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Annual Energy Outlook 2016

with projections to 2040

Independent Statistics & Analysis
U.S. Energy Information Administration

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AEO2016 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/forecasts/aeo/nems/documentation and will be updated for the AEO2016 during 2016.

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Preface

The *Annual Energy Outlook 2016* (AEO2016), prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2040. The projections, focused on U.S. energy markets, are 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 analysis in AEO2016 focuses on the Reference case and 17 alternative cases. EIA published an Early Release version of the AEO2016 Reference case (including U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP)) and a No CPP case (excluding the CPP) in May 2016.

The AEO2016 report is a complete edition of the *Annual Energy Outlook* (AEO) and includes the following major sections:

Executive summary: highlighting key results of the projections

Legislation and regulations: discussing evolving legislative and regulatory issues, including a summary of recently enacted legislation and regulations as incorporated in AEO2016, such as: the EPA's final rules for the CPP [*1*]; the California Air Resource Board Zero-Emission Vehicle program [*2*]; the extension of the production tax credit for wind and 30% investment tax credit for solar [*3*]; the International Convention for the Prevention of Pollution from Ships [*4*]; adoption of newly added or modified federal efficiency standards for residential and commercial appliances and equipment; and modifications to existing state renewable portfolio standard or similar laws [*5*].

Issues in focus: containing discussions of selected energy topics, including the effects of the CPP under alternative implementation approaches; the impact of Phase 2 standards for medium- and heavy-duty vehicles; a discussion that compares the Reference case to alternative cases based on different assumptions about the future course of existing energy policies; the impact on hydrocarbon gas liquids output from changing oil prices and related industrial development; and the sensitivity of steel industry energy consumption to technology choice.

Market trends: complete summary by sector of the projections for energy markets comparing the AEO2016 Reference case and the alternative cases, illustrating uncertainties associated with the Reference case projections for energy demand, supply, and prices.

Comparisons with other projections: comparing the AEO2016 Reference case to comparable aspects of projections provided by ExxonMobil, IHS Global Insight, International Energy Agency, ICF, BP p.l.c., National Renewable Energy Laboratory, Energy Ventures Analysis, Inc., and Wood Mackenzie, Inc., among others.

Summary tables for the Reference and alternative cases are provided in Appendixes A through D. Complete tables are available in a table browser on EIA's website, at http://www.eia.gov/forecasts/aeo/data/browser/. Appendix E provide a short description of the NEMS modules and a complete listing and discussion of the assumptions made for the alternative cases. Appendix F provides a summary of the regional formats, and Appendix G provides a summary of the energy conversion factors used in AEO2016.

The AEO2016 projections are based generally on federal, state, and local laws and regulations in effect as of the end of February 2016. The AEO2016 Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws which include sunset dates are no longer in effect at the time of those sunset dates) [*6*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded, or for which parameters will be set in a future regulatory process—are not reflected in the AEO2016 Reference case, but some are considered in alternative cases. However, where it is clear that a law or regulation will take effect shortly after the *Annual Energy Outlook* (AEO) is completed, it may be considered in the projection.

AEO2016 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.

Objectives of the AEO2016 projections

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The AEO2016 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 cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and different paths for the implementation of public policy. The main cases in AEO2016 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 AEO2016 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 2016* Reference case (August 2016)

The *Annual Energy Outlook 2016* (AEO2016) Reference case included as part of this complete report (released in July 2016) has been updated from the *Annual Energy Outlook 2015* Reference case (released in April 2015). The updated Reference case reflects new legislation and regulations enacted since April 2015, model changes, and data updates. The key model and data updates include:

Macroeconomic

- Updated historical data on industries and employment
- Updated information on natural gas extraction from the National Energy Modeling System (NEMS)
- Extended dynamic Input-Output framework from 2013 to 2040
- Disaggregation of three pulp and paper subindustries included in the NEMS macroeconomic model: pulp and paper mills, paperboard and containers, and all other pulp and paper
- Disaggregated ethanol, flat glass, and lime and gypsum subindustries in the Industrial Output and Employment Model
- Incremental electricity investment required to meet the standards in the U.S. Environmental Protection Agency (EPA) Clean Power Plan (CPP) [*7*]
- Re-estimated commercial floorspace model, using data from Dodge Data and Analytics, and transformation of floorspace estimates to projected growth rates rather than levels

Residential, commercial, and industrial

- New buildings equipment standards promulgated since the AEO2015 Reference case was completed, including standards affecting commercial cooling equipment, commercial furnaces, residential boilers, commercial oil-fired water heaters, fluorescent lamps, commercial pumps, and commercial ice makers and beverage vending machines
- Cost and energy impacts of energy efficiency activities in support of the CPP through rebates for energy-efficient buildings end-use equipment, based on EIA analysis and a report by Leidos [*8*]
- Updated cost and performance assumptions for distributed generation and combined heat and power technologies in the buildings sector, based on a draft report by Leidos and a joint presentation by the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory, reflecting recent and expected technological progress [*9*, *10*]
- Extension and phaseout of the investment tax credit for residential and commercial solar energy systems, included as part of the December 2015 budget reconciliation bill [*11*]
- Updated cost assumptions associated with switching of fuels and/or technologies for residential end-use services and updated estimates for efficiency of the installed stock of residential end-use equipment, based on reports by Navigant Consulting, Inc. and Leidos [*12*, *13*]
- A new NEMS submodule estimates energy use in the steel and pulp and paper industries and allows for detailed technology choice
- Updated motors model in NEMS to reflect increased efficiency standards for motors [*14*]
- Updated construction [*15*] and mining [*16*] input data to reflect the 2012 Economic Census
- Benchmarks added to individual industry tables in the Industrial Demand Module to allow comparison with aggregate industrial figures and application of benchmark factors in the Reference case to alternative cases

Transportation

- Implementation of a new regional (Census Division) marine model that captures impacts of International Convention for the Prevention of Pollution from Ships (MARPOL) emissions regulations, including modeling of fuel consumption in U.S. Emission Control Areas (ECAs); and incorporation of compliance options addressing fuel switching and the adoption of emission control technologies [*17*]
- New light-duty and heavy-duty vehicle regional (Census Division) sales and stock models, including updated data or revisions to scrappage rates, historical distributions of vehicles by car and light truck class, weight class categories for medium-duty and heavy-duty trucks, fleet use, fuel economy, and fuel type
- Modified calculations for technology adoption and fuel economics for heavy-duty vehicles, and addition of technology availability
- Updated historical data on light-duty and heavy-duty truck vehicle miles traveled through 2013 based on U.S. Department of Transportation (DOT), Federal Highway Administration (FHWA) data [*18*], extended through 2014 using the DOT/FHWA Traffic Volume Trends report [*19*]
- Addition of most recent California Zero-Emission Vehicle Program, starting in model year 2018 and reaching complete implementation in model year 2025, which mandates the sale of zero-emission vehicles and transitional zero-emission vehicles [*20*].

- Addition of historical data in freight rail ton-miles through 2013, using Class 1 Railroad data as reported through the DOT Surface Transportation Board [*21*]

Oil and natural gas production and product markets

- Adoption of a simplified approach to modeling the impact of technology advancement on U.S. oil and natural gas production to better capture a continually changing technological landscape, incorporating assumptions for ongoing innovation in upstream technologies and reflecting average annual growth rates for natural gas and oil resources, and cumulative production from 1990 between the AEO2000 and AEO2015 Reference cases
- Revision of resource assumptions for the offshore North Slope to reflect disappointing results in the Chukchi Sea, BOEM's cancellation of upcoming Arctic lease sales, and Repsol's deferral of exploration in the Arctic
- Updated natural gas plant liquids (NGPL) factors for tight oil and shale gas formations at the play and county levels
- Updated estimated ultimate recovery of tight and shale formations at the county level
- Updated list of offshore discovered and nonproducing fields in the Lower 48 states and their expected resource sizes and startup dates

Natural gas transmission and distribution

- Updated liquefaction capacity to represent the five liquefied natural gas (LNG) export facilities already under construction, updated data from the International Energy Outlook 2016 used in estimating representative world natural gas prices, and calibration of related equations to latest historical data
- Change in accounting for fuel used at LNG export terminals to a separate category, moved from the general category of lease and plant fuel to pipeline and distribution fuel use
- Inclusion of pipeline flow on bidirectional arcs in output report and addition of East North Central to South Atlantic as a bidirectional pipeline flow option
- Basing of fuel prices for compressed natural gas vehicles on data from the Alternative Fuels Data Center of DOE's Energy Efficiency and Renewable Energy Office [*22*] rather than on EIA data; updated federal and state motor fuels taxes for LNG vehicles
- Updated equations in NEMS for projecting consumption in Alaska and production in Canada and Mexico

Oil product markets and biofuels

- Allowing all crude types (not only processed condensate) to be exported from the United States
- Limiting the amount of crude exports from the PADD2-lakes region into Sarnia
- Explicit representation of crude oil withdrawals from the Strategic Petroleum Reserve (SPR), based on SPR plans dated December 2015 [*23*, *24*]
- Revised renewable fuel standard levels for historical and near-term years (through 2016), based on EPA decision [*25*]
- Expanded NEMS price curves for selected product imports and exports
- Revised Liquid Fuels Market Module in NEMS to reflect receipt of NGPL by state and paraffin type, as defined in the Oil and Gas Supply Module
- Change in first build years in NEMS, to 2020 for biomass-based liquids production and gas-to-liquids units and to 2025 for coal-to-liquids units
- Updated fuel use data for corn ethanol plants
- Allowing unplanned builds of splitters and atmospheric cracking units (ACUs) in the Gulf Coast region
- Inclusion of 0.4% capacity "creep" through 2020 for ACUs only
- Revised methodology for pricing fuel oil to electric utilities in Census Division 9
- Increased flexibility of the International Energy Model to choose between crude oil price quality differentials and product exports/imports for better representation of U.S. refinery processes and domestic and foreign oil markets

Electric power sector

- Representation of 3 gigawatts (GW) of unannounced nuclear retirements in the Reference case in the ReliabilityFirst East and West regions [*26*] and announced retirement of the James A. Fitzpatrick (December 2016), Pilgrim (June 2019), and Oyster Creek (December 2019) plants.
- Explicit representation of 8.8 GW of coal-fired units that are being converted to natural gas-fired steam units between 2016 and 2025
- Review of model representation of state RPS policies and incorporation of changes in NEMS

- Updated cost estimates for several electricity generation technologies, based on a draft report provided by external consultants [*27*]
- Modified Electricity Market Module (EMM) to include representation of the CPP [*28*]
- Added model structure to Electricity Fuel Dispatch linear programs to adjust model dispatch dynamically and align it with inputs based on EIA's Short-Term Energy Outlook results for specific model years; and made changes to allow benchmarking of coal and natural gas generation and consumption and of nuclear, hydroelectric, wind, solar, and geothermal generation at the national level

Endnotes

Links current as of July 2016

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26. The unannounced nuclear retirements in the Reference case reflect market uncertainty.
27. This report will be available on the EIA website when finalized. Costs were updated for coal with carbon capture and storage (CCS), combined cycle (without CCS) technologies, combustion turbine technologies, advanced nuclear, and onshore wind and solar photovoltaic technologies. Costs for other technologies are consistent with AEO2015 assumptions.
28. Model constraints were added in both the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) linear programs, to allow modeling of either carbon dioxide (CO2) emission caps or CO2 emission rate standards by EMM region. Model structure was also added to allow trading of allowances between regions, including pricing impacts. The model was updated so that CO2 allowances can be assumed to be allocated to generator or load entities, or auctioned, with appropriate feedback to electricity prices, under a mass-based standard.

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Appendixes

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Executive summary

Projections in the *Annual Energy Outlook 2016* (AEO2016) focus on the factors expected to shape U.S. energy markets through 2040. The projections provide a basis for examination and discussion of energy market trends and serve as a starting point for analysis of potential changes in U.S. energy policies, rules, and regulations, as well as the potential role of advanced technologies.

Key issues addressed in the AEO2016 Reference and alternative cases and discussed in this Executive summary include:

- Recent changes in laws and regulations, including the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) [*1*], which requires states to reduce carbon dioxide (CO2) emissions from existing fossil fuel generators, and an extension of tax credits for wind and solar energy. Together with lower natural gas prices, these changes significantly affect the projected electricity generation fuel mix.
- Implications of the changing electricity generation fuel mix for overall coal demand and the coal production outlook across U.S. coal supply regions.
- Slower electricity demand growth and increases in onsite generation, which together determine the demand for generation from central power stations.
- The effects of resource and technology improvements and prices on the outlook for U.S. oil and natural gas production, and the effect of changing production levels on prices projected consumption.
- Implications of the California Air Resources Board's Zero-Emission Vehicle program [*2*], which nine states have joined, representing 33% of the total U.S. market for new light-duty vehicles.
- Implications of EPA's proposed medium- and heavy-duty vehicle Phase 2 standards [*3*] for CO2 emissions and projected fuel use.
- Implications of alternative economic, energy market, and policy scenarios for energy-related CO2 emissions.

The Clean Power Plan's requirement to reduce carbon dioxide emissions accelerates the shift in the generation mix

The CPP requirement for states to develop plans to reduce CO2 emissions imposes additional costs on higher-emitting energy sources. Combined with lower natural gas prices and the extension of renewable tax credits, the CPP accelerates the shift toward less carbon-intensive generation. In the AEO2016 Reference case, which includes the CPP, 92 gigawatts (GW) of coal-fired capacity is retired by 2030—32 GW more than is retired by 2030 in the No CPP case, which excludes the CPP. In the Reference case, coal-fired generation in 2040 is 32% lower than the 2015 total (Figure ES-1).

From 2015 levels, natural gas-fired electricity generation in the Reference case increases by 26% in 2030 and by 44% in 2040, and generation from renewables increases by 99% in 2030 and by 152% in 2040. These projected changes result in electricity generation with both natural gas and renewables surpassing coal generation in 2024 (natural gas) and in 2028 (renewables). In the No CPP case, electricity generation with natural gas does not surpass coal generation until 2029, and renewable generation does not overtake coal-fired generation in the 2015–40 time frame of the projection (Figure ES-2).

How the states implement the Clean Power Plan influences its effect on electricity generators

The EPA provides several kinds of flexibility to states in implementing the CPP [*4*]. This flexibility allows the states to choose between a mass-based approach (with a cap on total CO2 emissions) and a rate-based approach (with a cap on pounds of CO2 emitted per megawatthour of electricity produced), with different potential consequences for electricity generators and customers. In the CPP Rate case, a rate-based target provides a more direct incentive for switching to carbon-free sources of energy by

Figure ES-1. Net electricity generation from coal, natural gas, and renewables in the AEO2016 Reference case, 2013–40 (billion kilowatthours)

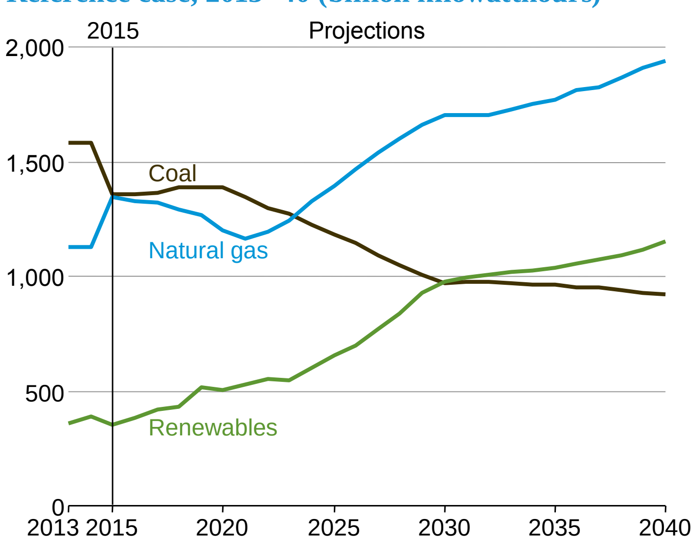
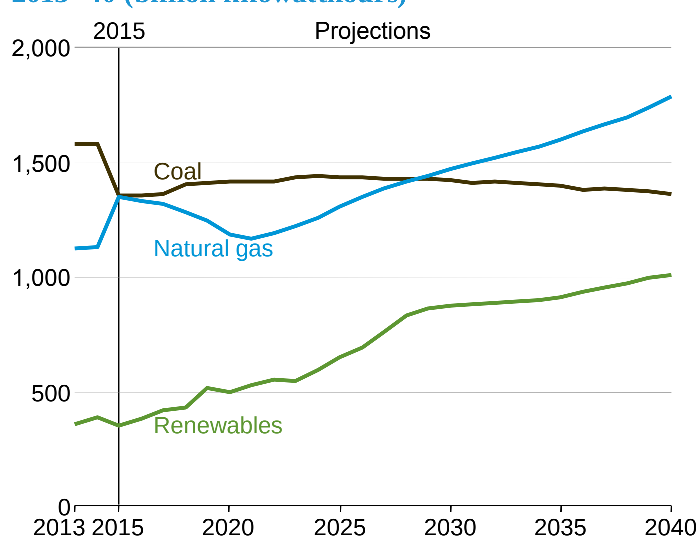


Figure ES-2. Net electricity generation from coal, natural gas, and renewables in the No CPP case, 2013–40 (billion kilowatthours)



rewarding generators that produce emissions below the intensity target and penalizing those with emissions above the target. The mass-based target in the AEO2016 Reference case, as modeled by EIA, treats every ton of CO2 emitted by fossil-fired generation uniformly, which does not provide the same incentive.

The changes in the mix of generating capacity (including central station and end-use generators) are affected differently by the two implementation approaches. In the CPP Rate case, with a rate-based approach, more renewable capacity is added (an additional 28 GW by 2040) than in the AEO2016 Reference case that assumes mass-based implementation. In the Reference case, 14 GW more coal-fired capacity is retired, and 48 GW more natural gas capacity is added between 2015 and 2040 than in the CPP Rate case.

With the mass-based implementation approach assumed in the Reference case in 2040, coal-fired generation is 436 billion kWh lower than in 2015; natural gas-fired generation is 594 billion kWh higher than in 2015; and renewable generation is 828 billion kWh higher than in 2015. With the rate-based approach adopted in the CPP Rate case in 2040, coal-fired generation is 275 billion kWh lower than in 2015, natural gas-fired generation is 375 billion kWh higher than in 2015; and renewable generation is 898 billion kWh higher than in 2015.

Allocating emissions allowances under a mass-based program can also affect how overall program costs are passed along to suppliers, service providers, and consumers. In the Reference case, the allocation of allowances to load-serving entities reduces the impact on retail electricity prices by reducing retailers' costs of compliance. With this allocation method, the average real (2015 dollars) electricity price in 2030 in the Reference Case is 1.7% lower than in the Allocation to Generators case, which assumes allocation of CPP carbon allowances to generators rather than to load-serving entities.

The coal-fired generation share of total electricity production continues to decline, even in the absence of the Clean Power Plan, and natural gas becomes the predominant fuel for electricity generation

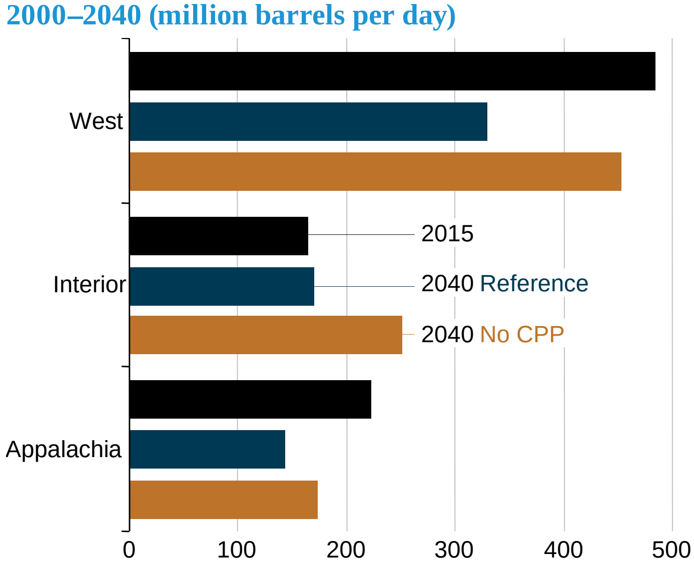
Even in the absence of the CPP, the extension of renewable tax credits, as well as declining capital costs for solar photovoltaics (PV), other emissions regulations that affect coal, and low natural gas prices contribute to a reduction in coal's share of total generation. In the No CPP case, coal-fired generation changes little from 2015–40, and the coal share of total electricity generation falls from 33% in 2015 to 26% in 2040. Additions to coal-fired capacity are limited in the near term by emission regulations and in the long term by low natural gas prices and increased pressure from renewable generation. In the No CPP case, 60 GW of coal-fired generating capacity is retired from 2016–30.

Natural gas-fired generation declines from 2016–20 in response to a surge in wind and solar capacity builds resulting from both declining installation costs and the extension of key federal tax credits for these technologies. After 2020, however, the natural gas share of total generation increases steadily in the No CPP case, overtaking coal before 2030 and accounting for 34% of total generation in 2040.

All coal supply regions are affected—though not equally—when the Clean Power Plan is implemented

The West region—which accounted for the largest share of total coal production in 2015—experiences the biggest decline in coal production, at about 155 million short tons from 2015–40 (Figure ES-3). Implementation of the Mercury and Air Toxics Standards beginning in 2015 and 2016 encouraged near-universal adoption of emissions control equipment at existing coal-fired plants, which enables more coal-fired generators to use high-sulfur coal from the Interior region. The lower demand for coal in the AEO2016 Reference case, which includes the CPP, results in slow growth of coal production in the Interior region over the projection period. In the No CPP case, production of higher sulfur coal from the Interior region increases by nearly 90 million short tons. The lower level of Appalachian coal production in the Reference case in 2040 compared to the No CPP case represents the smallest difference among the coal-producing regions. Production of coal in the Appalachian region declined sharply before 2015 as domestic coal buyers shifted from Appalachian steam coal toward other coal sources or to other fuels for economic reasons. The Appalachian region remains a major source of metallurgical coal, whose markets are not directly affected by the CPP. With or without the CPP, Appalachia's producers have a relatively high dependence on sales of both metallurgical and steam coal in international coal markets.

Figure ES-3. Petroleum and other liquid fuels production by region and type in the Reference case, 2000–2040 (million barrels per day)



Electricity demand growth slows as more on-site generation reduces the need for central-station generation

The extension of federal tax credits for PV systems, combined with a continued decline in PV prices, spurs the adoption of residential and commercial PV in the AEO2016 Reference case (Figure ES-4). Installed residential PV capacity increases by an average of 10%/year from 2015–40, while installed commercial PV capacity increases by an average of 6%/year. In 2040, generation from residential systems totals 90 billion kWh, and generation from commercial systems totals 37 billion kWh in the Reference case. Without the electricity generated by residential PV systems that is used onsite, electricity sales to residential customers would be nearly 6% higher in 2040. In addition, net PV generation accounts for more than 2% of commercial sector electricity sales in 2040.

Spurred by higher energy demand and lower interest rates in the High Economic Growth case, solar PV net generation is 16% higher in the residential sector and 4% higher in the commercial sector in 2040 than in the Reference case. With the higher level of total electricity generation in the High Economic Growth case, residential electricity sales back to the grid are 15% higher in 2040 than in the Reference case. In the Low Economic Growth case, solar PV net generation is 30% lower in the residential sector and 4% lower in the commercial sector in 2040 than in the Reference case.

After 2017, U.S. oil production increases as prices rise

Total U.S. oil production in the AEO2016 Reference case falls from 9.4 million barrels per day (b/d) in 2015 to 8.6 million b/d in 2017. After 2017, the total production grows to 11.3 million b/d in 2040 as real (2016 dollars) crude oil prices recover from an annual average of less than $50/barrel (b) in 2017 to more than $130/b in 2040 (Figure ES-5). The Lower 48 states lead the increase in crude oil production, which results largely from higher oil prices, continued advances in industry practices, and further development of technologies that reduce costs and allow for increased recovery of tight oil resources.

The Bakken, Western Gulf Basin (including the Eagle Ford play), and Permian Basin lead the continued development of tight oil resources in the Lower 48 states in the Reference case. With the recent decline in oil prices, tight oil production shows the largest reduction, from 4.9 million b/d in 2015 to 4.2 million b/d in 2017, before increasing to 7.1 million b/d in 2040. After 2017, higher oil prices, as well as ongoing exploration, appraisal, and development programs that expand operator knowledge about producing reservoirs, could result in the identification of additional tight oil resources and the development of technologies that reduce costs and increase oil recovery.

In the Lower 48 states, offshore production (which is less sensitive to short-term price movements than onshore production), increases to 2.0 million b/d in 2021, led by new deepwater projects in the Gulf of Mexico, including the Heidelberg and Appomattox fields that are scheduled to begin operations in 2016 and 2017, respectively. After 2021, Lower 48 offshore crude oil production declines to roughly 1.6 million b/d in 2030 and remains at about that level through 2040, as production from newly developed fields is offset by declines in legacy fields.

Lower 48 onshore crude oil production using CO2-enhanced oil recovery increases from 0.3 million b/d in 2015 to 0.7 million b/d in 2040 as oil prices rise and affordable sources of CO2 become available. Both onshore and offshore production in Alaska continue to decline, from a total of nearly 0.5 million b/d in 2015 to less than 0.2 million b/d in 2040.

U.S. natural gas production continues to rise despite low or moderately rising prices

Total U.S. dry natural gas production increases in the Reference case from 27.2 trillion cubic feet (Tcf) in 2015 to 42.1 Tcf in 2040, while average annual U.S. natural gas prices at the Henry Hub (in 2015 dollars) remain at about $5.00/million British thermal units (Btu) (Figure ES-6). Although natural gas prices remain relatively low and stable, projected development of natural gas

Figure ES-4. Electricity generation from solar power in the buildings sectors in three cases, 2010–40 (billion kilowatthours)

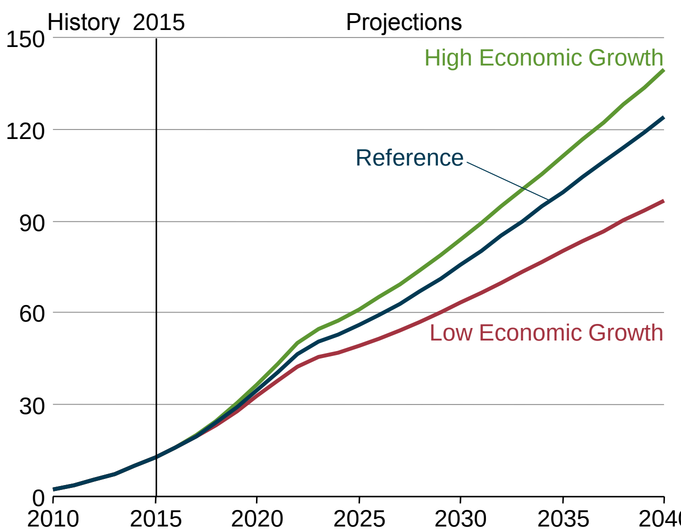
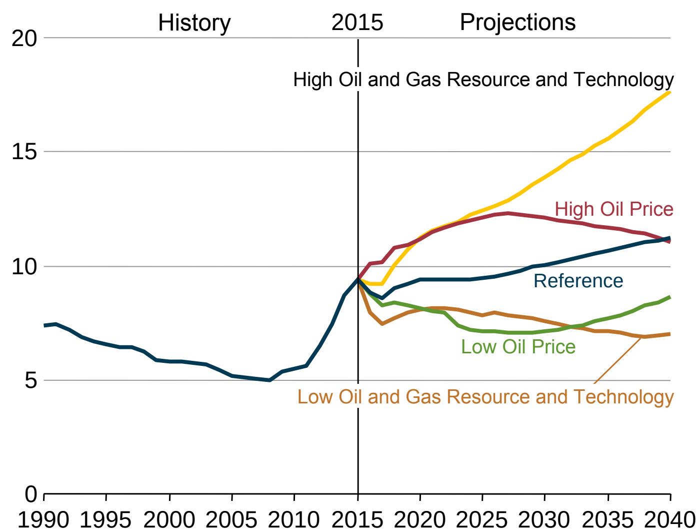


Figure ES-5. Total U.S. crude oil production in five cases, 1990–2040 (million barrels per day)



resources in shale gas and tight oil plays, tight gas, and offshore increases as a result of abundant domestic resources and technology improvements.

Production from shale gas and tight oil plays leads the increase in natural gas production in the Reference case from 13.6 Tcf in 2015 to 29.0 Tcf in 2040, as their share of total U.S. dry natural gas production grows from 50% in 2015 to 69% in 2040 (Figure ES-7). Shale gas and tight oil plays are resources in low-permeability reservoirs. They include the Sanish-Three Forks Formation beneath the Bakken, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey formations.

U.S. offshore natural gas supply, after declining from 2015 to 2016 to around 1.4 Tcf, remains stable from 2015–20 in the Reference case, then falls to 1.2 Tcf in 2023, reflecting declines in production from legacy offshore fields. After 2027, as increased production from new discoveries offsets the decline in legacy fields, offshore natural gas production increases to 1.7 Tcf in 2040.

Growing natural gas demand in the industrial and electric power sectors and increasing exports of liquefied natural gas (LNG) place upward pressure on domestic natural gas prices. Improvements in drilling technology allow production to keep pace with demand (both for domestic consumption and for export), resulting in relatively stable prices throughout the projection period.

Technology improvements increase U.S. production from tight and shale formations

Growth in U.S. oil and natural gas resources (proved reserves and technically recoverable resources) and cumulative production have averaged 1.8%/year and 2.5%/year for crude oil and natural gas, respectively, from 1990–2005, and 3.6%/year and 3.1%/year from 2005–15. Examples of technology improvements include better rigs and drill bits that can drill wells faster at lower unit costs, improved hydraulic fracturing techniques that expose more of the rock to the well, better control of the drill bit path, and better offshore rigs and platforms that can reach great depths and handle extreme pressures and temperatures. Multi well pad drilling and improvements in logistics also have contributed to the cost reductions. These technology improvements have allowed, and are likely to continue to allow, the expansion of tight and shale gas production, as indicated in Figure ES-7.

The Reference case incorporates assumptions about changes in upstream technologies and industry practices in developing tight oil, tight gas, and shale gas plays. The plays are divided into two tiers, with different aggregate technology change rates depending on their levels of development, which are based on the potential effects of future breakthrough technologies on resource recovery rates and drilling and operating costs, particularly in areas that are less developed.

Natural gas trade and LNG exports depend on the differential between U.S. and world natural gas prices

The size of the domestic oil and natural gas resource and technology improvement rates affect the ability of U.S. producers to supply natural gas and the cost of domestic supplies. Lower world oil prices reduce the competitiveness of U.S. LNG in world markets, while exports to Canada and Mexico are affected more directly by U.S. natural gas prices, with exports falling when natural gas prices rise and increasing when natural gas prices fall.

In the Reference case, total U.S. exports of natural gas increase to 8.9 Tcf in 2040, with LNG exports of 6.7 Tcf (Figure ES-8). In the High Oil Price case, with higher international natural gas prices, particularly in Asia, U.S. LNG exports are more competitive. The greater growth in LNG exports in the High Oil Price case increases the call on domestic production, which in turn leads to higher domestic natural gas prices. The increased demand for LNG exports is offset somewhat by lower natural gas exports to Canada and Mexico as prices rise. U.S. exports of natural gas increase in the High Oil Price case to 12.5 Tcf in 2035 and remain near that

Figure ES-6. Annual average Henry Hub natural gas spot market prices in the Reference case, 1990–2040 (2015 dollars per million Btu)

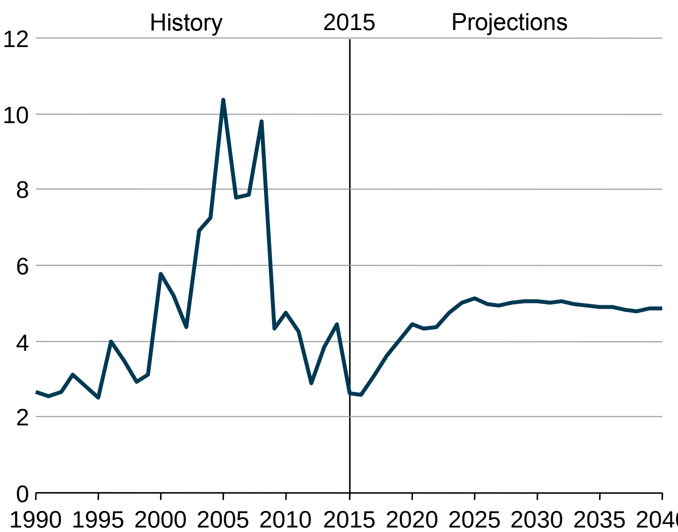
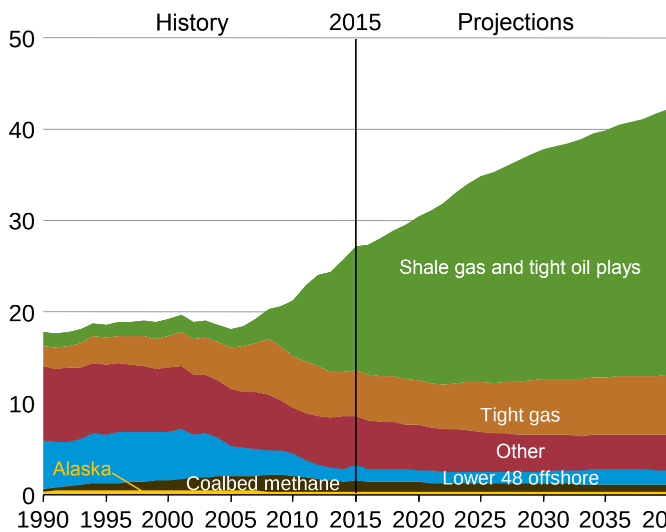


Figure ES-7. U.S. dry natural gas production by source in the Reference case, 1990–2040 (trillion cubic feet)



level through 2040, and LNG exports increase to 10.5 Tcf in 2040. In the Low Oil Price case, where there is less incentive for LNG exports, total U.S. exports of natural gas increase only to 6.8 Tcf in 2040, with LNG exports of 5.6 Tcf.

In the High Oil and Gas Resource and Technology case, lower production costs lead to more natural gas production. With assumptions of a larger resource base and more rapid improvement in production technologies in the High Oil and Gas Resource and Technology case than in the Reference case, the United States becomes a net exporter of natural gas to Canada in 2029 and U.S. LNG exports increase to 10.3 Tcf in 2035–40. In the Low Oil and Gas Resource and Technology case, U.S. natural gas production is lower because of a smaller resource base and slower improvement in technology than in the Reference case. In this case, U.S. natural gas exports total 4.7 Tcf in 2020, with LNG exports of 2.3 Tcf in that year, and remain at roughly the same level through 2034 before declining slightly through 2040.

California zero-emission vehicle program drives increasing sales of zero-emissions vehicles and transitional zero-emissions vehicles

The California zero-emissions vehicles (ZEV) (electric and hydrogen fuel cell) program issued in July 2014 is part of California's Advanced Clean Cars Program. The Advanced Clean Cars Program was adopted in the Annual Energy Outlook as part of AEO2016. The Advanced Clean Cars Program combines control of Clean Air Act-defined criteria emissions, including greenhouse gases, and the ZEV program. The program was enacted in addition to national corporate average fuel economy standards, primarily to increase the percentage of ZEVs and transitional zero-emissions vehicles (TZEV)s (plug-in hybrid-electric and hydrogen internal combustion engine vehicles) to combat California-specific smog and emissions concerns. Nine other states have adopted the California ZEV program. California and those 9 states represented 33% of the total U.S. market for new light-duty vehicles in 2015.

Manufacturers are required to produce ZEV credits equal to a percentage of their average conventional vehicle sales. Large manufacturers (more than 20,000 annual sales in California) are required to produce a minimum percentage of ZEVs. The remainder of the credits can be earned with TZEVs. Starting in model year (MY) 2018, manufacturers are required to produce ZEV credits equal to 4.5% of their conventional vehicle sales, and in MY 2025 the percentage requirement increases to 22%, with a minimum of 16% ZEVs. The credits awarded vary, depending on the vehicle type and driving range. With limitations, credits may be traded between manufacturers and between states, and requirements are lessened for smaller manufacturers.

The updated California ZEV program for MY 2018 and later drives increasing ZEV sales. In the AEO2016 Reference case, total U.S. annual sales increase to 590,000 ZEVs and 348,000 TZEVs in 2025, partly as a result of the ZEV program (Figure ES-9). Combined ZEV and TZEV sales account for 6% of national light-duty vehicle (LDV) sales in 2025, the first year of complete implementation. In 2025, states in the ZEV program account for 415,000 combined ZEV and TZEV sales, or 50% of total ZEV and TZEV sales. Currently, ZEV and TZEV sales in covered states account for 39% of total ZEV and TZEV sales. This represents compliance, as the credits earned would meet the credit percentage required. By 2040, nationwide ZEV and TZEV sales reach a combined 1.1 million sales.

Proposed medium- and heavy-duty vehicle Phase 2 standards reduce diesel fuel demand and carbon dioxide emissions

AEO2016 includes a Phase 2 Standards case that analyzes the estimated effects of more stringent regulations for fuel consumption and greenhouse gas emissions from medium- and heavy-duty vehicles. The proposed Phase 2 standards, issued jointly by the

Figure ES-8. U.S. exports of liquefied natural gas in five cases, 2005–40 (trillion cubic feet)

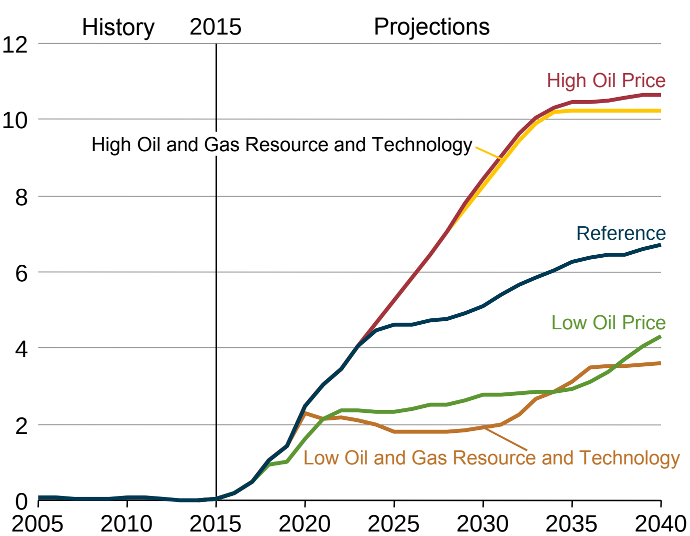
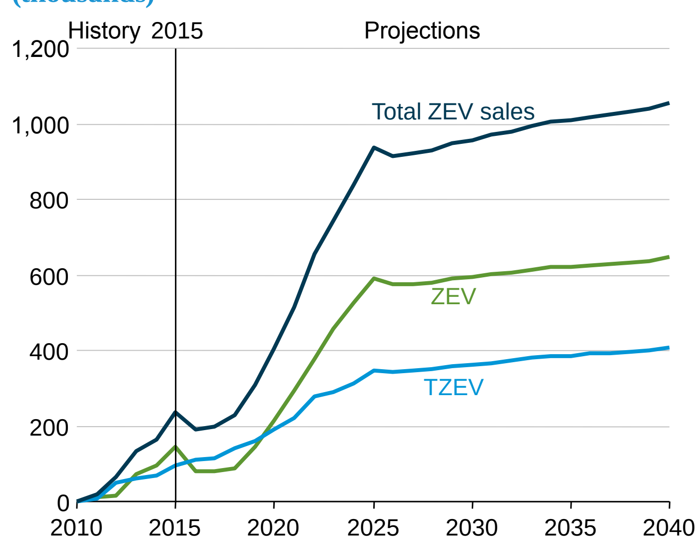


Figure ES-9. Sales of zero-emission vehicles and transitional zero-emission vehicles, 2010–40 (thousands)



National Highway Transportation Safety Administration and the EPA, are a continuation of the Phase 1 standards, which expire at the end of MY 2018. The Phase 2 standards would take effect in MY 2021, with total implementation in MY 2027, addressing vehicles in four discrete categories: combination tractors, trailers, heavy-duty pickup trucks and vans, and vocational vehicles [5].

In the AEO2016 Phase 2 Standards case, the vehicle categories are reduced to three gross vehicle weight groups: Class 3, Classes 4–6, and Classes 7–8. Compared with average new vehicle fuel economy in 2027 in the AEO2016 Reference case, average new vehicle fuel economy in the Phase 2 Standards case for combined Classes 3–8 increases by 28%. After 2027, the standards remain constant, but technology adoption continues as new cost-effective technologies become available. In 2040, the combined average fuel economy for vehicles in all three categories in the Phase 2 Standards case is 10.6 miles per gallon (mpg)—compared to 8.0 mpg in the Reference case—a 33% improvement. Higher on-road fuel economy of the medium- and heavy-duty truck stock, which is slowly affected by the introduction of new vehicles, reduces energy consumption in the Phase 2 Standards case by 22% in 2040 compared with the Reference case level. Cumulative medium- and heavy-duty vehicle consumption of diesel fuel from 2021–40 in the Phase 2 Standards case is 2.5 billion barrels lower than in the Reference case (Figure ES-10). Consequently, cumulative CO2 emissions in the transportation sector from 2021–40 are 1,186 million metric tons (3%) lower in the Phase 2 Standards case than in the Reference case.

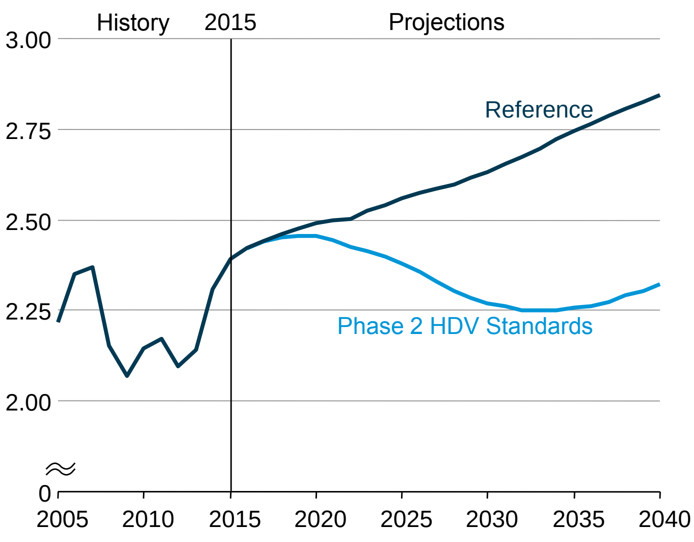
Class 2b pickup trucks and vans are included in the Phase 2 Standards case; however, the fuel economy and fuel consumption for these vehicles are not reported individually in AEO2016. Class 2b is included in the data for total transportation fuel consumption and emissions. Trailers are not explicitly modeled in the Phase 2 Standards case because of a lack of inventory and usage data. Despite improvements since the start of Phase 1, many limitations still exist in the availability of data on the technologies used to meet the Phase 1 compliance standards and on Phase 2 vehicle baseline performance, which makes it difficult to estimate future energy effects. The EPA baseline for Phase 2 is established by assuming compliance with Phase 1 in MY 2017, which is evaluated differently. Therefore, it is unknown whether Phase 1-compliant vehicles in MY 2017 accurately represent the proposed Phase 2 baseline. The discussion of the Phase 2 Standards case in the AEO2016 Issues in Focus details the proposed standards, the vehicles affected, and regulatory and modeling issues.

With lower natural gas prices, industrial sector energy consumption increases through 2040

The AEO2016 Reference case projects robust growth in industrial energy use of natural gas as shipments increase over the 2015–40 period. Low natural gas prices and increased availability of natural gas and related resources, including hydrocarbon gas liquids (HGL), benefit the U.S. industrial sector and the manufacturing sector, in particular, in several ways. Natural gas is used as a fuel to produce heat and to generate electricity. Natural gas is also used, along with HGL products, as a feedstock to produce chemicals, pharmaceuticals, and plastics. Low energy prices result in more rapid economic growth and increasing demand for industrial products.

Industrial shipments and improvements in energy efficiency over time have significant effects on energy consumption in the industrial sector in the Reference case. As a result of efficiency improvements, industrial energy consumption grows more slowly than shipments. Total delivered energy consumption in the industrial sector grows by 1.2%/year from 2015–40. In the near term, energy consumption grows by 1.8%/year in the Reference case between 2015 and 2025, more than twice the rate from 2025 to 2040, as a result of more rapid growth in shipments in the near term, 2.4%/year from 2015–25, compared with 1.5%/year from 2025–40.

Figure ES-10. Diesel fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40 (million barrels per day)



Growth in industrial production leads to increased natural gas consumption in the industrial sector, from 9.4 quadrillion Btu in 2015 to 11.3 quadrillion Btu in 2025 and to 12.9 quadrillion Btu in 2040. The projected rate of growth in natural gas consumption, at 1.3%/year from 2015–40, is slightly higher than the rate of growth for total industrial sector energy consumption. The bulk chemical industry is the largest user of natural gas in the industrial sector. Other large users include refining, food products, mining, iron and steel, paper products, and metal-based durables.

The bulk chemical industry accounts for much of the growth in industrial energy consumption, with a competitive price advantage for feedstocks, especially HGL, reflected in the growth of shipments from 2015–40. In the Reference case, energy consumption in the bulk chemical industry grows by 80% from 2015–40, compared with 18% for other manufacturing and 30% for nonmanufacturing industries (Figure ES-11). Energy consumption growth in the bulk chemical industry is concentrated in the 2015–25 period

(4.3%/year, compared with 1.1%/year from 2025–40), and shipments of bulk chemicals increase by 4.8%/year from 2015–25, compared with 1.4%/year from 2025–40.

Different assumptions about the rate of economic growth and the levels of oil and natural gas prices also affect energy consumption growth rates in the industrial sector (Figure ES-12). In both the High Economic Growth case and the High Oil Price case, energy consumption growth slows in the later years of the projections. In the High Oil Price case, energy consumption growth in the mining industry is considerably higher than in the Reference case and higher than in the High Economic Growth case, as shipments from the oil and gas extraction industry grow rapidly when energy prices are high. Energy consumption in the bulk chemical industry grows by more than 2%/year in the Reference, High Oil Price, Low Economic Growth, and High Economic Growth cases.

Energy-related CO2 emissions vary widely with different assumptions about economic growth, energy prices, and policies

The AEO2016 Reference case assumes that current laws and regulations remain in effect through 2040; however, the status of the CPP, which is on hold pending judicial review, is uncertain. In the Reference case, the CPP is assumed to be implemented as scheduled, using mass-based standards that impose limits on CO2 emissions from fossil fuel-fired generators. The No CPP case assumes that no federal carbon reduction program is implemented.

Across the alternative AEO2016 cases, total energy-related CO2 emissions in 2040 vary by more than 800 million metric tons, depending on the assumptions in each case about economic growth, energy prices, and energy policies (Figure ES-13). In the High Economic Growth case, which includes the CPP, total emissions in 2040 are close to the No CPP case total of 5,468 million metric tons because emissions from sectors other than electric power increase as the economy grows. In the Extended Policies case, CO2 emissions fall to 4,623 million metric tons in 2040, which is 23% lower than the 2005 total. The Extended Policies case assumes that existing policies and regulations remain in effect or are extended beyond sunset dates specified in current regulation; that efficiency policies—including corporate average fuel economy standards, appliance standards, and building codes—are expanded beyond current provisions; and that EPA CPP regulations that reduce CO2 emissions from electric power generation are tightened after 2030. As a result, energy-related CO2 emissions in 2040 in the Extended Policies case are 845 million metric tons lower than in the No CPP case.

Variations in energy prices have a smaller effect than the CPP requirements on total CO2 emissions. Because the CPP imposes a limit on CO2 emissions in the electric power sector that are met in all cases, differences in energy-related emissions are seen only in the end-use sectors. As a result, the difference in 2040 CO2 emissions between the Low Oil Price and High Oil Price cases is smaller than the difference between the No CPP case and the Extended Policies case.

Figure ES-11. Industrial sector energy consumption by application in the Reference case, 2010–40 (quadrillion Btu)

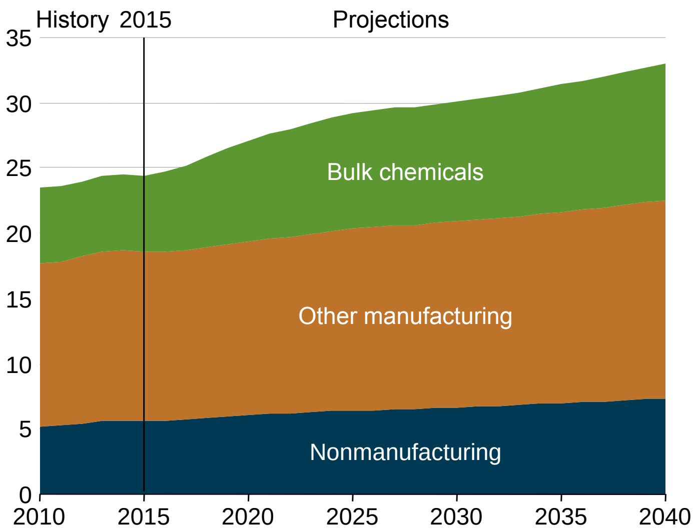


Figure ES-12. Industrial sector delivered energy consumption in four cases, 2010–40 (quadrillion Btu)

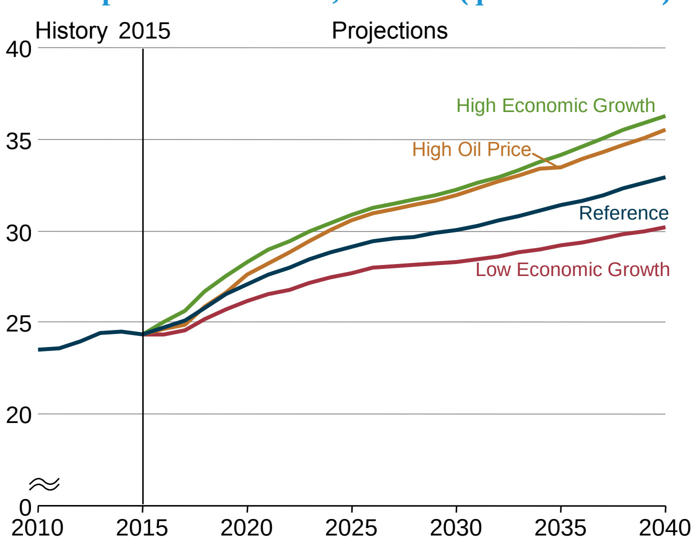
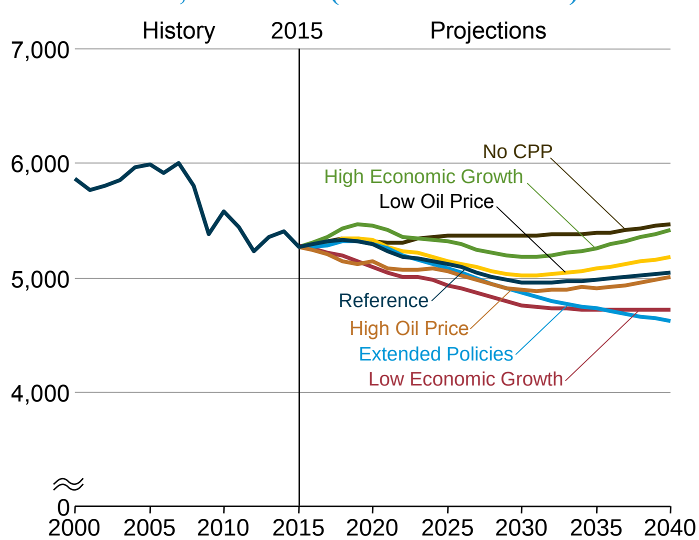


Figure ES-13. Energy-related carbon dioxide emissions in seven cases, 2000–2040 (million metric tons)



Endnotes for executive summary

Links current as of July 2016

1. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015) https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015) https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
2. California Environmental Protection Agency, Air Resources Board, "Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles" (Sacramento, CA: July 10, 2014), http://www.arb.ca.gov/msprog/zevprog/zevregs/1962.2_Clean.pdf.
3. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.
4. For example, whether or not to engage in interstate trading programs, to allow credits for *outside-the-fence* options like energy efficiency, to auction allowances or to allocate them freely if electing a mass-based approach, how to credit renewable energy projects under a rate-based program, and other options.
5. Vocational vehicles include any medium- or heavy-duty vehicle that is not a heavy-duty pickup or van or a semi-truck tractor with a 5th wheel trailer attachment (including vehicles like box or delivery trucks, buses, dump trucks, tow trucks, refuse haulers, and cement trucks).

Figure sources for executive summary

Links current as of July 2016

Figure ES-1. Net electricity generation from coal, natural gas, and renewables in the AEO2016 Reference case, 2013–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure ES-2. Net electricity generation from coal, natural gas, and renewables in the No CPP case, 2013–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF_NO_CPP.D032316A.

Figure ES-3. Petroleum and other liquid fuels production by region and type in the Reference case, 2000–2040: AEO2016 National Energy Modeling System, run REF2016.D032416A and REF_NO_CPP.D032316A.

Figure ES-4. Electricity generation from solar power in the buildings sectors in three cases, 2010–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWMACRO.D032516A, and HIGHMACRO.D032516A.

Figure ES-5. Total U.S. crude oil production in five cases, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** REF2016.D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure ES-6. Annual average Henry Hub natural gas spot market prices in the Reference case, 1990–2040: History: 1990–2014, U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC, September 2015). **Projection:** AEO2016 National Energy Modeling System, runs REF2016.D032416A.

Figure ES-7. U.S. dry natural gas production by source in the Reference case, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projection:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure ES-8. U.S. exports of liquefied natural gas in five cases, 2005–40: History: 1990–2014, U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC, September 2015). **Projection:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure ES-9. Sales of zero-emission vehicles and transitional zero-emission vehicles, 2010–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure ES-10. Diesel fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

Figure ES-11. Industrial sector energy consumption by application in the Reference case, 2010–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure ES-12. Industrial sector delivered energy consumption in four cases, 2010–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, HIGHPRICE.D041916A, LOWMACRO.D032516A, and HIGHMACRO.D032516A.

Figure ES-13. Energy-related carbon dioxide emissions in seven cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWMACRO.D032516A, HIGHMACRO.D032516A, LOWPRICE.D041916A, HIGHPRICE.D041916A, and TAXTENDED.D050216A.

Legislation and regulations

Introduction

The *Annual Energy Outlook 2016* (AEO2016) represents current federal and state legislation and final implementation of regulations as of the end of February 2016. The AEO2016 Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates are no longer in effect at the time of those sunset dates) [*1*]. The potential effects of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded, or for which parameters will be set in a future regulatory process—are not reflected in the AEO2016 Reference case, but some are considered in alternative cases. This section summarizes federal and state legislation and regulations newly incorporated or updated in AEO2016 since the completion of the *Annual Energy Outlook 2015* (AEO2015) in April 2015. This section also summarizes selected rules and regulations that have been proposed recently and have the potential to affect the projection significantly.

