-based CO_2 standards for new coal-fired power plants. In the GHG cases for AEO2014, no assumptions are made with regard to offsets, policies to promote CCS, or specific policies to mitigate impacts in selected sectors.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

Endnotes for Appendix E

Links current as of April 2014

1. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC, October 2009), http://www.eia.gov/oiaf/aeo/overview.
2. Selected EIA publications used for data sources include *Monthly Energy Review, Natural Gas Annual, Natural Gas Monthly, Electric Power Monthly, Electric Power Annual, Annual Coal Report, Petroleum Supply Annual*, and *Quarterly Coal Report*, as well as EIA surveys.
3. U.S. Energy Information Administration, *Short-Term Energy Outlook September 2013* (Washington, DC, September 2013), http://www.eia.gov/forecasts/steo/archives/Sep13.pdf. Portions of the preliminary information were also used to initialize the NEMS Liquids Fuels Market Module projection.
4. U.S. Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, January 2014), http://www.eia.gov/forecasts/steo/outlook.cfm.
5. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014*, DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
6. Alternative technologies for other liquids include all biofuels technologies plus CTL and GTL.
7. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014*, DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
8. High technology assumptions for the buildings sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, November 2012).
9. These assumptions are based in part on U.S. Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).

EPA FACT SHEET: Clean Power Plan

NATIONAL FRAMEWORK FOR STATES

SETTING STATE GOALS TO CUT CARBON POLLUTION

On June 2, 2014, the U.S. Environmental Protection Agency, under President Obama's Climate Action Plan, proposed a commonsense plan to cut carbon pollution from power plants. Nationwide, by 2030, the Clean Power Plan will help cut carbon emissions from the power sector by 30 percent from 2005 levels, while starting to make progress toward meaningful reductions in 2020.

- **Setting state goals**—To set state-specific goals, EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector. These include improving energy efficiency, improving power plant operations, and encouraging reliance on low-carbon energy. Together, these make up the best system for reducing carbon pollution because they achieve meaningful reductions, and create jobs by driving clean energy investment and reducing energy waste to save families money.
- **Goals give states flexibility**—Each state has the flexibility to choose how to meet the goal using a combination of measures that reflect its particular circumstances and policy objectives. While EPA identified a mix of four "building blocks" that make up the best system of emission reductions under the Clean Air Act, a state does not have to put in place the same mix of strategies that EPA used to set the goal. States are in charge of these programs and can draw on a wide range of tools, many of which they are already using, to reduce carbon pollution from power plants and meet the goal, including renewable energy portfolios and demand-side energy efficiency measures.

SETTING STATE GOALS

- EPA is proposing state-specific emissions goals for reducing carbon dioxide (CO_2) emissions from the power sector.
- These state goals are <u>not</u> requirements on individual electric generating units. Rather, each state has broad flexibility to meet the rate by 2030 by lowering the overall carbon intensity of the power sector in the state.
- The basic formula for the state goal is a rate: CO2 emissions from fossil fuel-fired power plants in pounds (lbs) divided by state electricity generation from fossil-fuel fired power plants and certain low- or zero-emitting power sources in megawatt hours (MWh).
    - This approach factors in megawatt hours from fossil fuel power plants plus other types of power generation like renewables and nuclear, as well as megawatt-hour savings from energy efficiency in the state.
- State- and regional-specific information is plugged into the formula, and the result of the equation is the state-specific goal.
- Each state's goal is different, because each state has a unique mix of emissions and power sources to plug in to each part of the formula.

- EPA is proposing a two-part goal structure: an "interim goal" that a state must meet on average over the ten-year period from 2020-2029 and a "final goal" that a state must meet at the end of that period in 2030 and thereafter.

GOALS GIVE STATES FLEXIBILITY

- Each state will choose how to meet the goal through whatever combination of measures reflects its particular circumstances and policy objectives. A state does not have to put in place the same mix of strategies that EPA used to set the goal, and there are no specific requirements for specific plants.
- EPA is proposing the state goal approach under Section 111(d) of the Clean Air Act, which requires that EPA identify the "best system of emission reduction ... adequately demonstrated" (BSER) that is available to limit pollution – and set guidelines for states to achieve reductions that reflect that system. States then make plans to get the reductions that would result from that system.
- In this case, EPA identified four sets of measures – or "building blocks" – that are in use today by many states and utilities and that together make up the best system for reducing carbon pollution.
- These building blocks recognize the interconnected nature of the power sector – looking broadly to find cost-effective and proven solutions.
    - For example, 47 states have utilities that run demand-side energy efficiency programs, 38 states have renewable portfolio standards or goals, and 10 states have market-based greenhouse gas programs.
- EPA analyzed historical data about emissions and the power sector to create a consistent national formula for reductions that reflects the building blocks. The formula applies the building blocks to each state's specific information, yielding a carbon intensity rate for each state.

Building Block	**Value Allocated in Goal-Setting Formula**
Make fossil fuel power plants more efficient • Improve equipment and processes to get as much electricity as possible from each unit of fuel • Using less fossil fuel to create the same amount of electricity means less carbon pollution.	Average heat rate improvement of 6% for coal steam electric generating units (EGUs)
Use low-emitting power sources more • Using lower-emitting power plants more frequently to meet demand means less carbon pollution.	Dispatch to existing and under-construction natural gas combined cycle (NGCC) units to up to 70% capacity factor
Use more zero- and low-emitting power sources • Expand renewable generating capacity, which is consistent with current trends. • Using more renewable sources, including solar and wind, and low-emitting nuclear facilities, means less carbon pollution.	Dispatch to new clean generation, including new nuclear generation under construction, moderate deployment of new renewable generation, and continued use of existing nuclear generation

Building Block	Value Allocated in Goal-Setting Formula
Use electricity more efficiently • Reducing demand on power plants is a proven, low-cost way to reduce emissions, which will save consumers and businesses money and mean less carbon pollution.	Increase demand-side energy efficiency to 1.5% annually

- EPA is also proposing to give states the option to convert the rate-based goal to a mass-based goal if they choose to in their state plans.
  - Adopting a mass-based goal would better allow a state or group of states to cap their tonnage of CO_2 emissions and set up a trading program if they choose that option.
- States can develop a state-only plan or collaborate with each other to develop plans on a multi-state basis to meet the goals outlined in the proposal.
- EPA is only proposing goals for states with fossil fuel-fired power plants. Vermont and Washington, DC are not included in this rule because they do not have fossil fuel-fired power plants.
- EPA is not proposing emission rate goals or guidelines for the four affected sources located in Indian country at this time. EPA will work with those tribes and sources to develop or adopt Clean Air Act programs.

FOR MORE INFORMATION

EPA will accept comment on the proposal for 120 days after publication in the Federal Register and will hold four public hearings on the proposed Clean Power Plan during the week of July 28 in the following cities: Denver, Atlanta, Washington, DC and Pittsburgh. The proposed rule, information about how to comment and supporting technical information are available online at: http://www.epa.gov/cleanpowerplan