Examples of federal and state legislation and regulations incorporated in the AEO2016 Reference case, or whose handling has been modified, include:

- Incorporation of the U.S. Environmental Protection Agency's final rules for the Clean Power Plan (CPP) [*2*] under the Clean Air Act (CAA) Section 111(b) and 111(d). Section 111(b) sets carbon pollution standards for new, modified, and reconstructed power plants. Section 111(d) sets performance standards for existing fossil fuel-fired plants. Final rules to support the performance standards and model trading rules were in effect by October 2015. However, in February 2016, the U.S. Supreme Court issued a stay on enforcement of the existing power plant rule, pending resolution of legal challenges [*3*]. The AEO2016 Reference case includes the CPP. An alternative No CPP case, which assumes that the CPP is not enforced, also is included in AEO2016, as are several cases that consider the implication of alternative approaches to CPP implementation.
- Incorporation of the California Air Resource Board (CARB) Zero-Emission Vehicle (ZEV) program for model year (MY) 2018 and later vehicles [*4*]. The ZEV program is part of California's Advanced Clean Cars Program. Nine other states have fully adopted the CARB Advanced Clean Cars program standards. The latest amendment to the ZEV program, which affects model year (MY) 2018 and later vehicles, requires a certain percentage of an automaker's sales to be made up of ZEVs and Transitional Zero-Emission Vehicles (TZEVs). The ZEV sales requirement is administered through credits, with the required allowable credits calculated as a percentage of the automaker's conventional gasoline and diesel light-duty vehicle (LDV) sales, averaged over the previous three model years.
- Revisions to reflect the extension of the production tax credit (PTC) for wind and a 30% investment tax credit (ITC) for solar, enacted in December 2015 as part of the 2016 Consolidated Appropriations Act [*5*]. Unlike previous extensions, which maintained the inflation-adjusted value of the PTCs for the duration of the extensions, the current extension introduces a phaseout that reduces the value of the credit over time before final expiration.
- Adoption of newly added or modified federal efficiency standards for residential and commercial appliances and equipment established under authority of the Energy Policy and Conservation Act of 1975, the National Appliance Energy Conservation Act of 1987, and the Energy Independence and Security Act of 2007. The Reference case includes only promulgated standards and comprehensive consensus agreements.
- Incorporation of modifications to existing state Renewable Portfolio Standards (RPS) or similar laws, to reflect the addition of a new RPS policy in Vermont and expanded RPS targets in California and Hawaii [*6*]. The Reference case does not include laws and regulations with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources.
- Updates in AEO2016 to better reflect the International Convention for the Prevention of Pollution from Ships (MARPOL) [*7*], which mandates that existing ships either burn fuel containing a maximum of 0.1% sulfur or use scrubbers to remove sulfur emissions. The U.S. Energy Information Administration (EIA) has updated AEO2016 to improve the calculation of the amount of fuel consumed by ocean-going vessels traveling though North American and Caribbean emissions control areas, including the effects of compliance strategies. Further, EIA has updated the methodology for calculating energy demand for oceangoing vessels to include estimations of fuel consumption by ship type and commodity moved.
- Laws and regulations will continue to evolve over time, and some laws include sunset provisions that may be extended. However, even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. The implications of some pending and possible developments are examined in alternative cases included in AEO2016. In addition, at the request of both federal agencies and Congress, EIA has regularly examined the potential implications of other possible energy options in special analyses that can be found on the EIA website at http://www.eia.gov/analysis/reports.cfm?t=138.

LR1. Clean Power Plan with New Source Performance Standards for power generation

The Clean Air Act (CAA) sets the regulatory framework for federal efforts to control emissions of air pollutants in the United States, requiring, among other things, the application of preferred technology standards to limit pollutants found to pose a threat to human health and the environment. Using CAA provisions, the U.S. Environmental Protection Agency (EPA) has developed a three-part program to limit carbon dioxide (CO2) emissions from the electric power sector:

1. CO_2 performance standards for new power plants
2. CO_2 performance standards for existing power plants (the CPP)
3. Rules for states electing federal implementation options and model trading program design

Final rules to support the performance standards were published in October 2015, with the performance standards for existing power plants and the proposed model trading rule scheduled to take effect starting in 2022. However, in February 2016 the Supreme Court issued a stay on enforcement of the existing power plant CPP, pending resolution of legal challenges. At the time the stay was issued, no lower court had considered the merits of the legal challenges to the rule, and there was no enforceable judgment either affirming or vacating the CPP. Under these circumstances the AEO2016 Reference case includes the CPP and an alternative No CPP case that excludes the CPP for comparison.

Regulatory background: legal basis for CPP/NSPS rules

In Section 111 of the CAA, Congress provided for the development of emissions standards to limit pollutants from new sources. The new source performance standards (NSPS) were intended to be nationwide and uniform, as a complement to the regional application of ambient air quality standards to control emissions from existing sources. However, the CAA requires that, once EPA has established standards for new sources EPA must require states to develop standards for existing sources.

For CO_2 emissions from electricity generation units, EPA developed the following regulations for new and existing sources concurrently:

- *Performance standards for new sources* (as well as modified and reconstructed sources) under authority of Section 111(b) [*8*]
- *Performance standards for existing sources* under Section 111(d), published in October 2015 [9] and stayed in February 2016 [*10*]
- *Federal plan and model trading rules,* proposed in October 2015 [*11*], with EPA's announced intent to finalize the rules for both mass-based (cap and trade) and rate-based versions by summer 2016

EPA provides for the exclusion of units subject to the Section 111(b) rule from Section 111(d) plans, so that if a source covered by a Section 111(d) plan is modified or reconstructed, it drops out of Section 111(d) coverage and only needs to meet the Section 111(b) requirements.

Representing new source CO_2 emission standards: Sec 111(b) rules

The CAA requires that standards issued under Section 111 reflect the degree of emissions limitation achievable through the best system of emission reduction (BSER) found by EPA to have been adequately demonstrated. In its final rule, for new sources, which also covers modified and reconstructed sources, EPA specified CO_2 standards for four types of new electric generating units (EGUs):

1. *New fossil steam EGUs:* 1,400 pounds CO_2/megawatthour (MWh) gross
2. *Modified fossil steam EGUs:* limit determined by unit's best historical annual CO_2 rate (from 2002 to the date of the modification) but no greater than reconstructed coal EGUs
3. *Reconstructed coal steam EGUs:*
   a. 1,800 pounds CO_2/MWh gross (if heat input is more than 2,000 million British thermal units (Btu)/hour)
   b. 2,000 pounds CO_2/MWh gross (if heat input is 2,000 million Btu/hour or less)
4. *New combined-cycle combustion turbine:* 1,000 pounds CO_2/MWh gross, or 1,030 pounds CO_2/MWh net, where the state has the option to choose between having combustion turbine operators report their generation output on a gross basis (including total electric output) or a net basis (excluding the power necessary to operate the plant itself)

The new coal plant technology modeled in the AEO2016 National Energy Modeling System (NEMS) includes 30% carbon capture to ensure the ability to meet the standard. New coal plants without carbon capture and storage technology are not allowed to be built. The new natural gas combined-cycle plants modeled in previous AEOs were already below the 1,000 pounds CO_2/MWh standard, and no change was necessary to the natural gas technology assumptions to reflect the final rule. The NEMS electricity model does not explicitly represent modified or reconstructed power plants.

Representing existing-source CO_2 emissions standards: Section 111(d) rules

EPA adopted interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired EGUs:

1. *Existing fossil steam EGUs:* interim/final rate, 1,534/1,305 pounds CO_2/MWh net
2. *Existing stationary CTs:* interim/final rate, 832/731 pounds CO_2/MWh net [*12*]

The emission performance rates, which are set uniformly for the nation for both subcategories, were determined using an analysis of BSER that reflects an emission adjustment according to EPA's assessment of the potential mass emission reductions associated with lower-emitting compliance options (e.g., new renewable energy generation or more efficient thermal plant operation). The adjustment is made by:

- Estimating the annual net generation from an achievable amount of qualifying incrementally lower-carbon and zero-carbon generation
- Substituting that generation to displace baseline electricity generation and CO2 emissions from the affected EGUs that have higher emissions
- Replacing fossil steam and natural gas-fired combined-cycle generation with regionally identified incremental (2012 and beyond) potential renewable generation on a pro rata basis corresponding to the baseline mix of fossil generation in each region [*13*]

To facilitate flexibility in state implementation of the CPP rule, EPA developed both rate-based and mass-based state-specific standards, with states able to choose between the two program types. In so doing, each state must determine whether to apply its emissions reduction requirements to affected EGUs, or to meet the equivalent state-wide CPP rate-based goal or the mass-based goal. After choosing the rate-based or mass-based compliance option, states must then choose between: (1) an Emission Standards Plan Type, in which the state places all requirements directly on its affected EGUs, with all requirements federally enforceable; and (2) a State Measures Plan Type, which can include a mix of measures that may apply to affected EGUs and/or other entities, and may lead to CO2 reductions from affected EGUs, but are not federally enforceable. States may use a wide variety of measures to comply with the rate-based standards, including options not assumed by EPA in the calculation of the standard. For example, new nuclear generation, new end-use renewable generation, and incremental demand reductions as a result of energy efficiency can be used as zero-emitting compliance options to offset emissions from affected generators.

Implementation of the CPP rule in AEO2016 reflects four key design choices:

- First, an assumption is made about which type of trading program states choosing interstate cooperation would elect: rate-based or mass-based. Based on a review of the existing literature, including comments made to EPA and in other public forums, a majority of comments (from state regulatory authorities and/or the regulated utilities) suggested a preference for a mass-based trading program. This preference appeared to be based on the states' familiarity with mass-based (cap and trade) programs and their ability to use mass-based allowance allocation to compensate affected parties, such as ratepayers and energy-intensive industries. The AEO2016 Reference case assumes that all states use the mass-based approach for all sources. In addition to the Reference case, the CPP Rate case assumes rate-based regulation in all states, and the CPP Hybrid case assumes a hybrid approach, in which some states use mass-based regulation and others use rate-based regulation.
- Second, an assumption is made about the level at which states would choose to cooperate (for example, regional, Independent System Operator/Regional Transmission Organization, interconnect, or national). Based on a review of public commentary and analysis, the AEO2016 Reference case assumes trading at the regional level, designed to replicate current power market trading patterns. The CPP Interregional Trading case examines the implications of trading beyond regional boundaries.
- Third, under a mass-based program, there is a need to specify the method by which allowances would be allocated. A review of the literature indicated that over time there has been an evolution in allowance allocation approaches in similar programs that tends to favor the offset of potential increases in electricity rates (for example, allocations to affected electric utilities under California's AB 32 program). The allocation of CPP allowances to load-serving entities in the AEO2016 Reference case is a broad approach with potential to minimize price impacts for consumers. The CPP Allocation to Generators case considers the implications of an allowance auction or allocation directly to generators, which can result in higher price impacts for electricity customers, even as they reduce effective costs for generators.
- Finally, to ensure the integrity of emissions reductions achieved under the program, EPA required states to warrant that their use of mass-based goals does not result in shifts of generation to unaffected sources (leakage). EPA allows states to design their own leakage control policies, or to regulate total mass emissions from both existing and new sources under a single limit for carbon emissions. The AEO2016 Reference case assumes a mass-based program using EPA's budgets that include new sources (rather than the budgets for existing units only), given that other policies to control for leakage are not yet well specified.

LR2. Other rules affecting the power sector

In addition to the CPP, many regulations or guidelines were either ruled upon by the Supreme Court or were finalized by EPA and the U.S. Department of the Interior (DOI) after the publication of the AEO2015. Several of the regulations or guidelines primarily affect the use of coal in electricity generation. Furthermore, the Cross State Air Pollution Rule (CSAPR) [*14*], which was upheld recently by the Supreme Court, replaces the Clean Air Interstate Rule (CAIR) [*15*], which was modeled in AEO2015. AEO2016 also includes the Mercury Air Toxics Standard (MATS) [*16*], despite the recent remand by the Supreme Court to incorporate an analysis of costs [*17*]. Although not included in AEO2016, EPA has finalized three additional rules that allow for site-specific compliance methods:

- The Clean Water Act Section 316(b) rule [*18*], which affects all electricity generating and manufacturing facilities with cooling water intakes that have the potential to use at least 2 million gallons of water per day
- Revised Steam Electric Power Generating Effluent Guidelines and Standards (EG) [*19*] specifying permissible levels of emissions in wastewater streams
- Coal Combustion Residual rule (CCR) [*20*] affecting the disposal of coal ash (a waste byproduct from coal-fired generation)

EPA regulatory analyses indicate a relatively small increase in coal plant retirements and costs to the power industry as a result of these regulations. These and other pending regulations or actions with the potential to affect coal supply for the power sector and other end-use sectors are discussed in detail in the following sections.

CAA rules. AEO2016 includes representation of CSAPR, which addresses the interstate transport of air emissions from power plants. After a series of court rulings over the years, the Supreme Court in October 2014, lifted its stay and upheld CSAPR as a replacement for CAIR. In an interim final rule in December 2014 (and reaffirmed in a ministerial action in February 2016), EPA realigned the CSAPR schedule to comply with the Court's ruling. Phase I began that month, and more stringent Phase II targets will take effect in January 2017. Although CSAPR remains in place, the courts remanded CSAPR back to EPA in June 2015 for additional refinement that affected the Phase II implementation of NOx emission limits.

Under CSAPR, 28 eastern states must restrict emissions of sulfur dioxide and nitrogen oxide, which are precursors to the formation of fine particulate matter (PM2.5) and ozone. CSAPR establishes four distinct cap-and-trade system groups composed of different member states. CSAPR permits allowance trading between states within a group (approximated in NEMS by trade between coal demand regions) but not between groups.

Under the authority of the CAA, EPA also established the Mercury and Air Toxics Standard (MATS), which regulates acid gases and mercury from coal-fired generators with capacities of 25 megawatts (MW) or greater. In June 2015, the Supreme Court remanded MATS to the District of Columbia Court of Appeals, stating that EPA failed to consider costs in developing the regulation. AEO2016 includes MATS, because many generators already have complied either by investing in retrofit equipment or by retiring capacity, and the court did not vacate or stay the regulation, thereby leaving MATS in place and enforceable.

Under MATS, mercury emissions must be 90% below their uncontrolled levels, which can be achieved through the application of various types of pollution control equipment and activated carbon injection. To simulate compliance with MATS restrictions on other hazardous air pollutants (such as acid gases), NEMS requires the installation of either a scrubber or a dry sorbent injection (DSI) system. A full fabric filter is modeled in combination with DSI to further meet the standard's acid gas requirement. Because 141 gigawatts of coal-fired generators were granted EPA's one-year extension for compliance [*21*], AEO2016 assumes that MATS is fully in place in 2016 (rather than in 2015).

Clean Water Act (CWA) rules. In August 2014, EPA promulgated Section 316(b) of the CWA, regulating electric power and manufacturing facilities that require cooling water structures to address the trapping of aquatic organisms against water intake structures (impingement) or within cooling water systems where they encounter thermal and mechanical stresses (entrainment). With consideration of costs, the rule establishes that best available technology (BAT) must be used for compliance and must be implemented in accordance with the expiration of a facility's National Pollutant Discharge Elimination System (NPDES) permits. Some negotiation of the compliance timeline between the facility and EPA may occur, depending on the date of expiration of the permit, but all facilities must provide a compliance plan by July 2018. Variation in compliance methods is expected, given that site-specific considerations may affect the practicality of some technologies. Existing technologies deemed as BAT for impingement include a closed-cycle system, reduction of intake flows to 0.5 feet per second, and a minimum distance of 800 feet from shore for intakes that use bar screens. Under the Section 316(b) rule, repowered units will be regulated as existing rather than new units.

The 316(b) rule also provides for some potential aberration from BAT compliance. Facilities that operate with a capacity utilization of 8% or less over a 24-month period may negotiate less stringent compliance standards. A power plant that is scheduled to be retired may also avoid implementation of BAT. Additional options include restriction of aquatic mortality to 24% over a two-year span. In some cases, facilities that use impoundments for cooling water, or that stock and manage fisheries, may be able to negotiate deviations from the BAT requirements provided that endangered species are not present at the site. Other methods or combinations of methods may be negotiated with EPA. For entrainment, NPDES state directors are responsible for determining the BAT required, and they can do so on a site-specific basis.

EPA's regulatory impact analysis found that about 1 gigawatt of coal-fired generation capacity would be retired as a result of implementation of Section 316(b), and that the industry would incur costs of $275 million to $297 million annually (excluding entrainment costs)—assuming that CSAPR and MATS already are in place but without accounting for costs associated with the CPP. Section 316(b) is not represented in AEO2016.

Under the authority of the CWA, EPA also promulgated revisions to the Steam Electric Power Generating Effluent Guidelines (EG) in September 2015. The guidelines, which are not included in AEO2016, address liquid waste streams from power plants (primarily coal-fired power plants) discharged directly or indirectly into water bodies and, for the first time, emissions of toxic or bio-accumulating chemicals (including arsenic, nickel, selenium, chromium, and cadmium) in the wastewater of coal power plants, which will be restricted using BAT.

Last updated in 1982, the guidelines are intended in part to address pollutants potentially detoured to wastewater streams as the result of compliance with CAA regulations. Under the rule, flue gas desulfurization wastewater (a byproduct of the use of air emission control equipment) must be treated chemically or biologically to address the potential presence of arsenic, mercury, selenium, and nitrate/nitrite. Flue gas mercury control wastewater, as well as fly ash transport water and bottom ash (including boiler slag) transport water, also must achieve zero discharge levels through use of dry handling. The rule also sets limits on total suspended solids in gasification wastewater and combustion residual leachate.

Although the EG became effective as of January 2016, specific compliance deadlines vary by power plant, according to the expiration date of each plant's NPDES permit. For all power plants, compliance must be achieved between 2018 and 2023. Because there are synergies between the EG and CCR compliance options (described below), it is likely that the facilities' compliance plans will meet the EG and CCR goals simultaneously to minimize costs. In particular, many facilities are expected to dispose of coal ash via dry methods to comply with both regulations.

EPA's regulatory impact analysis found that about 1 gigawatt of coal-fired plant capacity would be retired as a result of the changes in the EG, and that the industry as a whole would incur costs of $471 million to $480 million annually, assuming that CSAPR, MATS, 316(b), the CCR rule, and the CPP are in place before the EG takes effect.

In June 2015, under the authority of the CWA, EPA also published its final "Waters of the United States" rule, specifying the waterways that are subject to the jurisdiction of EPA and the U.S. Army Corps of Engineers. The rule defines the scope of a navigable body of water to include tributaries that contain flowing water for some portion of a year [*22*]. Although the rule is final, it was stayed by the U.S. Court of Appeals for the Sixth Circuit in October 2015 [*23*], and it is not included in AEO2016. If upheld, the rule could pose additional permitting responsibilities for the coal industry, requiring the added burden of considering nonperennial tributaries that previously were outside the scope of the permitting process and potentially affecting coal supplies.

Resource Conservation Recovery Act rules. According to the American Ash Association [*24*], 130 million tons of coal ash (an inorganic waste byproduct of coal combustion) were produced in 2014. Generators dispose of coal ash in a variety of ways. In some cases, coal ash is disposed directly in landfills, with or without liners to mitigate leaching. In other cases the ash is mixed with water to produce a wet slurry that can be transported via pipeline or truck and discarded in waste ponds or impoundments rather than as a dry solid. In still other cases, coal ash may be discarded in abandoned mines. Generators have also sold coal ash waste for use in consumer and industrial products.

In 2008, the failure of the Kingston coal ash impoundment in Tennessee highlighted issues surrounding coal ash disposal, and EPA considered whether coal ash should be regulated as a hazardous waste. Since the Kingston spill, additional accidents and citizen complaints and suits about groundwater leaching from coal ash containment structures have contributed to continued concerns about coal ash disposal.

In April 2015, EPA published its final CCR rule, which took effect in October 2015. The rule sets regulations for both new and existing landfills and impoundments used for the disposal of coal ash. As a result of the rule, coal ash will continue to be regulated as a nonhazardous waste under Subtitle D of the Resource Conservation Recovery Act [*25*]. However, any method of disposal via impoundments or landfills must comply with certain national minimum criteria. The compliance criteria were established with consideration of groundwater leaching, dust control, and avoidance of catastrophic failure. The rule also requires long-term recordkeeping and monitoring beyond the closure of the disposal site. Waivers for retrofitting include the closure of existing disposal sites. Although no regulatory enforcement mechanism is in place under the rule, responsible parties are susceptible to litigation from citizen groups or other stakeholders if compliance is not achieved.

In 2014, an estimated 48% of coal ash [*26*] was used for beneficial purposes as an input for consumer and industrial products, avoiding both disposal in an impoundment or similar structure and disposal costs while also providing revenue for the generator. A label of hazardous would have severely restricted this option. To the benefit of the generators, the final CCR rule allows for CCR products to remain unregulated if the CCR is encapsulated in a product that displaces the use of virgin materials. These products include gypsum wall board and concrete, but the use of coal ash as ground fill is specifically excluded.

EPA's regulatory impact analysis found that an incremental 0.8 gigawatts of coal-fired capacity retire as a result of the CCR rule, and that the industry would incur incremental costs of $509 million to $735 million annually evaluated over a 100-year period (2013 dollars). For its analysis, EPA assumed that CSAPR, MATS, and 316(b) were already in place, but the EG and CPP were not. EPA also included a sensitivity case in which the CPP was included. As indicated above, certain compliance synergies between the CCR and the amended Effluent Guidelines are expected.

U.S. Department of Interior (DOI) actions: In July 2015, the Office of Surface Mining Reclamation and Enforcement proposed the Stream Protection Rule (SPR) under the authority of the Surface Mining and Reclamation Act of 1977 [*27*]. The proposed rule would affect all surface mining operations and any underground mining operations that disturb the surface. The earliest implementation date for the rule is January 2017. Under the proposed rule, permits specifying the maximum allowable damage to the area would be a condition of mining, and the SPR would stipulate that the mining area be returned to a condition appropriate for its pre-mining use after operations cease. The rule would require data collection before beginning mining operations to provide baseline environmental conditions for the area. Critics have said that the rule would strand coal assets and pose additional permitting difficulties for the coal industry. The SPR is not final and is not represented in AEO2016.

In January 2016, DOI issued a temporary moratorium on additional coal leases on federal lands while it reviews the coal royalty program and leasing process [*28*]. DOI expects to complete the review process within three years and has stated that exceptions will be granted to ensure the reliability of coal supply. In particular, some pending leases that already are in progress may continue to be processed [*29*]. Three of those pending leases are located in the Wyoming Powder River Basin (PRB), where 100% of coal production comes from federal lands. About 40% of U.S. coal production is from federal and Indian lands, and about 80% of that amount is produced in Wyoming. Most of the current PRB leases contain enough coal to last 20 years or longer. Existing annual permit levels at individual mines [*30*], in combination with total recoverable reserves (reported to EIA by the mine operators), will allow the PRB region to reach its projected production levels in the AEO2016 Reference case until the mid- to late-2030s in the absence of further lease sales, although some individual mines may have difficulty maintaining production levels before then. In addition to Wyoming, regulations on coal production from federal lands largely affect western states. Alabama, Oklahoma, North Dakota, Arizona, New Mexico, Utah, Colorado, and Montana (in order from lowest to highest levels) produced between 0.8 million tons and 25 million tons of coal on federal and Indian lands in 2013, accounting for different percentages of each state's total coal production. The final outcome of DOI's leasing moratorium is uncertain, and it is not represented in AEO2016.

LR3. Impact of a Renewable Energy Tax Credit extension and phaseout

As part of the 2016 Consolidated Appropriations Act enacted in December 2015 (H.R. 2029) [*31*], Congress extended the qualifying deadlines for the production tax credit (PTC) and investment tax credit (ITC) for renewable generation technologies. The deadline for PTC-eligible technologies to receive the full production credit was extended by two years. Wind technologies are eligible to receive the PTC beyond the two-year extension, but the value of the PTC declines gradually over time before final expiration. This extension is unlike the treatment in previous years, in which the tax credit maintained a constant inflation-adjusted value. The five-year ITC extension for solar projects also includes a gradual reduction in the value of the credit, as well as a provision that allows it to begin when construction starts.

History

Energy Production Tax Credit

The Energy Policy Act of 1992 [*32*] established a production tax credit (PTC) under 26 U.S.C. 45 [*33*], which now applies to wind and other renewable generation. With enactment of the American Recovery and Reinvestment Act (ARRA) in 2009 [*34*], a qualified wind facility was given the option to elect either a 30% ITC, or an equivalent cash grant (authority for which has since expired) in lieu of the PTC. EIA has generally assumed that wind energy projects prefer the PTC over the ITC, because the PTC typically is more valuable for power plants with high capacity factors and lower capital costs. The PTC is adjusted annually for inflation. As of the end of 2015, the PTC provided 2.3 cents/kilowatthour (kWh) for qualifying electricity production from wind, closed-loop biomass, geothermal, and certain waste energy facilities. The PTC also provided a half-value credit of 1.1 cents per kWh for qualifying electricity production from open-loop biomass, incremental hydroelectric, marine, tidal, and certain other waste energy facilities. Facilities qualified to receive the PTC if they were built within the timeframe specified by the law and its various extensions, and they were able to claim the tax credit on generation sold during their first 10 years of operation.

Energy Investment Tax Credit (26 U.S.C. 48 and 26 U.S.C. 25D)

The Energy Investment Tax Credit is a federal tax credit primarily claimed by solar systems on individually-owned residential systems (Section 25D) and business-owned systems (Section 48) [*35*, *36*]. ARRA expanded the scope of the business credit, giving renewable electricity technologies otherwise eligible to receive the PTC the option to take the ITC instead. The ITC, based on a percentage of the amount invested in an eligible property, reduces the income tax paid by the person or company claiming the credit.

Originally established in the 1970s as a business tax credit for 10% of investment costs, the Energy Policy Act of 2005 (EPACT2005) [*37*] increased the value of the ITC to 30% and established a 30% tax credit for residential owners as well. Subsequently, the Energy Improvement and Extension Act of 2008 (EIEA2008) [*38*] extended the expiration date for projects entering service to the end of 2016, reverting to a permanent 10% credit for eligible commercial facilities entering service in 2017 and later, and ending the residential credit. EIEA2008 also extended the credit to 2017 for small wind energy systems and geothermal heat pumps, and the credits were further enhanced by the 2009 ARRA, which removed the maximum credit amount for all eligible technologies (except fuel cells) placed in service after 2008.

PTC and ITC provisions in the 2016 Consolidated Appropriation Act

The 2016 Consolidated Appropriation Act passed in December 2015 retroactively extended the PTC to the end of 2015. For wind projects, the tax credit retains its full value of 2.3 cents/kWh through 2016 and starts to phase out beginning in January 2017. Wind projects under construction after 2016 but before the end of 2017 are eligible to receive a credit equal to 80% of the current PTC value; those under construction in 2018 will receive a credit equal to 60% of the current value; and those under construction before the end of 2019 will receive a credit equal to 40% of the current value. The credits can be claimed during the first 10 years of a plant's operation. For other eligible technologies—including open- and closed-loop biomass, geothermal, certain waste energy facilities, incremental hydroelectric, marine, and tidal—the PTC was extended for two years, until January 1, 2017, with no reduction in value. Technologies eligible for the PTC still will have the option to claim the ITC in lieu of the PTC, but the subsidy will be subjected to the same value phaseout as the PTC.

Before December 2015, the value of the ITC was scheduled to drop from 30% to 10% of capital costs at the end of 2016. The 2016 Consolidated Appropriation Act enacted that month delayed the credit reduction, introduced a gradual phaseout of the credit, and changed the eligibility criteria. Qualifying projects now can claim the ITC for the year construction starts, as opposed to the year the project begins operation. For solar technology to be eligible, it must generate electricity or heat, or cool a structure. Passive solar building design and solar pool-heating systems are not eligible, but solar hot water heaters do qualify. Solar projects under construction before the end of 2019 will qualify for the full 30% ITC, and those starting construction in 2020 and 2021 will qualify for credits of 26% and 22%, respectively. Commercial projects under construction after 2021 will receive a credit equivalent to 10% of capital costs. Residential projects started in 2021 and finished by 2024 will receive a credit of 10%, but new residential projects constructed after 2022 will not receive a credit. Although the recent federal budget reconciliation bill extended residential and commercial tax credits for solar technologies, credits for technologies such as distributed wind and ground-source heat pumps were not extended.

The AEO2016 Reference case incorporates the gradual reduction in PTC value for wind and the extended expiration dates for all PTC-eligible biomass, geothermal, municipal solid waste, conventional hydroelectric, and onshore and offshore wind technologies. The ITC extension, phaseout, and change in qualifying criteria also are included in the AEO2016 Reference case for solar photovoltaic and solar thermal technologies. AEO2016 further reflects the extended tax credits for both residential and commercial buildings (Table LR3-1).

LR4. Recent federal energy efficiency standards for appliances and other end-use equipment

The Energy Policy and Conservation Act of 1975 [*39*] gave the U.S. Department of Energy (DOE) authority to develop, revise, and implement minimum energy conservation standards for appliances and equipment. The National Appliance Energy Conservation Act of 1987 [*40*] first established minimum efficiency standards for 13 consumer products. Since 1988, DOE has issued many energy efficiency standards for residential and commercial appliances. DOE's Buildings Technologies Office currently sets minimum energy conservation standards for more than 60 categories of appliances and equipment. For most products, Congress has passed laws that set initial federal energy efficiency standards and test procedures and has established schedules for DOE to review and update the standards and test procedures (Table LR4-1) [*41*]. Based on the laws, DOE maintains a rulemaking schedule and provides reports on its rulemakings to Congress every six months.

A key component of the AEO2016 residential and commercial sector projections is the inclusion of federal equipment efficiency standards. The AEO2016 Reference case includes only promulgated standards and comprehensive consensus agreements; the Extended Policies case includes optional updates and future standards. When DOE promulgates a new or updated efficiency standard, AEO assumptions are adjusted to include only compliant equipment choices after the new standards have taken effect.

Some individual states have mandated their own efficiency standards for certain appliances not covered by federal efficiency standards. The state standards are not explicitly represented in the AEO projections. If several states have adopted standards for a product, manufacturers often negotiate with the states and with efficiency advocates to develop recommendations for national standards, which in most cases would preempt state standards.

The passage of the Energy Independence and Security Act of 2007 (EISA) in December 2007 [*42*] provided additional minimum efficiency standards for various types of residential equipment. The EISA standards include: reductions of nearly 30% in the wattage of general service lighting in 2012–14 and about 65% by 2020; boiler standards in 2012; wattage reductions for external power supplies after 2008; and standards for clothes washers, dishwashers, and dehumidifiers to be implemented between 2010 and 2012. Determination of an updated federal residential furnace standard is still in progress. Stakeholder input halted implementation of an earlier regional standard that was issued in 2011 and slated to go into effect in 2015.

The Energy Policy and Conservation Act requires that, if the commercial equipment efficiency standards of the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) are amended, DOE must establish either standards at ASHRAE levels or more stringent standards if the additional energy savings are cost-effective. Recently, ASHRAE amended standards for commercial central air conditioners, heat pumps, and furnaces. As a result, DOE set new standards that will take effect in 2018

Table LR3-1. Production tax credits and investment tax credits included in the AEO2016 Reference case, 2015–23

Year	Wind PTC	Other PTC-eligible technologies	Commercial solar ITC	Residential solar ITC
2015	100%	100%	30%	30%
2016	100%	100%	30%	30%
2017	80%	--	30%	30%
2018	60%	--	30%	30%
2019	40%	--	30%	30%
2020	--	--	26%	26%
2021	--	--	22%	22%
2022	--	--	10%	0%
2023 and after	--	--	10%	0%

Note: For commercial solar projects under construction before January 1, 2022, but not placed in service before January 1, 2024, the tax credit will be 10%.

and 2023. Other recently promulgated standards incorporated in the AEO2016 Reference case include standards for commercial vending machines, ice makers, and oil-fired water heaters.

LR5. California Zero-Emission Vehicle regulations for model years 2018 and beyond

On July 10, 2014, the California Air Resource Board (CARB) issued a new rule for its Zero Emission Vehicle (ZEV) program for MY 2018 and later [*43*]. The ZEV program is part of California's Advanced Clean Cars Program, which also includes control of criteria emissions (including greenhouse gas emissions (GHG)). California is the only state that has the right to enact its own emissions standards for new engines and vehicles, and its standards often are more stringent than those established by the U.S. Environmental Protection Agency (EPA). Clean Air Act (CAA) Section 177 allows other states to adopt either the federal standards or the California standards. To date, nine other states have fully adopted the CARB Advanced Clean Cars program standards. CARB was involved in developing the latest corporate average fuel economy (CAFE) standards for light-duty vehicles (LDV), jointly issued by EPA and the U.S. National Highway Traffic Safety Administration (NHTSA), which set national fuel economy and GHG standards for model year (MY) 2017 and later. In addition, CARB issued the state-based ZEV program to address its California-specific smog and emissions concerns.

The latest amendment to the ZEV program, which affects MY 2018 and later, requires a certain percentage of an automaker's sales to be made up of ZEVs and Transitional Zero-Emission Vehicles (TZEVs). Advanced Technology Partial Zero-Emission Vehicles (ATPZEVs) and conventional Partial Zero-Emission Vehicles (PZEVs) can make up a small part of the required percentage. ZEVs are battery electric and hydrogen fuel cell vehicles; TZEVs are plug-in hybrid electric vehicles and hydrogen internal combustion vehicles; ATPZEVs are hybrid, compressed natural gas, and methanol fuel cell vehicles with near-zero emissions and extended emissions system warranties; PZEVs are extremely clean conventional vehicles with extended emissions system warranties.

The ZEV sales requirement is administered through credits, with the required allowable credits calculated as a percentage of an automaker's conventional gasoline and diesel LDV sales, averaged over the previous three model years. The ZEV sales requirement for large manufacturers is 4.5% starting in MY 2018 and increasing by 2.5 percentage points each MY through 2025, to a total of 22.0%. Large manufacturers must produce credits from ZEVs and TZEVs with increasing sales volumes through 2025 (Figure LR5-1). There are limits on the number of credits that can be claimed for TZEVs, and ZEVs are expected to account for a minimum of 16% of the required credits in MY 2025.

Table LR4-1. Effective dates of initial and current appliance efficiency standards for selected equipment

Appliance type	2011 and earlier	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Central air conditioners	Initial				Current								
Clothes dryers	Initial				Current								
Clothes washers	Initial				Current								
Dishwashers	Initial		Current					Current					
Furnaces	Initial / Current												
Water heaters	Initial				Current								
Boilers	Initial	Current									Current		
Boilers	Initial	Current											
Central air conditioners (rooftop)	Initial							Current					Current
Heat pumps	Initial							Current					Current
Gas and oil furnaces	Initial												Current
Incandescent reflector lamps	Initial	Current											
Fluorescent lamp ballasts	Initial			Current									
General service fluorescent lamps	Initial	Current						Current					
General service incandescent lamps	Initial			Current									

The number of credits assigned to a vehicle varies according to its zero-emission range, with more credits allotted to vehicles with higher ranges. To receive credits, ZEV vehicles must have a minimum driving range of 50 miles, determined in accordance with California Exhaust Emission Standards and Test Procedures [*44*]. The ZEV credit is calculated as:

$$ZEV\ credit = (0.01) \times (ZEV\ range) + 0.50.$$

Credits are administered for TZEV vehicles that have a zero-emission range of 10 miles or more, as calculated by the same procedure. An amendment in May 30, 2014, incorporated an equivalent all-electric range (EAER) for better comparisons with ZEVs, which generate the TZEV credit equation. TZEVs with a range of 80 miles or more have a credit cap of 1.10. The TZEV credit is calculated as follows:

$$TZEV\ credit\ (10\ mi \leq ZEV\ range < 80\ mi) = (0.01) * EAER + 0.30.$$

Credits for PZEVs and ATPZEVs may not account for more than one-quarter of a large manufacturer's allowed TZEV credit limit. PZEVs earn 0.2 credits each. ATPZEVs earn the same 0.2 credits, with the addition of credits for advanced components and low-emission fuels, which typically result in totals of 0.6 credits to 0.7 credits, depending on the vehicle. Manufacturers also can receive small amounts of credits for low-speed neighborhood electric vehicles and for vehicles used for advanced technology demonstration programs and transportation systems.

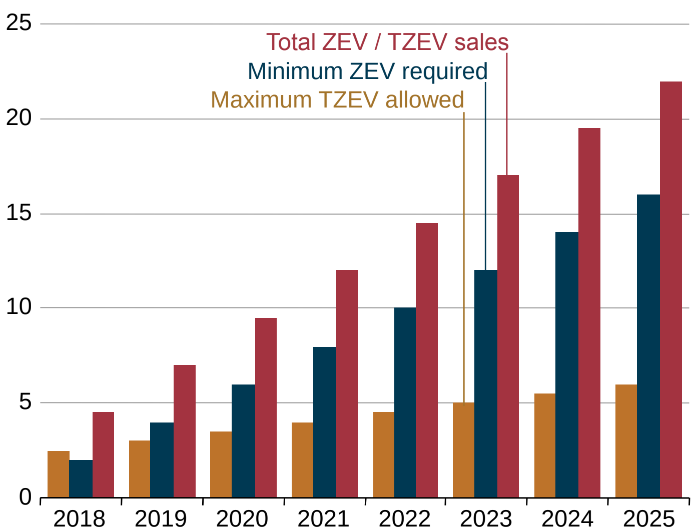
Credits are tradable and transferable with limitations, allowing manufacturers to meet their credit requirements when their vehicle sales do not meet the required minimums. Manufacturers that comply fully with the 10 Section 177 state requirements may trade and transfer credits from western states to eastern states with no penalty, and from eastern states to western states with a 30% penalty. However, credits can never be traded or transferred to or from California. Excess credits earned in MY 2012 and later also can be banked for future MYs, and can be used retroactively for the previous MY. The credit system provides greater flexibility for manufacturers to reach compliance.

Requirements are reduced for intermediate-volume manufacturers, who must meet the same total credit requirements but who are allowed to do so entirely with TZEVs. Small-volume manufacturers are not required to meet the credit percentage requirements, but they may participate in credit earning, marketing, trading, and banking.

If a manufacturer's sales increase or drop sufficiently over a sustained period of time, its size classification will change. If a manufacturer's average MY sales in California over a three-year period for three consecutive running averages crosses the sales threshold, it will be reclassified to the new manufacturer size for the next MY. The threshold between small and intermediate volume is 4,500 averaged sales per MY, and the threshold between intermediate and large volume is 20,000 averaged sales per MY. For example, if an intermediate-volume manufacturer exceeded 20,000 sales on average (more than 60,000 total sales over a three-MY period) for MY 2018–20, 2019–21, and 2020–22, that manufacturer would be reclassified as a large-volume manufacturer starting in MY 2023.

The AEO2016 Reference case includes the latest ZEV regulation for MY 2018 and later, with implementation applied to California and the other nine complying states. Projected sales of passenger cars, light-duty trucks, and combined LDVs, along with other alternative-vehicle sales, including ZEVs and TZEVs, reflect the impacts of the California Zero-Emission Vehicle regulations on a U.S. Census-division basis for model years 2018 and beyond, including their impacts on fuel demand and new LDV fuel economy.

Figure LR5-1. ZEV credit percentage requirements, model years 2018–25 (percent of average manufacturer conventional vehicle sales)



LR6. State RPS programs

To the extent possible, AEO2016 reflects state laws and regulations in effect at the end of December 2015 that mandate levels of renewable generation or capacity for utilities doing business in the state. These mandates are known as renewable portfolio standards (RPS) requirements. The AEO2016 projections do not include laws and regulations with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the projections do not account for fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, such distinct targets (sometimes referred to as tiers, set-asides, or carveouts) are subsumed into the broader targets, or they may not be included in the model because they are related to nonutility-scale generation.

The AEO2016 Reference case assumes that states will meet their ultimate RPS targets, but not necessarily targets for interim years. RPS compliance constraints in most regions are approximated, however, because NEMS is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. In general, EIA has confirmed requirements for each state through original legislative or regulatory documentation, and using the Database of State Incentives for Renewables & Efficiency (DSIRE) to support those efforts [*45*].

At present, most states are meeting or exceeding their required levels of renewable generation, based on qualified generation or purchase of renewable energy credits [*46*]. A number of factors helped create an environment favorable for RPS compliance, including:

- A surge of new RPS-qualified generation capacity timed to take advantage of federal incentives, some of which were set to decline or expire at the end of 2015 or 2016 but have since been extended
- Continued reductions in the cost of wind, solar, and other renewable technologies
- EPA's recently finalized mandatory carbon dioxide reduction program (the Clean Power Plan) [*47*]
- Complementary state and local policies that either reduce costs (for example, equipment rebates) or increase revenue streams (for example, net metering) associated with RPS-eligible technologies

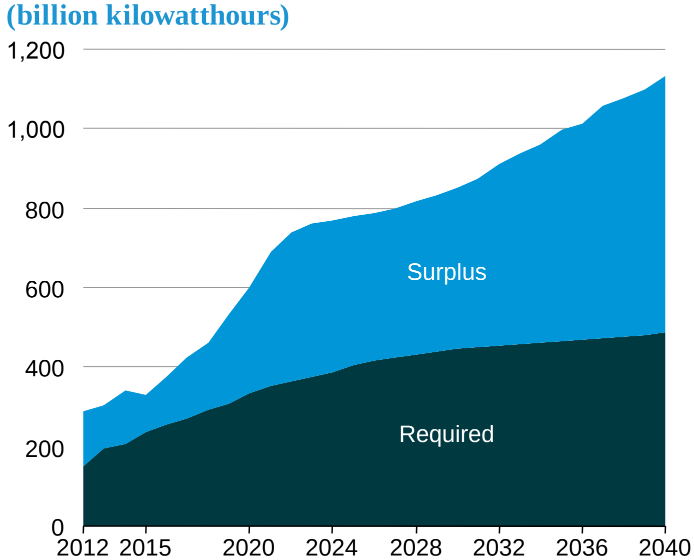
The aggregate RPS requirement for various mandatory state programs, as modeled for AEO2016, is shown in Figure LR6-1, along with total projected renewable generation. In 2025, the targets account for 40% of renewable generation and about 10% of U.S. electricity sales. However, the aggregate targets and qualifying generation shown in Figure LR6-1 may mask significant regional variation, as well as technology-specific or tier-specific shortfalls. Although some regions may produce excess qualifying generation, others may produce just enough to meet the requirement or may need to import electricity from adjoining regions to meet state targets.

One factor that could cause states to miss their RPS goals is slow or no growth in electricity demand. Reduced need for new generation would have the most significant effects on sources that are on the margin. To date, slowing demand has not been a problem, but the situation could change if demand is stagnant for an extended period of time. Implementation of EPA's CPP rule may mitigate the effects of slow demand growth on reaching RPS goals to the extent that it results in retirement of more existing coal-fired generation capacity.

Further, although there is now more qualifying generation in aggregate than needed to meet the targets, states with technology-specific goals could still have shortages of certain technologies. Also, the projected pattern of aggregate surplus does not necessarily imply that projected generation would be the same without state RPS policies, which may encourage investment in places where it would not occur otherwise or would not occur in the amounts projected, even as other parts of the country see substantial growth above state targets or the absence of targets. The results do, however, suggest that state RPS programs will not be the sole motivation for future growth in renewable generation.

Currently, 29 states and the District of Columbia have enforceable RPS or similar laws (Table LR6-1) [*48*]. Under such standards, each state determines its own levels of renewable generation, eligible technologies [*49*], and noncompliance penalties. Only one new RPS program has been enacted since 2009, but there have been a number of modifications to existing programs in recent years, building on state implementation experience and changing market conditions.

Figure LR6-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2012–40 (billion kilowatthours)



In 2014 and 2015, a large number of proposed legislative modifications were made to existing RPS programs [*50*, *51*]—including some attempts to weaken the targets of existing programs significantly—but only a small subset were enacted. One state froze progress toward its RPS, and another state repealed its mandate. Other states increased their targets. States making major changes to their RPS programs are discussed below.

California

By raising its 2030 commitment for total renewable generation from 33% to 50% (an estimated increase of more than 40 billion kWh), California made the largest absolute increase in its RPS generation requirement in 2015. Renewable resources provided 29% of California's total generation and 22% of its retail sales in 2014. Senate Bill 350 (SB350) [*52*], the legislation enacting the 50% mandate, specifies that 25% of retail sales in 2016 must come from qualified renewable generation. Other interim targets are 33% by 2020, 40% by 2024, and 45% by 2027. Solar photovoltaic (PV) technology has dominated recent capacity additions, and additions of wind capacity continue to provide more generation.

Table LR6-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates

State	Renewable target for total electricity sales	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable, distributed generation, etc.)	Compliance mechanisms
AZ	15% by 2025	Solar, wind, biomass, hydro, landfill gas (LFG), anaerobic digestion built after January 1, 1997	Direct use of solar heat, ground-source heat pumps, renewable-fueled combined heat and power (CHP), and fuel cells using renewable fuels	Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% by 2012 and beyond.
CA	50% by 2030	Geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, municipal solid waste (MSW), landfill gas (LFG), tidal, wave, ocean thermal, wind (small), hydroelectric (small), and anaerobic digestion	Energy storage, fuel cells using renewable energy	Credit trading is allowed, with some restrictions. Renewable energy credit prices capped at $50 per MWh.
CO	30% by 2020 for investor-owned utilities; 20% by 2020 for large electric cooperatives; 10% by 2020 for other cooperatives and municipal utilities serving more than 40,000 customers	Solar, wind, biomass, hydro, biomass, geothermal	Recycled energy, coal-mine methane, pyrolysis gas produced from MSW, and fuel cells	Credit trading is allowed. Renewable distributed generation requirement applies to investor-owned utilities (3% of sales by 2020) and electric cooperatives (0.75% or 1% of sales by 2020, depending on size). Generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals is eligible to earn credit multipliers.
CT	27% by 2020 (23% renewables, 4% efficiency and CHP)	Solar, wind, biomass, hydro (with exceptions), geothermal, LFG/MSW, anaerobic digestion, and marine	CHP, fuel cells	Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per MWh. The target is made up of three class tiers, with tier-specific targets.
DE	25% by 2026	Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, and marine	Fuel cells	Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including a 300% credit awarded for generation from in-state distributed solar and renewable-fueled fuel cells. Target increases for some suppliers can be subject to a cost threshold.
DC	20% by 2020	Solar, wind, biomass, hydro, geothermal, LFG/MSW, and marine	Direct use of solar, cofiring	Credit trading is allowed. The target includes a solar-specific set-aside, equivalent to 2.5% of sales by 2023. Obligated providers may also comply via a tier-specific alternative compliance payment.
HI	100% by 2045	Geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, hydroelectric, hydrogen, geothermal heat pumps, MSW, combined heat and power, LFG, tidal, wave, ocean thermal, wind (small), anaerobic digestion, and fuel cells using renewable fuels	Solar water heat, solar space heat, and solar thermal process heat	Credits cannot be traded. Eligibility of several of the qualifying other displacement technologies is restricted after 2015. Utility companies can calculate compliance over all utility affiliates.

(continued on page LR-13)

Table LR6-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates *(cont.)*

State	Renewable target for total electricity sales	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable, distributed generation, etc.)	Compliance mechanisms
IL	25% by 2026	Solar, wind, biomass, hydro, anaerobic digestion, and biodiesel	None	Credit trading is allowed. Target includes specific requirements for wind, solar, and distributed generation. The procurement process is subject to a cost cap.
IA	105 MW of eligible renewable resources	Solar, wind, some types of biomass and waste, small hydro	None	Iowa's investor-owned utilities are currently in full compliance with this standard, achieved primarily through wind capacity.
KS	20% of each peak demand capacity by 2020	Solar, wind, hydro, biomass, LFG	Direct use of solar heat, fuel cells	Credit trading is allowed. Eligible in-state capacity counts for 1.1 times its actual capacity.
ME	40% total by 2017, 10% by 2017 from new resources entering service in 2005 and beyond	Solar, wind, biomass, hydro, geothermal, LFG/ MSW, and marine	CHP, fuel cells	Credit trading is allowed. The Maine Public Utilities Commission sets an annually adjusted alternative compliance payment. Community-based generation projects are eligible to earn credit multipliers.
MD	20% by 2022	Solar, wind, biomass, geothermal, LFG/MSW, anaerobic digestion, and marine	Solar water heating, ground-source heat pumps, and fuel cells	Credit trading is allowed. The target includes minimum levels of compliance from solar and offshore wind. Utilities may pay an alternative compliance payment in lieu of procuring eligible sources, with a tier-specific compliance schedule.
MA	22.1% by 2020 (and an additional 1% per year thereafter)	Solar, wind, hydro, some biomass technologies, LFG/MSW, geothermal electric, anaerobic digestion, and marine	Fuel cells	Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 MW of in-state solar capacity, which is translated into an annual target for obligated providers. Obligated providers may comply via an alternative compliance payment (ACP), which varies in level by the requirement class. The ACP is designed to be higher than the cost of other compliance options.
MI	10% by 2015, with specific new capacity goals for utilities that serve more than 1 million customers	Solar, wind, hydro, biomass, LFG/MSW, geothermal electric, anaerobic digestion, and marine	CHP, coal with carbon capture and sequestration, and energy efficiency measures for up to 10% of a utility's sales obligation	Credit trading is allowed. Solar power receives a credit multiplier; other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn bonus credits.
MN	31.5% by 2020 (Xcel), 26.5% by 2025(other investor-owned utilities), or 25% by 2025 (other utilities)	Solar, wind, hydro, biomass, LFG/MSW, and anaerobic digestion	Cofiring, hydrogen	Credit trading is allowed. Target includes 1.5% solar standard for investor-owned utilities; Xcel's target also includes 25% of sales specifically from wind and solar (with a 1% maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance.
MO	15% by 2021	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, and ethanol	Fuel cells	Credit trading is allowed. Noncompliance payments are set at double the market rate for renewable.
MT	15% by 2015	Solar, wind, hydro, geothermal, biomass, and LFG	Compressed air energy storage	Credit trading is allowed, with a price cap of $10 per MWh. There are specific targets for community-based projects.

(continued on page LR-14)

Table LR6-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates *(cont.)*

State	Renewable target for total electricity sales	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable, distributed generation, etc.)	Compliance mechanisms
NV	25% by 2025	Solar, wind, hydro, geothermal, biomass, and LFG/MSW	Waste tires, direct use of solar and geothermal heat, efficiency measures (which can account for one-quarter of the target in any given year)	Credit trading is allowed. Solar PV receives a credit premium, with an additional premium for customer-sited systems.
NH	24.8% by 2025	Solar, wind, small hydro, marine, and LFG	Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps	Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target has four separate compliance classes, by technology type.
NJ	20.38% by 2021 with an additional 4.1% solar by 2027	Solar, wind, hydro, geothermal, LFG/MSW, and marine	None	Credit trading is allowed, with an alternative compliance payment set by state regulators. Solar and offshore wind are subject to separate requirements and have separate enforcement provisions.
NM	20% by 2020 for investor-owned utilities, 10% by 2020 for cooperatives	Solar, wind, hydro, geo-thermal, and LFG	Zero-emission technol-ogy, not including nuclear	Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3% of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources.
NY	29% by 2015[a]	Solar, wind, hydro, geo-thermal, biomass, LFG, an-aerobic digestion, certain biofuels, and marine	Direct use of solar heat, CHP, and fuel cells	Credit trading is not allowed. Compliance is achieved through purchases by state authorities, funded by a surcharge on investor-owned utilities. Government-owned utilities may have their own, similar programs.
NC	12.5% by 2021 for investor-owned utilities, 10% by 2018 for municipal and cooperative utilities	Solar, wind, small hydro, biomass, geothermal, LFG, and marine	Direct use of solar heat, CHP, hydrogen, and demand reduction	Credit trading is allowed. Impacts on customer costs are capped at specified levels. There are specific targets for solar and certain animal waste projects.
OH	12.5% renewable energy resources by 2026, 12.5% advanced energy resources by 2026	Solar, wind, hydro, biomass, geothermal, and LFG/MSW	Energy storage, fuel cells, and a separate 12.5% target for advanced energy technologies, including coal mine methane, advanced nuclear, and efficiency; microturbines	Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar electricity generation.
OR	5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with less than 3% of total sales; 25% by 2025 for all others	Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion, and marine	Hydrogen	Credit trading is allowed, with an alternative compliance payment and a limit on expenditures of 4% of annual revenue. Solar receives a credit multiplier.
PA	18% by 2020	Solar, wind, hydro, biomass, geothermal, and LFG/MSW	CHP, certain advanced coal technologies, certain energy efficiency tech-nologies, fuel cells, direct use of solar heat, ground-source heat pumps	Credit trading is allowed, with an alternative compliance payment. Separate targets are set for solar and two different combinations of renewable, fossil, and efficiency technologies.

[a]On November 2, 2015, the Governor of New York directed the Public Service Department to develop rules for a new renewable portfolio standard requiring of 50% renewable generation by 2030. The new standard is expected to be available by July 2016 and was not available for inclusion in AEO2016.

(continued on page LR-15)

Table LR6-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates *(cont.)*

State	Renewable target for total electricity sales	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable, distributed generation, etc.)	Compliance mechanisms
RI	16% by 2019	Solar, wind, hydro, biomass, geothermal, anaerobic digestion, LFG, biodiesel, and marine	Fuel cells	Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 MW of new renewable capacity.
TX	5,880 MW by 2018	Solar, wind, hydro, biomass, geothermal, LFG, and marine	Direct use of solar heat, ground-source heat pumps	Credit trading is allowed, with capacity targets converted to generation equivalents. State regulators may cap credit prices. 500 MW must be from resources other than wind.
VT	75% by 2032	Geothermal, solar, wind, biomass, hydro, LFG, marine, anaerobic digestion, and fuel cells using renewable fuels	Ground-source heat pumps, CHP	Generation of electricity from eligible renewable sources with environmental attributes attached, the purchase of RECs from plants whose energy is capable of delivery within New England, or a combination of the two; or alternative compliance payment of $0.01/kWh.
WA	15% by 2020	Solar, wind, hydro, biomass, geothermal, LFG, anaerobic digestion, biodiesel, and marine	CHP	Credit trading is allowed, with an administrative penalty for noncompliance.
WI	10% by 2015	Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, anaerobic digestion, and marine	CHP, pyrolysis, synthetic gas, direct use of solar or biomass heat, ground-source heat pumps, and fuel cells	Credit trading is allowed.

Hawaii

Hawaii became the first state to establish a 100% RPS. Hawaii House Bill 623 (HB623) [*53*] mandates that Hawaii's three major electrical utilities achieve 100% of sales from renewable generation by 2045. The law also specifies interim goals: 15% by 2015, 30% by 2020, 40% by 2030, and 70% by 2040. Currently, petroleum provides 68% of Hawaii's electricity (73% of retail electricity sales). In 2014, renewable electricity accounted for 12.7% of total generation from the state's three utilities, or 14.1% of sales. However, 12% of Hawaiian houses have rooftop PV installations, and distributed generation provided an additional 5.2% of 2014 utility-scale generation, displacing 5.6% of sales. Hawaii has severely restricted new rooftop installations because of the potential impacts of high levels of distributed generation on local distribution grids.

Kansas

Kansas converted its binding 2009 RPS into a nonmandatory goal in 2015, with the passage of Senate Bill 91 (SB91) [*54*]. Kansas had approved House Bill 2369 (HB2369) in 2009 [*55*], requiring the state's investor-owned utilities and electric cooperatives to generate or purchase at least 20% of their peak demand from renewable resources for each calendar year beginning in 2020.

Wind supplied about 22% of Kansas' net electricity generation in 2014. SB91 also provides new renewable energy facilities with a 10-year property tax exemption (assuming the facilities are not located behind the customer's utility meter) and making it easier for utilities to recover costs associated with meeting the previous mandate.

Ohio

Ohio decided in June 2014 to freeze for two years the progress toward its RPS 2024 mandate of 12.5%. Senate Bill 310 (SB310) [*56*] also includes renewable electricity imported from other states in its RPS determination. Current targets are for 12.5% by 2026. In-state renewables provide Ohio with less than 2% of its electricity sales.

Vermont

On June 11, 2015, Vermont passed House Bill 40 (HB40) [*57*], creating a requirement that 75% of retail electricity sales come from qualifying renewable generation by 2032. In doing so, it became the first state to establish a new mandatory RPS since 2009. Previously, Vermont had a nonmandatory goal of 20% by 2017. HB40 established an interim target of 55% by 2017.

With the closure of the Vermont Yankee nuclear generating station in 2014, more than 90% of Vermont's 2015 in-state generation is expected to be renewable. However, the state now imports about half of its 5.6 billion kWh in total sales. Vermont is a major port-of-entry for hydroelectric and other generation from Canada, with gross imports of nearly 11 billion kWh in 2014. Currently, much of that generation is passed through Vermont to other states.

West Virginia

In February 2015, West Virginia's House Bill 2001 (HB2001) [*58*] repealed the Advanced Energy Standard, eliminating the requirement that West Virginia obtain 25% of its electricity from renewable or other advanced energy sources, such as high-efficiency fossil generators. However, the state's House Bill 2201 retains net metering for distributed solar projects. Previously, EIA did not model the Advanced Energy Standard, because the standard could be met substantively with nonrenewable generation; therefore, its repeal is not incorporated in AEO2016.

LR7. State energy efficiency resource standards and goals through January 2016

In January 2016, 32 states had current or pending efficiency targets, including 22 states that would require utilities (electric, natural gas, or both) or third-party administrators to meet energy reduction targets over time. Efficiency policies for utilities complement efficiency gained from structural changes, federal appliance standards, and enhanced building codes. The extent of changes in demand varies by region and by sector. This section describes policies in states with electricity savings targets that were in effect at the end of January 2016 [*59*]. An energy efficiency resource standard (EERS), or energy efficiency portfolio standard (EEPS), is mandatory, sets long-term reduction targets (at least three years), is sufficiently funded to allow covered entities to meet their targets, uses financial incentives or nonperformance penalties, and usually (but not always) increases over time [*60*]. Both state legislatures and public utility commissions (PUC) have created energy efficiency (EE) policies. Savings targets may be set as reductions from a single base year or from an average of prior years; as a cumulative reduction over a compliance period; or as a percentage of projected electricity sales.

In AEO2016, EIA has explicitly incorporated rebates or incentives offered by utilities to residential and commercial customers to encourage the purchase of more-efficient equipment, which helps meet the goals of the CPP [*61*]. AEO2016 is the first time the projection has included incentives by technology and sector at a Census division level. AEO2016 also incorporates related efficiency policies, such as federal equipment standards and adoption of residential and commercial building codes, which reduce demand for energy.

The jurisdictional utilities covered by EERS vary by state. Some states cover only investor-owned utilities (IOUs). Other states use tiered savings targets by utility size, or between IOUs and publicly owned utilities (POUs). Table LR7-1 compares the targets and characteristics of states with statewide EE policies as of January 2016. States with large nonjurisdictional POUs often encourage them to set similar standards [*62*]. In 7 states the EERS apply to electricity savings only; 15 states set EERS targets for both electric and natural gas utilities [*63*]. Those differences account for variations in the percentage of retail sales covered by the different state EERS (Table LR7-1).

Texas established the first EERS in 1997 as part of its electricity restructuring. There was a great deal of activity between 2004 and 2010, and by 2010, 24 states had adopted mandatory EE targets or goals for utilities. Between 2005 and 2008, California and four New England states (Vermont, Rhode Island, Connecticut, and Massachusetts) began to adopt all cost-effective energy efficiency policies [*64*]. If states with such efficiency policies also fund mandatory, multi-year programs sufficiently, they are included as states with EERS. Some states—including Vermont and Oregon—later changed EE goals to long-term requirements.

No states added EE goals or mandates between 2010 and 2014. Moreover, the direction of adoption shifted in 2013, perhaps because of the recession or to strengthen renewable policies, rather than efficiency policies [*65*]. New Mexico lowered its final target in 2013, and Nevada began to phase EE out of its RPS. In 2014 and 2015, 4 states acted to slow or stop compliance with an EERS [*66*], and 11 states enhanced existing EERS, either by extending their time horizons or increasing savings targets. Two states opened regulatory proceedings either to adopt EERS or to promulgate EERS regulations, and one state started a pilot EE program [*67*]. As of January 2016, 22 states had adopted EERS. Six states without EERS have savings targets, including nonbinding efficiency goals, efficiency as a compliance mechanism in an RPS, or EE pilots [*68*] (Figure LR7-1).

Since the beginning of 2014, 18 states have made changes to their EERS or efficiency goals, including 14 states that have increased existing savings targets, extended the end years for energy reductions, or established regulations for an EEPS. In addition, four states eliminated, froze, or defunded existing targets. Key changes since January 2014 are summarized below.

Arkansas

In December 2015, the Arkansas Public Service Commission extended a 0.9% EERS savings target from the 2015–16 to the 2017–18 program-year, and it raised targets to 1% of 2015 sales in 2019 [*69*]. The General Assembly passed Act 78 in 2015, which limits the extent to which large customers can opt-out of EERS targets [*70*].

California

California has an all cost-effective energy efficiency requirement [*71*]. In October 2014, the PUC updated EERS funding and established 2015 portfolios [*72*]. In September 2015, the legislature enacted Senate Bill 15-350 [*73*], which requires establishing annual targets for statewide energy efficiency savings to achieve a cumulative doubling of statewide energy efficiency by January 1, 2030, and includes energy efficiency reductions in existing residential and nonresidential buildings.

Table LR7-1. Characteristics of state efficiency mandates or goals as of January 2016

State	Type[a]	Targeted electricity savings (mandates and goals)[b]	Percentage of state sales[c]	Current savings period (from-to)		Reported 2014 savings[d]	
						Megawatthours	Percent
AR	E&G	0.9% annual reduction from 2014 sales	53	2015	2016	249,303	0.53
AZ	E&G	2.5% annual saving; lower for co-ops	59	2016	2020	1,190,123	1.57
CA	E&G	Varies by utility; 16,298 gigawatthours by 2020	78	2012	2020	4,082,256	1.58
CO	E&G	5% of 2006 sales by 2018, rising incrementally	57	2007	2019	472,000	0.88
CT	E&G	1.51% reduction from 2015 base	94	2016	2018	369,686	1.26
DC	E&G	Sustainable Energy Utility has program goals	--[e]	--[e]	--[e]	59,105	0.53
DE	Elec	Proceeding to establish regulations and funding	TBD[f]	TBD	TBD	8,606	0.08
HI	Elec	Approximately 1.4% incremental savings by 2030, from 2009	100	2009	2030	144,240	1.53
IA	E&G	1.2% of sales	75	2014	2018	550,035	1.17
IL	E&G	2% of delivered energy; prior year as base	88	2016	No end	1,513,045	1.08
LA	Elec	Quick Start EE Pilot	76	2015	2016	48,226	0.05
MA	E&G	2.93% of forecasted 2016–2018 sales	86	2016	2018	1,351,105	2.48
MD	Elec	2% of sales by 2020 in 0.2% annual increments	99	2015	2017	817,906	1.33
ME	E&G	Approximately 1.6% of electric sales by 2016; 30% by 2020	100	2014	2016	161,571	1.36
MI	E&G	Approximately 1.0% of prior-year's sales	100	2012	No end	1,386,912	1.35
MN	E&G	1.5% of prior 3-years' weather-normalized average	100	2010	No end	824,756	1.22
MO	Elec	9.9% cumulative annual savings by 2020	70	2016	2018	431,218	0.52
MS	Elec	Quick Start EE program	74	2014	2016	75,815	0.15
NC	Elec	5% of 2021 sales from 2008 base; EE is an eligible RPS resource	100	2009	2021	854,582	0.64
NH	E&G	Docketed proceeding to establish an EERS	TBD	TBD	TBD	63,383	0.58
NM	Elec	Cumulative 8% reduction from 2005 sales	68	2014	2020	123,919	0.54
NV	Elec	Up to 20% of RPS may be met with EE measures	62	2015	2019	194,861	0.57
NY	E&G	Extend funding and 15% reductions under REV[g]	100	2016	TBD	1,421,287	0.96
OH	Elec	1% EE target frozen, 2015–16	89	2015	2016	1,565,049	1.05
OR	E&G	240 average megawatts over four years[h]	70	2015	2019	595,548	1.27
PA	Elec	Varies by utility; 2.6%–5.0%, average 3.7%	93	2016	2021	1,019,155	0.70
RI	E&G	2.5% relative to 2012 sales	99	2015	2017	268,468	3.51
TX	Elec	30% reduction in demand growth (~0.1%)	73	2013	No end	728,047	0.19
VA	Elec	Goal: 10% by 2022 relative to 2006 sales	100	2007	2022	102,770	1.85
VT	Elec	2.1% of sales; EE utility	100	2015	2017	96,557	1.73
WA	Elec	Varies by utility; approximately 1.2% for IOUs	81	2016	2017	946,565	1.02
WI	E&G	Varies by utility; 0.77% of annual sales	100	2015	2018	527,283	0.76

[a]If an energy efficiency resource standard (EERS) covers electric utilities only, the type is shown as *Elec*. If it covers both electric and natural gas utilities, the type is abbreviated as *E&G*.

[b]Sales reductions refer to reductions in retail sales of electricity. Unless otherwise noted, they are incremental annual reductions, rather than cumulative savings. Base year indicates year (or average of prior years) against which targeted savings are measured.

[c]American Council for an Energy-Efficient Economy, "The 2015 State Energy Efficiency Scorecard, Report U1509" (ACEEE2015), Appendix D, pp. 128–133, http://aceee.org/research-report/u1509. The percentage of affected retail sales in an EERS depends on what entities are covered by an EERS; this differs by state. EIA calculated percentages for states not included in ACEEE2015 (LA, MS, MO, VA), using state EE filings and U.S. Energy Information Administration, "2014 Utility Bundled Retail Sales–Total," http://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf.

[d]Incremental electricity savings reported to state PUCs for 2014, reported in both MWh and as percent of retail sales. **Sources:** ACEEE2015, p. 18; and Northeast Energy Efficiency Partnerships, *The Regional Roundup of Energy Efficiency Policy: Next Generation Energy Efficiency* (NEEP2016), pp. 31–42, http://www.neep.org/sites/default/files/resources/2016%20Regional%20Roundup-FINAL_1.pdf. NEEP2016 is the source for 2014 program year savings for the six New England states, five Middle Atlantic states (DE, MD, NY, NJ, PA), and the District of Columbia. Those jurisdictions report EE savings, expressed in net annual terms, to NEEP's Regional Energy Efficiency Database (REED).

[e]Not applicable.

[f]TBD: The percentage and the savings period remain *to be determined* within the setting of the regulatory proceeding.

[g]New York extended its earlier EERS goals while its *Reforming the Energy Vision* (REV) proceedings are underway.

[h]Oregon's efficiency targets are expressed in average megawatts (aMW) of electricity and annual therms (MMth) of natural gas saved. Energy Trust of Oregon, "2015–2019 Strategic Plan," page 5, http://energytrust.org/library/plans/2015-2019_Strategic_Plan0.pdf.

Connecticut

Connecticut has an all cost-effective energy efficiency requirement. In December 2015, the state's Department of Energy & Environmental Protection approved, with conditions, the 2016–18 triennial Conservation and Load Management Plan [*74*]. The plan increased investor-owned electric utility (IOU) targets from 1.4% of electric sales (2013–15) to 1.51%. Connecticut also eliminated EE as a means to fulfill its RPS, which could strengthen EE as a separate resource [*75*].

Delaware

Delaware has an all cost-effective energy efficiency requirement. The PUC had not established EE regulations or funding for an EERS enacted in 2009 [*76*]. In 2014, the legislature directed the state's Sustainable Energy Utility (SEU) to provide utilities with cost-effective EE programs, established an advisory council to help develop financing mechanisms, and directed the Department of Natural Resources to establish energy measurement and verification (EM&V) regulations [*77*]. Utilities committed to submitting plans in 2016 and beginning programs in 2017.

Indiana

In 2014, Indiana suspended its Energizing Indiana EERS, which had targeted a 2% savings by 2019, relative to 2009 sales [*78*]. In 2015, the legislature replaced the EERS with a law that allows voluntary programs and directs utilities to file triennial energy efficiency and demand response plans with the Indiana Utility Regulatory Commission [*79*].

Louisiana

In November 2014, the Louisiana PUC implemented Phase I of its voluntary Energy Efficiency Quick Start program [*80*]. Four IOUs offered programs across all sectors that could be implemented quickly and economically. Because each utility hired the same third-party administrator and evaluator, they offer similar programs and use a standardized reporting software package and EM&V.

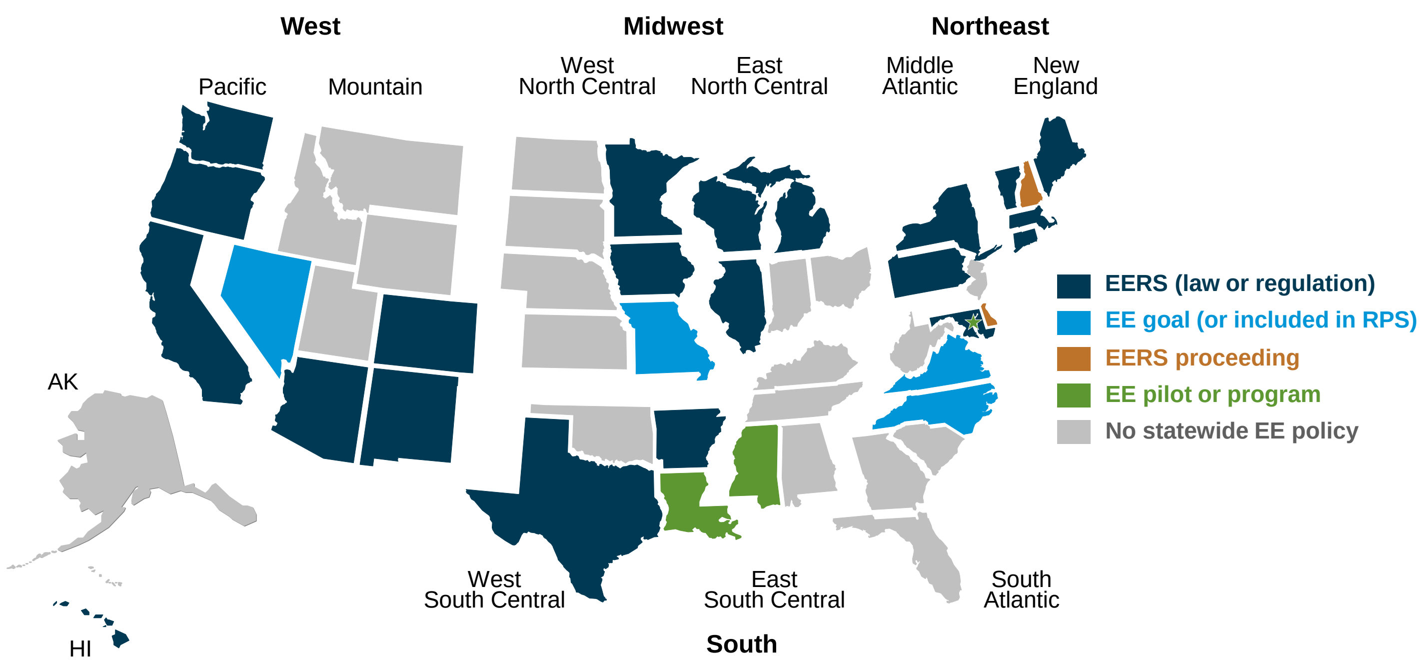
Maryland

In 2015, the Maryland PUC revised its EERS from one based on per capita reductions to savings based on a percentage of retail sales. The new EERS targets a 2% reduction in electricity sales from 2013 weather-normalized gross retail sales by 2020 for five large IOUs, in 0.2% annual increments. The previous EERS, EmPOWER Maryland, had a target of a 15% reduction in electricity use per capita by 2015 [*81*].

Massachusetts

Massachusetts has an all cost-effective energy efficiency requirement. In January 2016, its Department of Public Utilities approved the utilities' 2016–18 plans, developed in conjunction with the state Energy Efficiency Advisory Council [*82*]. The new plans raise energy savings targets for electric utilities from 2.6% in the 2013–15 plan cycle to 2.93% of projected sales. This plan also recognizes the role of demand response for peak load reductions. With the increase, Massachusetts set the highest electricity demand reduction target among all the states with EERS.

Figure LR7-1. States with energy efficiency resources standards (EERS) or energy efficiency (EE) goals that target savings in electricity use as of January 2016



Nevada

In 2013, Nevada's legislature voted to phase out EE requirements from its revised Energy Portfolio Standard. EE reductions can satisfy no more than 20% of compliance in the 2015–19 period, and they will not be an eligible resource after 2024 [*83*]. The Nevada legislature did not pass a bill for a separate EERS introduced in the 2015 legislative session.

New Hampshire

New Hampshire's PUC opened a docket in 2015 to establish an EERS [*84*]. The proceeding seeks input on appropriate goals, financing, cost recovery, incentives and penalties, and measurement and evaluation metrics. The regional energy efficiency organization, Northeast Energy Efficiency Partnership, has provided assistance to the PUC and stakeholders based on its experience with existing regional policies and with EM&V.

New York

In December 2015, the New York Department of Public Service extended energy savings targets under the state's EERS—which requires a 15% reduction below forecasted sales by 2015—and allocated funds from its Clean Energy Fund. New EE targets will be established along with revised cost-benefit tests under the Reforming the Energy Vision (REV) proceeding. The REV proceeding was opened in 2014 to transform the retail electricity market and overhaul the existing RPS and EERS [*85*].

Ohio

In 2014, Ohio froze its RPS and EERS for 2015 and 2016 and changed a number of other requirements for EE savings and peak demand reductions [*86*]. Established in 2008, the EERS had created annual targets leading to cumulative electricity savings of 22% by the end of 2025 compared with 2009 sales.

Pennsylvania

In 2015, Pennsylvania's PUC approved Phase III EERS targets for 2016–21. The targets, which vary by utility, range from 2.6% to 5% relative to the load forecast completed in 2010. The PUC also set utility-specific peak demand reduction requirements for utilities with at least 100,000 customers [*87*].

Rhode Island

Rhode Island has an all cost-effective energy efficiency requirement. The PUC increased the efficiency savings target in the 2015–17 triennial plan to an annual average of 2.5%, from 2.1% in the 2012–14 plan [*88*]. An Executive Order in December 2015 also directed state agencies to reduce energy consumption by at least 10% from fiscal year 2014 levels by 2019, and to establish a stretch (aspirational) energy efficiency building code [*89*].

Vermont

Vermont has an all cost-effective energy efficiency requirement. In 2015, the Vermont Public Service Board approved 2015–17 triennial plans both for Efficiency Vermont and for the City of Burlington Electric Department [*90*]. The plans include annual incremental kilowatthour (kWh) savings as well as summer and winter peak reduction targets. Efficiency Vermont is a statewide energy efficiency utility operated by the Vermont Energy Investment Corporation.

Washington

Washington's "Energy Independence Act," requires utilities with more than 25,000 customers to set biennial targets for all cost-effective, reliable, and feasible conservation [*91*]. In December 2015 and January 2016, the state Utilities and Transportation Commission approved 2016–17 plans for three large IOUs, and the Department of Commerce approved plans for 14 publicly owned utilities.

West Virginia

In 2015, West Virginia repealed its Alternative Renewable Energy Portfolio Act, under which energy efficiency had been eligible to earn credits. The Governor's statement indicated that changing economic factors had made the act no longer beneficial to the state [*92*].

LR8. Impacts on marine fuel choice from enforcement of Emissions Control Areas in North America and U.S. Caribbean Sea waters under the International Convention for the Prevention of Pollution from Ships (MARPOL)

Around the world, legislation and regulations mandating decreased emissions and lower levels of airborne pollutants have been put into place [*93*]. The implementation of regulations controlling emissions from the consumption of marine fuel in ocean-going vessels is one example. In March 2010, the International Maritime Organization (IMO) amended the International Convention for the Prevention of Pollution from Ships (MARPOL) to designate specific portions of the United States, Canada, and French waters as Emission Control Areas (ECAs) [*94*]. The area of the North American ECA includes waters adjacent to the Pacific coast, the Atlantic coast, and the Gulf coast, and the eight main Hawaiian Islands [*95*]. The ECAs extend up to 200 nautical miles from coasts of the United States, Canada, and the French territories but does not extend into marine areas subject to the sovereignty or jurisdiction of other countries. Compliance with the North American ECA became enforceable in August 2012 [*96*].

Emission Control Area Standards

The addition of ECAs to the international MARPOL treaty took effect in May 2005 and was amended in October 2008, when the member states of IMO [*97*]agreed to amend MARPOL Annex VI to establish new tiers or limits with progressive reductions of nitrogen oxide (NOx) and sulfur oxide (SOx) emissions from ship exhausts. The most stringent of the new international emission standards apply to ships (i.e., large ships and ocean vessels [*98*]) operating in designated ECAs, including the newly designated North American and Caribbean Sea ECA. Figure LR8-1 summarizes the Annex VI low-sulfur standards that apply globally (non-ECA) and within ECAs. AEO2016 considers the demands within North American and Caribbean ECAs, excluding energy demands occurring from shipping activity in non-ECA international waters.

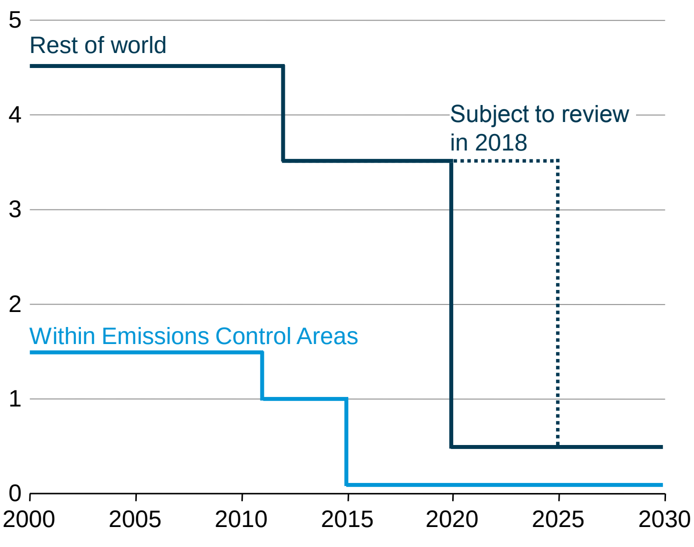
Although the start date for the new sulfur regulation is January 1, 2020, the plan will be reviewed to check the availability of the required fuel oil, because continued global investment by refiners probably will be needed to meet required emissions reductions. Depending on the outcome of that review, the startup date of new non-ECA sulfur regulations could be postponed until at least 2025, as indicated in Figure LR8-1 [*99*]. The original MARPOL Annex VI introduced global limits on sulfur content per gallon of bunker fuel at 4.5% by mass or 45,000 parts per million (ppm), with the levels within ECAs set at 1.5% by mass or 15,000 ppm.

The Tier I nitrogen oxides (NOx) standards for ships with engines built before 2000 range from 9.8 grams per kWh to 17.0 grams per kWh, depending on engine speed. The Tier II standards represent a 20% reduction from Tier I, and the Tier III standards represent an 80% reduction from Tier I. Tier III NOx limits will apply to all ships constructed on or after January 1, 2016, that operate inside a NOx ECA area with engines larger than 130 kilowatts.

NEMS is the primary source for EIA's analysis of recent history and AEO2016 projections of domestic energy markets. For AEO2016, the Freight Transportation Submodule of the NEMS Transportation Demand Module handles marine fuel choices and demand for ships operating within the North American and Caribbean ECA.

Compliance options associated with marine travel in the ECAs for both new and retrofitted vessels include the use of exhaust controls (e.g., scrubbers and selective catalytic reduction), changing fuels to marine gas oil (MGO) or liquefied natural gas (LNG), and installing engine-based controls (e.g., exhaust gas recirculation). Other technologies (e.g., biofuels and water injection), which are under development but have not yet reached wide-scale adoption, may provide additional options in the future. Ship efficiency improvements, shipping demand changes, and fuel price fluctuations also are considered in the Transportation Demand Module projections for international shipping fuel consumption within the North American and U.S. Caribbean ECAs [*100*].

Figure LR8-1. Current and proposed MARPOL regulations on sulfur content of fuel, 2000–2030 (percent by mass)



For marine travel within the North American and Caribbean ECA, AEO2016 assumes that consumption of distillate fuel oil, as the first and most widely used compliance solution, will rise rapidly between 2015 and 2019, then decline and level off after 2020, as fuel choices are affected by global emissions and fuel standards for ships. Although the long-term future of international marine fuel choice is unclear given current low and volatile prices for crude oil, it is likely that ship operators will invest in CO2 scrubbers in order to remain globally competitive, as refiners market heavy fuel oil (i.e., intermediate and residual fuel oils) at a significant discount relative to distillate fuel oil. In addition, for some types of oceangoing vessels, the use of LNG may begin to penetrate bunker fuel markets to some extent.

On July 24, 2008, the California Air Resources Board (CARB) adopted the regulation titled, Fuel Sulfur and Other Operation Requirements for Ocean-Going Vessels within California Waters and 24 Nautical Miles of the California Baseline [*101*].

Endnotes for legislation and regulations

Links current as of July 2016

1. A complete list of the laws and regulations included in AEO2016 is provided in *Assumptions to the Annual Energy Outlook 2016,* Appendix A, http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2016).pdf.
2. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015) https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
3. L. Deniston, SCOTUSBlog, "Carbon Pollution Controls Put On Hold" (Washington, DC: February 9, 2016), http://www.scotusblog.com/2016/02/carbon-pollution-controls-put-on-hold/.
4. California Environmental Protection Agency, Air Resources Board, "Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles" (Sacramento, CA: August 10, 2014), http://www.arb.ca.gov/msprog/zevprog/zevregs/1962.2_Clean.pdf.
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6. Vermont General Assembly, "H.40 (Act 56), An act relating to establishing a renewable energy standard and energy transformation program" (Montpelier, VT: May 15, 2015), http://legislature.vermont.gov/bill/status/2016/h.40; California Legislative Information, "SB-350 Clean Energy and Pollution Reduction Act of 2015" (Sacramento, CA: October 7, 2015), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350. LegiScan, "Hawaii House Bill 623" (Honolulu, HI: June 10, 2015), https://legiscan.com/HI/text/HB623/2015.
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8. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary.
9. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
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12. As indicated above, the EPA provided an option for certain new and reconstructed baseload CTs to elect between gross output-based and net output-based standards. For existing sources, EPA elected to specify a net generation basis for the standard.
13. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), Section IV.B.1 under Table 11, p. 64812, https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
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17. U.S. Environmental Protection Agency, "Legal Memorandum Accompanying the Proposed Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs)" (Washington, DC: December 1, 2014), https://www.epa.gov/mats.

18. U.S. Environmental Protection Agency, "National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities ," *Federal Register*, Vol. 79, No. 158 (Washington, DC: August 15, 2014), https://www.gpo.gov/fdsys/pkg/FR-2014-08-15/pdf/2014-12164.pdf.

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22. U.S. Department of Defense, Department of the Army, Corps of Engineers, and U.S. Environmental Protection Agency, "Clean Water Rule: Definition of 'Waters of the United States'; Final Rule," *Federal Register,* Vol. 80, No. 124 (Washington, DC: June 29, 2015), https://www.epa.gov/sites/production/files/2015-06/documents/epa-hq-ow-2011-0880-20862.pdf.

23. U.S. Environmental Protection Agency, "Clean Water Rule Litigation Statement" (Washington, DC: November 17 2015), https://www.epa.gov/cleanwaterrule/clean-water-rule-litigation-statement.

24. American Coal Ash Association, "2014 Coal Combustion Product (CCP) Production & Use Survey Report" (Farmington Hills, MI: not dated; accessed March 31, 2016), https://www.acaa-usa.org/Portals/9/Files/PDFs/2014ReportFinal.pdf.

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27. U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, "Stream Protection Rule; Proposed Rule," *Federal Register,* Vol. 80, No. 143 (Washington, DC: July 27, 2015), https://www.gpo.gov/fdsys/pkg/FR-2015-07-27/pdf/2015-17308.pdf.

28. U.S. Department of the Interior, "Order No. 3338, Subject: Discretionary Programmatic Environmental Impact Statement to Modernize the Federal Coal Program" (Washington, DC: January 15, 2016), http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.4909.File.dat/FINAL%20SO%203338%20Coal.pdf.

29. U.S. Department of the Interior, Bureau of Land Management, "Status of Currently Pending Lease and Lease Modification Applications (Updated 2/5/16)" (Washington, DC: February 5, 2016), http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.16330.File.dat/Status%20of%20Pending%20Leases.pdf.

30. U.S. Department of the Interior, "Wyoming Powder River Basin Coal Lease Status" (Washington, DC: January 22, 2016), http://www.blm.gov/style/medialib/blm/wy/programs/energy/coal/prb_maps.Par.66178.File.dat/prbcoallsestatmap.pdf.

31. Congress.gov, "H.R.2029 - Consolidated Appropriations Act, 2016" (Washington, DC: December 18, 2015), https://www.congress.gov/bill/114th-congress/house-bill/2029/text.

32. Library of Congress, "Bill Text, 102nd Congress (1991–1992), H.R.776.ENR, Energy Policy Act of 1992 (Enrolled Bill [Final as Passed Both House and Senate] - ENR)" (Washington, DC: January 3, 1992), https://www.congress.gov/bill/102nd-congress/house-bill/776/text/enr.

33. U.S. Internal Revenue Service, Title 26–Internal Revenue Code, pp. 215–225, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart D, Section 45, "Electricity produced from certain renewable resources, etc.)," https://www.gpo.gov/fdsys/pkg/USCODE-2014-title26/pdf/USCODE-2014-title26-subtitleA-chap1-subchapA-partIV-subpartD-sec45.pdf.

34. U.S. Senate and House of Representatives, 111th Congress, Public Law 111-5, "American Recovery and Reinvestment Act of 2009 (Washington, DC: February 17, 2009), https://www.gpo.gov/fdsys/pkg/PLAW-111publ5/pdf/PLAW-111publ5.pdf.

35. United States Internal Revenue Code, Title 26, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart A, Section 25D, "Residential energy efficient property," https://www.gpo.gov/fdsys/pkg/USCODE-2014-title26/pdf/USCODE-2014-title26-subtitleA-chap1-subchapA-partIV-subpartA-sec25D.pdf.

36. United States Internal Revenue Code, Title 26, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart E, Section 48, "Energy credit," https://www.gpo.gov/fdsys/pkg/USCODE-2014-title26/pdf/USCODE-2014-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf .

37. Congress.gov, Public Law 109-58, "Energy Policy Act of 2005" (Washington, DC: August 8, 2005), https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf.

38. Congress.gov, Public Law 110-343, "Emergency Economic Stabilization Act of 2008" (Washington, DC: October 3, 2008), https://www.congress.gov/110/plaws/publ343/PLAW-110publ343.pdf.

39. U.S. Senate and House of Representatives, "Public Law 94-163, 94th Congress, Energy Policy and Conservation Act" (Washington, DC: December 22, 1975), https://www.gpo.gov/fdsys/pkg/STATUTE-89/pdf/STATUTE-89-Pg871.pdf.

40. U.S. Senate and House of Representatives, "National Appliance Energy Conservation Act of 1987" (Washington, DC: March 17, 1987), https://www.gpo.gov/fdsys/pkg/STATUTE-101/pdf/STATUTE-101-Pg103.pdf.

41. Key legislation addressing energy conservation standards for residential and commercial equipment includes the National Appliance Energy Conservation Act of 1987, the Energy Policy Act of 1992, the Energy Policy Act of 2005, and the Energy independence and Security Act of 2007.

42. U.S. Senate and House of Representatives, "H.R. 6, Energy Independence and Security Act of 2007" (Washington, DC: January 4, 2007), https://www.gpo.gov/fdsys/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf.

43. California Air Resources Board, "Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles" (Sacramento, CA: August 10, 2014), http://www.arb.ca.gov/msprog/zevprog/zevregs/1962.2_Clean.pdf.

44. California Air Resources Board, *California Exhaust Emission Standards and Test Procedures for 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck and Medium-Duty Vehicle Classes* (Sacramento, CA: March 22, 2012; Amended December 6, 2012, May 30, 2014, September 2, 2015, and September 3, 2015), http://www.arb.ca.gov/msprog/levprog/cleandoc/2018+%20my%20hevtps_clean%20complete_1-16.pdf.

45. For information about the Database of State Incentives for Renewables & Efficiency (DSIRE), see DSIRE, "Database of State Incentives for Renewables & Efficiency" (Raleigh, NC: not dated), http://www.dsireusa.org.

46. G. Barbose, "U.S. Renewables Portfolio Standards: Overview of Status and Key Trends" (Berkeley, CA: November 2015), https://emp.lbl.gov/sites/all/files/2015%20National%20RPS%20Summit%20Barbose.pdf.

47. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015) https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

48. Enumerations of state RPS policies may vary from source to source. The policies vary significantly from state to state, with no universal definition. Previous discussion of state RPS policies by EIA have included a policy in West Virginia that allowed for several types of fossil-fueled generators to be built instead of renewable generators to meet the portfolio requirement. That policy is not included as an RPS in AEO2016.

49. Eligible technologies, and even the definitions of technologies or fuel categories, vary by state. For example, one state's definition of renewables may include hydropower, while another's may not. Table LR6-1 provides more detail on how the technology or fuel category is defined by each state.

50. Colorado State University, Center for the New Energy Economy, "Summary of State Renewable Portfolio Standard Legislation in 2014" (Fort Collins, CO: August 2014), http://www.aeltracker.org/graphics/uploads/CNEE-2014-State-RPS-Legislation-Analysis.pdf.

51. Colorado State University, Center for the New Energy Economy, "Summary of State Renewable Portfolio Standard Legislation in 2015" (Fort Collins, CO: April 2015), http://www.aeltracker.org/graphics/uploads/2015-Trends-in-Renewable-Portfolio-Standard-Legislation_4_15.pdf.

52. California Legislative Information, "SB-350 Clean Energy and Pollution Reduction Act of 2015" (Sacramento, CA: October 7, 2015), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

53. LegiScan, "Hawaii House Bill 623" (Honolulu, HI: June 10, 2015), https://legiscan.com/HI/text/HB623/2015.

54. Legislature of the State of Kansas, "House Substitute for Senate Bill No. 91: Renewable energy standards act and property tax exemptions for renewable energy resources" (May 28, 2015), http://www.kslegislature.org/li/b2015_16/measures/documents/sb91_enrolled.pdf.

55. Legislature of the State of Kansas, "Senate Substitute for House Bill No. 2369: Energy, generation, transmission, and efficiency" (May 22, 2009), http://www.kansas.gov/government/legislative/bills/2010/2369.pdf.

56. M. McClelland, Ohio Legislative Service Commission, "Sub. S.B. 310, Bill Summary, Renewable energy and advanced energy requirements" (May 7, 2014), http://www.lsc.ohio.gov/analyses130/s0310-rh-130.pdf.

57. Vermont General Assembly, "H.40, An act relating to establishing a renewable energy standard and energy transformation program" (May 15, 2015), http://legislature.vermont.gov/bill/status/2016/h.40.

58. West Virginia Legislature, "H.B. 2001, Article 2F. Alternative and Renewable Energy Portfolio Standard" (Charleston, WV: January 14, 2015), http://www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=hb2001%20intr.htm&yr=2015&sesstype=RS&i=2001.

59. This discussion focuses on electricity targets only, because of the range of electricity end uses in the AEO residential and commercial projections.

60. Different organizations may use different definitions. This is the definition adopted by EIA. Sources consulted included American Council for an Energy-Efficient Economy (ACEEE), Northeast Energy Efficiency Partnerships (NEEP2016), and the U.S. Environmental Protection Agency (EPA).

61. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

62. For example, the New York Power Authority (NYPA) and Long Island Power Authority (LIPA) in New York and the Los Angeles Department of Water and Power (LADWP) in California set separate targets from those required for investor-owned utilities (IOUs).

63. U.S. Environmental Protection Agency, "Climate and Energy Resources for State, Local, and Tribal Governments" (Washington, DC: May 6, 2016), https://www3.epa.gov/statelocalclimate/resources/action-guide.html.

64. See A. Gilleo, "Picking All the Fruit: All Cost-Effective Energy Efficiency Mandates" (Washington, DC: American Council for an Energy-Efficient Economy, 2014), http://aceee.org/files/proceedings/2014/data/papers/8-377.pdf.

65. Citations of the laws and regulations mentioned in this paragraph from 2014 forward are contained under the individual state descriptions following Table LR7-1, "Characteristics of state efficiency mandates or goals."

66. Energy efficiency resource standards have been suspended (Indiana, March 2014), frozen at current levels (Ohio, June 2014), defunded (Florida, November 2014), or repealed (West Virginia, March 2015).

67. States that enhanced existing EERS include Arkansas, California, Connecticut, Massachusetts, Maryland, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington. Delaware and New Hampshire opened EERS dockets. Louisiana began an EE pilot. The changes are described in detail in the state section following the table.

68. EIA confirmed each state's requirements through original legislative or regulatory documentation, discussions with Public Utility Commission (PUC) staff, consultations with regional energy efficiency organizations such as the Northeast Energy Efficiency Partnerships (NEEP), and referring to the Database of State Incentives for Renewables & Efficiency, at http://www.dsireusa.org.

69. Arkansas Public Service Commission, Docket No. 13-002-U, Order No. 31, "In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas" (Little Rock, AR: December 17, 2015), http://www.apscservices.info/pdf/13/13-002-U_226_1.pdf.

70. State of Arkansas, 90th General Assembly, Regular Session, 2015, Act 78 of the Regular Session, House Bill 1191, "An Act to Clarify the Regulation of Rates and Charges Under the Energy Conservation Endorsement Act Of 1977" (Little Rock, AR: January 13, 2015), ftp://www.arkleg.state.ar.us/acts/2015/Public/ACT78.pdf.

71. See A. Gilleo, "Picking All the Fruit: All Cost-Effective Energy Efficiency Mandates" (Washington, DC: American Council for an Energy-Efficient Economy, 2014), http://aceee.org/files/proceedings/2014/data/papers/8-377.pdf.

72. California Public Utility Commission, Decision 14-10-046, "Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets" (Sacramento, CA: October 16, 2014), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M129/K228/129228024.pdf.

73. California Legislature, "Senate Bill No. 350, Chapter 547: Clean Energy and Pollution Reduction Act of 2015" (Sacramento, CA: October 7, 2015), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

74. Connecticut Department of Energy & Environmental Protection, "Approval with Conditions of the Connecticut Energy Efficiency Fund's Electric and Natural Gas Conservation and Load Management Plan for 2016 through 2018" (Hartford, CT: December 31, 2015), http://www.ct.gov/deep/lib/deep/energy/conserloadmgmt/DEEP_Approval_with_Conditions_of_2016-2018_C&LM_Plan_with_Attachment_A_12-31-15.pdf.

75. Connecticut General Assembly, Public Act No. 13-303, "An Act Concerning Connecticut's Clean Energy Goals" (Hartford, CT: June 5, 2013), https://www.cga.ct.gov/2013/ACT/PA/2013PA-00303-R00SB-01138-PA.htm.

76. State of Delaware, "Title 26, Public Utilities, Chapter 15. Energy Efficiency Resource Standards" (Dover, DE: July 27, 2009), http://delcode.delaware.gov/title26/c015/index.shtml.

77. Delaware General Assembly, 147th General Assembly, "Senate Bill #150: An Act to Amend Title 29 of the Delaware Code Relating to Sustainable Energy Utility" (Dover, DE: August 6, 2014), http://legis.delaware.gov/LIS/lis147.nsf/vwLegislation/SB+150?Opendocument.

78. Indiana Senate Enrolled Act 340 (March 27, 2014) prohibited the Utility Regulatory Commission (U.R.C) from establishing an EERS or requiring an electricity supplier to meet such a target after December 31, 2014. (See http://iga.in.gov/static-documents/a/4/c/2/a4c2943f/SB0340.06.ENRS.pdf.)

79. Indiana's Senate Enrolled Act No. 412 (May 6, 2015) allowed utilities to set individual voluntary efficiency programs. See http://in.proxy.openstates.org/2015/bills/sb0412/versions/sb0412.05.enrs.

80. Louisiana Public Service Commission, Docket No. R-31106, "Statewide Energy Efficiency Program" (October 9, 2014), http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=8a69809f-a6c1-44c0-b326-ccf42f41869e, and "Comments of LPSC Staff" (April 1, 2016), http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=0fca1fdd-4b65-4a77-b314-77a1d8282493.

81. Maryland Public Service Commission, "EmPOWER Maryland Energy Efficiency Act of 2008" (April 24, 2008); Public Service Commission of Maryland, Order No. 87082, Case 9153, "In the Matter of [six utilities] Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008" (July 16, 2015), http://www.psc.state.md.us/wp-content/uploads/Order-No.-87082-Case-Nos.-9153-9157-9362-EmPOWER-MD-Energy-Efficiency-Goal-Allocating-and-Cost-Effectiveness.pdf.

82. Massachusetts Department of Public Utilities, "Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan" (approved January 28, 2016), http://ma-eeac.org/wordpress/wp-content/uploads/Exhibit-1-Gas-and-Electric-PAs-Plan-2016-2018-with-App-except-App-U.pdf.

83. State of Nevada, "Senate Bill No. 252—Committee on Commerce, Labor and Energy" (Carson City, NV: March 13, 2013), https://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB252.pdf.

84. New Hampshire Public Utilities Commission, Docket No. DE 15-137, "Gas and Electric Utilities, Energy Efficiency Resource Standard" (Concord, NH: May 8, 2015), http://www.puc.state.nh.us/Regulatory/Docketbk/2015/15-137.html. In this Order of Notice, the PUC noted its statutory authority to advance a policy of energy efficiency as a least-cost supply option. The proposal covers electric and/or natural gas utilities, with a proposed 2014 baseline.

85. New York State Department of Public Service, "Reforming the Energy Vision (REV)" (Albany, NY: April 2014), http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument; and http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-M-0252&submit=Search+by+Case+Number. The original EERS required a reduction of 2015 sales based on the forecast done in 2008.

86. State of Ohio, S.B. 310 (Columbus, OH: June 13, 2014), http://archives.legislature.state.oh.us/BillText130/130_SB_310_EN_N.pdf; and S.B. 221 (May 1, 2008), http://archives.legislature.state.oh.us/bills.cfm?ID=127_SB_221 (initial legislation).

87. Pennsylvania Public Utility Commission, "Energy Efficiency and Conservation (EE&C) Program, Phase III, Final Implementation Order" (Philadelphia, PA: June 19, 2015), and Phase III Clarification Order (August 20, 2015), http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/energy_efficiency_and_conservation_ee_c_program.aspx.

88. State of Rhode Island and Providence Plantations Public Utilities Commission, "Energy Efficiency Program Plan for 2016: Settlement of the Parties" (Providence, RI: October 15, 2015), http://www.ripuc.org/eventsactions/docket/4580-NGrid-2016-EEPP(10-15-15).pdf.

89. State of Rhode Island and Providence Plantations, Executive Order 15-17, "State Agencies to Lead by Example in Energy Efficiency and Clean Energy" (Providence, RI: December 8, 2015), http://www.governor.ri.gov/documents/orders/ExecOrder15-17.pdf.

90. Vermont Energy Investment Corporation, *Triennial Plan 2015–2017* (prepared for the Vermont Public Service Board) (Burlington, VT: December 1, 2014), http://psb.vermont.gov/utilityindustries/eeu/generalinfo/oversightactivities; City of Burlington Electric Department, "2015–2017 Triennial Energy Efficiency Plan" (prepared for the Vermont Public Service Board, December 1, 2014), http://psb.vermont.gov/sites/psb/files/EEU/BED2015-17Triennialplan.pdf; State of Vermont, Order under Docket EEU-2014-7, "Triennial Plans for 2015–2017 of Efficiency Vermont and City of Burlington Electric Department" (February 13, 2015); and "Oversight Activities Regarding the Energy Efficiency Utility" (not dated), http://psb.vermont.gov/utilityindustries/eeu/generalinfo/oversightactivities.
91. State of Washington, Department of Commerce, "Energy Independence Act (EIA or I-937)," http://www.commerce.wa.gov/Programs/Energy/Office/EIA/Pages/default.aspx. The UTC approved 2016–17 biennial conservation plans and targets under Docket Nos. UE-152076 (Avista), UE-152072 (Pacific Power & Light), and UE-152058 (Puget Sound Energy).
92. West Virginia, Office of the Governor, "Governor Tomblin Approves Repeal of Alternative Renewable Energy Portfolio Act" (Press Release, February 3, 2015), http://www.governor.wv.gov/media/pressreleases/2015/Pages/GOVERNOR-TOMBLIN-APPROVES-REPEAL-OF-ALTERNATIVE-RENEWABLE-ENERGY-PORTFOLIO-ACT.aspx.
93. U.S. Energy Information Administration, "Large reduction in distillate fuel sulfur content has only minor effect on energy content" (Today in Energy, February 24, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=20092.
94. U.S. Environmental Protection Agency, "MARPOL Annex VI" (Washington, DC: January 14, 2015), http://www2.epa.gov/enforcement/marpol-annex-vi.
95. The North American ECA does not include the Pacific U.S. territories, smaller Hawaiian Islands, the Aleutian Islands and Western Alaska, and the U.S. and Canadian Arctic waters. The U.S. Caribbean ECA includes the waters adjacent to the Commonwealth of Puerto Rico and the U.S. Virgin Islands out to approximately 50 nautical miles from the coastline.
96. On June 27, 2011, the U.S. Environmental Protection Agency and U.S. Coast Guard entered into a Memorandum of Understanding (MOU) to enforce Annex VI MARPOL.
97. International Maritime Organization (IMO), "Member States" (2016), http://www.imo.org/en/About/Membership/Pages/MemberStates.aspx. IMO currently has 171 Member States and three Associate Members. The United States became a signatory in 1950.
98. Ships propelled by Category 3 (C3) marine vessels or diesel engines are included. Marine engine and Category 3 have the same meanings given under 40 CFR 94.2. Category 3 marine vessels, for the purposes of 40 CFR Part 80, are vessels that are propelled by engines meeting the definition of "Category 3" in 40 CFR Part 1042.901. Source: IMO, Marine Environment Protection Committee (MEPC), 68th Session (May 11–15, 2015.
99. IMO, Marine Environment Protection Committee (MEPC), 68th session, 11 to 15 May 2015, http://www.imo.org/en/MediaCentre/MeetingSummaries/MEPC/Pages/MEPC-68th-session.aspx.
100. MARPOL Annex VI, Chapter 4, introduces two mandatory mechanisms intended to ensure an energy efficiency standard for ships: (1) the Energy Efficiency Design Index (EEDI), for new ships; and (2) the Ship Energy Efficiency Management Plan (SEEMP) for all ships. The regulations apply to all ships of and above 400 gross tonnage and entered into force on January 1, 2013. See International Maritime Organization, "Prevention of Air Pollution from Ships" (not dated), http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.
101. Fuel Sulfur and Other Operational Requirements for Ocean-Going Vessels within California Waters and 24 Nautical Miles of the California Baseline, Title 13, California Code of Regulations (CCR) §2299.2 and Title 17, CCR §93118.2. The California OGV Fuel Regulation requires that the fuel must not only have a per-gallon sulfur content of 0.10% or lower, but must also meet the specifications for distillates (marine gas oil or marine diesel oil). Therefore, vessels using new hybrid fuels to comply with the Annex VI ECA-SOx regulations do not automatically comply with the OGV Regulation; to do so they must obtain a "Temporary Experimental" or "Research Exemption" from CARB.

Figure and table sources for legislation and regulations

Links current as of July 2016

Table LR3-1. Production tax credits and investment tax credits included in the AEO2016 Reference case, 2015–23: U.S. Government Printing Office, "H.R.2029 - Consolidated Appropriations Act, 2016, Public Law 114-113" (Washington, DC: December 18, 2015), https://www.congress.gov/bill/114th-congress/house-bill/2029/text.

Table LR4-1. Effective dates of initial and current appliance efficiency standards for selected equipment: U.S. Energy Information Administration, Office of Energy Analysis. Based on U.S. Department of Energy, Building Technologies Office, http://energy.gov/eere/buildings/standards-and-test-procedures.

Figure LR5-1. ZEV credit percentage requirements, model years 2018–25: California Air Resources Board, "Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles" (Sacramento, CA: August 10, 2014), http://www.arb.ca.gov/msprog/zevprog/zevregs/1962.2_Clean.pdf.

Figure LR6-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2012–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Table LR6-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislations and regulatory actions from the various States on policies enacted prior to December 31, 2015, identified by the database of State Incentives for Renewables & Efficiency (as of March 24, 2016), website www.dsireusa.org.

Table LR7-1. Characteristics of state efficiency mandates or goals as of January 2016: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of each state's enabling legislations, implementing regulations, and annual efficiency achievement reports, as cited in the notes to Table LR7-1 and citations for the descriptions of individual states' policies.

Figure LR7-1. States with energy efficiency resources standards (EERS) or energy efficiency (EE) goals that target savings in electricity use as of January 2016: U.S. Energy Information Administration, Office of Energy Analysis. Based on an analysis of states with statewide efficiency policies as identified either in the Database of State Incentives for Renewables & Efficiency (DSIRE), http://programs.dsireusa.org/system/program/tables, or in the American Council for an Energy Efficiency Economy's (ACEEE) State and Local Policy Database, http://aceee.org/sector/state-policy.

Figure LR8-1. Current and proposed MARPOL regulations on sulfur content of fuel, 2000–2030: U.S. Energy Information Administration, based on International Convention of Pollution from Ships (MARPOL), http://www.imo.org/en/About/Conventions/ListOfConventions/Pages/International-Convention-for-the-Prevention-of-Pollution-from-Ships-(MARPOL).aspx.

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Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook* (AEO) provides in-depth discussions on topics of special interest, including possible changes in policies and developments in technologies and resources for energy production and consumption. Selected topics from recent AEOs are listed in Table IF1. Quantitative results from the issues discussed in AEO2016 are available in Appendix D.

Topics discussed in this section include:

- The Clean Power Plan, including analysis of alternative implementation approaches and the possible adoption of a more stringent Clean Power Plan program beyond 2030
- Proposed Phase 2 fuel consumption and greenhouse gas emissions standards for medium- and heavy-duty vehicles, which could significantly affect transportation fuel use
- An Extended Policies case that starts from current laws and regulations, which are the basis for the Reference case, and assumes future extensions of some major energy policies, including various energy tax credits, fuel economy regulations for light-duty and heavy-duty vehicles, and carbon dioxide emissions standards for existing power plants
- Growth in hydrocarbon gas liquids production and related developments in the industrial sector
- Sensitivity of the steel industry's energy consumption sensitivity to technology choices, and fuel and carbon prices in the AEO2016 Industrial Demand Module.

IF1. Effects of the Clean Power Plan

The Clean Power Plan (CPP) [*1*] rule, issued under Section 111(d) of the Clean Air Act, is the U.S. Environmental Protection Agency (EPA) program to regulate carbon dioxide (CO2) emissions at existing fossil-fired electric power plants. EPA estimates that the CPP will reduce CO2 emissions from the power sector by 32% from 2005 levels by 2030. As described in the *Annual Energy Outlook 2016* (AEO2016) Legislation and Regulations section, the CPP rule allows states to choose either mass-based or rate-based emissions targets. A mass-based target simply specifies an annual limit on the amount of CO2 that can be emitted by states from the affected sources. A rate-based target requires states to meet an annual adjusted emission rate (lbs CO2/MWh) based on emissions from affected sources divided by generation from affected sources, which for this calculation includes new non-emitting sources, such as nuclear and renewable capacity, and incremental energy efficiency. The rule also provides flexibility in other areas, such as regional cooperation through trading.

The final rule incorporated in the AEO2016 is a revision to the initial proposal [*2*] that U.S. Energy Information (EIA) analyzed in May 2015. [*3*] The final rule differs from the initial proposal in several ways, including:

Table IF1. "Issues in focus" analyses included in recent AEOs

AEO2014	AEO2013	AEO2012
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. reliance on imported liquid fuels in alternative scenarios	Potential efficiency improvements and their impacts on end-use energy demand
Potential of liquefied natural gas as a freight locomotive fuel	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
Light-duty vehicle energy demand: demographics and travel behavior	Nuclear power in AEO2013	Impacts of a breakthrough in battery vehicle technology
Effects of lower natural gas prices on projected industrial production	Effect of natural gas liquids growth	Heavy-duty natural gas vehicles
Implications of accelerated power plant retirements		Changing structure of the refining industry
Renewable electricity projections show growth under alternative assumptions in AEO2014		Changing environment for fuel use in electricity generation
Implications of low electricity demand growth		Nuclear power in AEO2012

Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2014*, DOE/EIA-0383(2014) (Washington, DC: April 2014); U.S. Energy Information Administration, *Annual Energy Outlook 2013*, DOE/EIA-0383(2013) (Washington, DC: April 2013); and U.S. Energy Information Administration, *Annual Energy Outlook 2012*, DOE/EIA-0383(2012) (Washington, DC: June 2012). The *Annual Energy Outlook 2015*, which was a shorter edition of the AEO, did not include an "Issues in focus" section.

- The compliance start date has been delayed from 2020 to 2022, and the reductions are phased in between 2022 and 2030 using 3 sets of multi-year, interim goals instead of one interim period
- Demand-side energy efficiency was not used in setting rate-based targets although it still may be used for compliance
- The variations between state targets have been reduced by using source-specific rates for fossil fuel steam and natural gas-fired combined-cycle generation at the interconnection level, rather than individual state emission rates
- Compliance calculations for rate-based targets have been limited to capacity additions since 2012, rather than also including pre-existing renewable capacity and at-risk nuclear plants
- Greater detail is provided for mass-based implementation approaches and emissions credit trading.

In comparison with the EIA's analysis of the preliminary CPP rule, which was based on the *Annual Energy Outlook 2015* (AEO2015) Reference case, the analysis described here includes other differences in underlying trends that are unrelated to the CPP but influence compliance decisions. These differences include lower natural gas prices, lower capital costs for renewable electricity generation plants, and extension of renewable tax credits.

In February 2016, the U.S. Supreme Court issued a stay of enforcement of the existing plant rule [*4*], pending resolution of legal challenges from the states and the affected industries. The AEO2016 Reference case assumes that the CPP will proceed as currently promulgated, and that all states will implement it by using a mass-based standard that caps emissions from both existing and new power plants, with allowance revenues rebated to ratepayers [*5*]. Alternative cases consider how outcomes could change with different implementation approaches, without the rule in place, and in a scenario with tighter standards beyond 2030.

Reductions in CO2 emissions can be achieved by switching from carbon-intensive fuels (such as coal) to less carbon-intensive natural gas-fired power plants or to zero-carbon technologies (such as renewables and nuclear power). Other options to reduce CO2 emissions include improving plant efficiency to reduce fuel use and increasing energy efficiency to reduce energy demand. Compliance decisions made by the states, as well as any future court decision regarding the rule, would have implications for plant retirements, capacity additions, generation by fuel type, demand, and prices.

Alternative Clean Power Plan cases

As described in the *Legislation and regulations* section below, the AEO2016 Reference case assumes that the CPP is upheld, and that all states choose to meet a mass-based standard to cover both existing and new sources. Using the standard that includes new sources ensures that *leakage* (which would represent a shift of emissions from existing sources to new natural gas-fired sources not covered by the CPP) does not occur. Because EIA's model is not developed at the state level, and because some level of trading is likely to happen among states with the mass-based approach, the Reference case assumes compliance at the same level in the 22 electricity regions included in the Electricity Market Model (EMM) [*6*]. An aggregate cap is calculated for each region, with the implicit assumption that carbon allowance trading can occur within the region. The Reference case also assumes that the allowances are allocated to load-serving entities, which provide the revenue back to consumers through lower distribution prices. The cap is specified for 2022 through 2030, based on EPA specifications, and remains flat at 2030 levels thereafter.

No CPP case

The No CPP case assumes that the final CPP rule is permanently voided and is not replaced by other controls on power sector CO2 emissions. States have no federal requirement to reduce CO2 emissions from existing power plants, but other programs remain in place, including the Regional Greenhouse Gas Initiative (RGGI) [*7*], the California Assembly Bill 32 (AB 32), and the Global Warming Solutions Act of 2006 [*8*]. Also, state and regional renewable portfolio standard programs remain in place, as described in the *Legislation and regulations* section, and may have an indirect impact on CO2 emissions.

CPP Rate case

The CPP provides state-specific, rate-based targets as an option for compliance. The affected electricity generation used in the rate calculation includes existing fossil steam and natural gas-fired combined-cycle units, incremental renewable generation added since January 2012, incremental nuclear generation, and incremental energy efficiency. Renewable capacity added in the end-use sectors also can be used to offset the affected emissions in the rate calculation. The CPP Rate case assumes that all regions (even those currently under mass-based programs such as in the Northeast and California) choose to comply with the CPP by meeting average rate-based targets—calculated as pounds of CO2 per megawatthour (lb/MWh)—in each EMM region. The rates are based on a weighted average of the state targets, specified by year from 2022 to 2030 as provided in the CPP. After 2030, the average emission rates for each region remain constant through 2040, implying that total emissions can increase after 2030 as electricity generation increases.

CPP Interregional Trading case

The EPA allows trading of carbon allowances among states, as long as the states involved use the mass-based compliance option. The CPP Interregional Trading case assumes that all regions choose to meet mass-based targets, covering existing and new sources (as in the AEO2016 Reference case), but with trading of carbon allowances between regions within the Eastern Interconnection and within the Western Interconnection. In the CPP Interregional Trading case, regions that reduce emissions by more than is needed to meet their own regional caps may trade their excess allowances, enabling the purchasing regions to exceed their nominal emissions caps.

CPP Extended case

The CPP Extended case further reduces the CO2 targets after 2030 instead of maintaining a constant standard, as specified in the CPP. This case assumes that the mass-based limits in 2030, which result in power sector CO2 emissions that are about 35% below 2005 levels, continue to decline linearly to achieve a 45% reduction below 2005 levels in 2040. The post-2030 reductions are applied using the same rate of decline for each state.

CPP Hybrid case

Unlike the CPP Rate case, the CPP Hybrid case assumes that regions in which existing programs enforce carbon caps (RGGI in the Northeast [9] and AB 32 in California) comply with the CPP through a mass-based target (considered more likely given their public comments on the rule). The CPP Hybrid case also assumes that states in other regions implement the CPP using a rate-based approach. This case assumes no interregional trading for CPP compliance. Because the RGGI and AB 32 constraints already are reducing emissions in these regions, the RGGI states and California tend to overcomply with their CPP requirements, whether implemented as a mass-based or rate-based standard. Consequently, the results of the CPP Hybrid case are similar to those of the CPP Rate case, because these regions do not need to behave differently to comply with either a mass-based or rate-based standard. The remaining regions are assumed to have rate-based standards in both cases. Because the results are indistinguishable, the following discussion of the case results does not include the CPP Hybrid case.

CPP Allocation to Generators case

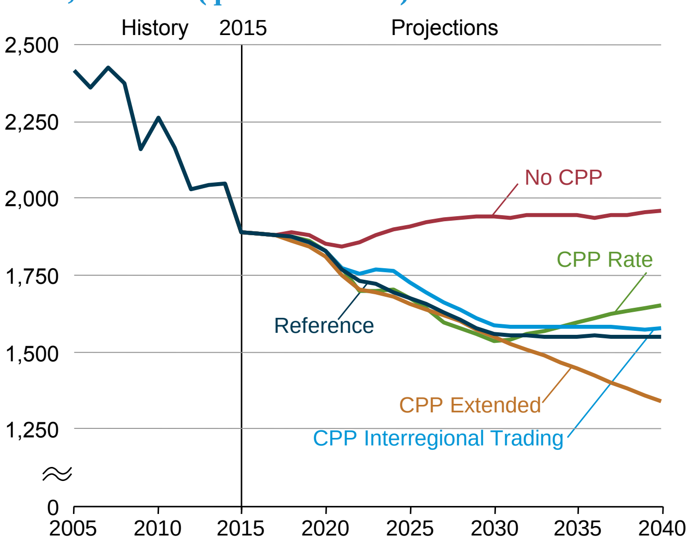
The CPP Allocation to Generators case assumes that (as in the Reference case) all regions meet mass-based caps that include new sources; however, the case also assumes that the carbon allowances are allocated to electricity generators rather than to load-serving entities. The CPP Allocation to Generators case also assumes that generators in competitive regions will continue to include the value of their carbon allowances in their operating costs. As a result, marginal generation costs will reflect the costs of allowances. The Reference case assumes that allowances are allocated to load-serving entities, which then refund the revenue from allowance sales to consumers through lower distribution prices. In the CPP Allocation to Generators case, retail electricity prices are higher than in the Reference case because there is no reduction of distribution costs, showing the impact of allowance allocation alternatives on retail prices. Because the impact of the CPP Allocation to Generators case is primarily on retail prices—and not on changes in how compliance is achieved, so that capacity and generation mix results are close to those in the Reference case—this case is discussed primarily in terms of pricing impacts.

Results

CO2 Emissions

cIn the Reference case, which assumes that states comply with mass-based CPP requirements, total CO2 emissions from the U.S. electric power sector in 2030 are 35% below their 2005 level. Emissions from the electric power sector, which have historically been the largest source of energy-related CO2 emissions in the United States, fall below those in the transportation sector by 2020 and throughout the remainder of the projection. After 2030, with the carbon cap assumed to remain flat and binding in almost all regions, emissions remain constant through 2040 (Figure IF1-1). Roughly the same reduction is seen in 2030 in the CPP Rate case, consistent with EPA's intent to develop equivalent measures for the alternate programs. After 2030, emissions increase in the CPP Rate case, and in 2040 they are only 32% below the 2005 total, because a constant emission rate standard can result in increasing emissions when overall generation is growing. Relative to the No CPP case, the power-sector CO2 emissions are 18% to 21% lower in 2030 across the cases that include the CPP and 16% to 21% lower in 2040 in all CPP cases except the CPP Extended case. The CPP Extended case assumes that further CO2 emissions reductions, beyond those currently specified in the CPP, are required after 2030, to 45% below 2005 levels in 2040, or 32% below the 2040 emissions total in the No CPP case.

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



In the CPP Interregional Trading case, emissions are slightly higher than in the Reference case because several regions overcomply, emitting less than their caps. This is typically because of enforcement of other state- or region-specific programs to reduce emissions or encourage renewables. In the CPP Interregional Trading case, where a market exists for those regions to sell their excess allowances, enabling other regions to emit above their caps. As a result, overall U.S. electricity-related CO2 emissions in the 2030–40 projection period are approximately 2% higher in the CPP Interregional Trading case than in the Reference case.

Capacity expansion and retirements

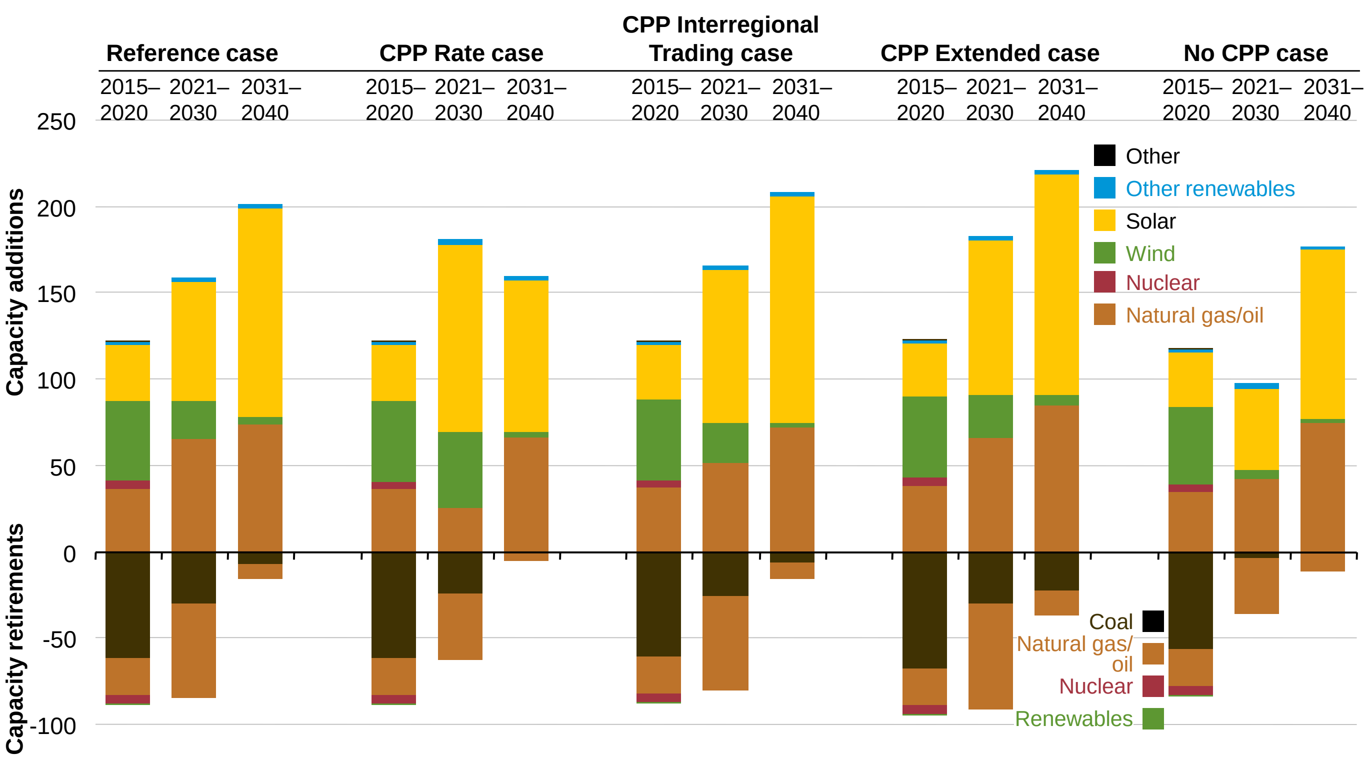
Relative to the No CPP case, the AEO2016 Reference case and the other CPP cases all result in more retirements of coal-fired and other fossil-fired steam plant capacity and increases in total renewable capacity additions, as regions reduce emissions to comply with mass-based or rate-based CO2 emissions standards (Figure IF1-2). The impact on natural gas-fired capacity varies somewhat with the CPP implementation decisions. Natural gas-fired plants produce less CO2 per kilowatthour (kWh) of electricity generated than is produced by coal-fired plants. However, replacement of coal plants with new natural gas plants does not reduce emissions to the same extent as replacement with new renewable plants.

Of the cases that maintain the final CPP target beyond 2030, the AEO2016 Reference case (which includes the mass-based approach) has the highest level of fossil-fired capacity retirements and the most new natural gas-fired capacity additions. To comply by EMM region using a mass-based standard, the EMM regions choose to replace existing fossil-fired plants with both new renewable generating capacity and new, more efficient, natural gas-fired combined-cycle plants. In the CPP Rate case, zero-emitting generation can help meet the rate standard both by offsetting emissions and by providing additional affected generation used to calculate the rate. As a result, more new renewable capacity is added than in the Reference case. Natural gas-fired combined-cycle capacity additions are 48 gigawatts (GW) lower than in the Reference case, and fossil-fired capacity retirements are 33 GW lower.

Because the rate standard allows new renewable generation to be included in the base of the rate calculation, additional incentive exists to meet incremental load growth with renewable capacity rather than with natural gas-fired capacity. Consequently, more existing fossil-fired capacity continues to operate. In the CPP Rate case, significantly more wind and solar capacity is added by 2030 than in the Reference case, but less is added after 2030. In the CPP Rate case, less incremental change is required after 2030 to maintain the emission rate standard than is required to maintain the mass-based cap in the Reference case as electricity demand increases.

In the CPP Interregional Trading case, a shift from natural gas-fired additions to renewable additions also occurs. Although regions are still required to meet a mass-based standard in the CPP Interregional Trading case, the ability to trade allowances provides regions that have cheaper renewable sources an incentive to exceed the required standards so they have excess allowances to sell. The availability and costs of renewable energy resources can vary significantly across the country. Broader allowance trading can allow for more economical means to achieve compliance overall. Regions that are best able to lower their emissions can sell allowances to regions that have fewer options to reduce emissions. In the CPP Interregional Trading case, solar capacity additions increase by 31 GW and natural gas-fired additions decrease by 15 GW from the 2040 totals in the Reference case. Also, 5 GW less capacity is retired as more existing capacity remains online in regions that purchase allowances.

Figure IF1-2. Cumulative additions and retirements of generating capacity in five cases, 2015–40 (gigawatts)



In the CPP Extended case, the mix of compliance actions is similar to that of the Reference case, but larger shifts are needed after 2030. From 2015 to 2030, plans for future declines in emissions targets will result in changes to the generation capacity mix, retiring an additional 12 GW of fossil-fired capacity and adding 20 GW of solar capacity beyond the Reference case totals. After 2030, the differences are more significant, with another 21 GW of incremental retirements of fossil-fired capacity in the CPP Extended case beyond those in the Reference case and additional solar (7 GW) and natural gas-fired (11 GW) capacity.

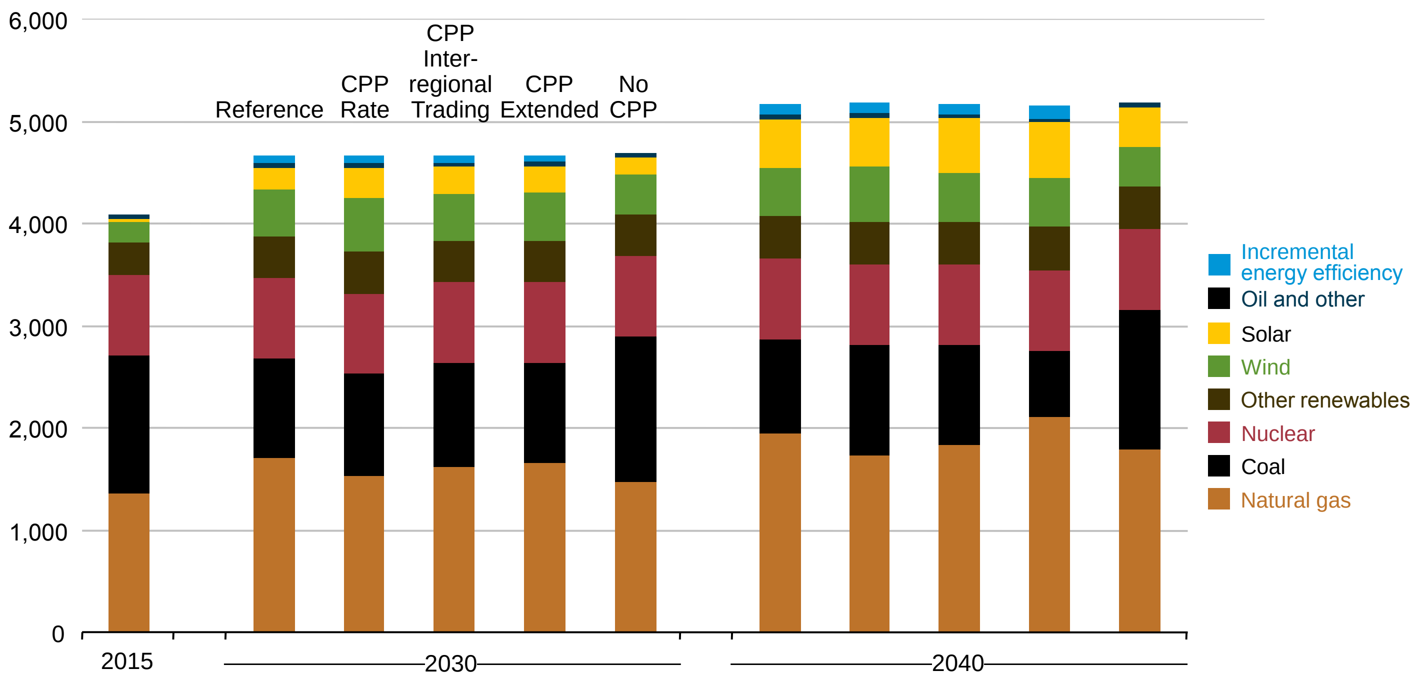
Generation fuel mix

Across the AEO2016 Reference case and CPP cases, shifts in the generation fuel mix reduce coal-fired generation by between 24% and 28% from 2015 to 2030 (Figure IF1-3). The declines from 2015 to 2040 vary across the cases, ranging from 20% to 32% across the cases that keep the CPP target constant after 2030. The rate-based case allows some increase in coal generation in the later years as long as sufficient renewable generation is available to offset it. The mass-based case continues to reduce coal generation and uses lower-emitting sources to meet new demand and maintain the same emission cap. In the CPP Extended case, which assumes that CO2 emissions target continues to decline after 2030, coal generation in 2040 is 52% below 2015 levels. In the No CPP case, coal electricity generation increases slightly from 2015 levels, as natural gas prices increase and as existing coal units are used at higher levels than in 2015, but remains relatively flat after 2020. Most growth in electricity demand is met by generation with natural gas and renewable capacity, which are more economic to build to meet new demand even without the CPP in place.

The tradeoff between natural gas and renewable capacity for compliance in the AEO2016 Reference case versus the CPP Rate case similarly affects the electricity generation mix across the cases. The natural gas share of total electricity generation grows from 33% in 2015 to 37% in 2030 in the Reference case and remains at 33% in the CPP Rate case, while the renewable share grows from 13% in 2015 to 24% in the Reference case and to 27% in the CPP Rate case. The CPP Interregional Trading case provides regions with more flexibility by allowing them to purchase allowances and reduce their own emissions, resulting in more renewable generation and less replacement of coal-fired generation with natural gas-fired generation than in the Reference case. Incremental demand-side energy efficiency (EE), measured as additional to what occurs without the CPP in place, lowers electricity demand by 73 billion kWh to 76 billion kWh in 2030 across the Reference, CPP Rate and CPP Interregional Trading cases. The additional EE impacts the calculation of the achieved emissions rate for a region, as the kWh are included in the denominator of the calculation. However, incremental EE can also help in meeting a mass-based target by reducing the need for additional fossil-fired generation by reducing electricity demand.

The CPP Extended case requires further shifts beyond 2030, resulting in a significant drop in coal's share of generation, from 33% in 2015 to 21% in 2030 and to 13% in 2040. In 2040, both the renewable share and the natural gas share, at 29% and 42% of total electricity generation, respectively, are higher than those in the Reference case. Incremental EE is also 21 billion kWh higher in the CPP Extended case compared with the Reference case. In 2030, natural gas-fired generation in the CPP Extended case is slightly lower than in the Reference case, as more early development of renewable capacity occurs in anticipation of the declining target.

Figure IF1-3. Electricity generation by fuel in five cases, 2015, 2030, and 2040 (billion kilowatthours)



Electricity prices

Retail electricity prices are higher when the CPP is in place than when it is not, as the fuel and capital costs of complying with the rule by shifting to natural gas-fired generation, or by building new renewable capacity, are passed through to retail prices. Price impacts are similar in the Reference and the CPP Rate cases, with constant dollar retail prices increasing by 1% to 5% above prices in the No CPP case over the 2022–30 CPP compliance period (Figure IF1-4). Prices remain, on average, 3% higher in constant dollars in the Reference and the CPP Rate case than in the No CPP case after 2030. In the CPP Extended case, average electricity prices are slightly lower than in the Reference case through 2030, as additional renewable capacity is added and as less natural gas-fired capacity is used for generation, with less impact on natural gas prices. Delivered natural gas prices in 2030 are 4% lower in the CPP Extended case than in the Reference case; but after 2030, the CPP Extended case requires further emissions reductions and more natural gas use. In the Reference case, electricity prices decline after 2030. In the CPP Extended case, incremental compliance costs keep electricity prices higher, and in 2040 they are 3% and 6% higher than in the Reference and No CPP cases, respectively.

Under a mass-based standard, states have options for the allocation of carbon allowances, with implications for electricity prices. The AEO2016 Reference case assumes that allowances will be allocated to load-serving entities, which will pass along the revenues from allowance sales to consumers in the form of rebates to lessen the price effects of CPP compliance. This rebate is reflected through lower electric distribution system costs. The CPP Allocation to Generators case assumes that allowances are distributed to generators. As a result, retail prices in competitive regions are higher, and average electricity prices from 2022 to 2040 in the CPP Allocation to Generators case are 1% higher than in the Reference case and 4% higher than in the No CPP case.

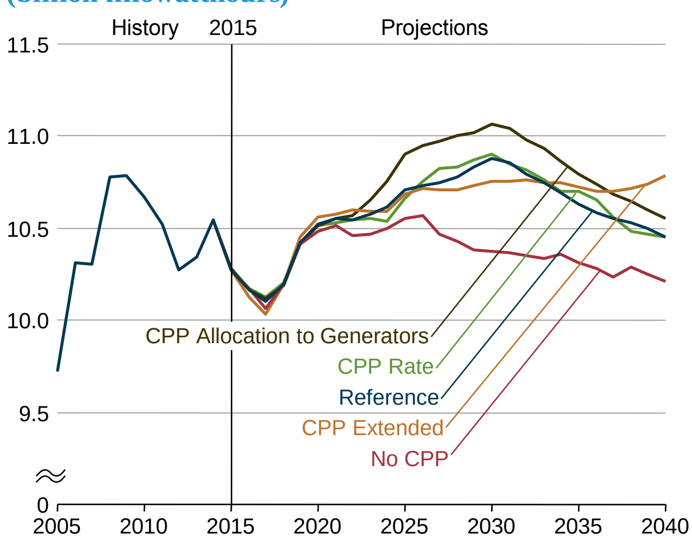
Regional Impacts

Although the targets in the final Clean Power Plan rule have less variability across the states than those in the proposed rule, different reduction levels still are required across the country, and compliance impacts differ among regions. As described earlier, EIA's modeling assumes that the CPP targets are implemented at the level of the electricity model regions [*10*] (see Appendix F). To permit a more concise display of the results in the following discussion of regional impacts, these 22 regions are grouped into 9 larger regions, with groupings of neighboring regions that have similar generation profiles and tend to use similar measures for CPP compliance (Table IF1-1 and Figure IF1-5). Detailed results for the 22 EMM regions are available on EIA's website at http://www.eia.gov/forecasts/aeo/data/browser/.

The current mix of generation types across the regions varies considerably. The Northern Plains, Midwest/Mid-Atlantic, and Southwest/Rockies regions rely the most on coal-fired generation (Table IF1-2 and Table IF1-3). Texas, the Southern Plains, and the Southeast have coal-fired generation in their mixes, along with nuclear and renewables, but these regions rely most heavily on natural gas-fired generation. The Northeast and California have almost no coal-fired generation, and their electricity is generated primarily from natural gas, along with renewables in California and a mix of nuclear and renewables in the Northeast. The Northwest has some coal-fired generation but relies predominantly on hydroelectric and other renewable electricity generation, with a relatively small share of natural gas-fired generation.

Even without the CPP (No CPP case), renewable electricity generation increases from 2015 to 2030 in all regions, with the largest increases in the Southeast, California, and the Northern Plains regions. Strong renewable electricity generation growth occurs as a result of the combination of extended tax credits, renewable portfolio standards in many regions, and declining construction costs. The Midwest/Mid-Atlantic region also experiences additional growth in natural gas-fired generation to replace generation from nuclear and coal-fired units that are retired during the 15-year period. Although these trends limit emissions growth, they do not result in the declines required by the CPP. In the No CPP case, total U.S. coal-fired generation grows slightly from the level in 2015, when low natural gas prices increased utilization rates for natural gas-fired plants and lowered utilization rates for coal-fired plants.

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



In the Reference case, the regions that currently have the highest levels of coal-fired generation make the largest shifts in generation mix to comply with the CPP. The Midwest/Mid-Atlantic region retires additional coal-fired capacity and increases natural gas use, in addition to reducing its required electricity generation by importing more power from neighboring regions—which also reduces the region's direct CO2 emissions in the Reference case. The EPA allows the states to determine how they will account for emissions in power trades, and EIA assumes that emissions counted against each region's target are based solely on electricity

Figure IF1-5. Change in emissions in the CPP Interregional Trading case relative to the Reference case, 2030

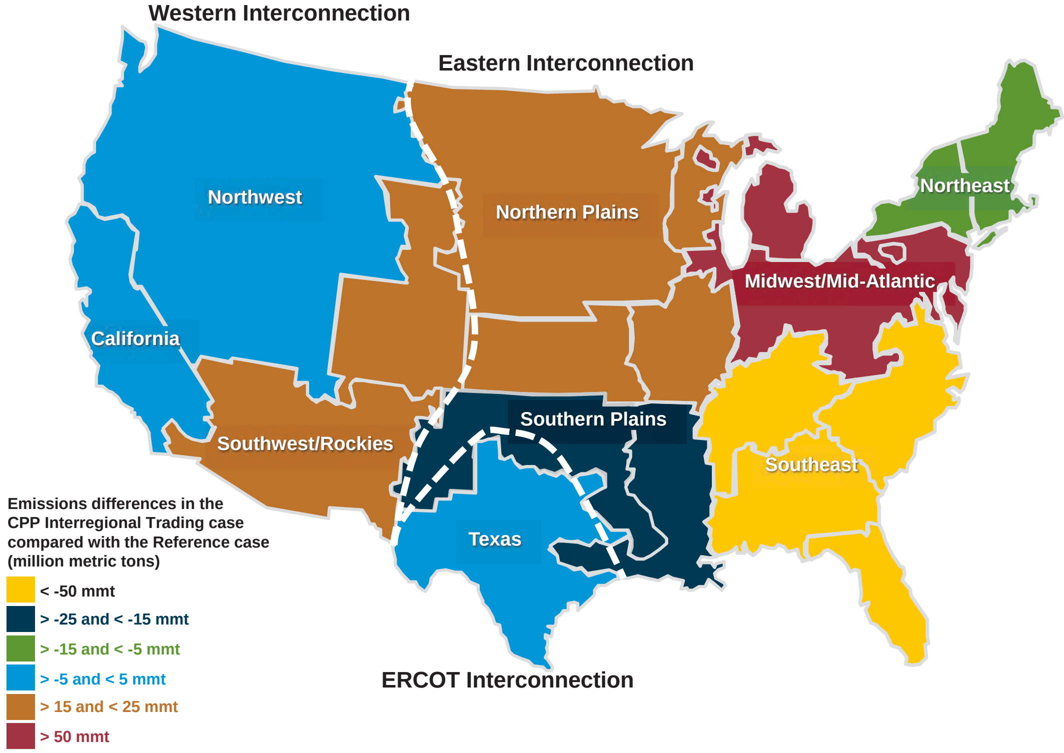


Table IF1-1. Mapping for aggregated electricity regions

Aggregate region	EMM regions included in aggregate region		
Northeast	5	NEWE	Northeast Power Coordinating Council (NPCC) / New England
Northeast	6	NYCW	NPCC / New York City-Westchester
Northeast	7	NYLI	NPCC/ Long Island
Northeast	8	NYUP	NPCC/ Upstate New York
Midwest/Mid-Atlantic	9	RFCE	ReliabilityFirst Corporation–East
Midwest/Mid-Atlantic	10	RFCM	ReliabilityFirst Corporation–Michigan
Midwest/Mid-Atlantic	11	RFCW	ReliabilityFirst Corporation–West
Southeast	2	FRCC	Florida Reliability Coordinating Council
Southeast	14	SRSE	SERC Reliability Corporation (SERC)/Southeastern
Southeast	15	SRCE	SERC/ Central
Southeast	16	SRVC	SERC/ Virginia-Carolina
Southern Plains	12	SRDA	SERC/ Delta
Southern Plains	18	SPSO	Southwest Power Pool Regional Entity / South
Texas	1	ERCT	Texas Reliability Entity
Southwest/Rockies	19	AZNM	Western Electricity Coordinating Council (WECC)/Arizona New Mexico
Southwest/Rockies	22	RMPA	WECC/ Rockies
California	20	CAMX	WECC/ California
Northwest	21	NWPP	WECC/ Northwest Power Pool Area
Northern Plains	3	MROE	Midwest Reliability Organization–East
Northern Plains	4	MROW	Midwest Reliability Organization–West
Northern Plains	13	SRGW	SERC/ Gateway
Northern Plains	17	SPNO	Southwest Power Pool Regional Entity / North

Notes: Names of grouped regions are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions. Aggregate region data are summed or averaged over the electricity model regions listed.

Table IF1-2. Electricity generation by region and fuel type in four cases, 2015 and 2030 (billion kilowatthours)

			2030			
Region	Fuel type	2015	Reference	CPP Rate	CPP Interregional Trading	No CPP
Northeast	Nuclear	76	63	63	63	63
	Coal	7	7	6	1	6
	Natural gas	130	150	134	135	137
	Wind/solar	9	25	24	24	25
	Other	45	51	51	51	51
Midwest/Mid Atlantic	Nuclear	275	242	242	242	242
	Coal	467	270	270	374	445
	Natural gas	177	377	308	317	265
	Wind/solar	25	50	145	50	46
	Other	27	32	33	32	32
Southeast	Nuclear	253	291	291	291	291
	Coal	230	232	248	165	333
	Natural gas	418	480	438	466	395
	Wind/solar	3	79	112	133	64
	Other	60	66	66	66	66
Southern Plains	Nuclear	41	40	40	40	40
	Coal	108	69	81	53	99
	Natural gas	173	221	176	217	177
	Wind/solar	25	67	81	71	69
	Other	20	21	21	21	21
Texas	Nuclear	40	40	40	40	40
	Coal	84	73	90	73	115
	Natural gas	214	230	195	231	230
	Wind/solar	36	97	111	99	60
	Other	3	4	4	4	4
Southwest/Rockies	Nuclear	32	32	32	32	32
	Coal	112	74	73	93	99
	Natural gas	62	60	84	63	67
	Wind/solar	19	87	70	75	71
	Other	18	21	21	21	21
California	Nuclear	18	18	18	18	18
	Coal	9	1	1	1	1
	Natural gas	116	116	113	110	122
	Wind/solar	32	83	75	82	75
	Other	42	68	67	67	67
Northwest	Nuclear	9	9	9	9	9
	Coal	73	52	56	55	56
	Natural gas	47	41	45	41	49
	Wind/solar	24	56	53	56	44
	Other	121	148	151	148	148

See notes at end of table.

(continued on page IF-10)

generation within the region, including generation exported to other regions. The Southeast region and the Southern Plains region also increase natural gas use considerably to comply with the CPP. In the Southeast region, where natural gas prices generally are relatively low, the available natural gas-fired, combined-cycle capacity is sufficient to support higher utilization levels.

The largest regional change in the increase in renewable electricity generation from 2015 to 2030 in the Reference case relative to the No CPP case is projected to be in Texas. The Northern Plains region also relies on increased wind generation and reduced coal-

Table IF1-2. Electricity generation by region and fuel type in four cases, 2015 and 2030 (billion kilowatthours) *(continued)*

			2030			
Region	Fuel type	2015	Reference	CPP Rate	CPP Interregional Trading	No CPP
Northern Plains	Nuclear	53	54	54	54	54
	Coal	261	194	169	213	266
	Natural gas	10	22	33	23	24
	Wind/solar	54	135	155	133	115
	Other	18	22	22	22	22
U.S. Total	Nuclear	798	798	789	789	789
	Coal	1,355	972	995	1,029	1,422
	Natural gas	1,348	1,702	1,531	1,607	1,471
	Wind/solar	227	683	830	727	571
	Other	362	443	446	442	442

Notes: Names of grouped regions are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions. Aggregate data for each region are summed or averaged over the electricity model regions listed. United States totals include estimated projections for Alaska and Hawaii, which are not included within any listed region.

Table IF1-3. Electricity generation shares by region and fuel type in four cases, 2015 and 2030 (percent of region total)

			2030			
Region	Fuel type	2015	Reference	CPP Rate	CPP Interregional Trading	No CPP
Northeast	Nuclear	29%	21%	23%	23%	22%
	Coal	3%	2%	2%	1%	2%
	Natural gas	49%	51%	48%	49%	49%
	Wind/solar	3%	8%	8%	9%	9%
	Other	17%	17%	18%	19%	18%
Midwest/Mid Atlantic	Nuclear	28%	25%	24%	24%	23%
	Coal	48%	28%	27%	37%	43%
	Natural gas	18%	39%	31%	31%	26%
	Wind/solar	3%	5%	15%	5%	4%
	Other	3%	3%	3%	3%	3%
Southeast	Nuclear	26%	25%	25%	26%	25%
	Coal	24%	20%	21%	15%	29%
	Natural gas	43%	42%	38%	42%	34%
	Wind/solar	0%	7%	10%	12%	6%
	Other	6%	6%	6%	6%	6%
Southern Plains	Nuclear	11%	10%	10%	10%	10%
	Coal	30%	16%	20%	13%	24%
	Natural gas	47%	53%	44%	54%	44%
	Wind/solar	7%	16%	20%	18%	17%
	Other	6%	5%	5%	5%	5%

See notes at end of table.

(continued on page IF-11)

fired generation to meet the CPP targets. The Southwest/Rockies region decreases coal-fired generation and more than triples solar electricity generation between 2015 and 2030 in the No CPP case. In the Reference case, solar electric power provides the region's most economical option for CPP compliance.

California and the Northeast regions have existing regional programs that are already reducing emissions. As a result, emissions tend to be below the emission caps that are applied with a mass-based implementation of the CPP in these regions. However, minor shifts in the generation mix occur relative to the No CPP case as both regions reduce their levels of imports in the Reference case, because compliance costs in neighboring regions affect the costs and relative economics of these imports.

The electricity price effects of the CPP vary across the regions, depending on the magnitude of changes required in each region's generation mix and the method of compliance (Table IF1-4). The Northeast region experiences larger price impacts, even though emissions are below the CPP cap in both the No CPP case and Reference case because the region relies heavily on natural gas-fired generation. The Northeast is also a competitive pricing market where the marginal cost of generation sets the wholesale power

Table IF1-3. Electricity generation shares by region and fuel type in four cases, 2015 and 2030 (percent of region total) *(continued)*

			2030			
Region	Fuel type	2015	Reference	CPP Rate	CPP Interregional Trading	No CPP
Texas	Nuclear	11%	9%	9%	9%	9%
	Coal	22%	16%	20%	16%	26%
	Natural gas	57%	52%	44%	52%	51%
	Wind/solar	9%	22%	25%	22%	13%
	Other	1%	1%	1%	1%	1%
Southwest/Rockies	Nuclear	13%	12%	11%	11%	11%
	Coal	46%	27%	26%	33%	34%
	Natural gas	25%	22%	30%	22%	23%
	Wind/solar	8%	32%	25%	26%	25%
	Other	7%	8%	8%	7%	7%
California	Nuclear	8%	6%	7%	6%	6%
	Coal	4%	0%	0%	0%	0%
	Natural gas	53%	41%	41%	40%	43%
	Wind/solar	15%	29%	27%	30%	27%
	Other	19%	24%	24%	24%	24%
Northwest	Nuclear	3%	3%	3%	3%	3%
	Coal	27%	17%	18%	18%	18%
	Natural gas	17%	13%	14%	13%	16%
	Wind/solar	9%	18%	17%	18%	14%
	Other	44%	48%	48%	48%	48%
Northern Plains	Nuclear	13%	13%	12%	12%	11%
	Coal	66%	45%	39%	48%	55%
	Natural gas	3%	5%	8%	5%	5%
	Wind/solar	14%	31%	36%	30%	24%
	Other	5%	5%	5%	5%	5%
U.S. Total	Nuclear	20%	17%	17%	17%	17%
	Coal	33%	21%	22%	22%	30%
	Natural gas	33%	37%	33%	35%	31%
	Wind/solar	6%	15%	18%	16%	12%
	Other	9%	10%	10%	10%	9%

Notes: Names of grouped regions are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions. Aggregate data for each region are summed or averaged over the electricity model regions listed. United States totals include estimated projections for Alaska and Hawaii, which are not included within any listed region.

price that, added to distribution charges, sets the retail price. Natural gas prices are higher in the Reference case compared to the No CPP case in all regions of the country, as a result of increased consumption, and thus result in higher marginal costs. The Midwest/Mid-Atlantic and Southeast regions also shift to greater natural gas use and see relatively larger price impacts. California and the Northwest, which have large shares of low-cost renewable generation, have smaller price impacts. Texas has an early price reduction because the region adds a large amount of wind capacity in the early years of the projection period to take advantage of available federal tax credits. Initially, this extra capacity with low operating costs lowers electricity prices. In the longer term, the price increases in Texas are consistent with those in other regions.

CPP Interregional Trading case

In the CPP Interregional Trading case, the EMM regions can trade carbon allowances within the Eastern Interconnection and within the Western Interconnection [*11*]. This trading allows emissions to be above an individual region's cap, as long as that region holds allowances from another region with total emissions that are below its limit. In the CPP Interregional Trading case, emissions are higher than their Reference case levels in the Eastern Interconnection's Midwest/Mid-Atlantic region and in the Northern Plains region, and emissions are lower in the Northeast, Southeast, and Southern Plains regions, indicating the directions of allowance trading (see Figure IF1-5). Trading is not limited to contiguous regions, and transactions can occur between any of the EMM regions within a given interconnect.

The generation mix in the regions changes as a result of emissions trading (see Tables IF1-2 and IF1-3). The Midwest/Mid-Atlantic region, which has the most purchases of allowances, retains more of its coal-fired generation and reduces the shift to natural gas use. The Southeast region, which has the most allowance sales, further reduces coal use and expands renewable electricity generation, as it has more favorable solar resources than the Midwest/Mid-Atlantic region. The shifts in power sales in those regions in the Reference case do not occur in the CPP Interregional Trading case, where the Midwest/Mid-Atlantic region can increase its electricity generation from lower cost, fossil fuel-fired generation and purchase allowances to cover excess emissions. The Northeast also reduces emissions in the CPP Interregional Trading case relative to the Reference case and provides allowances to the Midwest/Mid-Atlantic region.

In the middle of the country, shifts in emissions and allowance trading are not as large as in other regions, although some changes do occur. The Southern Plains region reduces emissions and sells allowances, and the Northern Plains region purchases allowances to increase its emissions. The Northern Plains region has coal-fired generation capacity that continues to operate when allowances are available at costs lower than the cost of developing less carbon-intensive generation facilities. The Southern Plains region has economically viable wind and solar potential.

Although the California region does not reduce emissions significantly from the Reference case, the Western Interconnection region is well below its CPP emissions cap in all CPP cases. In the Interregional Trading case, California provides more than 20 million allowances to other regions, primarily to the Southwest/Rockies region. As a result, a slight increase occurs in total national emissions in the CPP Interregional Trading case compared with the Reference case.

The interplay of interregional power trade and compliance occurs in several areas. The Southern Plains region increases exports to the Northern Plains and Southwest/Rockies regions in the Reference case, but reduces exports when allowance trading is permitted. Regions that purchase allowances can meet their own generation needs more economically by increasing generation with fossil fuels.

Table IF1-4. Differences in average electricity prices in the Reference case from the No CPP case by region, 2025, 2030, 2035, and 2040 (percent)

Region	2025	2030	2035	2040
Northeast	4%	7%	4%	3%
Midwest/Mid-Atlantic	0%	6%	3%	2%
Southeast	4%	6%	4%	3%
Southern Plains	0%	4%	3%	3%
Texas	-7%	4%	2%	0%
Southwest/Rockies	4%	5%	3%	3%
California	1%	2%	2%	2%
Northwest	2%	2%	2%	2%
Northern Plains	3%	4%	4%	4%
U.S.	1%	5%	3%	2%

Note: Differences are based on aggregate region averaged prices weighted by regional sales.

CPP Rate case

On a national level, power sector emissions in 2030 in the CPP Rate case are slightly lower than in the Reference case. However, regional emission reductions are more variable in the CPP rate case. The largest changes in emissions relative to the Reference case occur in the Midwest/Mid-Atlantic and Northern Plains regions, which reduce emissions by 5% and 10%, respectively, from their Reference case levels in 2030, and in the Texas region and the Southwest/Rockies region, which increase emissions by 6% and 9%, respectively, from Reference case levels. Total emissions with the rate-based target can vary by region, depending on the generation mix and total generation. New renewable sources also play a larger role in meeting the rate-based target, which allows for shifts in the mix of existing fossil-fired generation versus generation from new energy sources. Incremental EE can also be counted as affected generation in the rate-based calculation. After 2030, total U.S. emissions increase in the CPP Rate case. With an increase in electricity generation, total emissions can increase while the emission rate is maintained with the rate-based target. Total emissions increase in the CPP Rate case after 2030 in most regions; however, in California and the Northeast, where state and regional caps remain in place, emissions remain relatively constant through 2040.

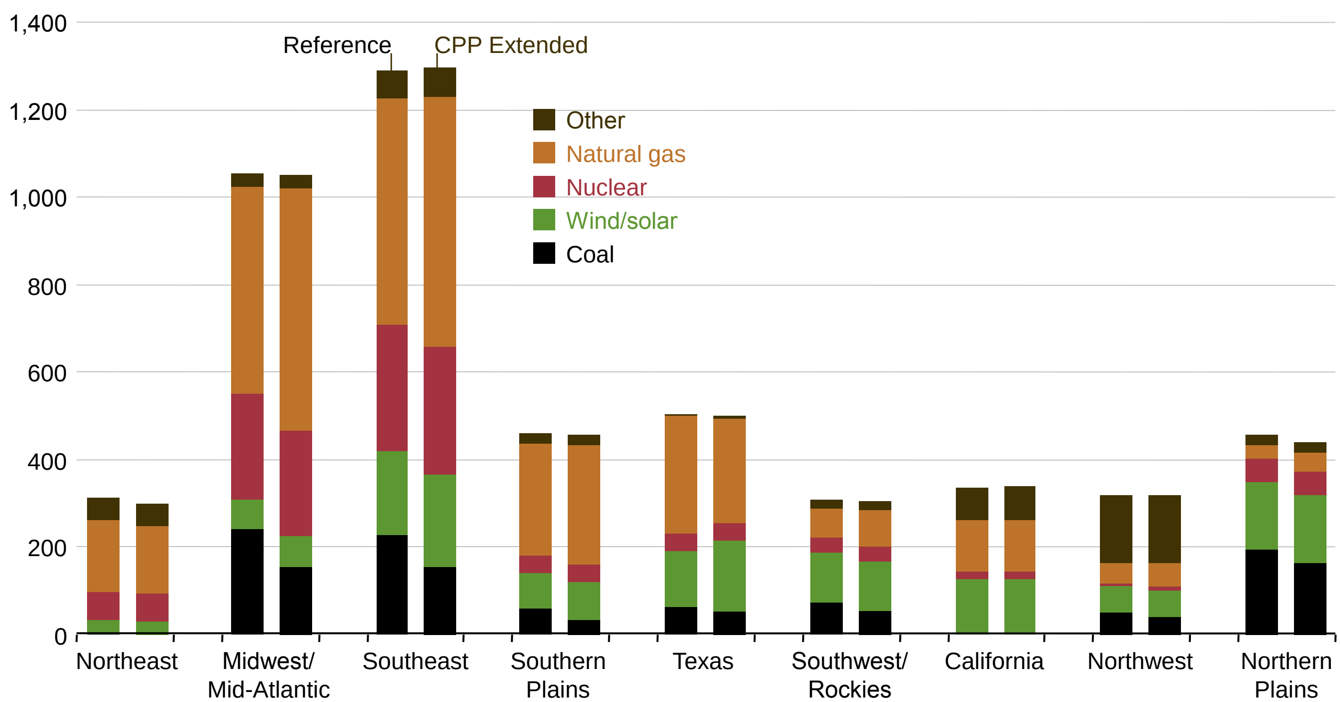
In most regions, new renewable electricity generation shifts occur in the CPP Rate case (Table IF1-2 and Table IF1-3), because the calculation of the emission rate includes generation from renewable sources in the denominator of the rate calculation. This is an added benefit from increasing renewable generation with the rate-based standard, in addition to simply offsetting emissions from fossil-fired generation. In the Midwest/Mid-Atlantic region, an additional 95 billion kWh of generation from wind and solar capacity occurs in 2030 in the CPP Rate case, relative to the Reference case, with a decline in natural gas-fired generation of 69 billion kWh compared with the Reference case. The new wind and solar capacity is added relatively early, before the production and investment tax credits are phased out, and this capacity provides a steady source of carbon-free electricity generation through 2030. However, coal-fired generation is reduced over time as the standard tightens. The patterns are similar in the Southeast, Southern Plains, and Texas regions, where generation from wind and solar energy sources in 2030 is higher than in the Reference case, and natural gas-fired generation is lower. (Coal-fired generation also increases slightly from the Reference case levels in these three regions.) In the Northern Plains region, which has little natural gas-fired capacity, electricity generation from wind and solar resources increases and coal use declines in the CPP Rate case.

CPP Extended case

In the CPP Extended case, the CPP emission targets continue to decline after 2030, and coal-fired electricity generation declines in all regions (Figure IF1-6). The most significant changes relative to the Reference case occur in the Midwest/Mid-Atlantic and Southeast regions. In the Midwest/Mid-Atlantic region, the additional emission reductions result primarily from switching to natural gas-fired generation from coal. In the Southeast region, both natural gas-fired generation and renewable electricity generation are higher in 2040 in the CPP Extended case than in the Reference case. In the Northwest and the Southern Plains regions, electricity generation from natural gas and from renewables in 2040 is higher than in the Reference case, as coal-fired generation declines. In the Southwest Rockies and Northern Plains regions, natural gas-fired generation is higher in 2040 to make up for the decline in coal consumption.

In Texas, coal-fired and natural gas-fired generation are lower in 2040 in the CPP Extended case than in the Reference case, as fossil fuel consumption is reduced to meet the declining emissions target, and large amounts of new solar capacity are added after 2035. In the Northeast region, as emissions targets are lowered in the CPP Extended case, the CPP target eventually becomes more stringent than the regional program (RGGI) that is in place, and natural gas use in 2040 is lower than in the Reference case. In contrast, California's AB 32 program continues to result in emissions below the 2040 targets in the CPP Extended case, and the generation mix is unchanged from that in the Reference case.

Figure IF1-6. Electricity generation in 2040 by region and fuel in the Reference and CPP Extended cases (billion kilowatthours)



Endnotes for IF1

Links current as of July 2016

1. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
2. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Proposed Rule), 79 Fed. Reg. 34,830 (June 18, 2014).
3. U.S. Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan* (Washington, DC: May 2015), http://www.eia.gov/analysis/requests/powerplants/cleanplan/pdf/powerplant.pdf.
4. L. Deniston, "Carbon pollution controls put on hold" (Washington, DC: February 9, 2016), http://www.scotusblog.com/2016/02/carbon-pollution-controls-put-on-hold/.
5. For a more detailed discussion of the status of the rule and its implementation in the Reference case, see "Legislation and regulations."
6. See map of EMM regions in Appendix F. Because they represent a single state, EIA groups Regions 6, 7, and 8 (New York City, Long Island, and Upstate New York) into a single CPP compliance region.
7. RGGI, Inc., "Regional Greenhouse Gas Initiative," http://rggi.org/.
8. California Environmental Protection Agency, Air Resources Board, "Assembly Bill 32 Overview" (Sacramento, CA: August 5, 2014), http://www.arb.ca.gov/cc/ab32/ab32.htm.
9. The CPP Hybrid case assumes that the New York and New England electricity regions use mass-based compliance. Although Delaware and Maryland also are members of RGGI, they are part of a larger electricity modeling region that includes states that are not part of RGGI, and they represent a relatively small share of the region's total emissions. Because CPP compliance is modeled by electricity model regions, not by state, the CPP Hybrid case assumes that the region including Delaware and Maryland complies by using a rate-based approach.
10. The three New York regions are modeled as one compliance region.
11. The Electric Reliability Council of Texas (ERCOT) is located entirely within Texas, so there is no opportunity for trade between states as in the other interconnections.

Figure and table sources for IF1

Links current as of July 2016

Figure IF1-1. CO2 emissions from the electric power sector in five cases, 2005–40: History: U.S. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2016/04) (Washington, DC: April 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_RATE.D032416A, REF_TRADE.D032416A, and REF_EXTEND.D050416A.

Figure IF1-2. Cumulative additions and retirements of generating capacity in five cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_RATE.D032416A, REF_TRADE.D032416A, and REF_EXTEND.D050416A.

Figure IF1-3. Electricity generation by fuel in five cases, 2015, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2016/04) (Washington, DC: April 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_RATE.D032416A, REF_TRADE.D032416A, and REF_EXTEND.D050416A.

Figure IF1-4. Average retail electricity prices in five cases, 2005–40: History: U.S. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (2016/04) (Washington, DC: April 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_RATE.D032416A, REF_EXTEND.D050416A, and REF_ALLOW_GEN.D032416A.

Table IF1-1. Mapping for aggregated electricity regions: U.S. Energy Information Administration.

Figure IF1-5. Change in emissions in the CPP Interregional Trading case relative to the Reference case, 2030: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_TRADE.D032416A.

Table IF1-2. Electricity generation by region and fuel type in four cases, 2015 and 2030: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_TRADE.D032416A, and REF_RATE.D032416A.

Table IF1-3. Electricity generation shares by region and fuel type in four cases, 2015 and 2030: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, REF_TRADE.D032416A, and REF_RATE.D032416A.

Table IF1-4. Differences in average electricity prices in the Reference case from the No CPP case by region, 2025, 2030, 2035, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure IF1-6. Electricity generation in 2040 by region and fuel in the Reference and CPP Extended cases: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_EXTEND.D050416A.

IF2. Fuel consumption and greenhouse gas emissions Phase 2 standards for medium- and heavy-duty vehicles

The transportation sector is the second-largest consumer of energy in the United States, accounting for more than 70% of U.S. petroleum consumption and thus playing a significant role in projections of energy demand. The *Annual Energy Outlook 2016* (AEO2016) Reference case reflects the effects of existing laws and regulations on the fuel consumption and greenhouse gas (GHG) emissions of medium- and heavy-duty vehicles, which in 2015 accounted for 20% of total energy consumption in the transportation sector and 60% of total delivered distillate fuel consumption.

EIA has produced a separate case—the Phase 2 Standards case—to analyze the impacts of a proposed rulemaking jointly issued by the U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) in July 2015 [*1*]. The proposed standards build on the Phase 1 GHG emissions standards for medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) that were implemented starting in model year (MY) 2014. The proposed Phase 2 rulemaking establishes a second round of standards for GHG emissions and fuel consumption by medium- and heavy-duty trucks. The Phase 1 standards extend through MY 2018. The proposed Phase 2 standards take effect in MY 2021 (or MY 2018 for trailers) and increase in stringency through MY 2027.

In the AEO2016 Phase 2 Standards case, average fuel economy increases for all new vehicles covered by the standards. In 2040, total MDV and HDV energy consumption, which is 3.4 million barrels per day oil equivalent in the AEO2016 Reference case, is 2.6 million barrels per day oil equivalent in the Phase 2 Standards case, or 22% lower. Total MDV and HDV diesel fuel use in 2040 is 18% lower than in the Reference case. With higher on-road fuel economy of the truck stock in the Phase 2 Standards case, total delivered energy consumption in the transportation sector is 6% lower in 2040 than in the Reference case. As the average fuel economy of conventional vehicles increases in the Phase 2 Standards case, there is less also incentive to pay high capital costs for natural gas and propane vehicles despite their lower fuel costs, and there is a shift away from natural gas and propane toward conventional diesel and gasoline fuels.

The proposed Phase 2 standards address specific vehicle categories, including combination tractors, trailers, heavy-duty (HD) pickup trucks and vans, and vocational vehicles (Table IF2-1). For combination tractors, standards are proposed by cab, roof, and fuel type. In addition, for the first time, standards are proposed for heavy-haul tractors [*2*] and for trailers pulled by Class 7 and Class 8 tractors. The proposed standards for trailers vary in stringency, depending on the type of trailer. For HD pickups and vans, the proposed standards are categorized by diesel or gasoline engine and are set as total gallons consumed per 100 miles or as grams per mile. For heavy-duty pickups and vans, the proposed standards consider a vehicle's work factor—the weighted average of payload and towing capacity. For vocational vehicles, the proposed standards are based on chassis type, gross vehicle weight rating (GVWR), engine type, and drive cycle.

The AEO2016 Phase 2 Standards case analyzes the estimated effects of the proposed regulations on fuel consumption and GHG emissions. The requirements for each of the vehicle categories are derived from U.S. Energy Information Administration projected sales, distributed into the size classes according to data from Polk Automotive [*3*] and the U.S. Census Bureau's Vehicle Inventory and Use Survey (VIUS) [*4*].

Heavy-duty pickups and vans

The proposed standards for heavy-duty pickups and vans in Class 2b (GVWR between 8,501 and 10,000 pounds) and Class 3 (GVWR between 10,001 and 14,000 pounds) are phased in from MY 2021 to MY 2027. Although heavy-duty pickups and vans often use efficiency improvements similar to those for light-duty pickup trucks and vans, the standards are based on a work-based metric rather than on the footprint metric used for light-duty vehicles. The work factor incorporates towing and payload capacity as well as four-wheel drive capability in determining minimum fuel efficiency requirements.

The proposed standards include an annual 2.5%/year reduction in allowable emissions from MY 2021 to MY 2027, an approximate 16% increase from the standards set by Phase 1 for MY 2018. Standards are set individually for vehicles with spark ignition engines

Table IF2-1. Types of vehicles regulated by the proposed Phase 2 standards

Vehicle category	Description	Truck classes covered
Combination tractors	Semi-trucks that typically pull trailers	Class 7 and Class 8 (GVWR 26,001 pounds and above)
Heavy-duty pickups and vans	Pickup trucks and vans, such as 3/4-ton or 1-ton pickups for example used on construction sites or 12- to 15-person passenger vans	Class 2b and Class 3 (GVWR 8,501 to 14,000 pounds)
Vocational vehicles	Wide range of truck configurations, such as delivery, refuse, utility, dump, cement, school bus, ambulance, and tow trucks. For purposes of the rulemaking, vocational vehicles are defined as all heavy-duty trucks that are not combination tractors or heavy-duty pickups or vans	Class 2b through Class 8 (GVWR 8,501 pounds and above)

and vehicles with compression ignition engines, but the standards are expected to improve at the same rate. Compliance test procedures for heavy-duty pickups and vans employ the same EPA drive cycles used to determine light-duty vehicle compliance, and manufacturer compliance retains the same Phase 1 production-weighted fleet average to determine compliance.

Combination tractor cabs

The proposed Phase 2 standards continue the attribute-based classification of combination tractor cabs from Phase 1—by Classes 7 and 8, day and sleeper cabs, and roof height (low, mid, high). In addition, a specific set of vocational tractors, heavy-haul tractors, are subject to a specific standard to reflect their unique powertrains. The proposed standards would require reductions in carbon dioxide (CO2) emissions and fuel consumption of up to 24% compared to the MY 2017 baseline [*5*]. They are based on expected technology improvements for engines, transmissions, drivelines, aerodynamics, tires, accessories, and extended idle reduction technologies. Tractors are certified with the Greenhouse Gas Emissions Model (GEM) [*6*].

Trailers

The contributions of trailers to fuel efficiency improvement are not regulated in Phase 1. The proposed Phase 2 standards apply to trailers pulled by Classes 7 and 8 tractors coupled to the fifth wheel. The most comprehensive requirements are applicable to traditional long-box trailers, both refrigerated and dry, which typically are pulled by high-roof cab tractors. The proposed changes center on improving aerodynamics and reducing rolling resistance. Compliance is determined with a version of GEM. The standards are less stringent for trailer categories with shorter boxes or trailers with aerodynamic limitations. Non-box trailers and non-aerodynamic box vans are required to adopt specific tire technologies to comply. In total, there are 10 separate categories:

- Long-box dry vans (longer than 50 feet)
- Long-box refrigerated vans (longer than 50 feet)
- Short-box dry vans (50 feet and shorter)
- Short-box refrigerated vans (50 feet and shorter)
- Partial-aero long-box dry vans
- Partial-aero long-box refrigerated vans
- Partial-aero short-box dry vans
- Partial-aero short-box refrigerated vans
- Non-aero box vans (all lengths of dry and refrigerated vans)
- Non-box trailers (tanker, platform, container chassis, and all other types of highway trailers that are not box trailers).

With the exception of refrigerated units, trailers typically do not directly emit GHGs. However, the proposed standards assign required levels of emissions and fuel consumption as if the trailers were pulled by a standard reference tractor [*7*]. The standards require reductions of 3% to 8% from MY 2021 to MY 2027 in fuel consumption and CO2 emissions, depending on the trailer type. Certain trailers are exempt, including those that operate only at low speed and those that are used for logging and mining. Trailers are also certified with GEM.

Vocational vehicles

Vocational vehicles are separated into three class groups: light heavy-duty (Classes 2b–5), medium heavy-duty (Classes 6–7), and heavy heavy-duty (Class 8). Each class group is separated by engine type (compression or spark ignition) and a duty cycle that captures expected vehicle usage and energy consumption. The three available duty cycles are urban, multi-purpose, and regional. Because power requirements for vocational vehicles vary widely, multiple baseline drivelines are available in the Phase 2 standards for calculating fuel efficiency and GHG emission improvements. Standards are set at increments starting in MY 2021, with updates in MY 2024 and MY 2027.

In comparison with MY 2017 baseline vehicles, the proposed standards require a 16% reduction in CO2 emissions and fuel consumption for all vehicles across all weight classes powered by compression ignition (primarily diesel) engines. Vocational vehicles powered by spark ignition engines are subject to emission and fuel-use reductions by MY 2027 of 12% for light heavy-duty, 13% for medium heavy-duty, and 12% for heavy heavy-duty. Like combination tractors and trailers, vocational vehicles are certified with GEM.

Certification for combination tractors, trailers, and vocational vehicles

As in Phase 1, compliance for tractors and vocational vehicles is certified in Phase 2 using an updated version of GEM that incorporates some fixed input values, such as payload and trailer weights, to determine fuel efficiency performance by drive cycle. Compliance can be achieved through adoption of various technology combinations. Improving on Phase 1, the Phase 2 GEM incorporates several changes to more accurately reflect the effects of technology adoption on fuel efficiency performance. These changes include road grade, an additional averaged aerodynamic drag coefficient, and improved simulation of engines and transmissions. Ultimately, the changes mean that a vehicle evaluated with the Phase 2 GEM would have higher CO2 emissions and fuel consumption than if evaluated with the Phase 1 GEM. Consequently, results from the two standards are not directly comparable. Trailers are modeled in GEM with attribute inputs for aerodynamics, tires, weight characteristics, and performance.

Results

The Phase 2 Standards case estimates fuel efficiency improvement and fuel consumption based on the proposed requirements for combination tractors, HD pickups and vans, and vocational vehicles. Trailer stocks are not explicitly modeled, because there are limited data on trailer inventories and usage; however, efficiency improvements as a result of the adoption of limited trailer improvements are included in the model. Between MY 2017 and MY 2027, the Phase 2 Standards case indicates that the proposed standards lead to the adoption of technologies to improve fuel economy that otherwise would not have been purchased. Although the standards do not start until MY 2021, manufacturers are expected to begin adoption beforehand to ensure initial compliance by MY 2021. Fuel economy and energy usage reports combine vocational and nonvocational vehicles for Classes 3, 4–6, and 7–8.

New vehicle average fuel economy increases for all size classes in the Phase 2 Standards case. From 2017 to 2027, new vehicle average fuel economy (combined Classes 3–8) rises by 28% in the Phase 2 Standards case compared to the Reference case. After 2027 the standards are held constant, but technology adoption continues as new technologies become available. In 2040, new vehicle fuel efficiency averages 10.6 miles per gallon gasoline equivalent in the Phase 2 Standards case, representing a 33% improvement compared to the Reference case. The improvements represent overcompliance as the model continues to adopt cost-effective technologies beyond 2027.

The increase in fuel economy of the entire vehicle stock is lagged, reflecting slow turnover in the stock of Classes 2b–8 trucks, which have a median lifetime of 12 years [8]. As new medium- and heavy-duty trucks are added to the total stock, and older trucks with lower fuel economy are removed from service, the average on-road fuel economy for the total stock of heavy-duty trucks increases in the Phase 2 Standards case (Figure IF2-1).

In comparison with the AEO2016 Reference case, differences in total vehicle sales and stocks are negligible in the Phase 2 Standards case. Between 2017 and 2040, new MDV and HDV sales per year are equal to about 5% of the total truck stock, ranging from about 660,000 to 790,000 new MDV and HDV sales per year out of a total stock that grows from 11.7 million in 2017 to 17.2 million in 2040. However, there is a shift away from natural gas and propane toward conventional diesel and gasoline in the Phase 2 Standards case. As the average fuel economy of conventional vehicles increases, there is less incentive to pay high capital costs for natural gas and propane vehicles, despite their lower fuel costs.

The most significant effect of Phase 2 is a reduction of diesel consumption—the most commonly used fuel—in medium- and heavy-duty vehicles. In the Reference case, MDV and HDV diesel consumption increases steadily through 2040, as industrial output grows (Figure IF2-2). In the Phase 2 Standards case, diesel consumption decreases from 2015 to 2033 as gains in fuel economy more than offset growth in transport requirements. After 2033, diesel consumption increases slowly without continued enhancement of the standard, but in 2040 it still is 18% lower in the Phase 2 Standards case than in the Reference case. Cumulative MDV and HDV consumption of diesel fuel from 2021 to 2040 in the Phase 2 Standards case is 2.5 billion barrels lower than in the Reference case.

The reduction in diesel consumption in the Phase 2 Standards case has significant implications for the mix, as well as the amount, of petroleum products consumed in the United States. Implications for refiners would depend on the extent to which similar

Figure IF2-1. Average on-road fuel economy of vehicles by weight class, 2005–40 (miles per gallon gasoline equivalent)

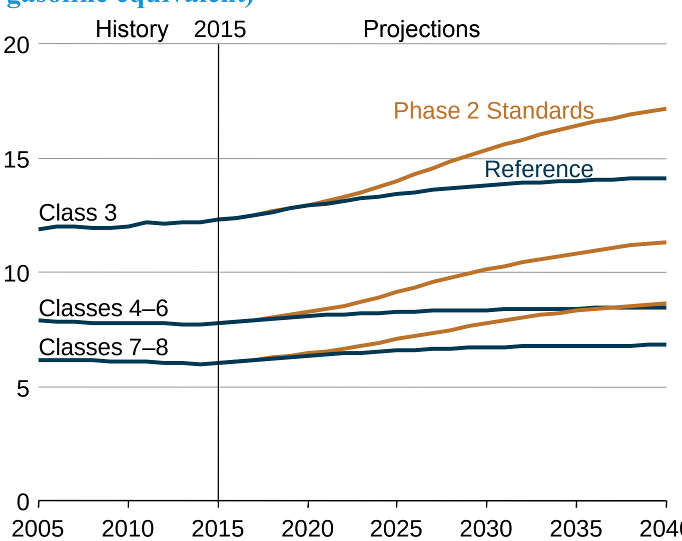
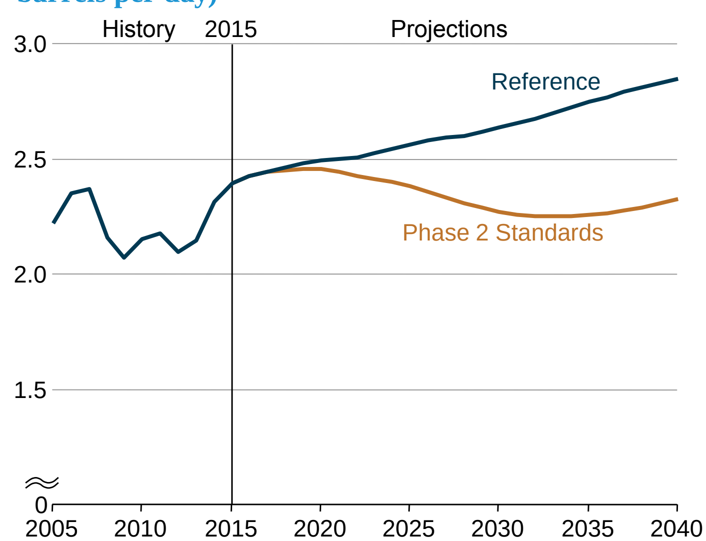


Figure IF2-2. Diesel fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40 (million barrels per day)



standards were adopted in other countries with significant trucking activity, because diesel and other petroleum products are widely traded in global markets.

Consumption of other fuels by MDVs and HDVs—including gasoline, propane, liquefied natural gas (LNG), and compressed natural gas (CNG)—is lower in the Phase 2 Standards case than in the Reference case (Figure IF2-3). In the Phase 2 Standards case, diesel fuel consumption accounts for 90% of all fuel consumption by MDVs and HDVs in 2040, with the remainder consisting primarily of gasoline and a small amount of natural gas. The higher diesel share in the Phase 2 Standards case reflects a shift away from alternative fuels as improved fuel economy reduces the incentive to pay high capital costs for natural gas and propane vehicles despite their lower fuel costs.

In the Phase 2 Standards case, higher on-road fuel economy of the truck stock reduces total delivered energy consumption in the transportation sector. From 2021 to 2040, cumulative delivered energy consumption in the transportation sector is 3% lower in the Phase 2 Standards case than in the Reference case, and total transportation sector energy consumption in 2040 is about 750,000 barrels per day oil equivalent (22%) lower than in the Reference case (Figure IF2-4). Cumulative CO2 emissions from

Figure IF2-3. Fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40 (million barrels oil equivalent per day)

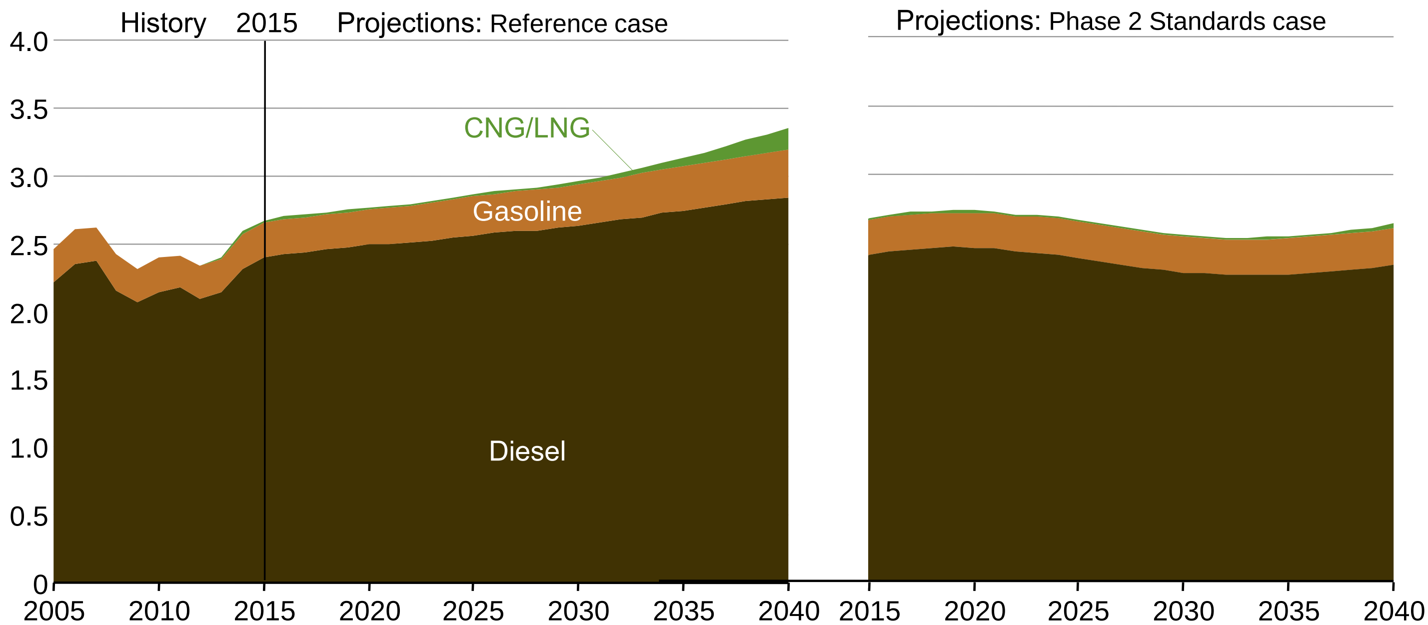
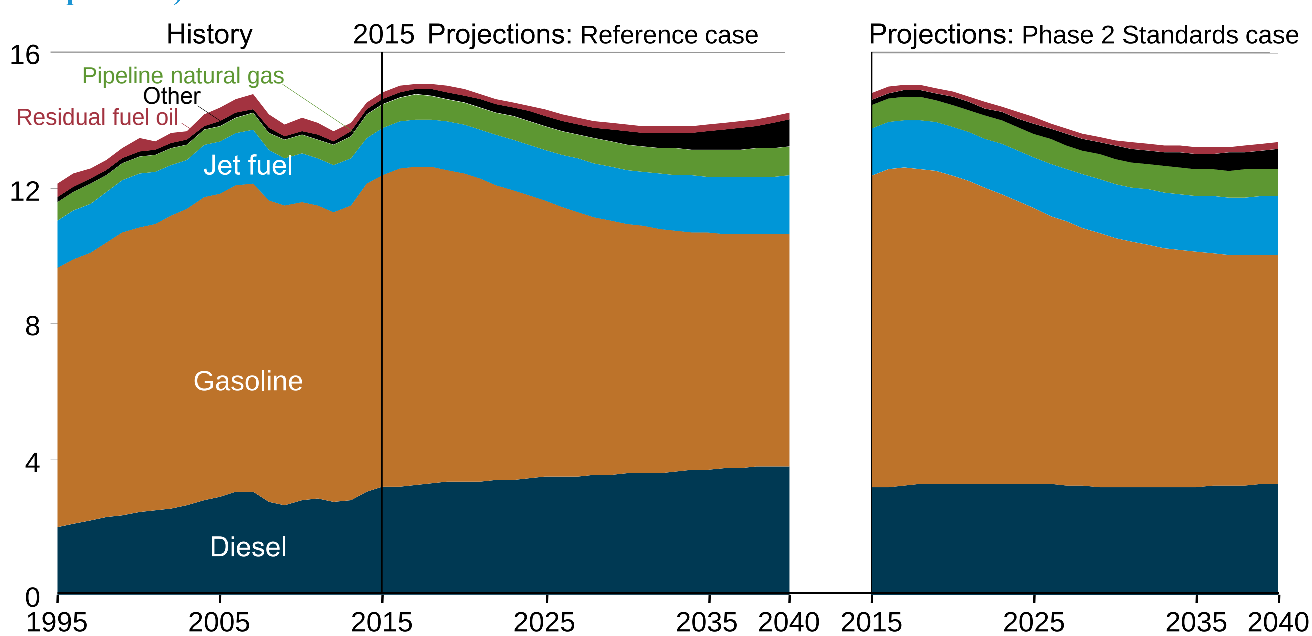


Figure IF2-4. Transportation sector energy consumption by fuel in two cases, 1995–2040 (million barrels per day oil equivalent)

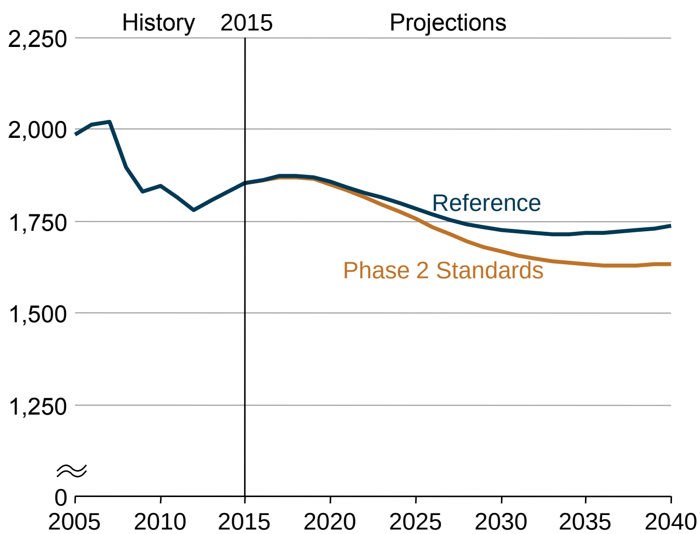


2021 to 2040 in the transportation sector are 1,200 million metric tons (3%) lower in the Phase 2 Standards case than in the AEO2016 Reference case. In 2040, total transportation sector CO2 emissions are 6% lower in the Phase 2 Standards case than in the AEO2016 Reference case (Figure IF2-5).

Regulatory and data issues

- Although Class 2b pickup trucks and vans are included in the Phase 2 Standards case, their fuel economy and consumption are not reported individually. However, the effects of Class 2b are included in total transportation fuel consumption and emissions data.
- The Phase 2 Standards case approximates the proposed rulemaking by disaggregating Class 7 and Class 8 tractor vehicle body types (based on data from the VIUS survey [9], which has not been updated since 2002). As a result, there may be significant differences between the tractor market today and more than a decade ago. Further, there are data uncertainties associated with vehicle usage reported in the VIUS survey. Nevertheless, the data were used because VIUS is the only source of information on tractor type.
- Trailers were not explicitly modeled in this study, because there are limited data on trailer inventories and usage. There are more registered trailers than tractors, and an understanding of usage logistics is critical to evaluating the adoption and overall results of improving trailer technology.
- Despite improvements since the start of Phase 1, there are still limits on data about the technologies used to meet the Phase 1 compliance standards. Consequently, it is difficult to estimate the energy outcomes that could be expected as medium- and heavy-duty trucks begin to comply with the new Phase 2 standards. Without better data, it is difficult to analyze the composition of the truck market at the level of diversity included in the proposed standards, or the efficiency and fuel economy metrics associated with each classification in the standards.
- A critical issue is the limited availability of information that would provide a baseline from which to measure improvement. The lack of baseline data is a result of the previously discussed data limitations, as well as operational changes in Phase 2 compared with Phase 1. Although many improvements have been made in GEM, the changes evaluation methods for the different technology categories make it difficult to map Phase 1 compliance to Phase 2. The baseline for Phase 2 (MY 2017) assumes compliance with Phase 1 at that time, and it is evaluated differently. As a result, it is not known whether Phase 1 compliant vehicles in MY 2017 accurately represent the proposed Phase 2 baseline.

Figure IF2-5. Transportation sector carbon dioxide emissions in two cases, 2005–40 (million metric tons)



- Continuing issues from Phase 1 include how compliance will be measured and how well compliance testing procedures will replicate the average real-world performance of combination tractors, heavy-duty pickups and vans, vocational vehicles, and trailers. Phase 2 has three vocational drive cycles that can be used for compliance (urban, multi-purpose, and regional). Only the multi-purpose cycle is used in the AEO2016 Phase 2 Standards case. GEM has many new categories and improvements compared with Phase 1, but many of the categories are simplified to Yes or No responses, rather than to custom inputs. Some inputs, including payload and trailer weights, are fixed.
- Compliance for heavy-duty pickups and vans will be determined by a vehicle test procedure similar to that used in the national program for light-duty vehicles, including the highway fuel economy test and the federal test procedure for city driving, weighted 45% and 55%, respectively. Heavy-duty pickups and vans are assumed to be loaded to one-half of their payload capacity.

Endnotes for IF2

Links current as of July 2016

1. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.
2. Heavy-haul tractors have a gross combined weight rating of more than 120,000 pounds.
3. IHS-Polk Automotive, unpublished data (Southfield, MI: 2014).
4. Microdata available online at U.S. Department of Commerce, U.S. Census Bureau, "2002 Vehicle Inventory and Use Survey," https://www.census.gov/svsd/www/vius/2002.html.
5. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.
6. The GEM model is a MATLAB/Simulink based model with a spreadsheet interface that determines compliance based on set factors and user inputs (such as vehicle class, engine data, transmission type, aerodynamics, technology adoption, etc.) with variations for the different vehicle types. U.S. Environmental Protection Agency, "Greenhouse Gas Emissions Model (GEM) for Medium- and Heavy-Duty Vehicle Compliance," https://www3.epa.gov/otaq/climate/gem.htm.
7. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.
8. IHS-Polk Automotive, unpublished data (Southfield, MI: 2014).
9. Microdata available online at U.S. Department of Commerce, Bureau of the Census, "2002 Vehicle Inventory and Use Survey," https://www.census.gov/svsd/www/vius/2002.html.

Figure and table sources for IF2

Links current as of July 2016

Table IF2-1. Types of vehicles regulated by the proposed Phase 2 standards: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.

Figure IF2-1. Average on-road fuel economy of all motor vehicles by weight class, 2005–40: AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

Figure IF2-2. Diesel fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40: **History:** U.S. Energy Information Administration, *Monthly Energy Review*, February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

Figure IF2-3. Fuel consumption by large trucks, Classes 3–8, in two cases, 2005–40: **History:** U.S. Energy Information Administration, *Monthly Energy Review*, February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

Figure IF2-4. Transportation sector energy consumption by fuel in two cases, 1995–2040: **History:** U.S. Energy Information Administration, *Monthly Energy Review*, February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

Figure IF2-5. Transportation sector carbon dioxide emissions in two cases, 2005–40: **History:** U.S. Energy Information Administration, *Monthly Energy Review*, February 2016, DOE/EIA-0035(2016/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351602.pdf. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D0324A and PHASEII.D041316A.

IF3. Extended Policies case

The *Annual Energy Outlook 2016* (AEO2016) Extended Policies case includes selected policies that go beyond current laws and regulations. Existing tax credits that have scheduled reductions and sunset dates are assumed to remain unchanged through 2040. Other efficiency policies, including corporate average fuel economy standards, appliance standards, and building codes, are expanded beyond current provisions; and the U.S. Environmental Protection Agency (EPA) Clean Power Plan (CPP) [*1*] regulations that reduce carbon dioxide emissions from electric power generation are tightened after 2030.

No attempt is made to cover the full range of possible uncertainties, and the policy assumptions used in the Extended Policies case should not be construed as a U.S. Energy Information Administration (EIA) opinion regarding how laws or regulations should, or are likely to, be changed. The Extended Policies case includes only federal laws and regulations and does not include state laws or regulations. In general, the Extended Polices case leads to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), reduced energy-related carbon dioxide (CO2) emissions, lower energy prices, and higher government tax expenditures.

Background

The AEO2016 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, except for those current laws or regulations that include sunset dates or specific changes over time. The Reference case serves as a starting point for analysis of proposed changes in legislation or regulations. The Extended Policies case assumes updates or extensions of current laws and regulations, including:

- 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 EPA.
- Laws or regulations that allow or require regulatory agencies to issue new or revised regulations under certain conditions. Examples include many provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality goal is not being met.

Extended Policies case

The Extended Policies case adopts the following assumptions:

- Electricity generation technologies eligible for the Production Tax Credit (PTC) retain their full credit value through 2040, as opposed to declining in value starting in 2017 (wind) or expiring at the end of 2016 (other PTC-eligible technologies, including geothermal and hydroelectric).
- For solar power, the full Investment Tax Credit (ITC) value of 30% remains in effect through 2040 for the residential, commercial, and electric power sectors, whereas in the Reference case, the value of the ITC begins to decline in 2020.
- In the buildings sector, tax credits for the purchase of energy-efficient and renewable equipment are assumed to be extended indefinitely at their current levels. For the residential sector, the extensions include personal tax credits for solar photovoltaic (PV) installations, solar water heaters, small wind turbines, fuel cells, and geothermal heat pumps. For the commercial sector, the extensions include the business ITC for solar PV, solar water heaters, small wind turbines, fuel cells, microturbines, geothermal heat pumps, and conventional combined heat and power (CHP). The ITC for solar PV and solar water heaters is assumed to remain at 30%, rather than being phased out in 2022 (residential systems) or declining to 10% (commercial systems).
- Standards for residential and commercial equipment are assumed to be updated as prescribed by the timeline in the DOE multi-year plan, at levels based on ENERGY STAR™ specifications or on Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards also are updated for products that currently are not subject to federal efficiency standards but are covered by voluntary industry agreements or by prevailing state standards.
- Federal energy codes for residential and commercial buildings are assumed to be updated twice over the projection, with implementation beginning in 2025 and in 2034, each phased in over nine years. The updates provide additional improvements 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 Reference case and the Extended Policies case include the joint attribute-based CAFE and vehicle greenhouse gas (GHG) emissions standards for model years (MY) 2012 to 2025 for light-duty vehicles (LDV). In the Reference case, the CAFE standards are assumed to remain 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 assumes continued increases in CAFE standards at an annual average rate of 1.4% for new LDVs after MY 2025.

- The Reference case and the Extended Policies case include the medium-duty vehicle (MDV) and heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards for MY 2014 to MY 2018. In the Reference case, the standards are held constant at MY 2018 levels in subsequent model years, although the fuel economy of HDVs continues to rise modestly. The Extended Policies case includes tighter standards for fuel consumption and GHG emissions for MDVs and HDVs, as proposed in the Phase 2 standards jointly issued by EPA and NHTSA in July 2015 [*2*].
- The Reference case includes the CPP, which under current regulations is phased in over the 2022–30 period, and assumes that states comply by setting mass-based compliance strategies that cover both existing and new electric generators. The Extended Policies case assumes a further reduction in the CO2 targets after 2030. The mass-based limits, which in the Reference case result in power sector CO2 emissions that in 2030 are about 35% below 2005 levels, are assumed to continue to decline linearly to 45% below 2005 emission levels in 2040 in the Extended Policies case.
- In the industrial sector, the 10% ITC for combined heat and power (CHP), which in the Reference case ends in 2016 [*3*], continues through 2040. Also, the ITC is modified to increase the size limit for eligible CHP units from 15 megawatts (MW) to 25 MW. The ITC for CHP is extended to cover all properties with CHP, no matter the powerplant size, instead of being limited to properties with plants smaller than 50 MW as in the Reference case [*4*]. These extensions are consistent with previously proposed legislation.

Analysis results

In general, estimates for overall delivered energy consumption are lower in the Extended Policies case than in the Reference case, with renewable fuels providing an increasing share of U.S. electricity generation and total energy-related CO2 emissions declining. Average electricity prices are marginally affected, leading to small declines in 2040 relative to the Reference case. Energy expenditures are lower in the Extended Policies case than in the Reference case, because the assumed tax credits and efficiency standards lead to lower energy demand. Appliance purchase costs also are affected, and government tax expenditures generally are higher as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the Extended Policies case is lower than in the AEO2016 Reference case throughout the projection period (Figure IF3-1) as a result of improvements in energy efficiency. In 2040, total energy consumption in the Extended Policies case is 4% lower than in the Reference case, as the combination of the extension of tax credits and other policies reduces overall demand even after taking price declines into account.

Buildings sector energy consumption

In the Extended Policies case, delivered energy consumption in the buildings sector falls below its 2015 level from 2022 to 2034 (Figure IF3-2), with renewable distributed generation (DG) technologies (PV systems and small wind turbines) providing much of the energy savings. With the continuation of tax credits spurring wider adoption of DG systems, onsite electricity generation from renewable DG increases to 90 billion kilowatthours (kWh) in 2025, compared with 61 billion kWh in the Reference case. In 2040, onsite electricity generation from renewable sources totals 249 billion kWh in the Extended Policies case—nearly double the Reference case total.

Figure IF3-1. Total energy consumption in two cases, 2000–2040 (quadrillion Btu)

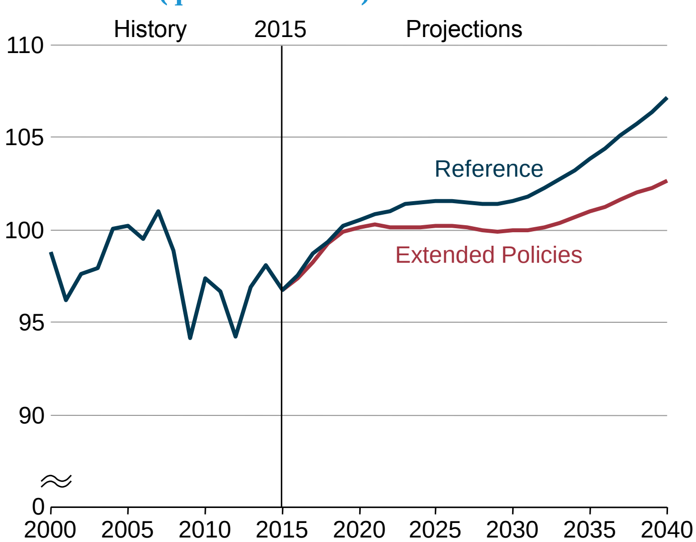
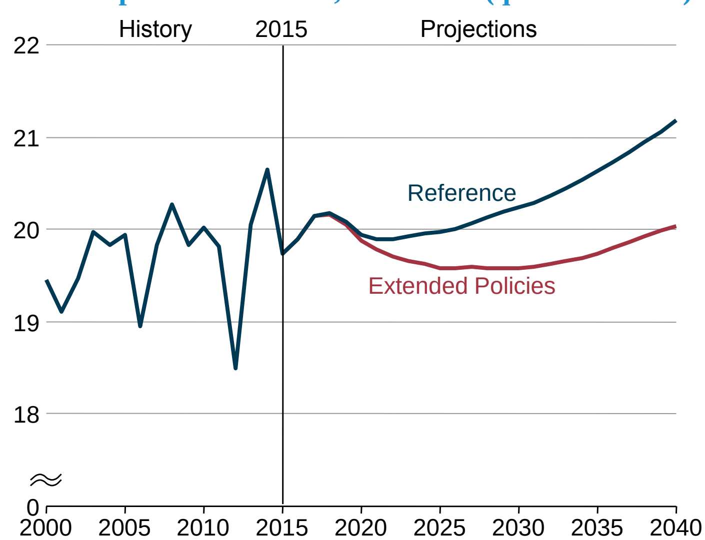


Figure IF3-2. Buildings sector delivered energy consumption in two cases, 2000–2040 (quadrillion Btu)



Efficiency gains from assumed future standards and more stringent building codes further reduce delivered energy use in the buildings sectors in the Extended Policies case. Including savings from distributed generation, delivered energy use in the buildings sector in the Extended Policies case is 1.9%, or 0.4 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.

Among delivered energy sources, electricity is the buildings fuel source most affected in the Extended Policies case. Efficiency standards and buildings codes affect appliances that run on all fuels, but distributed generation has a larger impact on electricity purchases than other fuel purchases. In comparison with the Reference case, building sector electricity purchases are 2.6% lower in the Extended Policies case in 2025 and 7.4% lower in 2040, and natural gas and distillate fuel oil purchases are 3.7% and 1.6% lower, respectively, in 2040.

Energy consumption levels for all end uses are lower in the Extended Policies case than in the Reference case (Figure IF3-3), with space heating, cooling, and ventilation accounting for almost 50% of the reduction. Delivered energy consumption continues to grow for many end uses in the buildings sector, as commercial floorspace and the number of households continue to expand. In particular, energy consumption for laundry and other uses, which includes small devices and other miscellaneous uses that typically are not covered by efficiency standards.

Industrial sector energy consumption

In the industrial sector, the 10% ITC for CHP is extended to 2040 in the Extended Policies case, the maximum size of individual generating units eligible for the ITC is increased from 15 MW to 25 MW, and there is no ITC cap on total plant size (compared with a cap of 50 MW in the Reference case). Although most CHP units are smaller than 15 MW, approximately 15% of operable industrial CHP units as of 2014 were between 15 MW (the unit size cap in the Reference case) and 25 MW (the unit size cap in the Extended Policies case). In addition to the tax credit extension, the higher size cap also has an effect, given that 30% of operable CHP plants in 2014 exceeded the Reference case cap of 50 MW [5]. In 2040, industrial CHP capacity is 8% higher in the Extended Policies case than in the Reference case (Figure IF3-4), and delivered energy intensity is slightly lower.

Transportation sector energy consumption

The Extended Policies case differs from the AEO2016 Reference case in assuming that the joint CAFE and GHG emissions standards promulgated by EPA and NHTSA for MY 2012–25 are extended through 2040 with an average annual increase of 1.4%. Sales of LDVs that do not rely solely on gasoline internal combustion engines for power (including those that use diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to 80% of new LDV sales in the Extended Policies case, compared with 61% in the Reference case, in 2040.

In the Reference case, LDV energy consumption declines from 15.9 quadrillion Btu, or 8.6 million barrels per day (b/d) oil equivalent, in 2015 to 14.1 quadrillion Btu (7.7 million b/d oil equivalent) in 2025 as a result of more stringent CAFE standards. Extension of the CAFE standards in the Extended Policies case further reduces LDV energy consumption, to 11.0 quadrillion Btu (6.0 million b/d oil equivalent) in 2040, or 7% lower than in the Reference case.

The Extended Policies case includes the proposed Phase 2 standards for MDVs and HDVs. The average fuel economy of new MDVs and HDVs increases from a combined 7.4 miles per gallon (mpg) in 2017 to 10.8 mpg in 2040 in the Extended Policies case. MDV and HDV annual energy consumption falls from 5.6 quadrillion Btu (2.7 million b/d oil equivalent) in 2015 to 5.4 quadrillion Btu

Figure IF3-3. Changes in buildings sector delivered energy consumption by end use in two cases, 2015–40 (percent)

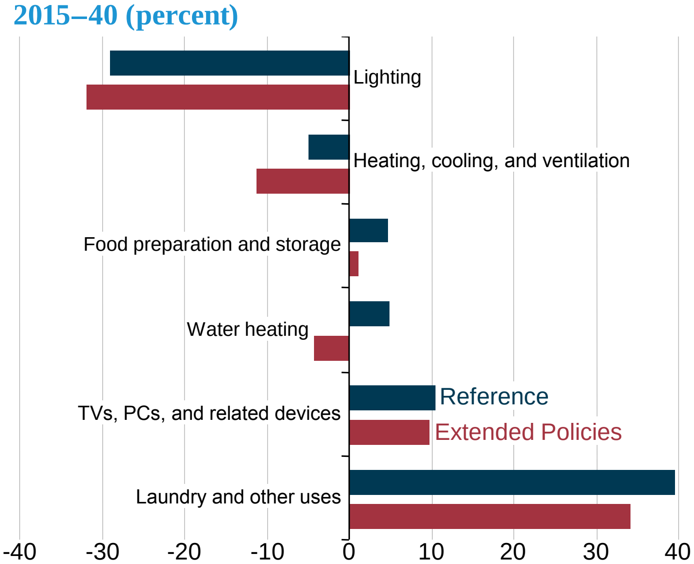
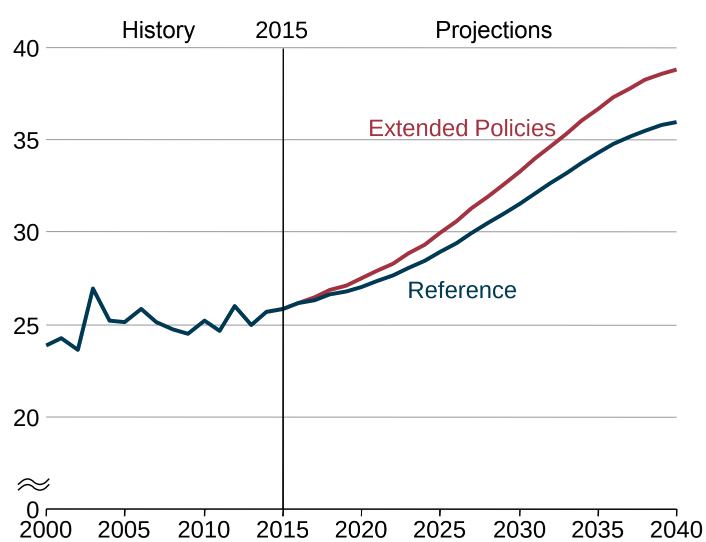


Figure IF3-4. Industrial sector combined heat and power capacity in two cases, 2000–2040 (megawatts)



(2.6 million b/d oil equivalent) in 2040 in the Extended Policies case. In 2040, MDV and HDV fuel consumption is 1.6 quadrillion Btu (0.8 million b/d oil equivalent), or 23%, lower than in the Reference case. Consumption of petroleum and other liquids in the transportation sector declines in the Extended Policies case from 14.3 million b/d oil equivalent in 2017 to 11.6 million b/d oil equivalent in 2040, compared with 12.7 million b/d oil equivalent in 2040 in the Reference case (Figure IF3-5).

Electricity generation

The Extended Policies case assumes that the value of the tax credits for eligible renewable electricity generation sources as of 2016 is extended through 2040, and that the stringency of the CPP increases from 2030–40, requiring emissions in 2040 to be 45% below the 2005 total. As a result, coal-fired generation declines to 779 billion kWh in 2040 in the Extended Policies case, compared with 919 billion kWh in the Reference case (Figure IF3-6). Generation from oil and natural gas in 2040 also is lower in the Extended Policies case, at 1,686 billion kWh, compared with 1,952 billion kWh in the Reference case. Generation from renewable technologies in 2040 is higher in the Extended Policies case, at 1,663 billion kWh, than in the Reference case (1,374 billion kWh), and nuclear power generation is virtually the same in the two cases.

The Extended Policies case includes energy efficiency measures that result in slower load growth and lower demand for new generating capacity. Because of those measures, differences in renewable technology trends between the Extended Policies case and the Reference case can be seen in the mix of energy sources for electricity generation. As a result of the PTC extension for wind energy in the Extended Policies case, the share of electricity generation from wind resources declines from Reference case levels in the near term. Wind projects built in anticipation of expiring tax credits in the Reference case are built later in the projection period in the Extended Policies case, at a time when electricity demand and economic conditions are more favorable. In 2040, the share of electricity generation from wind energy resources is larger in the Extended Policies case than in the Reference case (Figure IF3-7).

In the Extended Policies case, the share of total electricity generation from wind resources more than doubles, from 5% in 2015 to 13% in 2040, as compared with 9% in 2040 in the Reference case. In the Extended Policies case, extension of the PTC through 2040 makes wind projects more attractive throughout the projection. In the Reference case, the value of the PTC starts to decline in 2017 and expires in 2020, and as a result, more wind capacity is added earlier in the projection

Figure IF3-5. Transportation sector petroleum and other liquids demand in two cases, 2000–2040 (million barrels per day)

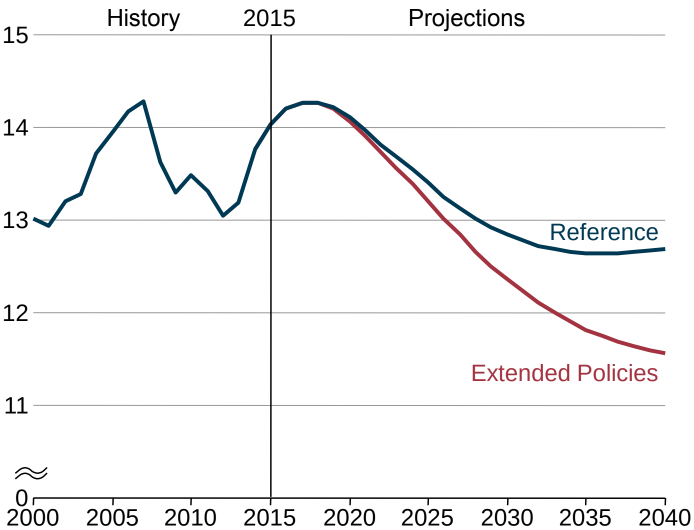
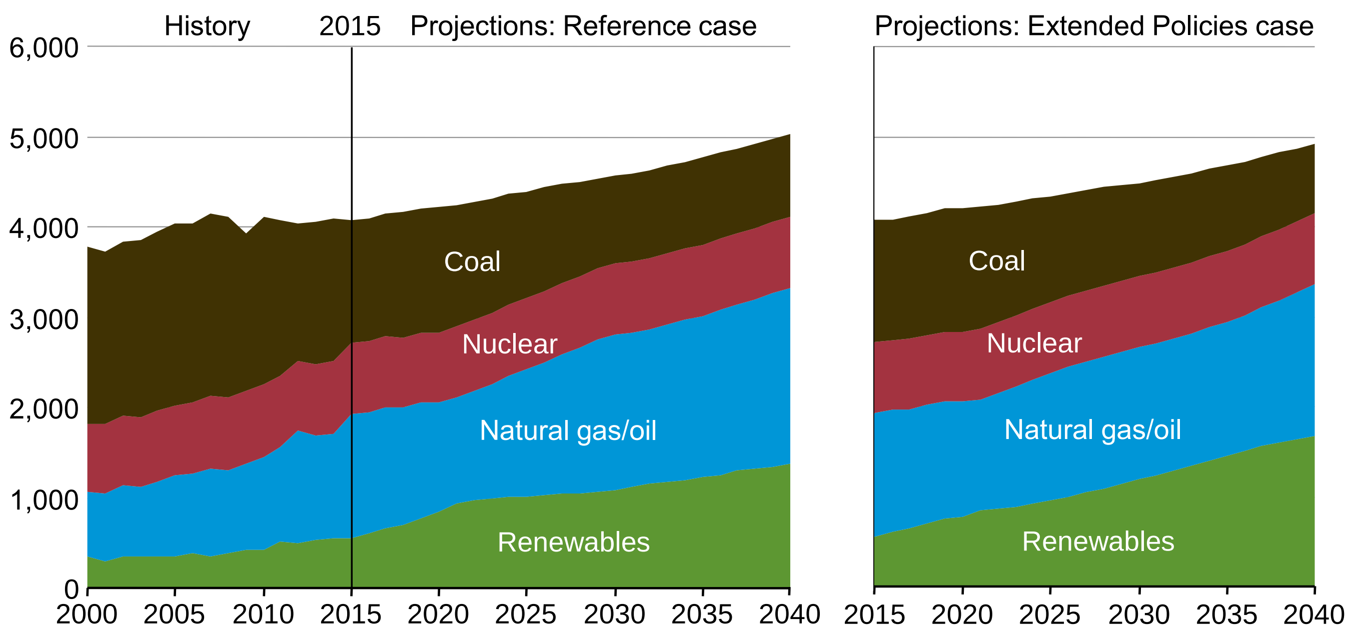


Figure IF3-6. Electricity generation by fuel in the Reference and Extended Policies cases, 2000–2040 (billion kilowatthours)



period. In the Extended Policies case, more capacity is added after 2020, and more electricity is generated from wind installations, than in the Reference case.

The solar ITC for utility-scale projects in the Reference case decreases gradually from 30% in 2019 to 10% by 2022. In the Extended Policies case, the value of the ITC remains at 30% through 2040, and as a result, the share of total electricity generation from utility-scale solar PV increases from 0.5% in 2015 to 8.0% in 2040, compared with 6.8% in 2040 in the Reference case.

While tax credits for residential projects expire in the Reference case, and those for commercial projects decline to 10% starting in 2022, the solar ITC continues through 2040 in the Extended Policies case. As a result, electricity generation from solar PV in the end-use sector grows more rapidly in the Extended Policies case than in the Reference case, by an average of 10.6%/year from 2015 to 2040, compared with 8.4%/year in the Reference case—as a result of the extension of the solar ITC through 2040 in the Extended Policies case, while tax credits for residential projects expire and those for commercial projects decline to 10% starting in 2022 in the Reference case. The effects of tax credit extensions on other eligible renewable generation technologies, including hydropower, biomass, and geothermal, are minimal in comparison.

Energy-related CO2 emissions

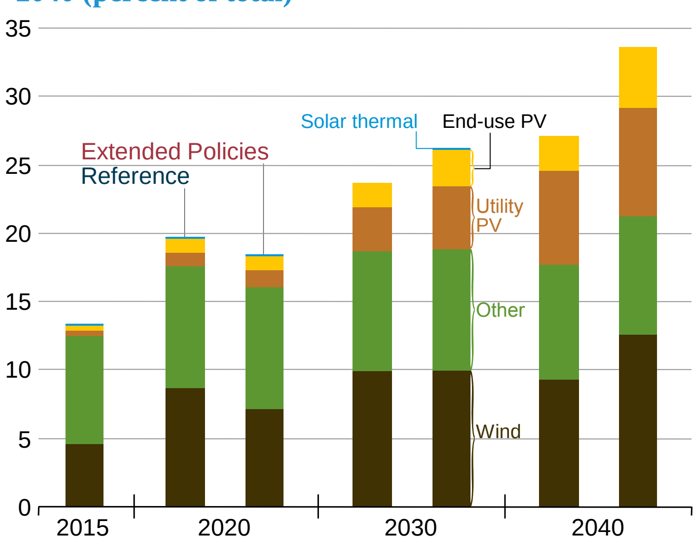
In the Extended Policies case, lower overall demand for fossil energy results in lower energy-related CO2 emissions than in the Reference case (Figure IF3-8). From 2015 to 2040, energy-related CO2 emissions are reduced by a cumulative total of 3.2 billion metric tons (or 2.4%) in the Extended Policies case compared with the Reference case. Electric power sector emissions also differ significantly between the two cases after 2030, reflecting the impact of more stringent CPP requirements over the 2030–40 period. With the CPP becoming more stringent after 2030, cumulative power sector CO2 emissions are reduced by 1.3 billion metric tons (or 3.0%) from 2015 to 2040 in the Extended Policies case compared with the Reference case. The increase in fuel economy standards for new LDVs, MDVs, and HDVs in the Extended Policies case accounts for 50% of the total cumulative reduction in CO2 emissions from 2015 to 2040 in comparison with the Reference case. The rest of the increase results from greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Because the effects of the Extended Policies case on energy use and CO2 emissions increase over time, the maximum percentage difference in projected emissions between the Reference case and the Extended Policies case occurs in 2040 (8.4% lower in the Extended Policies case than in the Reference case). In the Extended Policies case, space cooling, water heating, and small devices and miscellaneous end uses together account for most of the emissions reductions from Reference case levels in the buildings sector, and lower petroleum use accounts for most of the emissions reductions in the industrial sector.

Energy prices and tax credit payments

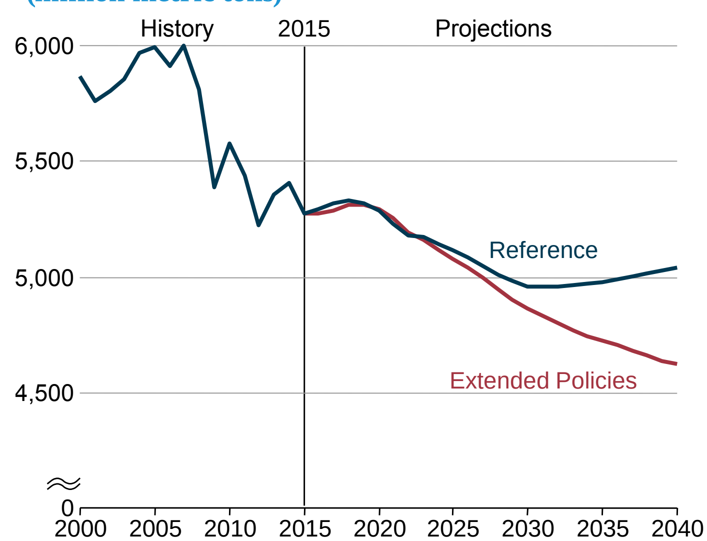
Average electricity prices in both the Reference case and Extended Policies case remain in a relatively tight range between 10.1 cents/kWh and 10.9 cents/kWh (2015 dollars) through 2040 (Figure IF3-9). Electricity prices in the near term are higher in the Extended Policies case than in the Reference case. With the certainty of continued tax credits in the Extended Policies case, renewable capacity—particularly wind—is added later than in the Reference case, resulting in more electricity generation from natural gas, which increases fuel costs and electricity prices. As more renewable capacity is added later in the Extended Policies

Figure IF3-7. Renewable electricity generation by energy source in two cases, 2015, 2020, 2030, and 2040 (percent of total)



Note: "Other" includes generation from hydroelectric, geothermal, and biomass sources.

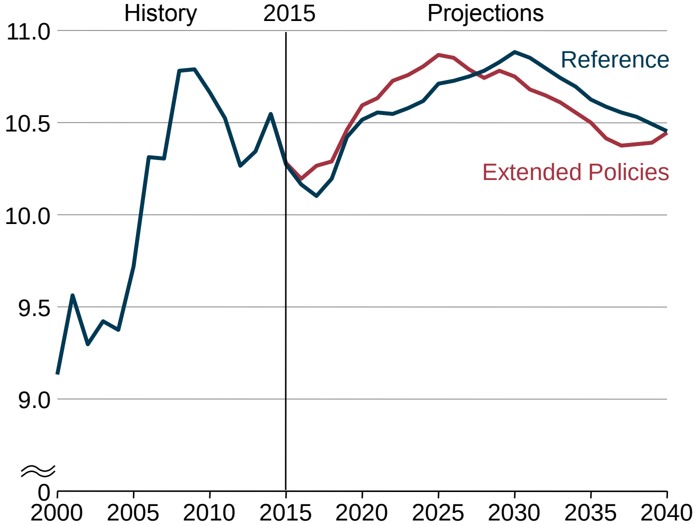
Figure IF3-8. Energy-related carbon dioxide emissions in two cases, 2000–2040 (million metric tons)



case, electric power sector fuel costs decline, leading to lower electricity prices. Increased energy efficiency expenditures in the Extended Policies case bring electricity prices back to levels close to those in the Reference case in 2040.

The reductions in delivered energy consumption and CO2 emissions in the Extended Policies case are accompanied by higher equipment costs for consumers and increased tax expenditures that reduce tax revenue for the U.S. government. In comparison with the AEO2016 Reference case, residential and commercial consumers in the Extended Policies case pay an extra $15.6 billion/year (2015 dollars) on average from 2015 to 2040 for end-use equipment, residential building shell improvements, and additional distributed generation systems. The government pays an extra $7.3 billion/year on average in tax credits to consumers (or, from the government's perspective, net revenues are reduced by that amount) in the buildings sector. The additional investments by consumers in the Extended Policies case are offset, however, by savings on energy purchases as a result of efficiency improvements and increases in distributed generation. Compared with the Reference case, consumers in the residential and commercial sectors save an average of $14.9 billion (2015 dollars) in annual energy costs from 2015 to 2040 in the Extended Policies case.

Figure IF3-9. U.S. average electricity prices in two cases, 2000–2040 (2015 cents per kilowatthour)



In the electric power sector, the extension of the PTC in the Extended Policies case increases government tax expenditures by approximately $4.1 billion/year from 2015 to 2040, compared with $2.0 billion/year in the Reference case. Most of the change in tax expenditures between the two cases is attributable to additional generation from wind energy. Over the 2015–40 period, the ITC increases government tax expenditures in the electric power sector by approximately $3.6 billion/year in the Extended Policies case, compared with $1.6 billion/year in the Reference case, primarily as a result of additional credits for utility-scale PV in the Extended Policies case. For all sectors combined, tax credit extensions in the Extended Policies case over the 2015–40 period have an average aggregate value of $16.4 billion/year, or more than three times the average of $5.1 billion/year in the Reference case.

Endnotes for IF3

Links current as of July 2016

1. U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary; and U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
2. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2" (Washington, DC: June 19, 2015), http://www.nhtsa.gov/fuel-economy.
3. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), https://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf.
4. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), https://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf.
5. U.S. Energy Information Administration, Form 860, 2014 data (Washington, DC: October 21, 2015; corrected February 21, 2016): https://www.eia.gov/electricity/data/eia860/.

Figure sources for IF3

Links current as of July 2016

Figure IF3-1. Total energy consumption in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-2. Buildings sector delivered energy consumption in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-3. Changes in buildings sector delivered energy consumption by end use in two cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-4. Industrial sector combined heat and power capacity in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016). Projections: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-5. Transportation sector petroleum and other liquids demand in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-6. Electricity generation by fuel in the Reference and Extended Policies cases, 2000–2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-7. Renewable electricity generation by energy source in two cases, 2015, 2020, 2030, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-8. Energy-related carbon dioxide emissions in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

Figure IF3-9. U.S. average electricity prices in two cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2016/02) (Washington, DC: February 2016). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D051216A.

IF4. Hydrocarbon gas liquids production and related industrial development

Hydrocarbon gas liquids (HGL) are produced at refineries from crude oil and at natural gas processing plants from unprocessed natural gas. From 2010 to 2015, total HGL production increased by 42%. Natural gas processing plants accounted for all the increase, with recovered natural gas plant liquids (NGPL)—light hydrocarbon gases such as propane—rising by 58%, from 2.07 million barrels per day (b/d) in 2010 to 3.27 million b/d in 2015, while refinery output of HGL declined by 7%. The rapid increase in NGPL output was the result of rapid growth in natural gas production, as production shifted to tight gas and shale gas resources, and as producers targeted formations likely to yield natural gas with high liquids content.

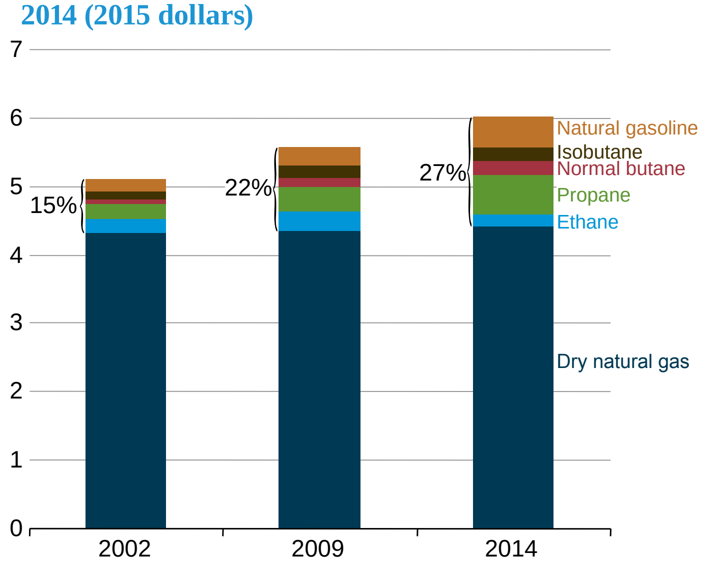
NGPL, contained in the unprocessed natural gas stream, are recovered from natural gas at gas processing plants, yielding a stream of liquids that is then separated at fractionation plants into ethane, propane, normal butane, isobutane, and natural gasoline, as well as dry natural gas (or residue gas), which is moved to markets. On an energy content basis, NGPL prices historically have been close to the prices of petroleum products and are generally well above the price of natural gas. This premium on the recovered NGPL portion of the unprocessed natural gas stream generates additional revenue beyond what is achievable from the sale of unprocessed natural gas at the dry natural gas prices alone.

The additional revenue from NGPL sales can vary significantly, depending on the relative prices of NGPL and natural gas (Figure IF4-1). NGPL prices are linked to both crude oil prices and natural gas prices. In 2002, 2009, and 2014, Henry Hub spot natural gas prices averaged between $4.33 and $4.44 per million British thermal units (Btu), while North Sea Brent crude oil prices averaged $5.63 per million Btu ($32.33/barrel (b)) in 2002, $11.81 per million Btu ($67.82/b) in 2009, and $17.40 per million Btu ($99.92/b) in 2014 (all prices in 2015 dollars).

Changes in industry practice, combined with the increasing premium generated by the NGPL component of the unprocessed natural gas stream relative to dry natural gas, resulted in both an increasing share of Btu coming from NGPL, relative to dry natural gas, and rapid growth in the value generated by those liquids, relative to the dry natural gas component of the unprocessed natural gas. Consequently, although the NGPL contribution to the total Btu value of natural gas produced increased only marginally, from 11.6% in 2002 to 13.4% in 2014, its contribution to the total value of natural gas produced nearly doubled, from 15.1% in 2002 to 26.7% in 2014 (Figure IF4-2).

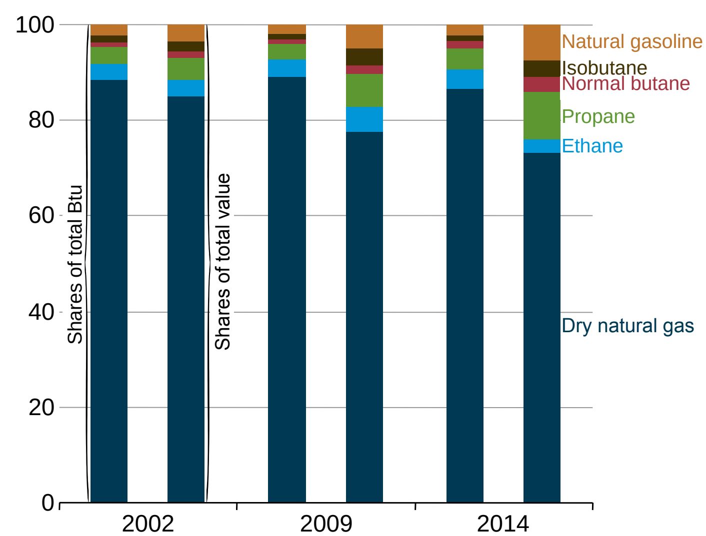
Natural gas production from tight and shale gas formations has grown rapidly in recent years. From 2010 to 2015, total U.S. gross withdrawals, the broadest measure of total wellhead flows, increased by 23%, from 73.5 billion cubic feet per day (Bcf/d) to 90.1 Bcf/d. The geography of natural gas production has also changed over this period, with the northeastern United States (previously a net recipient of large amounts of natural gas from the rest of the country and abroad) now producing more natural gas than it uses. The Marcellus Formation, which underlies much of West Virginia, Pennsylvania, and other states in the northern Appalachian region, has become the most prolific natural gas-producing formation in the country. The presence of the Utica Formation, which overlaps but is deeper than the Marcellus Formation, bolsters production in the Northeast and improves the economics for producers, adding to their return on investment.

Figure IF4-1. U.S. revenue per million Btu of unprocessed natural gas generated by natural gas plant liquids and dry natural gas, 2002, 2009, and 2014 (2015 dollars)



Note: Values are U.S. averages based on natural gas prices reported at the Henry Hub natural gas plant liquid prices at Mont Belvieu, Texas.

Figure IF4-2. Relative heat contents and values of natural gas plants liquids, 2002, 2009, and 2014 (percent of total)



Changes accompanying the rapid shift of natural gas production, both geographically and geologically, have required all segments of the oil and gas industry to adapt: producers have moved personnel and equipment to the locations of the new resources; midstream companies have started building additional natural gas processing and pipeline capacity; and consuming industries such as power producers and petrochemicals have invested in new plants and related infrastructure.

The recent surge in natural gas production, together with several mild winters that lower natural gas demand, resulted in a decline in U.S. natural gas prices (as reported at the Henry Hub natural gas trading hub) from $6.33/million Btu in January 2010 to $2.23/million Btu in January 2016 (2015 dollars). The increasing spread between spot natural gas prices and Brent crude oil prices, on which NGPL prices are largely based, spurred producers to explore for and develop natural gas resources that yield a higher share of NGPL. When crude oil prices started falling in late 2014, the premium commanded by NGPL over dry natural gas diminished, and producers began to shift activity out of areas with high liquids yield to resources yielding higher quantities of pipeline-ready natural gas at the lowest net production cost.

Activity in the Rocky Mountains region (Petroleum Administration for Defense District 4 [PADD 4]) illustrates the shift from development of dry natural gas resources to wet natural gas resources as the ratio of crude oil prices to natural gas prices increases. Historically, Wyoming has accounted for most of the natural gas production in PADD 4. In January 2010, more than 7 Bcf/d of natural gas was produced in Wyoming, accounting for 56% of the PADD 4 total. Natural gas produced in Wyoming is generally considered dry. The U.S. Geological Survey has reported that natural gas produced from coalbed resources in the Powder River Basin, which underlies eastern Wyoming and Montana, contains "trace amounts (0.005 to 0.97 parts per million) of [other] hydrocarbons (for example, propane, isobutane, butane, isopentane, and pentane)" [*1*]. Composition of the unprocessed natural gas produced from the considerably wetter Jonah field in western Wyoming (Table IF4-1) includes 16.4% hydrocarbons, and the gas produced has a heat content of 1,215 Btu per standard cubic foot (Btu/scf)—well above the heat content of 1,010 Btu/scf for dry natural gas consisting of 100% methane.

Unprocessed natural gas produced from the Niobrara Formation [*2*], located predominantly in Colorado, has an even higher heat content of 1,350 Btu/scf and an NGPL content of 22.6%. The natural gas comes out of a lease separator at the wellhead and requires further processing to remove impurities and to separate out the NGPL before the dry natural gas is suitable for transport via interstate pipelines. In the Niobrara Formation, significant quantities of liquids, classified as crude oil, also are recovered at the lease separator. Because of the high ratio of crude oil to natural gas volumes produced from the Niobrara Formation, it is considered a crude oil resource, and activity in the field is determined more by the economics of crude oil and NGPL than by the economics of natural gas.

The shift of production in PADD 4 from Wyoming to Colorado since 2009 reflects a broader shift of natural gas production from dry to wet resources, in part because of consistently high crude oil prices from 2011 through the third quarter of 2014. After reaching more than 7 Bcf/d in January 2010 (56% of PADD 4 production), natural gas production in Wyoming declined by 1.9 Bcf/d (25% of PADD 4 production) to 5.0 Bcf/d in January 2016 (46% of PADD 4 production). Natural gas production in Colorado increased from

Table IF4-1. Composition of oil and natural gas produced from the Niobrara formation in Colorado and the Jonah field in Wyoming

Key characteristics	Niobrara Formation	Jonah Field
Crude oil		
Crude oil to natural gas (barrels per million cubic feet)	86.4	9.5
Crude oil heat content (million Btu/barrel)[a]	5.570	4.980
Share of Btu from crude oil	26%	4%
Wet natural gas		
Heat content (Btu/standard cubic foot)[b]	1,350	1,215
Composition (percent of total)		
Methane	76.2%	77.9%
Ethane	13.7%	8.7%
Propane	5.5%	4.2%
Butane	2.6%	2.5%
Pentane plus	0.8%	3.2%
Inert gases	1.2%	3.5%

[a]Heat content of oil barrel calculated by U.S. Energy Information Administration based on reported API gravity and/or reported composition of crude oil.
[b]Heat content for Niobrara Formation is as reported; heat content for Jonah field is estimated based on gas composition.

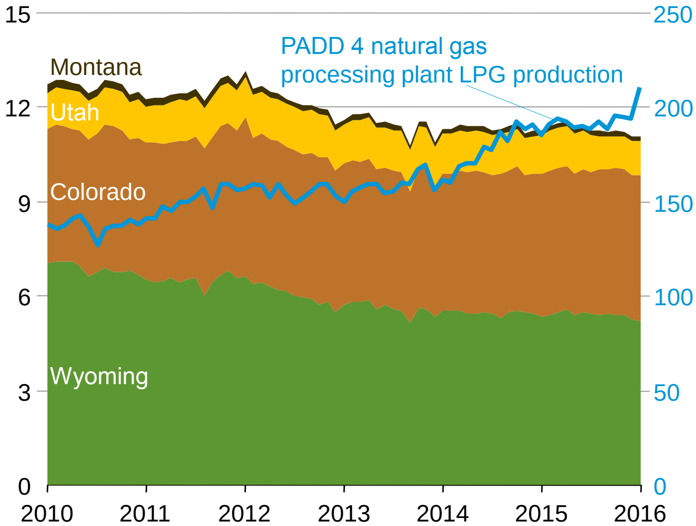
4.2 Bcf/d in 2010 (33% of PADD 4 production) to 4.6 Bcf/d in January 2016 (42% of PADD 4 natural gas production), approaching the production levels in Wyoming.

The focus of producers on crude oil resources and natural gas that is rich in NGPL has led to more production of liquids in PADD 4, even as natural gas output has declined (Figure IF4-3). From January 2010 to January 2016, PADD 4 production of propane and butanes increased by 52%, from 138 thousand b/d to 210 thousand b/d [3], while gross withdrawals of natural gas declined by 13%, from 12.7 Bcf/d in January 2010 to 10.9 Bcf/d in January 2016.

The increase in PADD 4 propane and butanes production, at a time when natural gas production growth is stagnant or falling and when crude oil production is declining, mirrors trends in NGPL production nationwide. Even the reduction of activity in the wettest areas over the past year or so has not slowed the growth of NGPL production, which has exceeded the growth of dry natural gas production (Figure IF4-4).

The growth of NGPL output since 2010–11 has outpaced the growth of domestic demand. The resulting market imbalance has spurred investment in midstream and downstream capacity to process, transport, store, consume, and export increasing quantities of HGL. For example, projects either completed since 2013 or currently under construction will increase the capacity to produce ethylene from ethane by 31%—from 29 million metric tons (mmt)/year to 38 million mmt/year. Investments made in propane dehydrogenation (PDH) capacity, which converts propane to propylene) [4], have increased total PDH capacity more than threefold—from 0.66 mmt/year to 2.16 mmt/year. U.S. capacity to export HGL also has undergone significant expansion since 2013. Capacity to ship propane and butane overseas has grown by more than 550%—from 0.2 million b/d in 2013 to 1.32 million b/d in 2017, and capacity for marine exports of ethane, which only five years ago were not considered viable, have increased from zero to 0.28 million b/d [5]. EIA estimates total investment in these projects at approximately $33 billion, and more projects have been proposed with completion dates in 2018 and beyond [6].

Figure IF4-3. Rocky Mountain region (PADD 4) total natural gas processing plant liquids production (thousand barrels per day) and natural gas production by state (billion cubic feet per day), 2010–16



NGPL production in AEO2016

The future production profile for NGPL will be determined to a large extent not only by the natural resources endowment but also by production economics, which are influenced primarily by natural gas and crude oil prices and the spread between their prices on an energy-equivalent basis. In the Annual Energy Outlook 2016 (AEO2016), the High Oil and Gas Resource and Technology case and the Low Oil and Gas Resource and Technology case, as well as the High Oil Price case and the Low Oil Price case (Figure IF4-5), reflect different possible futures for U.S. NGPL production. The High and Low

Figure IF4-4. U.S. total natural gas and natural gas plant liquids production, 2010–16 (index, January 2010 = 1.00)

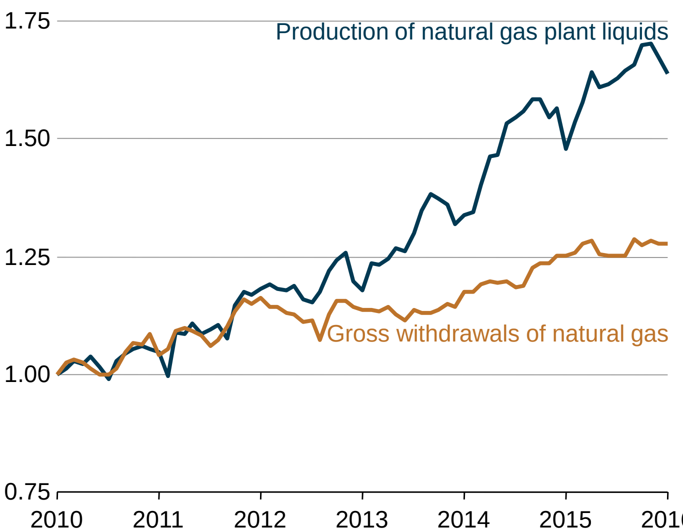
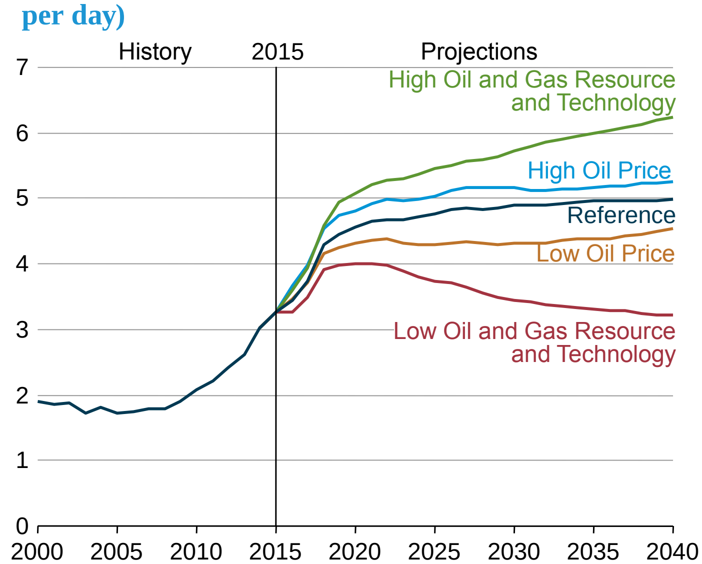


Figure IF4-5. U.S. total natural gas plant liquids production in five cases, 2000–2040 (million barrels per day)



Oil and Gas Resource and Technology cases have a more significant effect on NGPL output because of changes in natural gas and crude oil production. In the High and Low Oil Price cases, production levels are influenced by the changes in value resulting from increases or decreases in the amount of NGPL contained in the unprocessed natural gas.

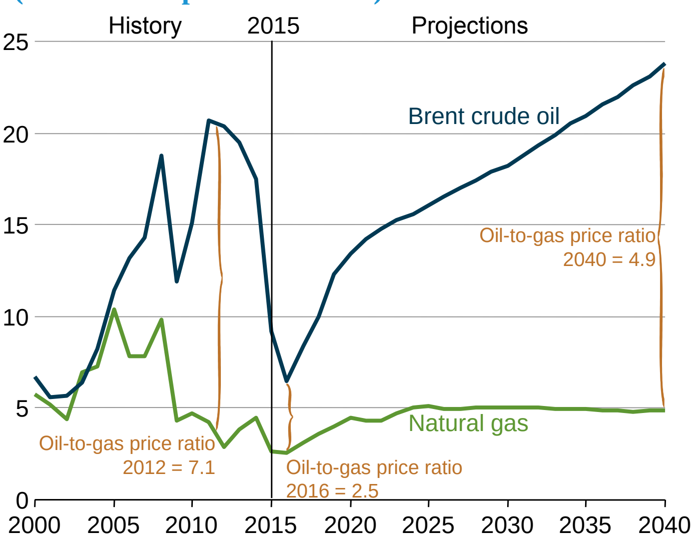
As in the 2010–14 period, when a high premium for liquids led to a shift in natural gas production to those areas where natural gas yielded higher shares of NGPL relative to dry natural gas, the AEO2016 results suggest varying rates of NGPL production growth, depending on relative crude oil and natural gas prices. Until crude oil prices began their sustained decline in the fourth quarter of 2014, natural gas producers generally had chosen wet gas production over dry natural gas production. That choice required some tradeoffs: wet gas needs to be processed before it can be injected into interstate natural gas pipelines for delivery as dry natural gas to consumers, and wells drilled in formations that yield wet natural gas generally have lower initial production rates. However, the extra revenue generated by the liquids can improve the economics of natural gas production and create an incentive to focus drilling on wet natural gas resources.

In the AEO2016 Reference case, with Brent crude oil prices rising from an average of $37/b in 2016 to $136/b in 2040 (2015 dollars), the oil-to-gas price ratio (2015 dollars/million Btu) increases from 2.5 in 2016 to 5.0 in 2040 (Figure IF4-6). Total U.S. NGPL production increases from 3.5 million b/d in 2016 to 4.8 million b/d in 2025 and to almost 5 million b/d in the late 2030s. In the Low Oil Price case, with oil prices remaining below $40/b until 2022 and then increasing to $73/b in 2040, NGPL production averages between 4.3 million b/d and 4.5 million b/d from 2020 to 2040, even as natural gas production grows from 75 Bcf/d in 2016 to 115 Bcf/d in 2040. In the High Oil Price case, natural gas production increases at a slightly higher rate, to 127 Bcf/d in 2040, and NGPL production increases rapidly to 5.0 million b/d in 2025 and then levels off at about 5.2 million b/d from 2025–40. The additional revenue from NGPL sales also shifts production to other regions of the country, resulting in a decrease in PADD 4 natural gas output, where unprocessed natural gas is generally drier, and an increase in production from the Bakken Formation (primarily associated with oil production) and parts of the Marcellus Formation, centered around western Pennsylvania and the West Virginia panhandle, where the unprocessed natural gas has a relatively high liquids content.

Downstream development

Since 2012, when NGPL production started to increase, the U.S. industry has responded with an aggressive build-out of capacity to consume or export the liquids. Operators of petrochemical crackers (plants designed to convert ethane, propane, and normal butane, as well as naphtha, to ethylene, propylene, and other building blocks of the petrochemical industry) announced plans to expand their facilities to take advantage of the rising availability of feedstock, particularly NGPL. In the first wave of projects in the United States from 2012 to 2015, an additional 300,000 b/d of feedstock demand, primarily for ethane, was developed through plant expansions and restarts of mothballed facilities. In the second wave from 2016 to 2018, large established petrochemical companies, including Dow Chemical, Chevron Phillips Chemical, and ExxonMobil, have announced plans for new large-scale ethylene crackers and propane dehydrogenation facilities that would increase demand for ethane feedstock by up to 0.5 million b/d and for propane feedstock by an additional 0.15 million b/d by 2018. In the third wave from 2019 onwards, a further 0.37 million b/d expansion of ethane and propane feedstock demand has been proposed. In addition, midstream companies brought more than 0.97 million b/d of propane and butane export capacity into service by the end of 2015, with another 0.2 million b/d of propane and butane capacity and nearly 0.2 million b/d of marine ethane export capacity slated to come online by the end of 2018.

Figure IF4-6. Brent crude oil and Henry Hub natural gas spot prices in the Reference case, 2000–2040 (2015 dollars per million Btu)



In the AEO2016 Oil and Gas Resource and Technology cases and Oil Price cases, the significant commitment of capital to projects in the first and second waves of petrochemical industry expansion, as well as most of the export capacity expansion, results in completion of the projects. However, later waves of petrochemical projects, as well as any further expansion of U.S. HGL export capacity, have different outcomes across those cases.

The primary motivation for the buildout of U.S. industrial and export HGL capacity is the impact of the wide price spread between U.S. natural gas prices and international crude oil prices on NGPL production, which creates a price advantage for U.S. producers relative to producers in other countries. As such, any narrowing of the price spread would reduce the competitive advantage and reduce opportunities for exports of U.S. NGPL to international destinations, possibly to the point of making exports of spot cargoes unprofitable. However, for many countries seeking to diversify sources of supply for strategic reasons, the United States may still have an advantage in long-term contracts. The price spread has narrowed recently, and sponsors of major petrochemical projects in the United States have announced postponements of some investment decisions, pushed back completion dates, and scaled down the scopes of some projects.

In the High Oil Price case, U.S. natural gas producers are projected to target formations with the highest liquids content, resulting in greater supply of NGPL to the U.S. market. In addition, the High Oil Price case provides U.S.-based petrochemical plants with a cost advantage relative to their international peers, resulting in better opportunities for U.S. exporters in international markets. With an estimated $33 billion in projects between 2013 and 2017 directly tied to the growing availability of HGL feedstock, and billions more in associated upstream and downstream activities, HGL-related economic activity has become a major factor in the U.S. economy. Depending on future prices, developments in the U.S. petrochemical industry may provide either further growth in this segment of the U.S. economy or a slowdown from recent high activity levels.

Endnotes for IF4

Links current as of July 2016

1. R.M. Flores, *Coalbed Methane in the Powder River Basin, Wyoming and Montana: An Assessment of the Tertiary-Upper Cretaceous Coalbed Methane Total Petroleum System*, Version 1.0 (Denver, CO: U.S. Geological Survey, Information Services, 2004), p. 14, http://pubs.usgs.gov/dds/dds-069/dds-069-c/REPORTS/Chapter_2.pdf.
2. U.S. Energy Information Administration, "Niobrara Region Drilling Productivity Report" (Washington, DC: May 2016), http://www.eia.gov/petroleum/drilling/pdf/niobrara.pdf.
3. Ethane, an NGPL that may be recovered or left in pipeline natural gas, depending on gas processing economics, is not included in the total.
4. U.S. Energy Information Administration, "Today in Energy: Growing U.S. HGL production spurs petrochemical industry investment" (Washington, DC: January 29, 2015), https://www.eia.gov/todayinenergy/detail.cfm?id=19771.
5. U.S. Energy Information Administration, "Short-Term Outlook for Hydrocarbon Gas Liquids," Appendix, pp. 21–22 (Washington, DC: March 2016), http://www.eia.gov/forecasts/steo/special/supplements/2016/hgl/pdf/2016_sp_01.pdf.
6. Based on publicly available data from company announcements and SEC filings, EIA estimates average investment requirements of $2.8 billion per million metric tons per year of ethylene capacity, $2 billion per million metric tons per year of PDH capacity, $0.2 billion per 0.1 million barrels per day of propane and butane export capacity, and $0.6 billion per 0.1 million barrels per day of marine ethane export capacity.

Figure and table sources for IF4

Links current as of July 2016

Figure IF4-1. U.S. revenue per million Btu of unprocessed natural gas generated by natural gas plant liquids and dry natural gas, 2002, 2009, and 2014: U.S. Energy Information Administration, "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm; "Natural Gas: Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm; "Natural Gas: Heat Content of Natural Gas Consumed," http://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm; and "Natural Gas: Natural Gas Spot and Futures Prices (NYMEX)," http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm. **NGL prices:** Bloomberg Markets, Energy: Crude Oil & Natural Gas, http://www.bloomberg.com/energy (subscription site).

Figure IF4-2. Relative heat contents and values of natural gas plants liquids, 2002, 2009, and 2014: U.S Energy Information Administration, "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm; "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm; "Natural Gas: Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm; "Natural Gas: Heat Content of Natural Gas Consumed," http://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm; and "Natural Gas: Natural Gas Spot and Futures Prices (NYMEX)," http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm. **NGL prices:** Bloomberg Markets, Energy: Crude Oil & Natural Gas, http://www.bloomberg.com/energy (subscription site).

Table IF4-1. Composition of oil and natural gas produced from the Niobrara formation in Colorado and the Jonah field in Wyoming: *Niobrara:* D.K. Higley and D.O. Cox, "Oil and Gas Exploration and Development along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming" (Reston, VA: U.S. Geological Survey, 2007), Chapter 2, p. 15, https://pubs.usgs.gov/dds/dds-069/dds-069-p/REPORTS/69_P_CH_2.pdf. *Jonah: Final Environmental Impact Statement, Jonah Infill Drilling Project, Sublette Country, Wyoming*, Appendix DP-B, "Reclamation Plan, Jonah Infill Drilling Project" (Cheyenne, WY: Bureau of Land Management, January 2006), http://www.blm.gov/style/medialib/blm/wy/information/NEPA/pfodocs/jonah.Par.6420.File.dat/17B.pdf.

Figure IF4-3. Rocky Mountain region (PADD 4) total natural gas plant liquids production and natural gas production by state, 2010–16: U.S Energy Information Administration, "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm; and "Natural Gas: Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm.

Figure IF4-4. Annual changes in U.S. total natural gas and natural gas plant liquids production, 2010–16: U.S Energy Information Administration, "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm; and "Natural Gas: Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm.

Figure IF4-5. U.S. total natural gas plant liquids production in five cases, 2000–2040: History: U.S Energy Information Administration, "Petroleum & Other Liquids: Natural Gas Plant Field Production," http://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbbl_m.htm. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, HIGHPRICE.D041916A, LOWRT.D032516A, and HIGHRT.D032516A.

Figure IF4-6. Comparison of Brent crude oil and Henry Hub natural gas spot prices in the Reference case, 2000–2040: History: U.S Energy Information Administration, "Petroleum & Other Liquids: Spot Prices," http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; and "Natural Gas: Natural Gas Spot and Futures Prices (NYMEX)," http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm. **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

IF5. Steel industry energy consumption: Sensitivity to technology choices, fuel prices, and carbon prices in the AEO2016 Industrial Demand Module

The manufacture of steel and related products is an energy-intensive process. According to the U.S. Energy Information Administration's (EIA) Manufacturing Energy Consumption Survey (MECS), steel industry energy consumption in 2010 totaled 1,158 trillion British thermal units (Btu), representing 8% of total manufacturing energy consumption [*1*]. Energy consumption in the steel industry is largely for crude steel production using basic oxygen furnace (BOF) and electric arc furnace (EAF) technologies. Overall energy intensity in EAF, used primarily to melt scrap steel, is significantly lower than in BOF, which is used to create virgin steel by reducing (i.e., removing oxygen from) iron ore [*2*]. In 2014, BOF technology accounted for 37% of total U.S. steel production, and EAF accounted for 63% of the total [*3*]. Over the past two decades, a shift from BOF to EAF has contributed to a substantial reduction in the energy intensity of the U.S. steel industry. From 1991 to 2010, the EAF share of total U.S. steel production in physical units increased from 38% to 61%, and the overall energy intensity of crude steel production in Btu per metric ton decreased by 37% [*4*].

The basic process choice for crude steel production is not the only factor affecting energy intensity in the steel industry. Technology choices are based on product specifications, demand, fuel prices, and environmental policies. Technology advances in both BOF and EAF crude steel production processes—including blast furnace gas recovery, pulverized coal injection, and scrap preheating—as well as advances in rolling and casting processes have continued to lower the energy intensity of the overall manufacturing processes for steel and finished steel products. For example, direct reduced iron (DRI), a newer technology used only recently in the United States [*5*], is now commercially available and growing, accounting for 8 million tons (9%) of iron production in 2015. DRI involves the direct conversion of iron ore using a reducing gas (usually natural gas). The resulting sponge iron is readily used as feed in the EAF process. The DRI process performs the same function as a blast furnace, in that it converts iron ore to iron, but it does not involve the use of coke (produced by anaerobic baking of metallurgical coal). The DRI process converts iron ore to iron using less energy and with a lower capital cost than the blast furnace process. In addition, DRI plants in the United States are able to take advantage of relatively low natural gas prices [*6*].

In the future, steelmaking processes and technologies will continue to evolve in response to commodity prices for iron ore and scrap steel, investment in energy efficiency, product-specification demand, environmental regulations, and fuel prices. Differences in those factors can change the processes (BOF or EAF) and technologies used for each process, which in turn can lead to differences in energy intensity and fuel mix. However, because capital investments in particular technologies last for many years, energy use does not react quickly to price changes. To explore how such conditions affect steel technology choice and energy intensity, this article compares the *Annual Energy Outlook 2016* (AEO2016) Reference case with three alternative cases, two of which include demand-side energy efficiency incentives and one that assumes more rapid adoption of energy-efficient technologies. Although fuel intensity and some technology choices vary across the AEO2016 Reference case and alternative cases, the major choice in 2040 remains either BOF or EAF. New or revolutionary technological breakthroughs are not assumed for this analysis.

Energy use in steelmaking depends on both the technology chosen for a process step and the energy intensity of the different technologies. In the steelmaking process, technology choices may be available in some but not all of the following process steps. Iron production has two alternative technologies: blast furnace (BF) and DRI. The BF process reduces iron ore, using a mixture of iron ore, coking coal, and limestone. The BF output is further processed in a BOF to produce steel. DRI reduces iron, which can then be fed into either a BOF or an EAF to produce crude steel. A BOF receives iron either from a BF or from the DRI process and uses oxygen to remove impurities. An EAF melts down steel scrap to produce steel and can also use DRI. Continuous casting can then be used to produce slabs of molten steel for further processing, and hot rolling can be used to further process the cast steel into intermediate and final products.

Alternative cases

In two of the AEO2016 alternative cases, CO2 fees are used as a proxy for demand-side energy efficiency incentives. A third case assumes that more efficient technology is available, and that new, more energy-efficient capacity will be available sooner than in the Reference case. These alternative cases assume that technology and process choices achieve more energy efficiency than in the AEO2016 Reference case, as existing steelmaking capacity is retired and new capacity is brought online to meet the projected growth in industry shipments [*7*].

Industrial Efficiency Incentive Low (Low Incentive) case

In the Low Incentive case, a CO2 fee is used as a proxy for demand-side energy efficiency incentives. The fee increases gradually from zero in 2017 to $12.50 (2015 dollars) per metric ton (mt) of CO2 in 2023. After 2023 the CO2 fee increases by 5%/year, to approximately $29/mt CO2 in 2040.

Industrial Efficiency Incentive High (High Incentive) case

The High Incentive case also uses a CO2 fee as a proxy for demand-side energy efficiency incentives. In this case, the fee increases gradually from zero in 2017 to $35/mt CO2 (2015 dollars) in 2023. Thereafter, the CO2 fee increases by 5%/year, to approximately $80/mt CO2 in 2040.

Energy Efficiency for Manufacturing Industries with Technical Choice (Energy-Efficient Technology) case

The Energy-Efficient Technology case assumes the deployment of more energy-efficient technologies over time than in the AEO2016 Reference case in five industries—aluminum, cement and lime, glass, iron and steel, and paper—with no demand-side efficiency incentives. Existing technologies are retired sooner, and new technologies have shorter lifespans than in the AEO2016 Reference case, providing more opportunities for deployment of energy-efficient technologies. In addition, new technologies penetrate the industry more rapidly than in the Reference case.

The CO2 fee paths in the Low Incentive and High Incentive cases (Figure IF5-1) translate to higher fuel prices for metallurgical coal, natural gas, and electricity than in the AEO2016 Reference case, with the impacts differing for each fuel. The largest price impact is on metallurgical coal, the smallest price impact is on electricity, and the price impact on natural gas falls between the two.

Results

Technology choice

In the High Incentive and Low Incentive cases, differences in the prices of metallurgical coal, natural gas, and electricity that result from the inclusion of demand-side energy efficiency incentives favor technology choices that use less metallurgical coal and more natural gas and electricity than in the Reference case. The metallurgical coal price is 20% higher in the Low Incentive case than in the Reference case and 56% higher in the High Incentive case than in the Reference case in 2025, and the price differences continue to increase through 2040. Similarly, natural gas prices in 2025 are 10% higher in the Low Incentive case than in the Reference case and 38% higher in the High Incentive case than in the Reference case. The smallest effects are on electricity prices; the electricity price is 8% higher in the Low Incentive case than in the AEO2016 Reference case and 23% higher in the High Incentive case in 2025 than in the AEO2016 Reference case.

Changes in the alternative case assumptions affect both the process choice and technology choice. In terms of process, the selection of BOF or EAF for crude steel production results in the largest energy consumption difference. Over the projection period, across all cases, most of the growth in steel output is in EAF. As a result, crude steel production uses relatively more natural gas over time, and its energy intensity declines.

In the AEO2016 Reference case, BOF output increases by 1.3%/year on average from 2015 to 2025 (Figure IF5-2), while EAF output grows at more than twice that rate. Between 2025 and 2040, total steel output growth slows. BOF output in the Reference case increases by 0.4%/year, and EAF output increases by 1.6%/year. As a result of more rapid EAF growth, the EAF output share increases from 62% in 2015 to 69% in 2040. The increasing EAF output share in the Reference case continues the long-term trend toward more EAF steel production in the United States.

In the Low Incentive case, coal prices are higher than in the Reference case, and the difference between metallurgical coal prices and electricity prices is generally greater than in the Reference case. As a result, in the Low Incentive case BOF production of crude steel increases by 0.4%/year on average from 2015 to 2025 and by 0.5%/year from 2025 to 2040, while EAF output grows by 2.9%/year from 2015 to 2025 and by 1.8%/year from 2025 to 2040. Because metallurgical coal is more expensive in the Low Incentive case than in the Reference case, the BOF output share declines more rapidly than in the Reference case (Table IF5-1).

Figure IF5-1. Carbon dioxide proxy prices in two cases, 2015–40 (2015 dollars per metric ton)

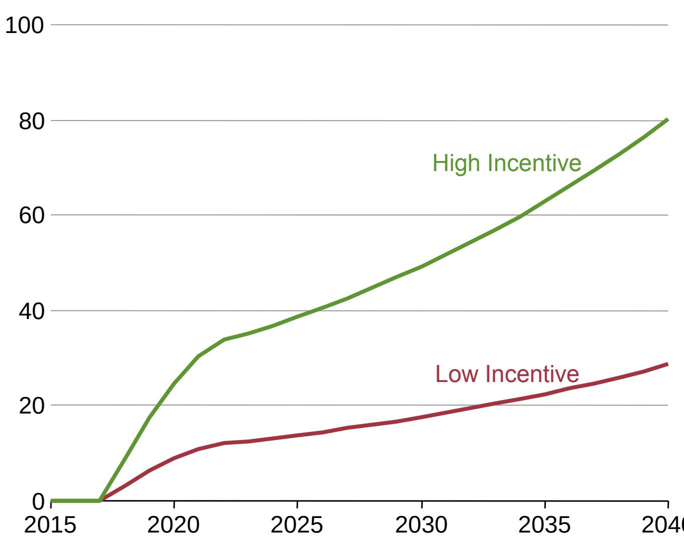
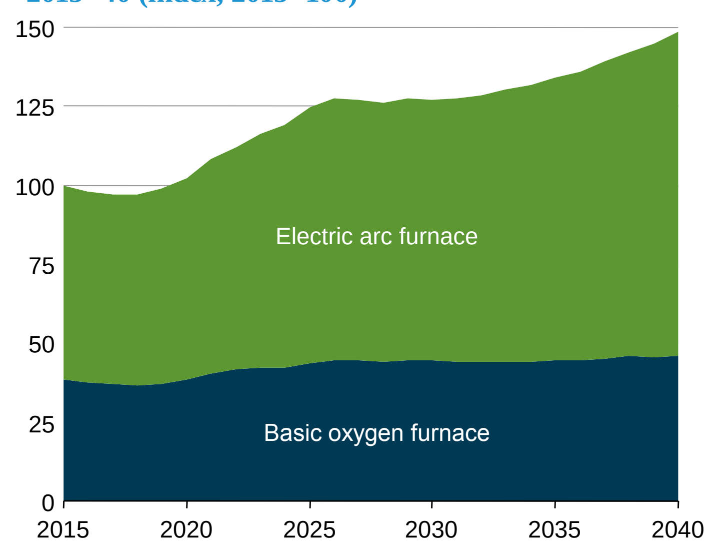


Figure IF5-2. Changes in U.S. total crude steel production by technology in the Reference case, 2015–40 (index, 2015=100)



In the High Incentive case, the difference between metallurgical coal prices and electricity prices also is greater than in the AEO2016 Reference case, by an even a larger amount, and the prices are much higher than in the Reference case. As a result, BOF output declines by 1.5%/year on average from 2015 to 2025 and increases by 1.7%/year from 2025 to 2040, while EAF output increases by 2.1%/year from 2015 to 2025 period and by 2.5%/year from 2025 to 2040. In response to increasing CO2 prices in the High Incentive case, the BOF output share declines by 8 percentage points from 2015 to 2025 and by a more moderate 2 percentage points from 2025 to 2040 as BOF output increases.

In the Energy-Efficient Technology case, BOF output grows by an average of 0.2%/year from 2015 to 2025, similar to the growth rate in the Reference case, because prices are the same as in the Reference case and there is no additional incentive for innovation. From 2025 to 2040, BOF output grows by 0.7%/year in the Energy-Efficient Technology case. EAF output grows much more rapidly than BOF output in the Energy-Efficient Technology case, by averages of 3.4%/year from 2015 to 2025 and 1.4%/year from 2025 to 2040, as the new technology is adopted more rapidly than in the Reference case.

In 2015, BOF accounted for approximately 38% of total steel output. In 2040, it accounts for about 30% of the total in all the AEO2016 cases for three reasons. First, the BF process uses significant amounts of "off-gas" to provide waste heat for the smelting process, displacing fuel use that would otherwise be needed in the smelting process, and thereby mitigating CO2 emissions. EAFs do not have this feature. Second, as DRI production increases with EAF use, it is available as a less CO2-intensive feedstock for BOF as well. Finally, there will always be a need for steel made using BOF, because BOF-produced steel is better suited for products that require formability, such as automobile body panels [*8*].

In the Low Incentive and High Incentive cases, DRI accounts for a larger share of BOF iron input than in the Reference case (Figure IF5-3). DRI is less carbon-intensive than BF, because DRI uses natural gas to reduce iron, whereas BF relies on metallurgical coal that has been coked, and the coking process is carbon-intensive. Also, DRI is less energy-intensive than BF because the DRI process does not involve melting iron and thus operates at lower temperatures [*9*].

In the Low Incentive case and the High Incentive case, greater demand-side energy efficiency incentives result in a shift to more energy-efficient technologies, leading to more use of high-technology plasma torches (a plasma torch delivers an electric charge to the metal for heating [*10*]) in the BOF process than occurs in the Reference case [*11*]. For continuous casting of steel, greater demand-side incentives increase the use of electric ladles (a ladle transfers molten steel from the furnace to a continuous casting process). In the Energy-Efficient Technology case, higher CO2 fees encourage the use of more efficient natural gas-based technologies than in the Reference case, including natural gas ladles. In the Low Incentive case and the High Incentive case, higher CO2 emissions fees reduce the use of more energy-intensive alternative ironmaking technologies [*12*].

Fuel use and energy intensity

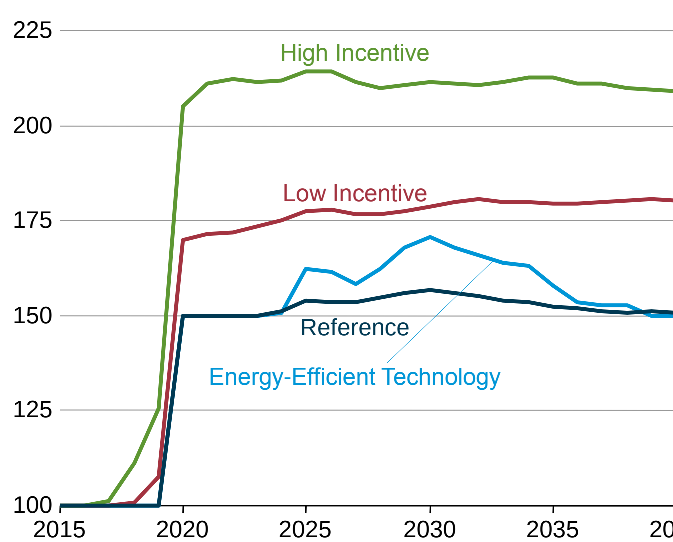
The total energy intensity of U.S. steelmaking declines from 2015 to 2040 in all the AEO2016 cases (Figure IF5-4), with the smallest decline in the Reference case (27%) and the largest decline in the Energy-Efficient Technology case (32%). The decline in steelmaking energy intensity in the Reference case is greater than the average decline of 18% projected in the Reference case for all other energy-intensive industries from 2015 to 2040, primarily as a result of the shift toward greater use of more energy-efficient steelmaking technologies, with EAF increasing at a much faster rate than BOF, and DRI increasing at a faster rate than BF.

Natural gas is used in DRI production in electric arc furnaces, and is also used extensively in continuous casting and hot rolling. In the Reference case, the overall natural gas intensity of U.S. steelmaking declines by a total of 25% from 2015 to 2040, with the

Table IF5-1. BOF and EAF shares of total crude steel production in four cases, 2015–40 (percent)

AEO case and type of production	2015	2025	2040
Reference case			
Basic oxygen furnace	38%	35%	31%
Electric arc furnace	62%	65%	69%
Low Incentive case			
Basic oxygen furnace	38%	33%	29%
Electric arc furnace	62%	67%	71%
High Incentive case			
Basic oxygen furnace	38%	30%	28%
Electric arc furnace	62%	70%	72%
Energy-Efficient Technology case			
Basic oxygen furnace	39%	32%	30%
Electric arc furnace	61%	68%	70%

Figure IF5-3. U.S. direct reduced iron (DRI) production in four cases, 2015–40 (index, 2015=100)



declines spread evenly over the period. Although natural gas-intensive technologies are more widely used, new technologies and efficiency gains outweigh the use of natural gas-intensive technologies. In the Low Incentive and High Incentive cases, natural gas consumption intensity declines by just over 20%—slightly less than in the Reference case, because technologies that use more natural gas, including DRI and EAF, are more widely employed. In the Energy-Efficient Technology case, natural gas intensity declines more rapidly than in the Reference case, by a total of slightly more than 30% from 2015 to 2040, because many steelmaking processes, including continuous casting and hot rolling, use natural gas more efficiently than in the Reference case (Figure IF5-5). Approximately 50% of the Reference case decline in energy intensity occurs from 2015 to 2025. Although natural gas-intensive technologies are more likely to be selected in the Energy-Efficient Technology case, overall levels of natural gas consumption also decline in this case, because gains in energy efficiency outweigh the impact of fuel switching to natural gas.

Figure IF5-4. Total energy intensity of U.S. steel production in four cases, 2015–40 (thousand Btu per 2009 dollar of shipments)

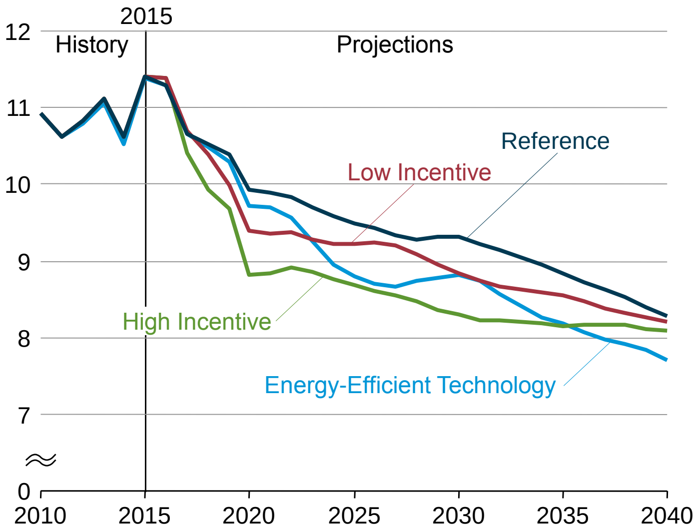
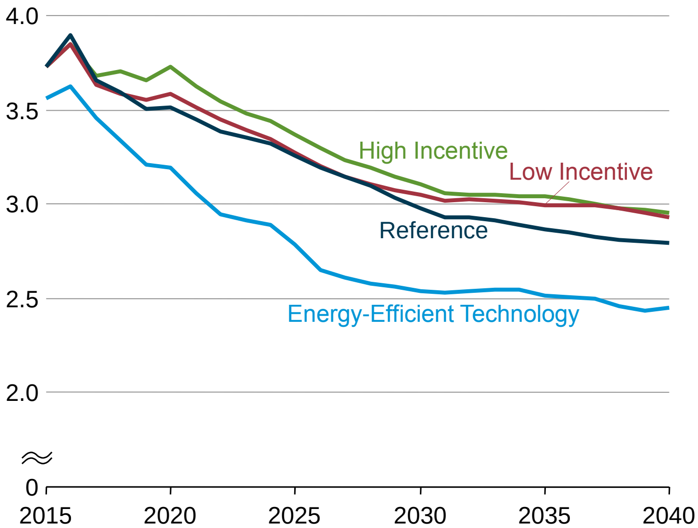


Figure IF5-5. Natural gas intensity of U.S. steel production in four cases, 2015–40 (thousand Btu per 2009 dollar of shipments)



Endnotes for IF5

Links current as of July 2016

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Figure and table sources for IF5

Links current as of July 2016

Figure IF5-1. Carbon dioxide proxy prices in two cases, 2015–40: AEO2016 National Energy Modeling System, runs LOWINNOVATE.D032516A and HIGHINNOVATE.D032516A.

Figure IF5-2. Changes in U.S. total crude steel production by technology in the Reference case, 2015–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Table IF5-1. BOF and EAF shares of total crude steel production in four cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWINNOVATE.D032516A, HIGHINNOVATE.D032516A, and EFFICIENTTECH.D032516A.

Figure IF5-3. U.S. direct reduced iron (DRI) production in four cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWINNOVATE.D032516A, HIGHINNOVATE.D032516A, and EFFICIENTTECH.D032516A.

Figure IF5-4. Total energy intensity of U.S. steel production in four cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWINNOVATE.D032516A, HIGHINNOVATE.D032516A, and EFFICIENTTECH.D032516A.

Figure IF5-5. Natural gas intensity of U.S. steel production in four cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWINNOVATE.D032516A, HIGHINNOVATE.D032516A, and EFFICIENTTECH.D032516A.

Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2016* (AEO2016) generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technological progress, and policy changes.

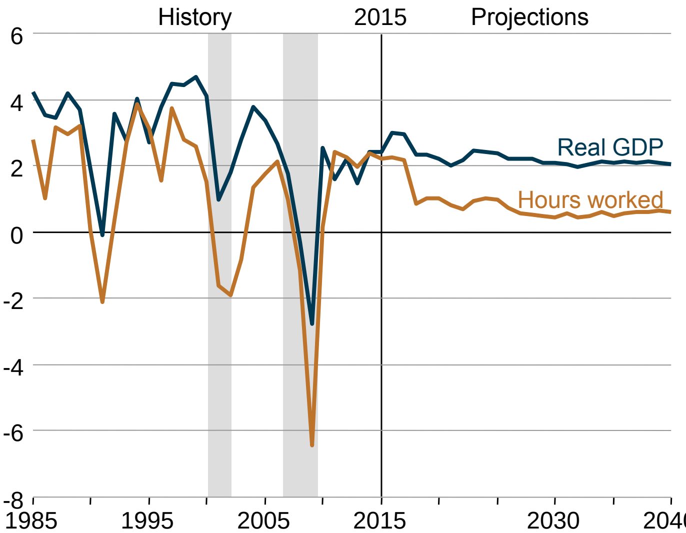
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 tried to make these projections as objective, reliable, and useful as possible. However, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

With lower labor productivity growth, investment is key to improving living standards

Figure MT-1. Growth of real gross domestic product and hours worked in the Reference case, 1985–2040 (annual percent)

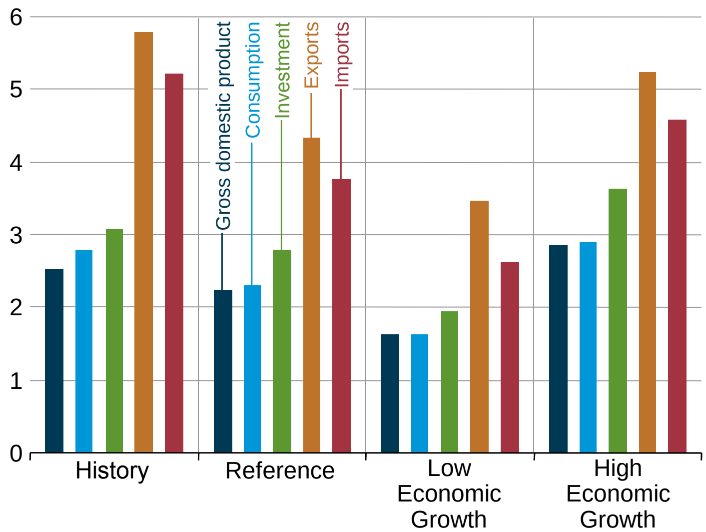


Growth in labor productivity is an important determinant of economic growth [*1*]. Since the end of the latest U.S. recession in June 2009 [*2*], labor productivity has been slow to recover. From 1987–2014, U.S. labor productivity growth averaged 1.9%/year [*3*]. The average rate of growth in the previous expansion (2001–07) was 2.6%, compared with 1.3%/year in the current expansion (2009–15). In the AEO2016 Reference case, labor productivity growth averages 1.7%/year from 2015–40. From 2009–15, the number of hours worked by private, nonfarm workers has increased by an average of 0.7%/year, compared with 0.3%/year from 2001–07. This difference implies that growth of output has not kept pace with growth of hours worked. In the AEO2016 Reference case, the number of hours worked grows by an average of 0.9%/year from 2015–40, compared with the historical average of 1.2%/year from 1987–2014, and real GDP grows by an average of 2.2%/year from 2015–40, which is below the historical average of 2.6%/year from 1987–2014 (Figure MT-1).

Many economists attribute the current slump in labor productivity to the slow recovery of capital spending. Businesses servicing excessive debt after the financial crisis have delayed investment spending until they can restore their financial positions, and lower capital investment leads to higher costs of production and distribution of all goods and services. Investment spending as a share of GDP from 2001–07 was 12.6%, compared with 12.1% from 2009–15. In the AEO2016 Reference case, investment spending averages 14.4% of GDP from 2015–40, compared with the historical average of 12.5% from 1987–2014.

Three economic growth cases show a range of possible future trends in economic growth

Figure MT-2. Average annual growth rates for real gross domestic product and its major components in three cases, 2015–40 (percent per year)

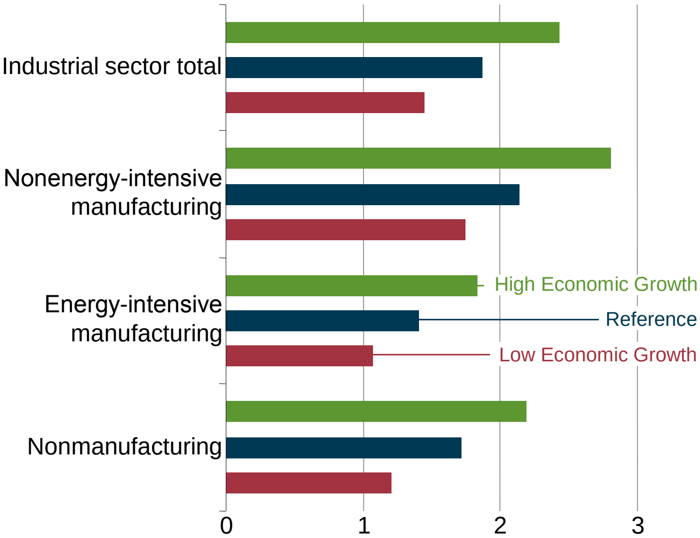


The AEO2016 Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth from 2015 to 2040 (Figure MT-2). The High Economic Growth case assumes higher growth and lower inflation than in the Reference case, and the Low Economic Growth case assumes lower growth and higher inflation. In each case, the short-term outlook (five years) represents different IHS Global Insights scenarios [*4*] of economic activity in the United States and the rest of the world, the impacts of fiscal and monetary policies, and potential risks that could affect U.S. economic activity.

Beyond five years, all three cases assume smooth economic growth and no shocks to the economy. Differences among the AEO2016 Reference, High Economic Growth, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity. The projections are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real gross domestic product from 2015 to 2040 in the Reference case is 2.2%, compared with 2.8% in the High Economic Growth case and 1.6% in the Low Economic Growth case (Figure MT-2). Compared with the 1987–2014 period, both the Reference and Low Economic Growth cases show lower growth for all components of the U.S. economy over the projection period, and the High Economic Growth case shows higher growth for all components of the economy, except for trade.

Industrial sector output growth highly dependent on trade

Figure MT-3. Average annual growth rates of shipments from the U.S. industrial sector and its components in three cases, 2015–40 (percent per year)



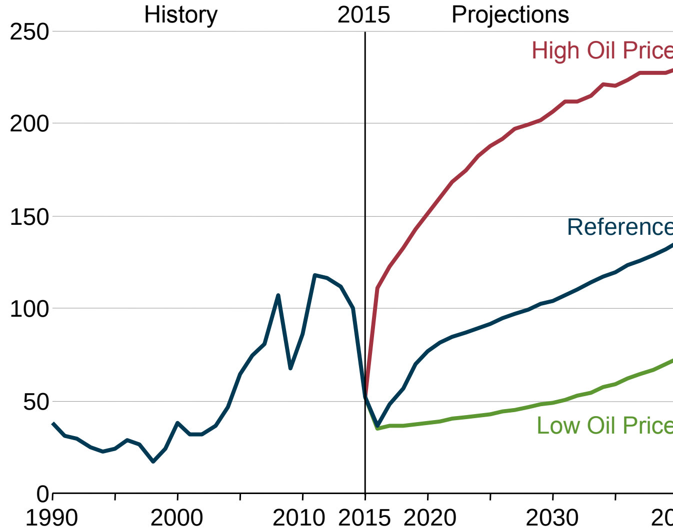
In the future, growth of the U.S. industrial sector [5] contributes to overall economic growth, led by growth in the production of manufactured goods, which in 2015 accounted for 17% of the total real value of shipments of all goods and services in 2015 [6]. In the AEO2016 Reference case, manufacturing shipments grow by 1.9%/year from 2015 to 2040, compared with overall industrial sector growth of 1.9%/year and 1.7%/year growth in nonmanufacturing shipments (Figure MT-3). In the first 5 years of the projection, industry growth rates vary in response to changes in economic factors, such as a strong dollar or low energy prices, but by 2025 growth becomes consistently positive across all industries. In the last decade of the projection, however, growth slows in certain industries (for example, pulp and paper and bulk chemicals) and increases in other industries (for example, primary metals and metal-based durables) in response to changes in U.S. net exports.

In the Low and High Economic Growth cases, industry growth rates generally mirror changes in the rate of GDP growth. However, in the final decade of the projection period, growth rates for the bulk chemical industry are slower in the High Economic Growth Case than in the Reference case, because appreciating exchange rates reduce net U.S. exports of industrial supplies. For the other energy-intensive industries, growth rates in the High Economic Growth case are higher than in the Reference case, as a result of increasing net exports of labor-intensive consumer and capital goods.

Industrial production growth is strongly linked to trade, along with consumer demand and investment. In the Reference case, declining exchange rates and modest growth in labor costs lead to increased U.S. exports. From 2015 to 2040, real exports of goods and services increase by 4.3%/year on average in the Reference case, compared with average increases of 3.8%/year for real imports of goods and services. The growth rate for net exports of industrial supplies is strongest in the first 10 years of the projection period, and the growth rate for net exports of capital and consumer goods is strongest in the last 10–15 years of the projection.

Range of oil price cases represents uncertainty in world oil markets

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990–2040 (2015 dollars per barrel)

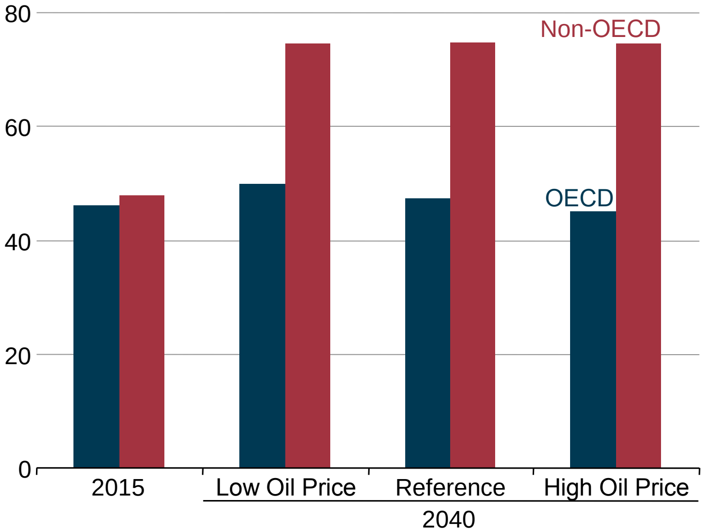


In AEO2016, the North Sea Brent crude oil price is the main benchmark for world oil prices. Three oil price cases—Reference, High Oil Price, and Low Oil Price—examine the potential effects of alternative price paths on energy markets (Figure MT-4). In the Low Oil Price case, global demand for liquids is assumed to be relatively low, and supply is relatively high; in the High Oil Price case demand is high and supply is low. Crude oil prices begin rising early in the High Oil Price case and continue on an upward trend throughout the projection. The oil price cases illustrate offsetting shifts in global supply and demand that keep liquids consumption close to the Reference case levels even though prices are substantially different. In all three cases, non-Organization for Economic Cooperation and Development (non-OECD) countries account for about 60% (roughly 75 million barrels/day) of world liquids use in 2040.

The AEO2016 price cases include different assumptions about investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC) as well as non-OPEC countries; about the pace of development of tight and shale oil resources in non-OPEC countries (including the United States); and about demand growth in China, the Middle East, and other non-OECD countries. In the Low Oil Price case, which assumes lower demand for liquids in non-OECD regions and more abundant supply than in the Reference case, OPEC supplies 47% of the world's liquid fuels in 2040, compared with 42% in the Reference case. In the High Oil Price case, the OPEC share of world liquids production never exceeds the 41% level reached in 2012.

Prices, policies, technologies, and economic growth rates influence demand for liquids

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2015 and 2040 (million barrels per day)



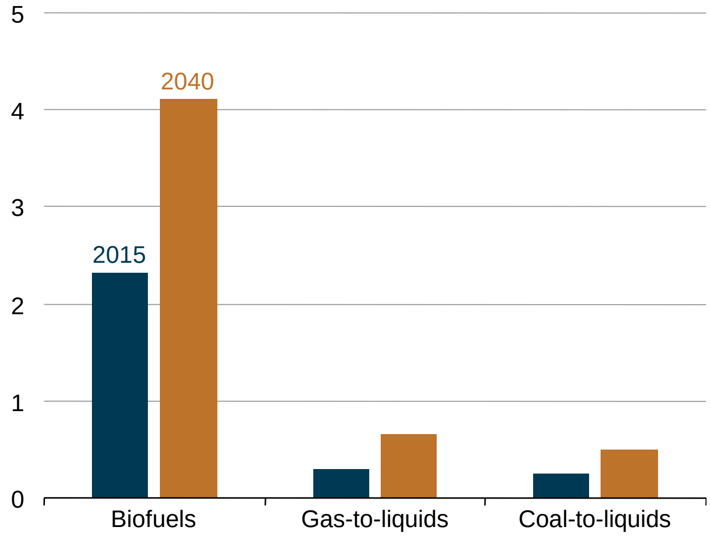
In the AEO2016 Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 119 million barrels/day (b/d) to 124 million b/d (Figure MT-5). The alternative oil price cases illustrate the effects of supply differences from the Reference case that lead to substantial differences in prices while consumption remains relatively close to demand in the Reference case. Variations in liquids consumption levels among the Organization for Economic Cooperation and Development (OECD) countries are influenced primarily by oil prices. On the other hand, consumption levels in the non-OECD countries are influenced by prices, technologies, policies, and economic growth rates, resulting in nearly identical demand in the three oil price cases in 2040, at about 75 million b/d, or 60% of world liquids consumption.

In the AEO2016 High Oil Price case, stronger economic growth in the non-OECD nations leads to increased demand for liquid fuels, greater demand for personal travel, and more consumption of goods in the industrial sector. In addition, liquid fuels continue to provide the energy needed to meet growing demand in the nonmanufacturing sector, and national policies favor the use of liquids over coal for chemical feedstocks.

In the Low Oil Price case, world economic growth is slower than in the Reference case, and demand for liquid fuels is lower. OECD countries reduce energy consumption through the use of more-efficient technologies, extended corporate average fuel economy standards, less travel demand, and/or more use of natural gas or electricity in the transportation sector. In the non-OECD countries, demand for liquids in the Low Oil Price case remains relatively strong as low oil prices result in more consumption of liquid fuels relative to other energy sources.

World production of liquid fuels from biomass, coal, and natural gas increases

Figure MT-6. World production of nonpetroleum liquids by type in the Reference case, 2015 and 2040 (million barrels per day)



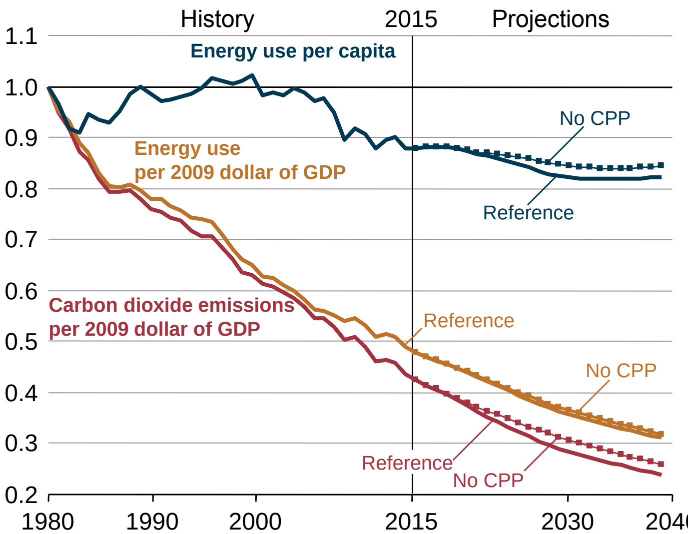
Nonpetroleum fuels are a small but increasing source of total liquids supply in the AEO2016 Reference case. Combined world production of biofuels, coal-to-liquids (CTL), and gas-to-liquids (GTL) totaled 2.9 million barrels per day (b/d) or 3% of total world liquids production in 2015. In 2040, synthetic fuels production in the Reference case totals 5.3 million b/d, or 4% of total world liquids production (Figure MT-6). Production of these fuels is supported by high oil prices, but in the United States high prices alone are not sufficient to increase domestic production of nonpetroleum liquids. As a result, the United States produces no CTL or GTL in the Reference case. Biofuels production grows only slightly, from 1.0 million b/d in 2015 to 1.1 million b/d in 2040, and the U.S. share of world biofuels production falls from 44% in 2015 to 26% in 2040.

Biofuels development relies heavily on country-specific programs or mandates and outlooks for consumption of transportation fuels. U.S. demand for transportation fuels declines in the Reference case, and without significant additional market penetration of fuels with high-percentage ethanol blends or of drop-in fuels [7], the possibilities for expanded biofuel production are limited.

Biofuels production accounts for the largest share of total world nonpetroleum liquid fuels production throughout the projection, although its share falls from 81% in 2015 to 78% in 2040. In 2040, world biofuels production of 4.1 million b/d is more than 250% greater than world production of CTL and GTL combined.

Energy use per capita continues to decline in the Reference and No CPP cases

Figure MT-7. Energy use per capita and per dollar of gross domestic product and carbon dioxide emissions per dollar of gross domestic product in two cases, 1980–2040 (index, 1980 = 1)



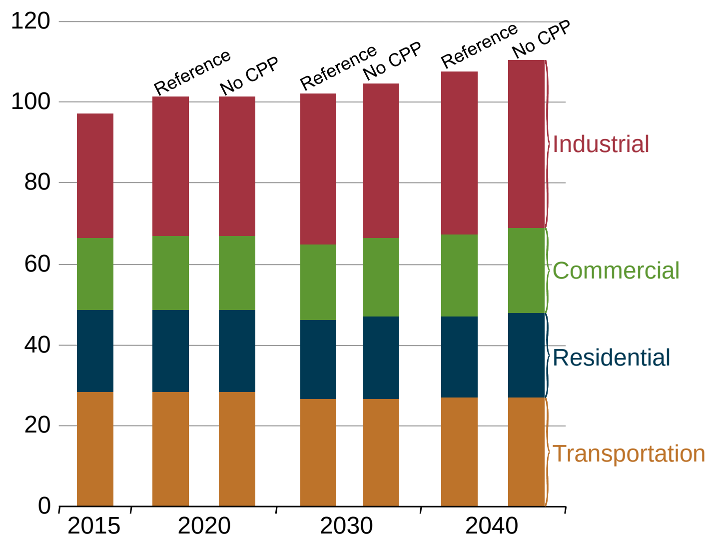
Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. In the AEO2016 Reference case, which includes the U.S. Environmental Protection Agency's Clean Power Plan (CPP), the U.S. population grows by 0.7%/year from 2015 to 2040; the national economy, as measured by gross domestic product (GDP), grows by an average of 2.2%/year; and total energy consumption increases by 0.4%/year. In the No CPP case, which excludes the CPP, total energy consumption grows at a faster rate of 0.5%/year. Energy intensity, measured both as energy use per capita and as energy use per dollar of GDP, declines (Figure MT-7).

The structure and efficiency of the U.S. economy are changing in ways that can lower total energy use and energy use per dollar of GDP. The service industry share of total shipments remains at or just below 77% through 2040 in the Reference case, and in the manufacturing sector output continues to shift from energy-intensive industries to nonenergy-intensive industries. In the No CPP case, the manufacturing output and energy-intensive manufacturing output shares of total shipments are slightly higher than in the Reference case.

Changes in consumer behavior also affect energy consumption. The Reference case decline in energy use per capita results largely from gains in appliance efficiency, a shift in population from cooler to warmer regions, and an increase in vehicle efficiency standards combined with modest growth in travel per licensed driver. From 1970 through 2008, energy use dipped below 320 million British thermal units (Btu) per person for only a few years in the 1980s. In 2012, energy use per capita was about 300 million Btu, the lowest level since 1967; however, it has increased slightly since 2012. In the Reference case, energy use per capita in 2020 is below the 2012 level, and in 2040 it is 281 million Btu per capita. Efficiency gains in appliances reduce demand for electricity, and efficiency gains in the electric power sector also reduce overall energy intensity, as older, less-efficient generators are retired as a result of slower growth in electricity demand, changing dispatch economics related to rising fuel prices, and stricter environmental regulations.

Industrial and commercial sectors lead U.S. growth in primary energy use

Figure MT-8. Primary energy consumption by end-use sector in two cases, 2015–40 (quadrillion Btu)



Total energy consumption increases by an average of 0.4%/year, reaching 107.1 quadrillion British thermal units (Btu) in 2040 in the AEO2016 Reference case, and at a somewhat faster 0.5%/year in the No CPP case, to 109.9 quadrillion Btu in 2040 (Figure MT-8). Energy consumption declines over the 2015–40 period in the transportation and residential sectors and increases in the commercial and industrial sectors. The decline in transportation sector energy consumption would be even greater with the Phase 2 standards for medium- and heavy-duty vehicles proposed jointly by the National Highway Traffic Safety Administration and the U.S. Environmental Protection Agency, which are not considered in the Reference case. Feedstock use in the chemical industry accounts for approximately 40% of the 9.6 quadrillion Btu increase in total industrial sector energy consumption in the Reference case and almost 40% of the 10.4 quadrillion Btu increase in the No CPP case. Increases in non-feedstock industrial natural gas use account for slightly more than 25% of the sector's increase in the Reference case, more than half of which results from the use of natural gas as lease and plant fuel and to liquefy natural gas for export.

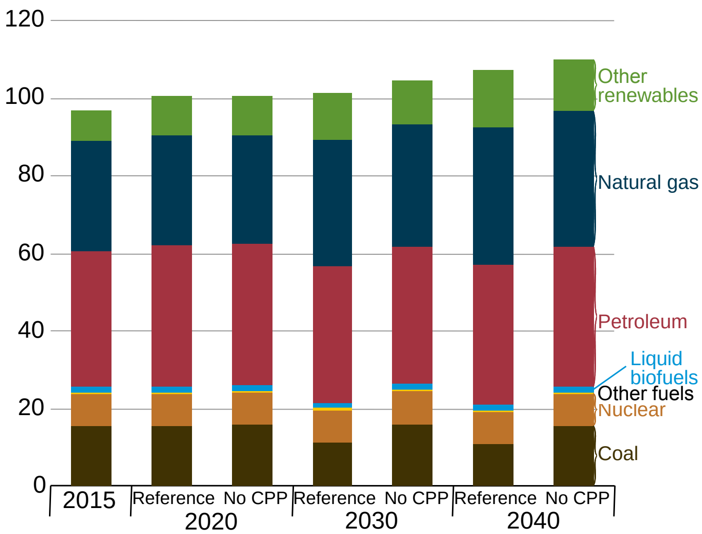
Energy use in the commercial sector increases by about 2.2 quadrillion Btu from 2015 to 2040 in the Reference case, with most of the increase attributable to electricity consumption despite increases in efficiency that reduce energy use for space heating, lighting, refrigeration, and personal computers. In the No CPP case, energy use in the commercial sector increases by 3.3 quadrillion Btu from 2015 to 2040.

U.S. energy demand

In both the residential and transportation sectors, energy use in the AEO2016 Reference case declines from 2015 through the early 2030s before it begins to increase again. Energy use in the transportation sector is affected less by the CPP than the other end-use sectors, as the CPP has no direct effect on transportation sector energy consumption. In the Phase 2 Standards case, transportation sector energy consumption is more than 1.5 quadrillion Btu lower in 2040 compared with the Reference case. In the Reference case, energy use in the residential sector declines despite population growth, as the efficiency of space heating and lighting improves. For the residential and transportation sectors combined, energy use declines by 1.6 quadrillion Btu from 2015 to 2040 in the Reference case, as compared with a decline of 0.7 quadrillion Btu in the No CPP case.

Renewables and natural gas lead rise in primary energy consumption

Figure MT-9. Primary energy use by fuel in two cases, 2015, 2020, 2030, and 2040 (quadrillion Btu)



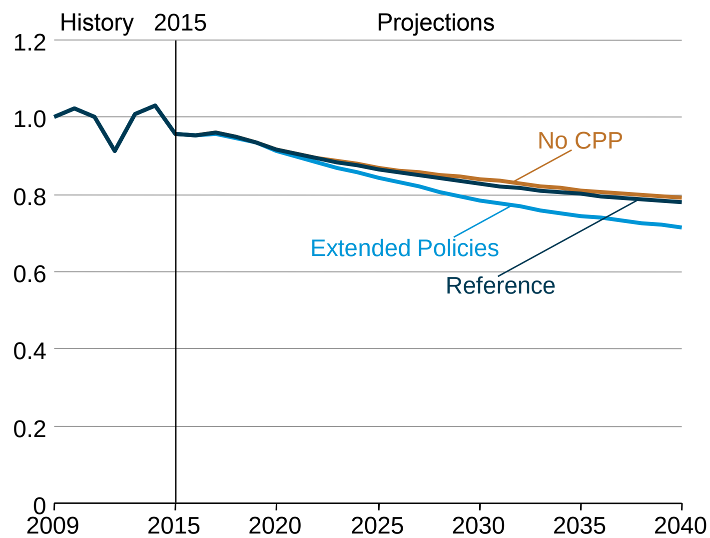
The fossil fuel share of total energy use declines in the Reference case from 82% in 2015 to 77% in 2040, while renewable energy use grows (Figure MT-9). The renewable share of total energy use (including liquid biofuels) increases from 9% in 2015 to 15% in 2040 in response to the Clean Power Plan (CPP), availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection, and state renewable portfolio standard programs.

Natural gas consumption grows by about 0.9%/year from 2015–40, led by increases in natural gas use for electricity generation and in the industrial sector. Growing production from tight shale keeps the price of natural gas to end users below 2009–10 levels through 2040. Increases in vehicle fuel economy offset growth in transportation and industrial fuel use, resulting in a decline in total consumption of petroleum and other liquids from 2020–30. After 2030, petroleum and other liquids consumption rises through 2040 but does not return to the 2020 peak level. With the proposed medium- and heavy-duty vehicle Phase 2 standards for fuel consumption and greenhouse gas emissions in effect, consumption of petroleum and other liquids would be 1.5 quadrillion British thermal units (Btu) lower in 2040 than in the Reference case, or about equal to 2014 levels.

Coal consumption declines by an average of 1.4%/year from 2015–40, with most of the reduction occurring from 2015–30. A small amount of coal-fired power plant capacity is added through 2040, including a total of 0.3 gigawatts (GW) currently under construction and another 0.2 GW (with carbon sequestration capability) added after 2016. Consumption of renewable energy surpasses the use of energy from coal-fired generation in 2026. Energy consumption—both the total and the mix—in the No CPP case is different from that in the Reference. Total energy consumption in 2040 is about 2.7 quadrillion Btu higher in the No CPP case, with about 4.7 quadrillion Btu more coal consumption, 1.6 quadrillion Btu less renewable energy consumption, and 0.6 quadrillion Btu less natural gas consumption than in the Reference case.

Residential energy intensity declines across a range of policy assumptions

Figure MT-10. Residential delivered energy intensity in three cases, 2009–40 (index, 2009 = 1)

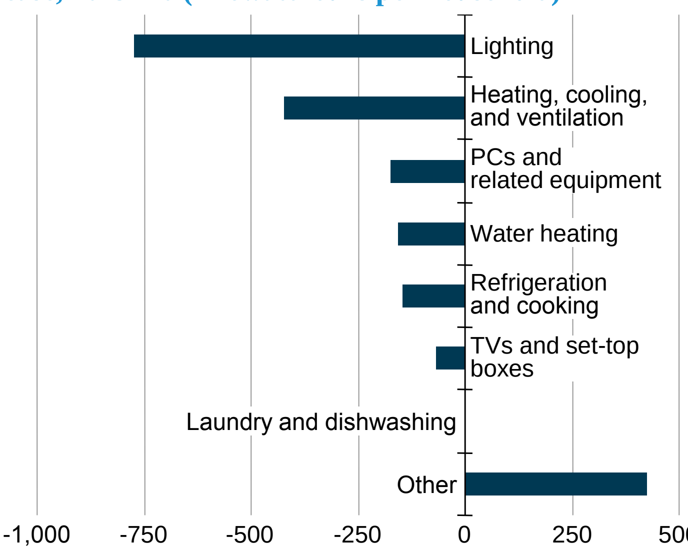


The intensity of residential energy demand, defined as annual delivered energy use per household, declines by 18% from 2015–40 in the Reference case (Figure MT-10). The major factors leading to the decline include energy efficiency policies and standards and population shifts to warmer climates in the south and west. Space heating and water heating account for almost 74% of the reduction in energy intensity and lighting for about 15%, primarily as a result of the phasing in of the light bulb efficiency standards mandated by the Energy Independence and Security Act of 2007 [8]. The continued growth of renewable capacity in the residential sector, such as rooftop solar photovoltaic panels, also reduces delivered energy intensity, given that solar panels are considered to be a distributed generation source rather than delivered energy purchased from a centrally located utility or energy provider.

The AEO2016 Reference case includes all current laws and regulations, including the Clean Power Plan (CPP) [9]. Alternative cases model the effects of different policy assumptions on residential energy intensity. In the No CPP case, which assumes no implementation of the CPP, there are fewer rebates and subsidies for efficient end-use equipment. In the Extended Policies case, there are additional rounds of appliance standards and building codes, as well as the extension of tax credits for efficient equipment and distributed generation technologies, including solar photovoltaics and wind. As a result, household energy intensity declines by 18% from 2015 to 2040 in the No CPP case and by 25% in the Extended Policies case. The CPP assumptions in the Reference case lead to additional efficiency improvements for electricity end uses, particularly lighting and electric heating, ventilation, and air conditioning (HVAC) appliances. Assumptions in the Extended Policies case lead to lower consumption as a result of efficiency gains in all residential fuels (particularly fuels used for HVAC and water heating), including electricity, and an increase in distributed generation.

Electricity use per household declines in the Reference case

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2015–40 (kilowatthours per household)

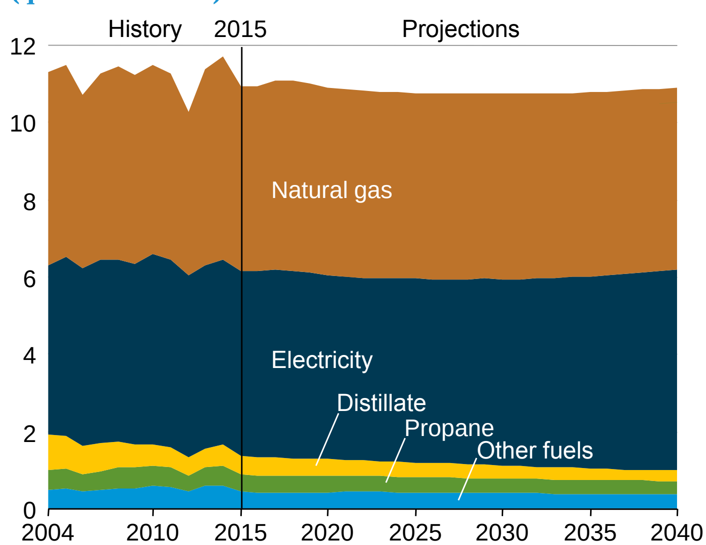


Annual electricity demand for the average household declines by 11% in the Reference case, from 12.1 megawatthours (MWh) in 2015 to 10.8 MWh in 2040. In 2015, the largest uses of electricity at the household level are space cooling, small devices and other minor electric end uses, and lighting. In 2040, electricity consumed for small devices and other minor electric end uses per household is 13% higher, and electricity use for lighting and space cooling per household is 62% lower and 9% lower, respectively (Figure MT-11). The growth in electricity use per household for small devices and other minor appliances results from the continued proliferation of appliances available and adopted by consumers. Regulations implementing the lighting efficiency standards in the Energy Independence and Security Act of 2007 are a major factor in the replacement of incandescent bulbs with more efficient lighting technologies, including light-emitting diode lamps and compact fluorescent lighting, which results in the decrease in electricity use for lighting. Space cooling energy use per household declines as efficiency improvement more than offsets the increased load due to the shift of population to warmer climates. Also contributing to the decline is increased distributed generation, particularly rooftop solar, that offsets purchased electricity sales.

Although electricity consumption for most end uses declines from 2015–40 on a per-household basis, electricity consumption for the residential sector as a whole increases as a result of growth in the U.S. population and number of households. Most of the increase results from market penetration of smaller electric devices, most of which are not covered by efficiency standards, and from growing demand for space cooling as the U.S. population shifts to warmer climates in the South and West. Overall, residential electricity use grows by 9% from 2015–40, as the fuel mix in the residential sector moves increasingly toward electricity. Petroleum and other liquids lose fuel share for almost every residential end-use service, particularly for space heating, where both electricity and natural gas gain share. Natural gas loses fuel share in every end-use service except space heating and water heating but continues to account for more than 50% of the fuel consumed for space heating, water heating, and cooking. In 2040, total natural gas use in the residential sector is 1% lower, and petroleum and other liquids use is 34% lower, than in 2015.

Residential sector energy consumption shows little change from 2015 to 2040

Figure MT-12. Residential sector delivered energy consumption by fuel in the Reference case, 2004–40 (quadrillion Btu)



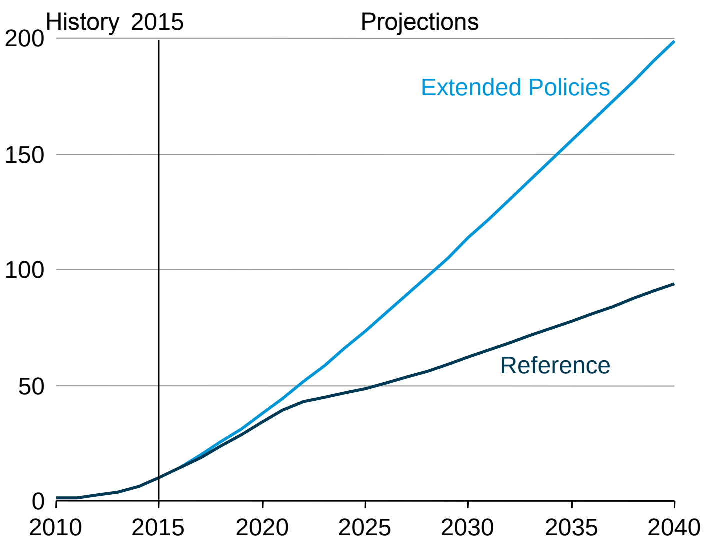
In the Reference case, total delivered energy use in the residential sector is virtually unchanged from 2015–40 (Figure MT-12), while the number of households grows by 0.8%/year. As a result, residential sector energy intensity declines [10]. Over the same period, consumption of purchased electricity increases by

0.3%/year. Although demand for electricity is affected more than other fuels by the adoption of new uses, consumption of electricity for residential lighting declines in the Reference case. The use of natural gas for residential space heating and water heating remains nearly flat over the 2015–40 period.

Residential distillate fuel consumption declines by an average of 2.4%/year in the Reference case, as a result of decreasing use of distillate fuel for space and water heating. The price of distillate fuel rises relative to the prices of natural gas and electricity. Similarly, propane consumption in the residential sector falls by an average of 0.9%/year as its use for home and water heating continues to decline. The cost of propane remains lower than the cost of electricity for residential uses but increases relative to the cost of natural gas over the projection period.

Investment tax credit extension increases adoption of renewable energy sources

Figure MT-13. Residential distributed electricity generation in two cases, 2010–40 (billion kilowatthours)



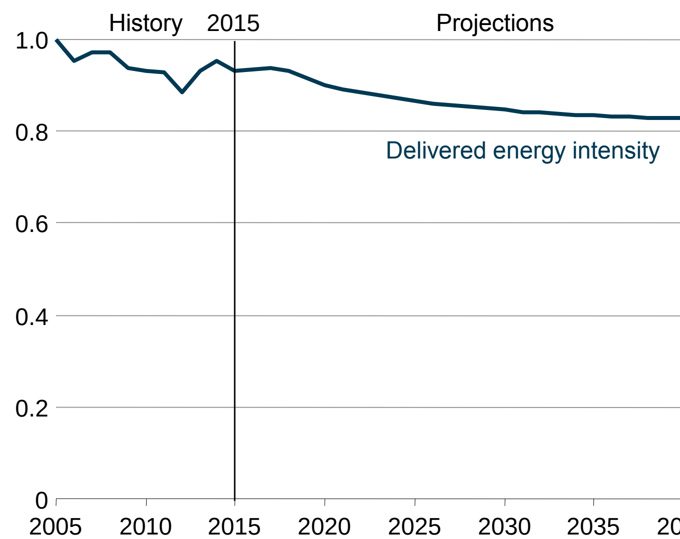
Distributed electricity generation in the residential sector, including solar photovoltaic (PV) and wind technologies, increased tenfold from 2010–15. In the Reference case, it more than triples from 2015–20, in part as a result of financial incentives for residential distributed generation. The 30% federal investment tax credit (ITC) for solar technologies that was slated to expire at the end of 2016 has been extended through 2019 and currently is scheduled to be phased out gradually from 2020–21. In the Extended Policies case, the 30% ITC continues indefinitely.

The Extended Policies case represents a more optimistic future for the growth of distributed generation in the residential sector, based on the tax credits available for installations of solar and other distributed generation technologies. With the ITC extended beyond its currently legislated 2016 expiration date for wind and a 2022 phaseout date for solar, residential generation doubles in the Extended Policies case from 2021–28 and more than doubles from 2028–40. Residential distributed generation, including solar and wind, totals 199 billion kilowatthours (kWh) in 2040, compared with 10 billion kWh in 2015 (Figure MT-13).

The effects of the ITC on installation costs for residential distributed generation systems are significant. For example, solar PV installation costs (excluding tax credits and other financial incentives) fall in the Reference case from $4,042 per kilowatt (kW) of capacity in 2015 to $2,387 per kW in 2025 and to $2,170 per kW in 2040. Along with declining installation costs, the 30% tax credit in the Extended Policies case increases the adoption of renewable electricity generation technologies in the residential sector.

Commercial sector energy intensity continues to decline

Figure MT-14. Commercial sector delivered energy intensity in the Reference case, 2005–40 (energy use per square foot, index, 2005 = 1.0)



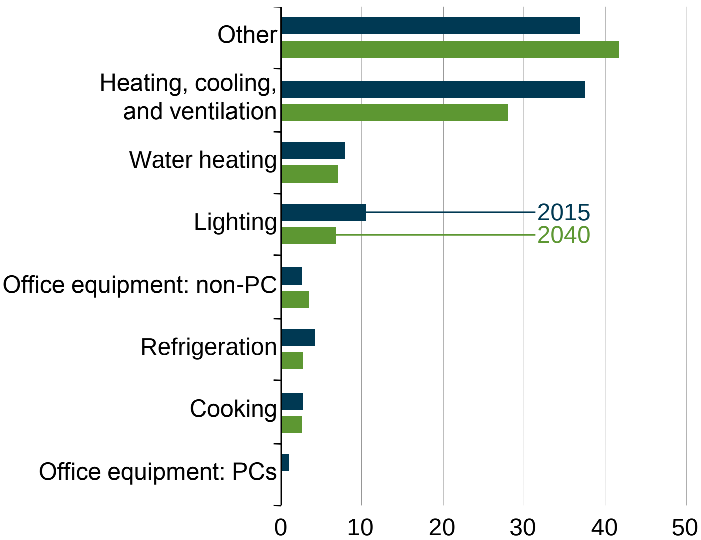
In the AEO2016 Reference case, commercial sector energy intensity, defined as delivered energy consumption per square foot of commercial floorspace, declines by an average 0.5%/year from 2015–40 (Figure MT-14). While commercial buildings energy intensity decreases, delivered energy consumption grows by 0.6%/year, and commercial floorspace grows by 1.1%/year.

In the commercial sector, delivered electricity consumption grows faster than natural gas consumption in the Reference case. As a result, natural gas intensity declines by an average of 0.5%/year from 2015–40, compared with an average decline of 0.3%/year in commercial sector electricity intensity. The natural gas share of total delivered energy use in the commercial sector declines from 38% in 2015 to 37% in 2040 in the Reference case, while the electricity share of total delivered energy use increases from 53% in 2015 to 55% in 2040.

The continued decline in energy intensity of commercial buildings is explained in part by improvements in the energy efficiency of lighting, heating, cooling, and ventilation systems, as well as more stringent building codes. Improvements in the efficiency of major end-use equipment help to slow the growth of delivered energy consumption in the commercial sector. In the Extended Policies case, which assumes the issuance of more stringent efficiency standards for end-use equipment in the future, overall energy intensity is lower than in the AEO2016 Reference case. In 2040, total commercial sector energy per square foot in the Extended Policies case is more than 2% lower than in the Reference case.

Federal efficiency standards reduce commercial sector energy intensity

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2015 and 2040 (thousand Btu per square foot)

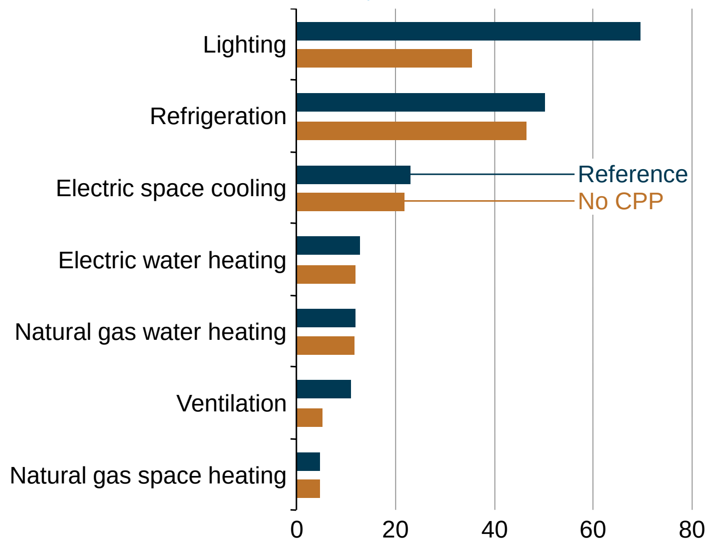


While commercial floorspace grows by an average of 1.1%/year from 2015–40 in the AEO2016 Reference case, delivered energy consumption for many commercial end uses decreases or grows more slowly than floorspace, resulting in declines in commercial sector energy intensity (the ratio of energy consumption to commercial floorspace) (Figure MT-15). Virtually every major use of energy in commercial buildings, including space heating and cooling, water heating, lighting, and refrigeration, is covered by some sort of federal energy efficiency standard. The U.S. Department of Energy is required by law to investigate whether updated standards are technologically feasible and economically justified and to work with stakeholders to develop updated standards as appropriate. As a result, energy intensity decreases in the Reference case by 1.7%/year from 2015–40 for lighting and refrigeration and by 1.2%/year for space heating, cooling, and ventilation.

The energy intensity of miscellaneous electric loads in commercial buildings—equipment ranging from large medical imaging equipment to video displays and other electric devices—increases by a total of 11.5% from 2015–40. While voluntary efficiency programs such as ENERGY STAR may help to reduce energy use for some devices and appliances, many other devices and appliances are not covered by federal efficiency standards. In large part, the growth of energy use for commercial non-PC office equipment results from new data centers for web- and network-based services and connectivity, with energy intensity increasing by 1.1%/year in the AEO2016 Reference case. For commercial PC office equipment, energy intensity decreases by 5.9%/year as users shift from desktop computers to more efficient laptops and mobile computing devices. Although no national standard exists, a growing number of states and municipalities continue to adopt more stringent building energy codes, often aligning with newer versions of the American Society of Heating, Refrigerating, and Air-Conditioning Engineers Standard 90.1. Improvements in building shells, including tighter air sealing, more efficient windows, and more insulation, also reduce energy use for heating and cooling of buildings.

Efficiency gains for advanced technologies reduce commercial energy consumption growth

Figure MT-16. Efficiency gains for selected commercial equipment in two cases, 2015–40 (percent change from 2015 installed stock efficiency)



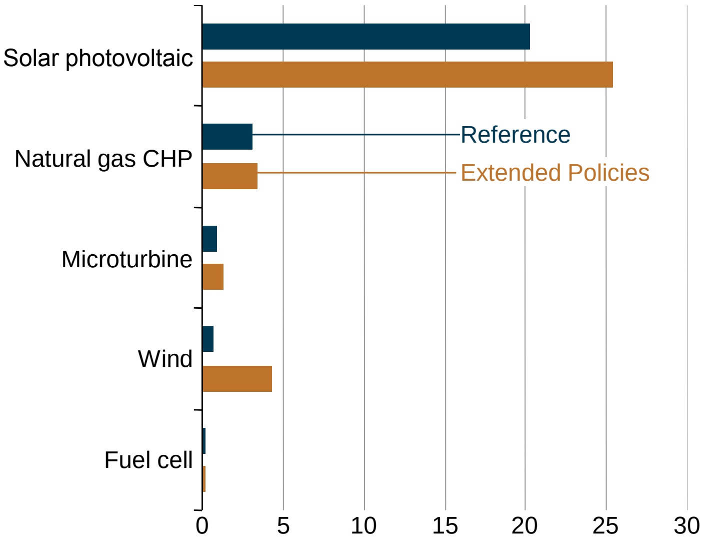
In the commercial sector, the largest efficiency gains in the AEO2016 Reference case are for lighting. Lighting efficiency, or efficacy (light output per unit of energy consumed, measured in lumens per watt), increases by 70% from 2015–40 in the Reference case with continued improvements as a result of federal standards and the increasing penetration of light-emitting diode lighting technologies. Refrigeration and electric space cooling also show significant efficiency gains (Figure MT-16).

The largest impacts of the Clean Power Plan (CPP) on efficiency in the commercial sector are on lighting and ventilation. Efficiency gains from 2015–40 in the Reference case are about twice those in the No CPP case for both end uses. Rebates offered in support of the CPP in the Reference case make efficient technology purchases more attractive to consumers.

Total commercial energy demand increases by an average of 0.5%/year from 2015–40 in the Reference case. However, energy use for office equipment other than personal computers increases by 1.9%/year as local servers are replaced by central data storage and network computing. Energy use for nonbuilding services and miscellaneous electric loads (such as portable and plug-in devices) increases by an average of 1.4%/year. The AEO2016 Reference case reflects the efficiency effects of federal equipment standards, technology advances, and efficiency rebates and incentives offered in support of the CPP.

Extended investment tax credits result in more additions to renewable distributed generation capacity

Figure MT-17. Additions to commercial sector electricity generation capacity in two cases, 2015–40 (gigawatts)



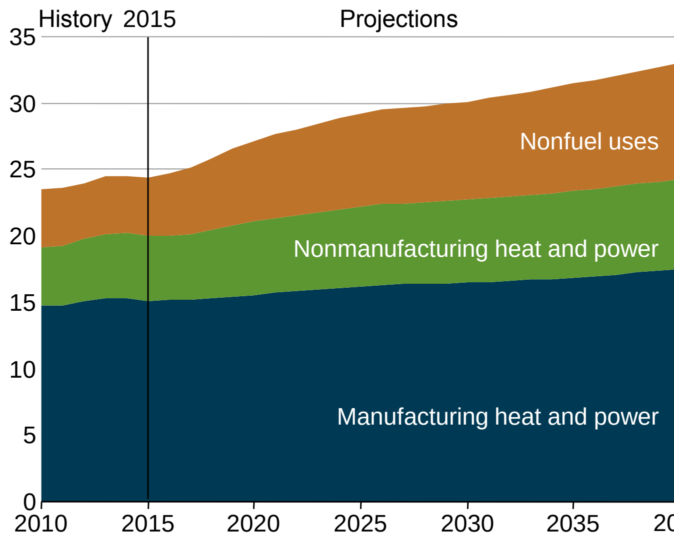
Solar photovoltaic (PV) capacity for electricity generation accounts for nearly 78% of the 33.3 gigawatts (GW) of commercial sector distributed generation (DG) capacity in 2040 in the Reference case. The costs of PV inverters, solar panels, and equipment installation continue to decline, while state and utility rebates and extensions of federal investment tax credits contribute to the growth of installed PV capacity. In the Reference case, solar PV capacity increases by more than 6%/year on average, from 5.6 GW in 2015 to 25.8 GW in 2040.

Federal business investment tax credits for solar technologies, including PV, which were set to expire after 2016, have been extended. The 30% credit will continue through 2019, then decrease to 26% in 2020, 22% in 2021, and 10% in 2022 and after. Tax credits for combined heat and power (CHP) and small wind generators will expire after 2016. The Extended Policies case assumes that the CHP and wind tax credits do not expire. As a result, in the Extended Policies case, commercial wind capacity increases by 16%/year from 2015–40, compared with more than 8%/year in the Reference case (Figure MT-17), and accounts for 10% of the 42.8 GW of total commercial distributed generation capacity in 2040, compared with 72% for PV.

Use of natural gas-fired CHP continues to grow in the commercial sector, with conventional natural gas-fired CHP capacity—including reciprocating engines and turbines—growing by more than 4%/year and accounting for 14% of commercial DG capacity in 2040 in the Reference case. The total capacity of natural gas microturbines grows by almost 8%/year and accounts for more than 3% of commercial DG capacity in 2040, while the total capacity of fuel cells grows by 7%/year and accounts for almost 1% of commercial DG capacity in 2040. Higher commercial electricity prices as a result of the CPP also contribute to the increased use of DG technologies.

Industrial shipments grow more rapidly than energy consumption

Figure MT-18. Industrial energy consumption by application in the Reference case, 2010–40 (quadrillion Btu)



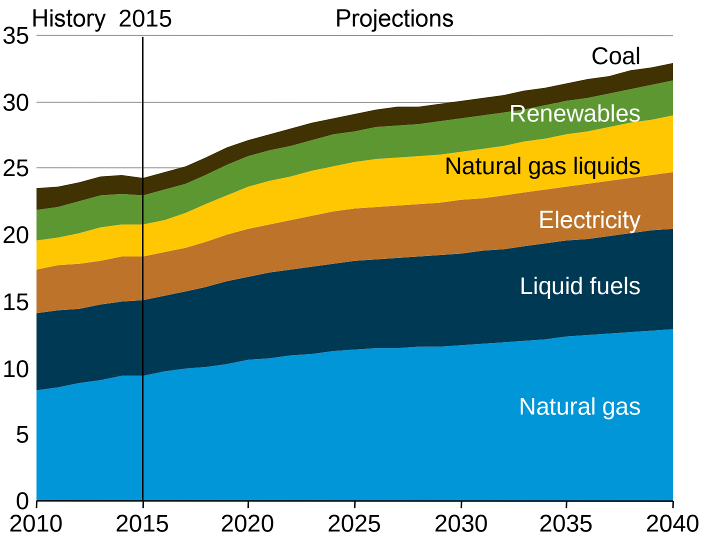
In the AEO2016 Reference case, manufacturing shipments increase by more than 60% from 2015–40, while delivered energy consumption for heat and power in the manufacturing sector increases by 16%. The continued decline in energy intensity of manufacturing results in part from continued improvement in the efficiency of industrial equipment, as well as a shift in the share of shipments from energy-intensive manufacturing industries to nonenergy-intensive industries. With lower fuel prices, shipments and energy use in many energy-intensive industries (bulk chemicals, petroleum refineries, iron and steel, and aluminum) continue to increase throughout the projection, but shipments in less energy-intensive manufacturing industries (plastics, metal-based durables) grow more rapidly.

With lower prices for natural gas and hydrocarbon gas liquids, shipments in the bulk chemical industry expand faster than those in other energy-intensive industries. Shipments in the bulk chemical industry increase by 4.8%/year from 2015–25, then slow to 1.4%/year growth from 2025–40. Energy use increases by 4.3%/year from 2015–25 and 1.1%/year from 2025–40, when energy use for bulk chemicals exceeds 10 quadrillion Btu and accounts for more than 31% of total industrial sector energy consumption. In the nonmanufacturing industries (agriculture, mining, and construction), energy intensity declines from 2015–40, as shipments increase by 53% and total delivered energy consumption increases by 30%. The overall decline in energy intensity is limited by the mining industry, where energy intensity increases as resource extraction moves into less-productive areas.

In the manufacturing sector, energy consumption for heat and power grows steadily in the Reference case, averaging 0.5%/year growth from 2015–40 (Figure MT-18). Nonmanufacturing energy consumption grows by an average of 2.2%/year from 2015–25, then slows to 0.8%/year from 2025–40. Nonfuel energy use (principally used for bulk chemical feedstocks and asphalt) grows by 4.7%/year from 2015–25, largely as a result of an increase in shipments of bulk chemicals. After 2025, nonfuel energy use grows by 1.5%/year in parallel with bulk chemical shipments.

Reliance on natural gas, natural gas liquids, and renewables rises as industrial energy use grows

Figure MT-19. Industrial sector energy consumption by fuel in the Reference case, 2010–40 (quadrillion Btu)



Total delivered energy consumption in the industrial sector increases in the Reference case by 35%—8.6 quadrillion British thermal units (Btu)—from 2015–40 (Figure MT-19). As a result of relatively low prices, natural gas use accounts for 41% of the total increase. The mix of industrial energy sources stays relatively constant, however, reflecting limited capability for switching from other fuels to natural gas in most industries.

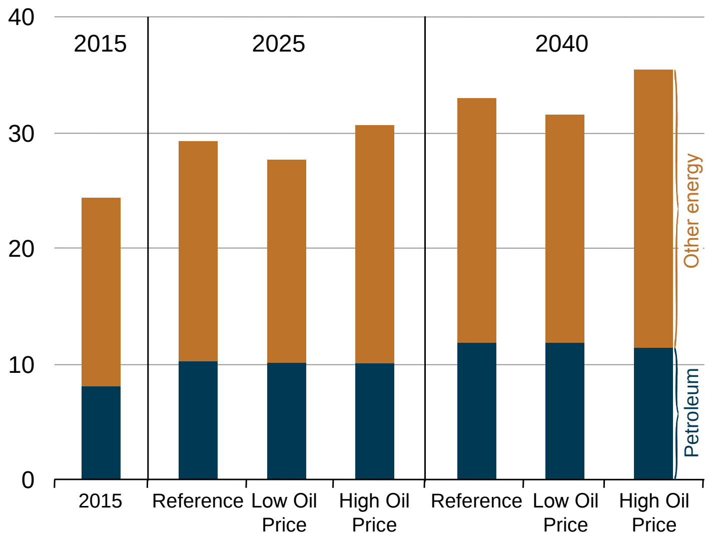
Consumption of renewable fuels (including biofuels heat and coproducts) increases by 16% from 2015–40 and accounts for a 5% share of total delivered energy consumption in 2040. The paper industry continues to be the predominant user of renewable energy, at 41% of the industrial sector total in 2040.

Industrial consumption of liquefied petroleum gases (LPG) increases by 47% from 2015–25 and by 21% from 2025–40. LPG are consumed predominantly as feedstocks in the bulk chemicals industry, with smaller amounts (mostly propane) consumed for process heat in other industries. Coal is the only industrial fuel whose share declines consistently over the projection, from 6% of the total in 2015 to 4% in 2040 as coal consumption remains relatively constant while total industrial energy use grows.

Low natural gas prices contribute to increasing use of combined heat and power (CHP) generation in the industrial sector, which grows by 48%, from 139 billion kilowatthours (kWh) in 2015 to 206 billion kWh in 2040. CHP is used primarily in the bulk chemicals, paper, and refining industries. Smaller amounts are used in the iron and steel industry and the food industry.

Petroleum share of industrial sector energy use increases in all oil price cases

Figure MT-20. Industrial consumption of petroleum and other energy in three cases, 2015, 2025, and 2040 (quadrillion Btu)



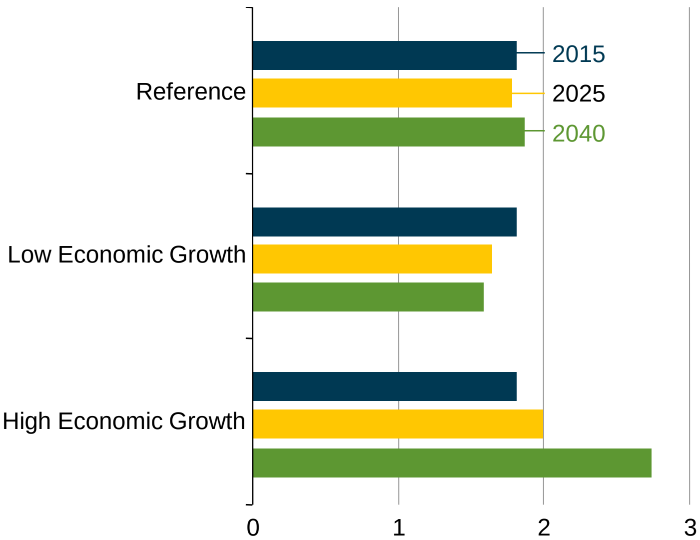
Because there are few substitutes for petroleum in construction, mining, agriculture, and manufacturing applications, industrial petroleum use varies only modestly across alternative oil price cases. In the Reference case, the petroleum share of total industrial energy use grows from 33% in 2015 to 36% in 2040. Industrial petroleum consumption increases by 46%, from 8.1 quadrillion British thermal units (Btu) in 2015 to 11.8 quadrillion Btu in 2040, compared with a 30% increase for all other energy sources.

While petroleum consumption in the industrial sector in 2040 is similar in the AEO2016 Reference and Low Oil Price cases, consumption of other fuels grows by 30% in the Reference case and 21% in the Low Oil Price case from 2015–40. The petroleum share of total consumption in 2040 in the Low Oil Price case is slightly higher than in the Reference case as a result of increased shipments from petroleum refineries. Lower oil prices create less incentive for improving the efficiency of petroleum consumption.

In the High Oil Price case, petroleum consumption in the industrial sector increases by 40% over 2015–40, reaching 11.3 quadrillion Btu in 2040. With a lower petroleum-intensive manufacturing share of shipments, including bulk chemicals and refining, petroleum intensity is slightly lower than in the Reference case. Consumption of other fuels, particularly natural gas, increases by 48% from 2015–40 in the High Oil Price case. The increase in natural gas consumption in the High Oil Price case is a result of higher levels of gas-to-liquids (GTL) production and more exports of liquefied natural gas, which consumes natural gas in liquefaction, than in the Reference case. GTL production is economical only in the High Oil Price case.

Energy use in the pulp and paper industry depends on technology choices

Figure MT-21. Energy consumption for pulp and paper production in three cases, 2015, 2025, and 2040 (quadrillion Btu)

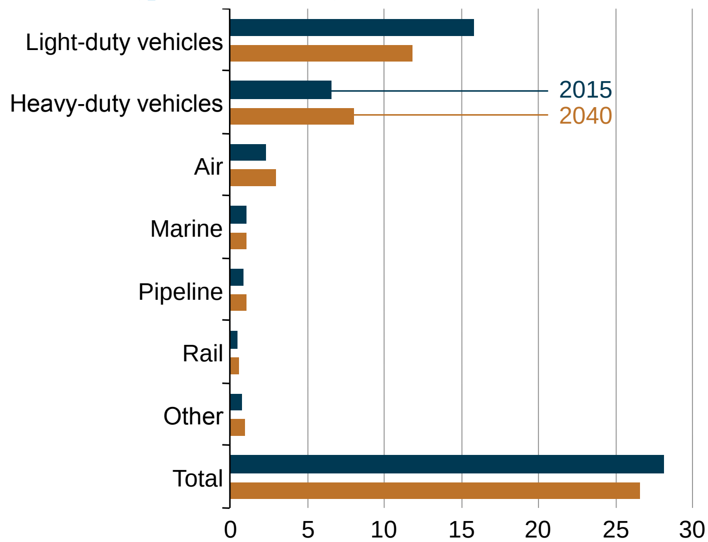


Energy use in the pulp and paper industry, which is closely related to shipment volumes, differs significantly in the AEO2016 Reference, Low Economic Growth, and High Economic Growth cases (Figure MT-21). Most of the energy consumed in the industry is from renewable sources. In the Reference case, the renewable share of total energy consumption in the pulp and paper industry grows from 55% in 2015 to 58% in 2040. The amount of energy used in the industry also depends on the technologies chosen for each process step, with the choices generally based on capital costs, operation and maintenance costs, fuel costs, and emissions. Some technologies use recycled products and waste, including recycled paper for pulp, wood waste for fuel, and chemical recovery (such as black liquor from the Kraft pulping process) for combined heat and power.

In the AEO2016 Reference and Low Economic Growth cases, slow growth in shipments and the adoption of more-energy-efficient technologies result in declines in energy consumption over the first 10 years of the projection. In the Reference case, pulp and paper industry shipments increase by 3%, while energy consumption declines by 1% from 2015–25. From 2025–40, with an 8% increase in pulp and paper industry shipments, energy consumption increases by 4%. In the Low Economic Growth case, with a 4% decline in pulp and paper industry shipments, energy consumption declines by 9% from 2015–25. From 2025–40, with a 2% increase in pulp and paper industry shipments, energy consumption declines by a smaller 3%. In the High Economic Growth case, with more rapid 13% growth in pulp and paper industry shipments from 2015–25, energy consumption increases by 10%, and from 2025–40 both pulp and paper industry shipments and energy consumption increase by about 37%. Although energy efficiency improves in the 2025–40 period, more rapid growth in combined heat and power generation results in a higher rate of increase in energy consumption.

Higher light-duty vehicle fuel economy reduces transportation energy consumption after 2018

Figure MT-22. Delivered energy consumption for transportation by mode in the Reference case, 2015 and 2040 (quadrillion Btu)



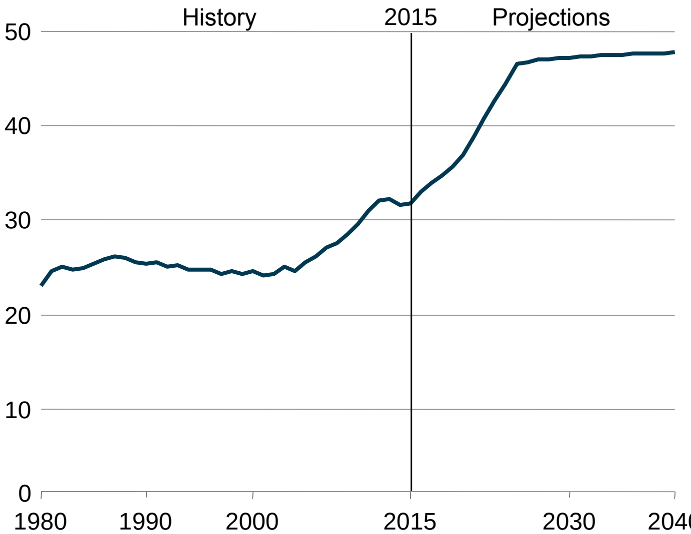
In the Reference case, transportation sector delivered energy consumption increases from 28.1 quadrillion British thermal units (Btu) in 2015 to 28.6 quadrillion Btu in 2017, declines to 26.1 quadrillion Btu in 2033, then rises to 26.6 quadrillion Btu in 2040. Transportation energy consumption increased by 1.6%/year on average from 1995 to 2007 (to 28.6 quadrillion Btu), then fell to 26.0 quadrillion Btu in 2012 as economic recession reduced demand for freight and passenger transportation. After 2012, growth in demand for transportation services offset efficiency improvements. The decline after 2017 in the Reference case results from a drop in light-duty vehicle (LDV) energy use with the implementation of new corporate average fuel economy standards, more than offsetting increases in energy use for heavy-duty vehicles (HDVs), aircraft, marine vessels, pipelines, and rail. The Reference case does not include the proposed Phase 2 standards for trucks (see discussion in the AEO2016 Issues in focus section), which if finalized would further reduce transportation energy use.

LDV energy demand falls sharply in the Reference case, from 15.9 quadrillion Btu in 2015 to 11.8 quadrillion Btu in 2040, as higher fuel economy more than offsets increases in LDV travel. Although new fuel efficiency and greenhouse gas emissions standards for HDVs took effect in 2014, energy use by HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickup trucks and vans) grows from 6.6 quadrillion Btu in 2015 to 8.1 quadrillion Btu in 2040 in the Reference case, as travel demand increases with economic growth.

Because growth in personal air travel is not fully offset by increases in aircraft fuel efficiency, aircraft energy consumption increases at a faster rate than other transportation modes, from 2.4 quadrillion Btu in 2015 to 3.0 quadrillion Btu in 2040s. Energy consumption by marine vessels also grows, as increased international trade boosts demand for shipping (despite a modest decline in domestic shipping), and rising incomes increase demand for recreational boating. Pipeline energy use is tempered as more natural gas is produced closer to end-use markets. With travel demand growing more rapidly than efficiency improvements, energy consumption for freight and passenger rail travel also increases slightly.

Corporate average fuel economy and greenhouse gas emissions standards boost light-duty vehicle fuel economy

Figure MT-23. Average fuel economy of new light-duty vehicles in the Reference case, 1980–2040 (miles per gallon)



In the Reference case, transportation sector delivered energy consumption increases from 28.1 quadrillion British thermal units (Btu) in 2015 to 28.6 quadrillion Btu in 2017, declines to 26.1 quadrillion Btu in 2033, then rises to 26.6 quadrillion Btu in 2040. Transportation energy consumption increased by 1.6%/year on average from 1995 to 2007 (to 28.6 quadrillion Btu), then fell to 26.0 quadrillion Btu in 2012 as economic recession reduced demand for freight and passenger transportation. After 2012, growth in demand for transportation services offset efficiency improvements. The decline after 2017 in the Reference case results from a drop in light-duty vehicle (LDV) energy use with the implementation of new corporate average fuel economy standards, more than offsetting increases in energy use for heavy-duty vehicles (HDVs), aircraft, marine vessels, pipelines, and rail. The Reference case does not include the proposed Phase 2 standards for trucks (see discussion in the AEO2016 Issues in focus section), which if finalized would further reduce transportation energy use.

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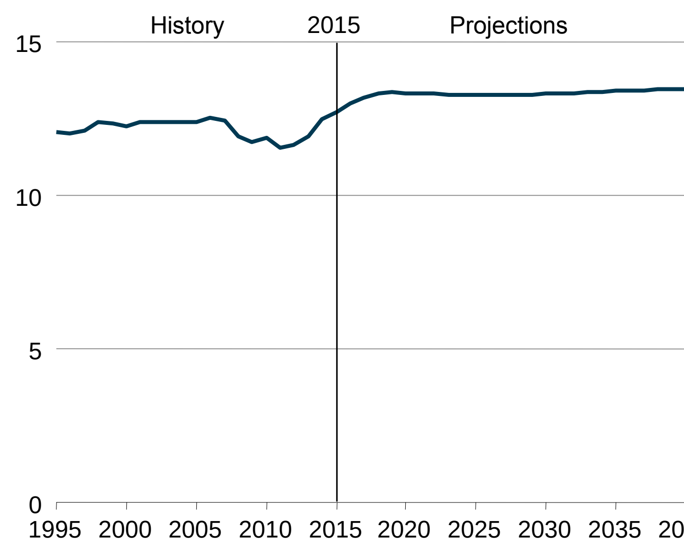
Miles traveled per licensed driver grows through 2018 and then levels off

Figure MT-24. Vehicle miles traveled per licensed driver in the Reference case, 1995–2040 (thousand miles)



Demand for personal vehicle travel, measured as annual vehicle miles traveled (VMT) per licensed driver, continues to grow beyond 2015 levels in the AEO2016 Reference case, from 12,700 miles in 2015 to 13,300 miles in 2018, remains at about 13,300 until 2033, and then increases again to 13,500 in 2040 (Figure MT-24). The major factors influencing personal vehicle travel include motor gasoline prices, personal income, vehicle fuel efficiency, travel patterns, driving population, and employment rates.

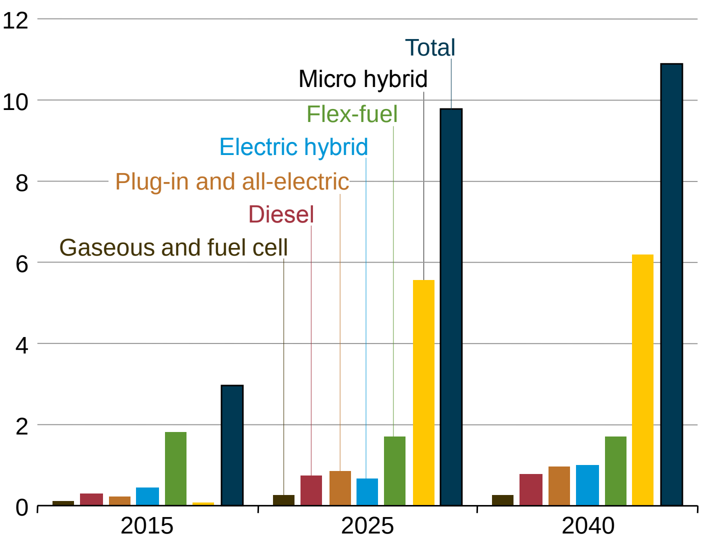
Transportation sector energy demand

The number of licensed drivers grows by an average of 0.7%/year from 2015–40, as the employment rate of the licensed driver population (the employed, nonfarm population ages 16 and over) increases by an average of 0.7%/yr from 2015–40. Total light-duty VMT increases in the Reference case to 3.4 trillion in 2040—a 25% increase from 2015—partly as a result of 18% overall growth in the number of licensed drivers, from 217 million in 2015 to 255 million in 2040.

Although vehicle sales decline between 2017 and 2022 before generally increasing through 2040, the number of vehicles per licensed driver stays constant at 1.1 from 2015–40. Motor gasoline prices fall from 2015 levels and do not exceed that level again until 2019, while real personal disposable income per licensed driver increases by 47% from 2015–40. Income growth and lower motor gasoline prices, combined with increasing fuel economy for both light-duty cars and light trucks, contribute to the increase in VMT per licensed driver throughout the projection.

Sales of vehicles using nongasoline technologies triple from 2015 to 2040

Figure MT-25. Sales of light-duty vehicles capable of using nongasoline technologies by type in the Reference case, 2015, 2025, and 2040 (million vehicles sold)



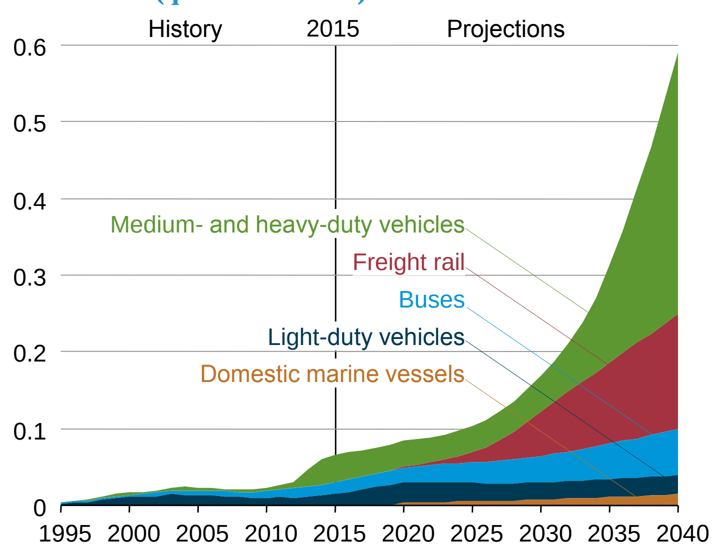
Light-duty vehicles (LDVs) that use diesel, alternative-fuel, hybrid-electric, or all-electric systems play a significant role in meeting more stringent greenhouse gas emissions and corporate average fuel economy (CAFE) standards in the AEO2016 Reference case, with sales increasing from 18% of all new LDV sales in 2015 to 61% in 2040. Micro hybrid vehicles, defined here as conventional gasoline internal combustion engine vehicles with micro hybrid systems that manage engine operation at idle, represent 34% of new LDV sales in 2040 (Figure MT-25). Flex-fuel vehicles (FFVs), which can use blends of up to 85% ethanol, represent about 10% of all new LDV sales in 2040. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire at the end of 2019. As a result, the FFV share of LDV sales rises through 2019 and then remains flat through the rest of the projection.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow substantially in the Reference case. Gasoline- and diesel-electric hybrid vehicles account for 5% of total LDV sales in 2040. Plug-in hybrid and all-electric vehicles account for 5% of total LDV sales and 9% of total sales of vehicles using diesel, alternative-fuel, hybrid, or all-electric systems in 2040.

The diesel vehicle share of total LDV sales increases slightly from 2015–40 in the Reference case, from 2% to 4%. Light-duty gaseous and fuel cell vehicles account for less than 2% of new vehicle sales because of limited fueling infrastructure and the high incremental costs of the vehicles.

Natural gas use for transportation increases but remains a small share of total transportation energy

Figure MT-26. Transportation sector natural gas consumption by vehicle type in the Reference case, 1995–2040 (quadrillion Btu)



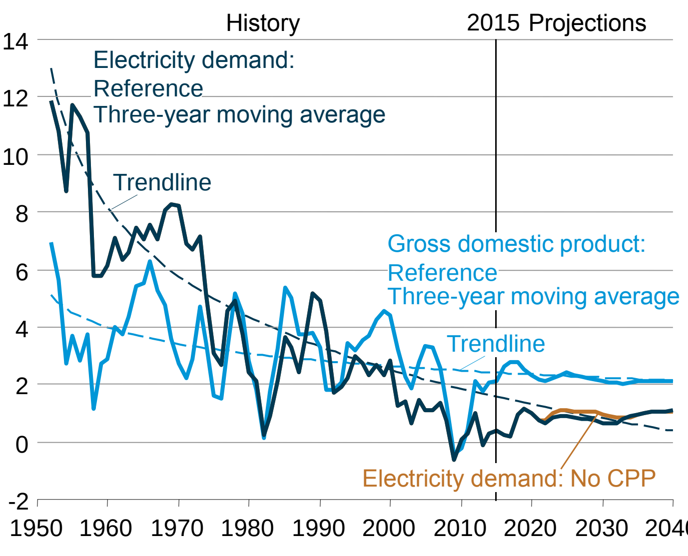
Unlike natural gas applications in other demand sectors, consumption of natural gas by rail, marine, and road vehicles in the transportation sector—in both dedicated and dual-fueled engines—generally requires additional processing to meet energy storage requirements on vehicles, either as compressed natural gas (CNG) or liquefied natural gas (LNG). In the AEO2016 Reference case, demand for natural gas in the transportation sector grows from 66 trillion British thermal units (Btu) in 2015 to 591 trillion Btu in 2040 (Figure MT-26). However, natural gas still accounts for just 2% of the sector's total delivered energy consumption in 2040, or slightly more than half of the 1,069 trillion Btu of natural gas consumed in pipeline transport operations in 2040.

Medium-duty and heavy-duty vehicles—including tractor trailers, vocational vehicles, pickups, and vans with gross vehicle weight rating of 10,001 pounds or more—become the largest consumers of CNG and LNG in the Reference case, increasing from 35 trillion Btu in 2015 to 342 trillion Btu in 2040. Most of the increase occurs after 2025, when natural gas is marketed at a steadily increasing discount compared to petroleum fuels. Initially, natural gas is used primarily as CNG in medium-duty trucks, but over time it is used increasingly as LNG to fuel heavy-duty trucks (primarily tractor trailers)—a relatively energy-dense storage, high-mileage application in which the fuel cost savings of LNG offset the significant incremental capital costs of LNG vehicles.

LNG energy consumption by freight rail locomotives grows to 150 trillion Btu in 2040, when it accounts for 30% of total freight rail energy consumption, with natural gas fuel cost savings offsetting the incremental capital costs of LNG locomotives. CNG and LNG energy demand for transit, intercity, and school buses also grows, from 16 trillion Btu in 2015 to 60 trillion Btu in 2040, primarily as a result of high CNG adoption rates for transit buses, which account for 95% (57 trillion Btu) of the natural gas used by buses in 2040. Use of CNG in light-duty vehicles and LNG in marine vessels remains relatively minor, at 24 trillion Btu and 15 trillion Btu in 2040, or 0.2% and 2.0% of each mode's energy consumption, respectively.

Growth in electricity use from 2015 to 2040 slows to 24% with Clean Power Plan (CPP) and to 27% with no CPP

Figure MT-27. U.S. gross domestic product growth and electricity demand growth rates, 1950–2040 (percent, three-year moving average)

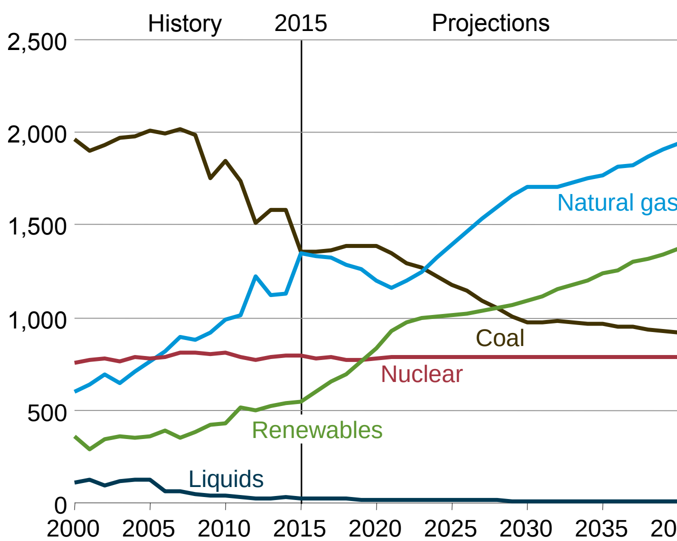


Electricity demand growth (including retail sales and direct use) has slowed in every decade since the 1950s, from 9.8%/year from 1949–59 to 0.5%/year from 2000–2015. In the AEO2016 Reference case and No CPP case, electricity demand growth remains relatively slow, as rising demand for electric services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment. Total electricity demand grows by 24% (0.9%/year) from 2015–40 in the Reference case, which includes the effects of the Clean Power Plan (CPP). In the No CPP case, demand increases by 27% from 2015–40 (1.0%/year). U.S. electricity demand is affected primarily by population growth and economic activity. However, electricity demand growth has been significantly slower than gross domestic product (GDP) growth in recent years and continues to be slower in the projections (Figure MT-27).

Electricity sales grow at a slower rate than electricity use, given the increasing role of self-generation in all end-use sectors. Total retail electricity sales increase by 20% (0.7%/year) from 2015–40 in the Reference case and by 23% (0.8%/year) in the No CPP case. Population shifts to warmer regions increase cooling requirements, which affects both residential and commercial electricity sales. In the residential sector, electricity sales grow by 9% and 11% from 2015–40 in the Reference case and No CPP case, respectively. The increasing energy efficiency of residential appliances and consumer electronics offsets some of the growth in electricity demand that would otherwise have occurred as a result of the increasing availability and sales of electronic devices. In the commercial sector, electricity demand grows by 21% in the Reference case and by 26% in the No CPP case from 2015–40, as demand for electrical devices and equipment continues to rise. In the industrial sector, electricity demand grows by 30% in the Reference case and by 32% in No CPP case from 2015–40, initially as a result of increasing sales in the primary metals, bulk chemical, and food industries, and later as a result of growth in the construction and metal-based durables industries. However, while demand increases for most industrial uses, total electricity use per unit of output declines in both the Reference case and No CPP case as energy efficiency increases.

Clean Power Plan accelerates shift from coal to natural gas and renewables

Figure MT-28. Net electricity generation by fuel in the Reference case, 2000–2040 (billion kilowatthours)



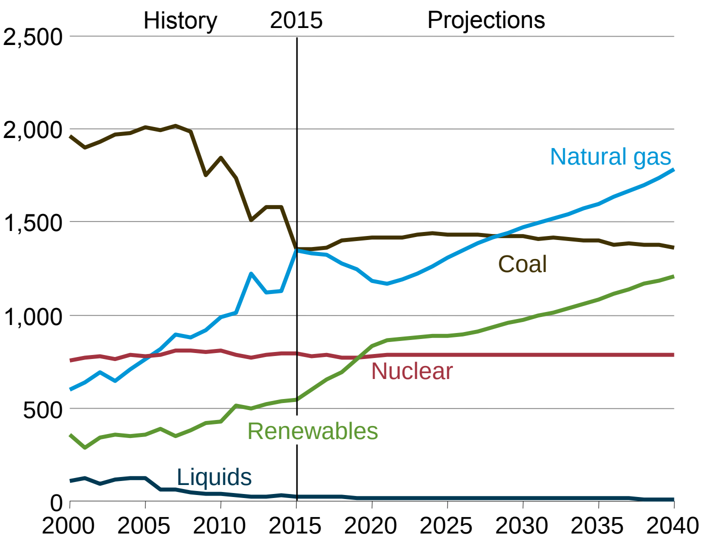
The Clean Power Plan (CPP) requires states to develop plans to reduce carbon dioxide (CO2) emissions from existing fossil-fired electric generating units. The AEO2016 Reference case assumes that states will choose to cooperate with each other at the regional level [*11*], using a mass-based (cap-and-trade) program that allocates allowances to load-serving entities to reduce the potential impacts of higher rates on consumers.

If the CPP emerges intact from legal challenges, it is expected to reinforce the trend toward less carbon-intensive generation by accelerating the shift away from coal to natural gas and renewables, and toward increased energy efficiency. In the Reference case, coal use for electricity generation is overtaken by natural gas in 2024 and by renewables in 2028.

In the Reference case, higher electricity prices and the push for greater energy efficiency slows the 2015–30 growth rate of U.S. total electricity sales, from 1%/year from 2015–30 in the No CPP case to 0.8%/year in the Reference case. In addition, the higher cost associated with CO2 emissions under the CPP contributes to a 1.5% annual decline in electricity generated from coal, which drops from 1,355 billion kilowatthours (kWh) (a 33% share) in 2015 to 919 billion kWh (18%) in 2040. Retirements of coal-fired generators by 2030, increase from 60 gigawatts (GW) in the No CPP case to 92 GW in the Reference case, or about one-third of current capacity (Figure MT-28). Growth in generation from renewable energy sources also accelerates from 3.2%/year in the No CPP case to 3.8%/year in the Reference case, as total renewable generation increases from 546 billion kWh (13% of current generation) to 1,374 billion kWh (27% of 2040 generation in the Reference case). The average growth rate of nonhydropower renewable generation from 2015–40 increases from 4.5%/year in the No CPP case to 5.3%/year in the Reference case.

With no Clean Power Plan (CPP), coal-fired generation shows little change from 2015 level

Figure MT-29. Net electricity generation by fuel in the No CPP case, 2000–2040 (billion kilowatthours)



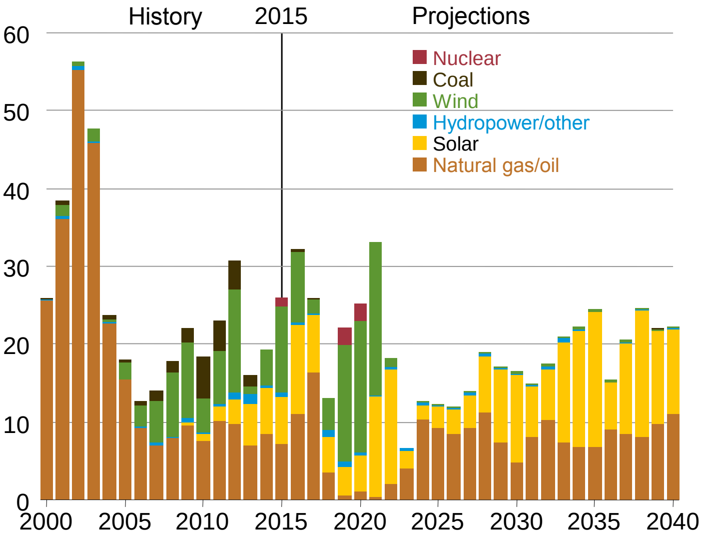
The decline in natural gas prices since 2009 has threatened the cost competitiveness of existing U.S. coal-fired generators, resulting in a 25% reduction in coal-fired generation in 2015 from its level in the mid-2000s. In the No CPP case, natural gas-fired generation roughly equals coal generation in the United States on an annual basis in 2016. After declining somewhat from 2016–20 with strong renewable growth as a result of tax credits, the natural gas share increases steadily in the No CPP case, overtaking the coal share in 2029 as the predominant fuel for electricity generation. In 2040, the natural gas share of total generation is 34% in the No CPP case.

Recent policy and technology developments, including the extension of production and investment tax credits for renewable generation technologies enacted in December 2015, as well as reduced capital costs for solar photovoltaic systems, are further increasing the pressure on coal. In the No CPP case, renewables generation increases at 3.2%/year from 546 billion kilowatthours (kWh) (a 13% share) in 2015 to 1,204 billion kWh (a 23% share) in 2040 (Figure MT-29). Nonhydro renewables generation grows at the fastest rate through 2040, increasing at 4.5%/year, from 252 billion kWh in 2015 to 750 billion kWh in 2040. Over the same period, hydroelectric generation grows at 0.7%/year, from 245 billion kWh in 2015 to 294 billion kWh in 2040.

The coal share of total electricity generation falls from 48% in 2008 to 31% in 2029, when the natural gas share surpasses it, and then continues to decline, falling to a 26% share in 2040. Coal generation is essentially flat from 2015 to 2040 in the No CPP case. A large portion of the decline in coal generation is attributable to the retirement of coal generating capacity in the No CPP case. The No CPP case has 60 gigawatts of cumulative coal capacity retirements between 2016 and 2030. Nuclear generating capacity remains virtually unchanged over the projection in the No CPP case, as additions are more than offset by retirements. Total nuclear generation is flat at about 789 billion kWh, accounting for a 20% share in 2015 and a 15% share in 2040. Coal and nuclear generation, which together satisfied 70% of U.S. generation requirements as recently as 2005, fall to a 47% share of total generation in 2030 and a 42% share in 2040 in the No CPP case.

Renewables and natural gas lead capacity additions through 2040 in the Reference case

Figure MT-30. Additions to electricity generation capacity by fuel in the Reference case, 2000–2040 (gigawatts)

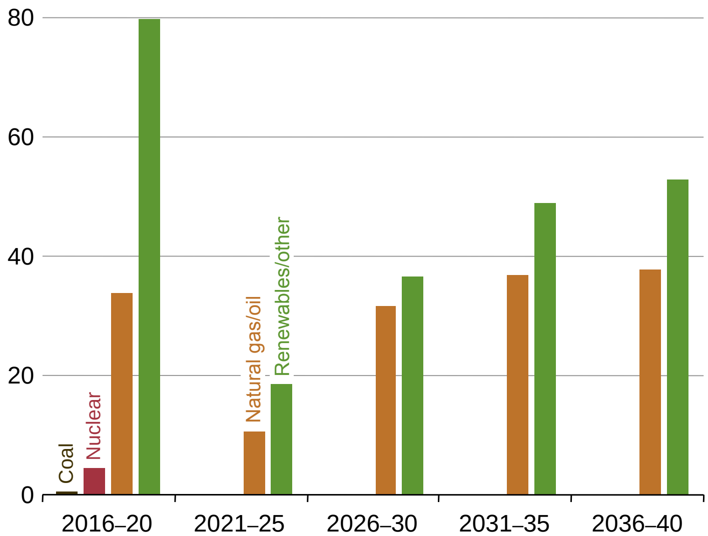


In the AEO2016 Reference case, two developments significantly improve the prospects for renewable capacity: extension of favorable federal tax treatment for renewable generators, and continued dramatic reductions in the capital cost of solar photovoltaic (PV) systems. In the Reference case, cumulative additions to U.S. generating capacity from 2016–40 total 483 gigawatts (GW) for all technologies, including 302 GW of renewable technology additions (63% of the total), both power-sector and end-use generators (Figure MT-30). Renewable generation capacity additions consist primarily of wind (73 GW) and solar (221 GW) technologies, including 77 GW of solar PV installations in the end-use sectors.

The increase in renewable capacity additions helps offset the retirement of 100 GW of coal-fired capacity as a result of environmental legislation, including implementation of the Clean Power Plan. Relatively low natural gas prices from 2016–40 also lead to a significant increase in natural gas-fired capacity, with 175 GW of gas-fired capacity additions accounting for 36% of the total increase. Total renewable capacity additions average 16 GW/year through 2024. From 2025–40, renewable capacity additions slow to 10 GW/year, as electricity demand growth slows. Virtually all capacity additions after 2025 in the Reference case are solar PV and natural gas, which account for 53% and 43% of total additions, respectively, over the 2025–40 period. Among fossil fuel generating technologies, natural gas-fired combined-cycle plants remain the least-cost option for new capacity additions, and they generally are more efficient to operate than existing steam plants fueled with natural gas, oil, or coal.

In the No CPP case, most new electricity generation capacity uses natural gas and renewables

Figure MT-31. Cumulative additions to electricity generation capacity by fuel in the No CPP case by period (gigawatts)



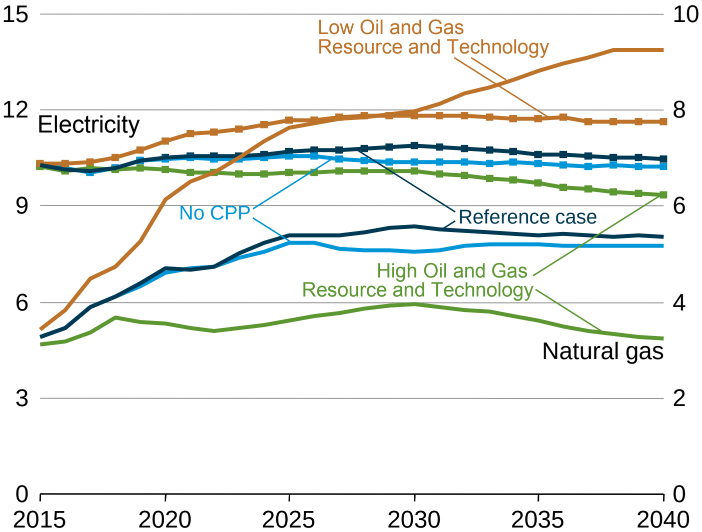
In the No CPP case, additions to electricity generation capacity—including those in the end-use sectors—total 392 gigawatts (GW) from 2016–40 (Figure MT-31). Capacity additions in the near term replace retiring coal-fired plants, which are the result of low natural gas prices and implementation of the Mercury Air Toxic Standards. Coal-fired capacity declines from 284 GW in 2015 to 215 GW in 2040, with much of that capacity retired by 2025. A total of 60 GW of coal-fired capacity is retired from 2016–25 in the No CPP case, including both announced retirements and those projected on the basis of market factors. Total capacity additions average 16 GW/year from 2016–40, with 97 GW of renewable capacity additions from 2016–25 and 44 GW of natural gas additions over the same period.

Renewable additions in the No CPP case benefit from the extension of the federal tax credit in the near term and from declining costs in the long term. Renewable additions total 236 GW from 2016–40, primarily solar (178 GW) and wind (52 GW). The solar capacity additions include 74 GW of rooftop and other distributed solar generation installations in the end-use sectors. Most of the wind capacity is added before 2025 to take advantage of the production tax credit, which is available only to projects beginning substantive development before 2020. Solar capacity is added steadily through 2040, as it becomes more cost-competitive as a result of declining capital cost and the investment tax credit. The tax credit phases down from 30% in 2016 to 10% in 2022 and then remains at that level for utility and commercially operated solar projects but ends for residential solar projects.

In the No CPP case, natural gas accounts for 38% (150 GW) of cumulative capacity additions from 2016–40. The relatively steady growth of natural gas capacity, which helps to maintain baseload generation and provide grid reliability services, also results from continued low natural gas prices.

Electricity prices rise and fall with natural gas availability and prices

Figure MT-32. Electricity prices and natural gas prices to electricity generators in four cases, 2015–40 (left axis, 2015 cents per kilowatthour; right axis, 2015 dollars per million Btu)



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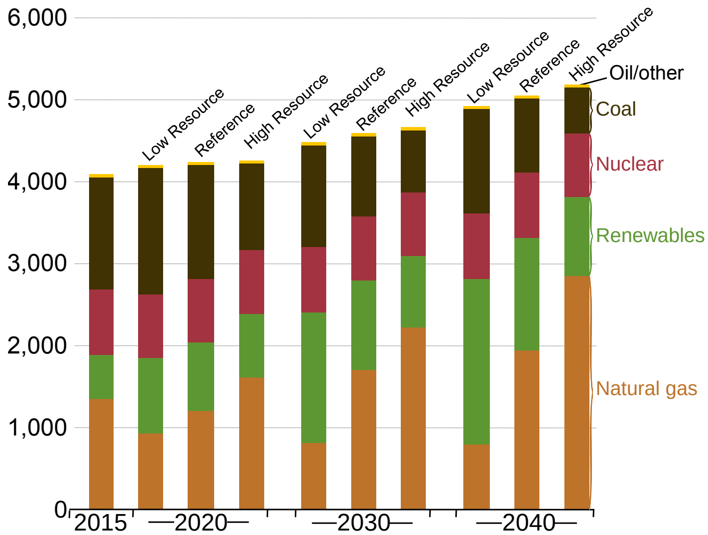
Electricity generation mix responds significantly to natural gas prices

Figure MT-33. Electricity generation by fuel in three cases, 2015, 2020, 2030, and 2040 (billion kilowatthours)



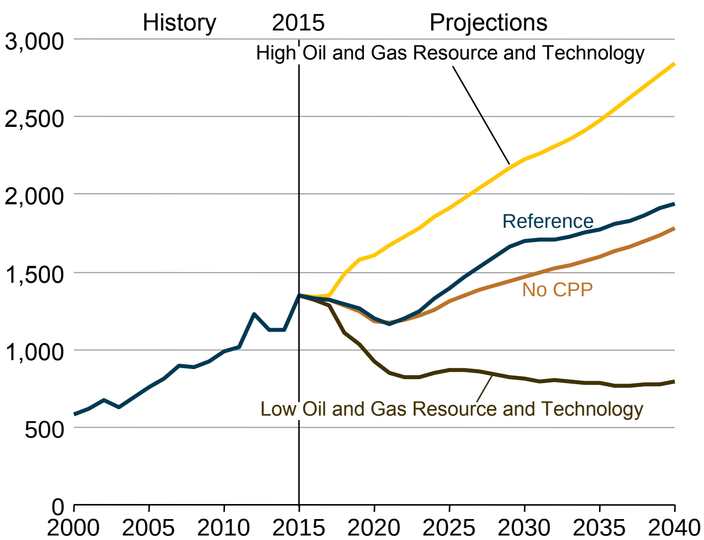
Recent low natural gas prices have led to a shift from coal to natural gas for electricity generation. In addition, favorable federal and state policies have supported increases in renewable capacity. The future generation mix will depend to significant extent on future natural gas prices, as existing natural gas plants compete with coal for dispatch decisions in the short term, and natural gas combined-cycle capacity competes with wind and solar capacity in the longer term. The AEO2016 Low and High Oil and Gas Resource and Technology cases provide a range of potential future natural gas price paths that could affect the mix of fuels used for electricity generation. In the High Oil and Gas Resource and Technology case, delivered natural gas prices remain below $4/million British thermal units (Btu) through 2040. In the Low Oil and Gas Resource and Technology case, delivered natural gas prices rise steadily, to $8/million Btu in 2030 and more than $9/million Btu in 2040.

Lower natural gas prices in the High Resource and Technology case lead to a 48% natural gas share of total generation in 2030—compared with 37% in the Reference case—and a 55% share in 2040 (Figure MT-33). An additional 39 gigawatts of coal-fired capacity is retired by 2040, and the coal share of total generation falls from 33% in 2015 to 17% in 2030 and to 11% in 2040. Renewable capacity additions in the same case are less than half of those in the Reference case, and the overall renewable share of total generation is 18% in 2030 and 19% in 2040, compared with 24% and 27%, respectively, in the Reference case.

In the Low Oil and Gas Resource and Technology case, higher natural gas prices reduce the natural gas share of total electricity generation from 33% in 2015 to 18% in 2030 and to 16% in 2040. Fewer coal plants are retired, allowing for higher levels of coal-fired generation than in the Reference case. More new renewable generation reduces the share of more expensive natural gas-fired generation needed to meet the growth in demand for electricity.

Resource availability has more effect than the Clean Power Plan on natural gas-fired generation

Figure MT-34. Natural gas-fired electricity generation in four cases, 2000–2040 (billion kilowatthours)



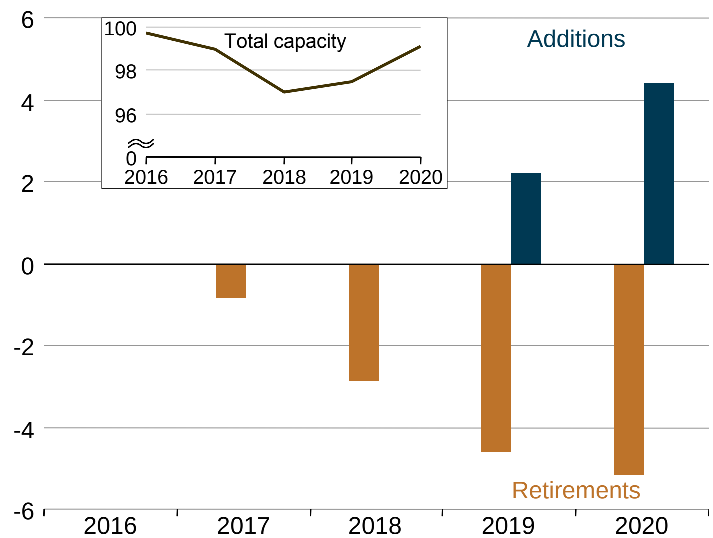
In the No CPP case, additions to electricity generation capacity—including those in the end-use sectors—total 392 gigawatts (GW) from 2016–40 (Figure MT-31). Capacity additions in the near term replace retiring coal-fired plants, which are the result of low natural gas prices and implementation of the Mercury Air Toxic Standards. Coal-fired capacity declines from 284 GW in 2015 to 215 GW in 2040, with much of that capacity retired by 2025. A total of 60 GW of coal-fired capacity is retired from 2016–25 in the No CPP case, including both announced retirements and those projected on the basis of market factors. Total capacity additions average 16 GW/year from 2016–40, with 97 GW of renewable capacity additions from 2016–25 and 44 GW of natural gas additions over the same period.

Renewable additions in the No CPP case benefit from the extension of the federal tax credit in the near term and from declining costs in the long term. Renewable additions total 236 GW from 2016–40, primarily solar (178 GW) and wind (52 GW). The solar capacity additions include 74 GW of rooftop and other distributed solar generation installations in the end-use sectors. Most of the wind capacity is added before 2025 to take advantage of the production tax credit, which is available only to projects beginning substantive development before 2020. Solar capacity is added steadily through 2040, as it becomes more cost-competitive as a result of declining capital cost and the investment tax credit. The tax credit phases down from 30% in 2016 to 10% in 2022 and then remains at that level for utility and commercially operated solar projects but ends for residential solar projects.

In the No CPP case, natural gas accounts for 38% (150 GW) of cumulative capacity additions from 2016–40. The relatively steady growth of natural gas capacity, which helps to maintain baseload generation and provide grid reliability services, also results from continued low natural gas prices.

Nuclear power generation faces competition from natural gas and renewables

Figure MT-35. Cumulative nuclear generation capacity additions and retirements, 2016–20 (gigawatts)



Decisions to build new nuclear capacity, uprate existing reactors, or extend their operating lifetimes depend on the cost-competitiveness of nuclear generation in electric power markets. Independent power producers [*12*] have faced financial losses in recent years on their nuclear capacity as a result of competition from lower-cost energy sources—including natural gas and wind—and declining electricity demand and reduced capacity payments in some regions [*13*].

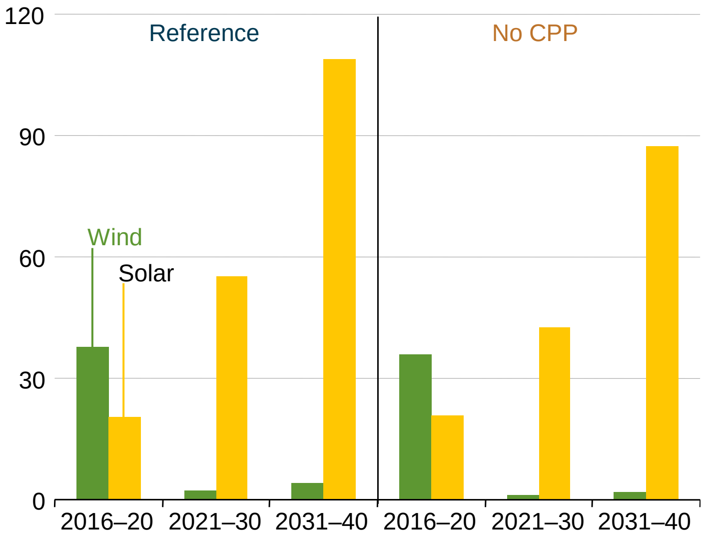
Low natural gas prices reduce the competiveness of newly built nuclear capacity relative to natural gas-fired combined-cycle plants, and they reduce wholesale market prices for electricity from existing nuclear power plants. As a result, no uprates or new builds of nuclear capacity beyond those already underway occur in any of the AEO2016 cases.

The Reference case incorporates 2,139 megawatts (MW) of planned and announced nuclear plant retirements (Figure MT-35), including FitzPatrick (852 MW) in 2016, and Pilgrim (678 MW) and Oyster Creek (610 MW) in 2019. The Reference case also assumes early retirement of 3 gigawatts (GW) of nuclear capacity, modeled as derates in competitive regions, based on an assessment of market uncertainties. These retirements represent a total reduction in nuclear capacity of 5.1 GW from the existing nuclear fleet. Market uncertainties and regulatory issues have led to recent announcements of reactor retirements that are not reflected in the Reference case: Clinton (1,065 MW), Quad Cities Units 1 and 2 (1,819 MW), Fort Calhoun (479

MW), and Diablo Canyon Units 1 and 2 (2,240 MW). These reecent announcements represent an additional incremental reduction of 2.6 gigawatts of retirements not reflected in the Reference case. The Reference case addresses near-term accelerated nuclear retirements but assumes that subsequent license renewals will allow for long-term operation up to 80 years. Future AEOs will discuss the ability of nuclear power stations to achieve long-term operation beyond 60 years.

Renewable capacity additions are dominated by solar photovoltaics

Figure MT-36. Wind and solar electricity generation capacity additions in all sectors by energy source in two cases, 2016–20, 2021–30, and 2031–40 (gigawatts)



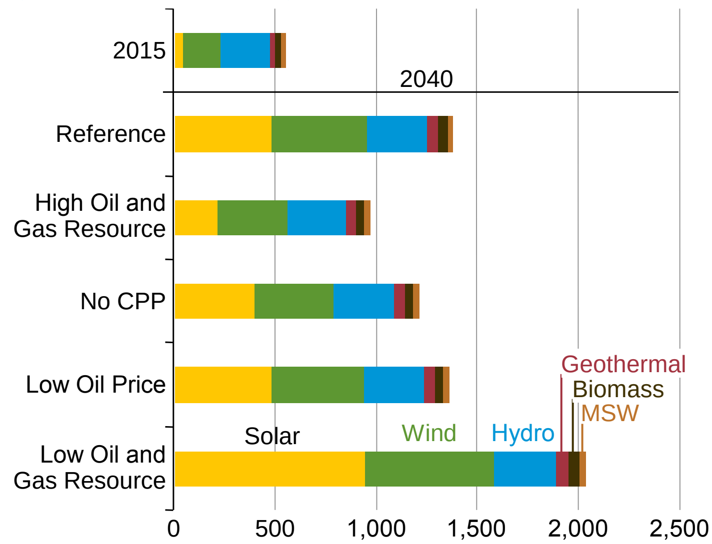
In the AEO2016 Reference case, total wind and solar electricity generation capacity grows by 5%/year from 2016–40, adding more than 294 gigawatts (GW) to provide 80% of total renewables capacity in 2040 (Figure MT-36). In the No CPP case, which assumes that the Clean Power Plan (CPP) is not implemented, wind and solar capacity together increase by more than 4%/year, adding almost 230 GW of generating capacity over the 2016–40 period. Wind and solar capacity increases by 10%/year from 2016–20 and then slows to 3%/year from 2021–40 in both the Reference and No CPP cases.

Solar power provides the largest increase in renewable capacity, from 25 GW in 2015 to more than 246 GW in 2040 in the Reference case and more than 202 GW in the No CPP case. The increases in wind capacity are much smaller, at 73 GW in the Reference case and less than 52 GW in the No CPP case from 2016–40. Solar installations have benefitted from significant reductions in technology costs in recent years, while wind capacity is hampered by the need to access wind sites farther from existing transmission lines or with less favorable development characteristics. Wind capacity additions are particularly slow between 2030–40, at slightly more than 4 GW in the Reference case and 2 GW in the No CPP case. With slow growth in wind capacity additions and continued fast growth in solar additions, solar capacity surpasses wind capacity in 2032 in the Reference case and in 2033 in the No CPP case.

Renewable capacity growth is supported by a variety of federal and state policies. The recent five-year extension of production tax credits and investment tax credits supports the growth of new renewable capacity through 2022. The CPP policy takes effect in 2022, providing additional incentives for renewable capacity additions to meet CO2 emissions targets from 2022–29. Although the targets remain flat after the interim period, additions of renewable capacity continue in order to meet CO2 emissions targets while satisfying demand for new generation.

Renewable electricity generation sensitive to government policies and natural gas prices

Figure MT-37. Renewable electricity generation by fuel type in all sectors in five cases, 2015 and 2040 (billion kilowatthours)



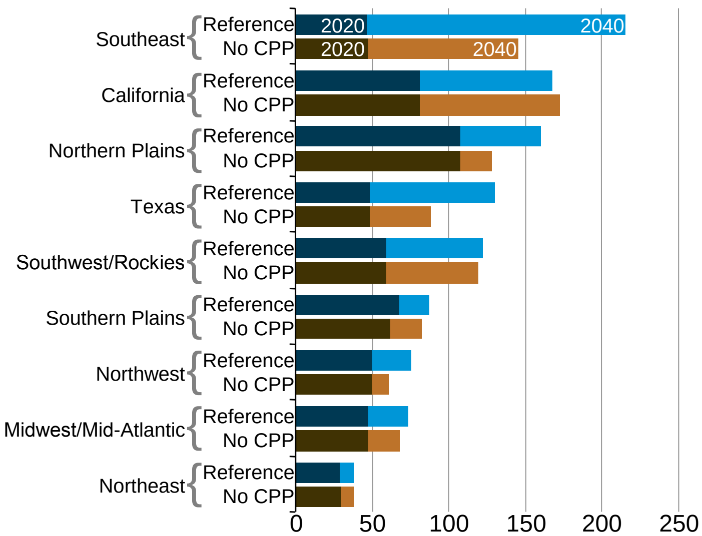
Total renewable electricity generation increases in the Reference case by more than 150%, from 546 billion kilowatthours (kWh) in 2015 to 1,374 billion kWh in 2040 (Figure MT-37). The total varies in the alternative cases with different price, resource, and policy assumptions, ranging from a 76% increase in the High Oil and Gas Resource and Technology case to a 271% increase in the Low Oil and Gas Resource and Technology case. Generation from wind and solar resources represents the largest share of the increase in renewable generation. In the Reference case, solar generation increases by an average of 11%/year, from 38 billion kWh in 2015 to 477 billion kWh in 2040, and wind generation increases by an average of 4%/year, from 190 billion kWh in 2015 to 473 billion kWh in 2040. Solar power provides about 35% of total renewable electricity generation in 2040 in the Reference case, up from 7% in 2015.

In the Low Oil and Gas Resource and Technology case, which has the highest natural gas prices among all the AEO2016 cases, renewable generation increases to 2,030 billion kWh in 2040, with approximately 46% of the total coming from solar generation, 31% from wind, and 15% from hydropower. Because natural gas often is the marginal fuel in determining wholesale electricity prices, higher natural gas prices tend to make renewable generation more competitive. Solar generation, which is available during the day to meet peak demand and can displace natural gas-fired generation, serves 19% of total load in 2040.

In the High Oil and Gas Resource and Technology case, low natural gas prices reduce growth in total renewable generation, which increases to only 961 billion kWh in 2040. Lower natural gas prices increase the cost-effectiveness of natural gas-fired power plants and make renewable generation less competitive.

Southeast region leads growth in non-hydropower renewable electricity generation

Figure MT-38. Nonhydropower renewable electricity generation in all sectors in two cases, 2020 and 2040 (billion kilowatthours)



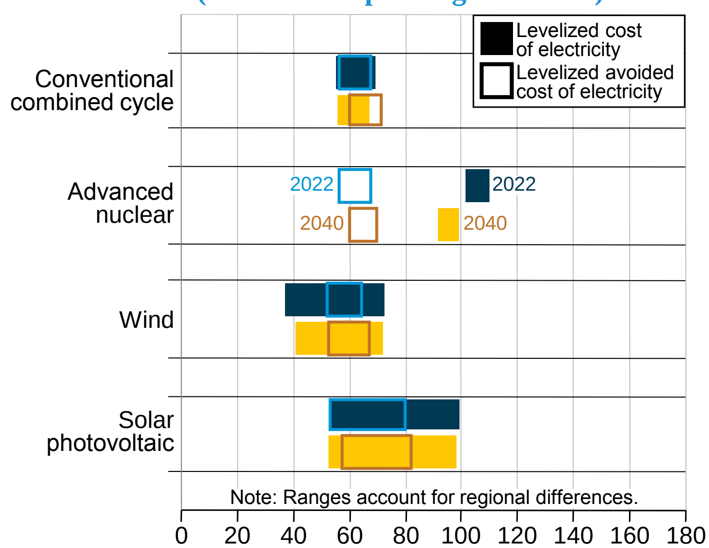
In the AEO2016 Reference case and the No CPP case, nonhydropower renewable generation increases from 2020 to 2040 in all the electricity regions. (For a map of regions, see Appendix F.) Regional growth in renewable generation is determined by four factors: implementation of the Clean Power Plan (CPP), state renewable portfolio standards (RPS), availability of renewable energy resources, and cost competition with fossil fuel technologies. Factors such as electricity demand growth, non-RPS policies (such as net metering), and electricity prices also affect regional growth rates.

From 2020–40, the Southeast region experiences the largest increases in nonhydropower renewable electricity generation both in the Reference case (360%) and in the No CPP case (206%), with growth led by utility-scale solar and wind capacity additions in the Tennessee Valley and in Florida (Figure MT-38). In the Reference case, which includes the CPP, nonhydropower renewable generation in the Southeast in 2040 is the largest among all regions and is 48%, or 70 billion kilowatthours (kWh), greater than in the No CPP case. In the California and Southwest/Rockies regions, generation from nonhydropower renewables doubles from 2020–40 in both the Reference and No CPP cases, partly as a result of mandatory RPS policies. Solar power leads the growth in nonhydropower renewable generation in California, making up more than 65% of the growth from 2020–40 in both the Reference and No CPP cases. Solar makes up more than 80% of the growth in the Southwest/Rockies region in both cases. In Texas, nonhydropower renewable electricity generation in 2040 in the Reference case is approximately 165% higher than in 2020 (an increase of more than 80 billion kWh). The growth over the same period in the No CPP case is 80% (an increase of nearly 39 billion kWh).

Nonhydropower renewable generation growth is generally higher with the carbon emission restrictions of the CPP in the Reference case than without the restrictions. However, both the growth and the resulting generation mix vary substantially among regions, depending on the cost and availability of resources and state policies.

Levelized generation and avoided costs influence the economics of new technologies

Figure MT-39. Levelized electricity costs with tax credits for new power plants in the Reference case, 2022 and 2040 (2015 dollars per megawatthour)



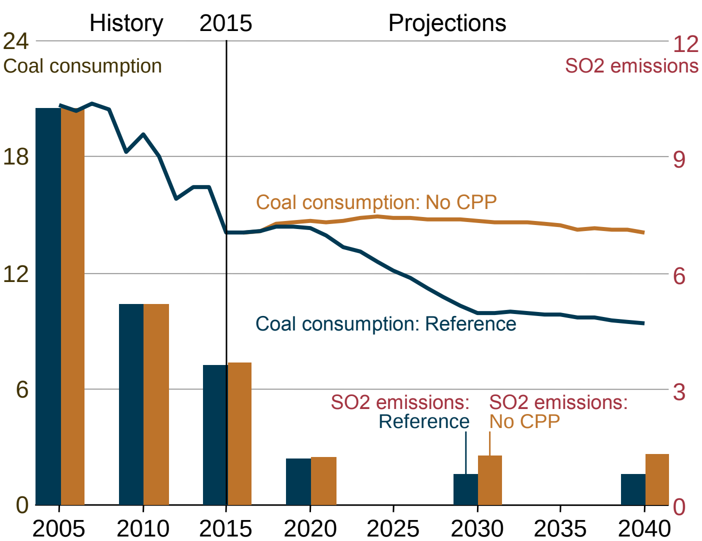
Factors that influence technology choices for new generating capacity are difficult to compare. Different technologies can have vastly different costs (capital, fuel, maintenance, financing), utilization rates, fuel resources, and value to the grid. The levelized cost of electricity (LCOE) is often used to compare costs among technologies with similar operating characteristics; the levelized avoided cost of electricity (LACE) is used to compare value across technologies with different duty cycles (Figure MT-39). LCOE—which represents the costs of building and operating a plant per kilowatthour of output over an assumed financial life and activity level (e.g., baseload, peaking, seasonal)—can vary significantly across regions and over time. Because solar photovoltaic (PV) and wind generation have no fuel costs and relatively small variable operation and maintenance costs, their LCOE is determined mostly by capital and financing costs. LACE, which represents the per-kilowatthour value of generation to the electric grid, reflects the cost of the electricity displaced by the new technology. A technology is generally considered economically competitive when its LACE exceeds its LCOE.

Emissions from electricity generation

In comparisons of two new plants using different technologies, LCOE may not account for differences in the grid services each is providing. For example, nuclear plants and natural gas combined-cycle plants both provide baseload services to the grid and thus have similar LACE values, even if their LCOE values differ. By 2040, the LACE range for most technologies is expected to shift upward, indicating the increasing value of new generation to the grid as demand for new sources grows. Wind plants have increased generation during the night (when the demand for and value of electricity typically are low) and thus provide a limited contribution to system reliability reserves. Solar PV plants produce most of their energy during the middle of the day, when higher demand increases the value of electricity. Consequently, in 2040, the upper bound of LACE for solar PV generation, at 55.7–80.3 dollars/megawatthour (MWh), is higher than the upper bound of LACE for wind (50.6–65.3 dollars/MWh). In 2022, the lower bound of LCOE without tax credits for solar PV generation (not shown) is generally much higher than the lower bound for generation with tax credits, although available tax credits close the gap in some regions. In 2040, the LCOE and LACE ranges for solar PV are overlapping, even without the 10% investment tax credit that, under current law, would be available for solar PV in 2040.

With Clean Power Plan, power plant coal use and sulfur dioxide emissions decline in the Reference case

Figure MT-40. Coal consumption (quadrillion Btu) and sulfur dioxide emissions (million short tons) in the Reference and No CPP cases, 2005–40



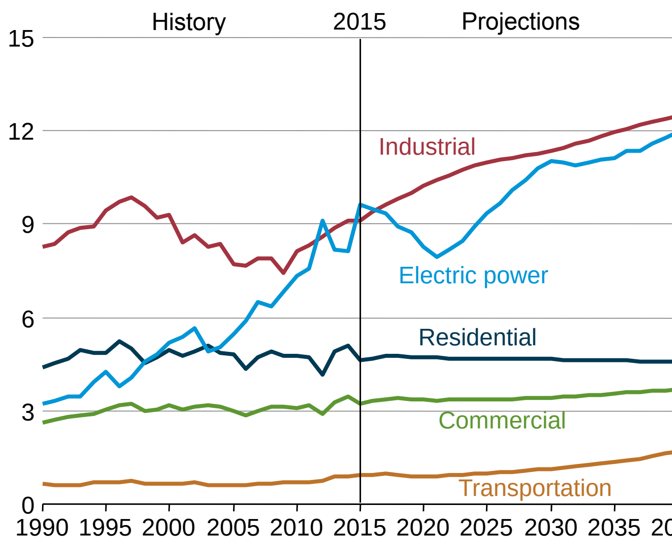
Sulfur dioxide (SO2) emissions from electricity generation have declined with reduced coal use. In 2016, SO2 emissions are expected to fall by nearly two-thirds from 2015 levels with the lapse of extended deadlines for compliance with the Mercury and Air Toxics Standards (MATS) for almost all generating units in April 2016. The MATS rule requires that any coal-fired power plant in operation after the deadline must be retrofitted to control mercury and acid gases with either dry sorbent injection or flue-gas desulfurization (scrubbing) equipment, which also removes 70%–90% of SO2 emissions. Although the Cross-State Air Pollution Rule (CSAPR) is still in effect and covers SO2 emissions from these units, the more stringent reduction requirements under MATS render CSAPR irrelevant.

For some generators, the prospect of meeting MATS compliance requirements is uneconomical, based on cost recovery with likely lower operating rates for retrofitted coal units in a market driven by lower natural gas prices. Even in the No CPP case, a cumulative total of 40 gigawatts (GW) of coal-fired capacity is retired by 2016 and 57 GW by 2020. Utility sector coal use increases slightly from 2016–20 with increased utilization, but SO2 emissions are largely unchanged as a result of high levels of SO2 removal with newly installed retrofits and remain at about the same level through 2040.

In the AEO2016 Reference case, which includes the requirement for power plants in each state to lower CO2 emissions beginning in 2022, retirements continue to a cumulative total of 92 GW in 2030 and to nearly 100 GW in 2040. As a result, utility coal consumption in the Reference Case falls by approximately 35%, from 14.3 quadrillion Btu in 2020 to 9.4 quadrillion Btu in 2040 (Figure MT-40). SO2 emissions also fall by about one-third, from 1.2 million tons in 2020 to 0.8 million tons in 2040.

Electric power sector accounts for 35% of U.S. natural gas consumption in 2040

Figure MT-41. Natural gas consumption by sector in the Reference case, 1990–2040 (trillion cubic feet)



Total U.S. natural gas consumption grows from 27.5 trillion cubic feet (Tcf) in 2015 to 34.4 Tcf in 2040 in the AEO2016 Reference case (Figure MT-41). Consumption of natural gas for electric power generation increases by 2.4 Tcf, accounting for 34% of the total increase. Natural gas consumption was at a record high in 2015, which resulted primarily from low natural gas prices and the retirement of coal-fired capacity. In the Reference case, natural gas use for electricity generation declines from 2015–21 as a result of rising natural gas prices and increasing use of renewable fuels. With implementation of the Clean Power Plan starting in 2022, as well as the reduction or phasing out of some renewable tax credits, and relatively low natural gas prices, natural gas use for electric power generation grows by an average of approximately 4%/year from 2021–30 and continues to increase at a more modest pace of just under 1%/year from 2031–40.

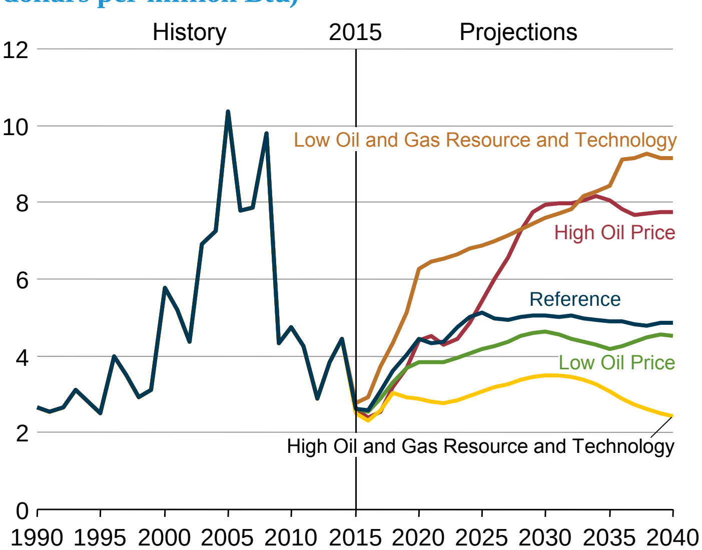
Natural gas consumption in the industrial sector, which includes the use of natural gas for lease and plant fuel and liquefaction of natural gas for export, increases by 3.4 Tcf from 2015–40, an average increase of 1.3%/year. Energy-intensive industries and those that use natural gas as a feedstock, such as bulk chemicals, benefit from relatively low natural gas prices throughout the projection. Increasing use of lease and plant fuel, which is correlated with natural gas production, and fuel used for the production of liquefied natural gas for export also contribute to the growth of natural gas consumption in the industrial sector.

Natural gas use in vehicles currently accounts for only a small portion of U.S. total natural gas use, but it grows rapidly from 64 billion cubic feet (Bcf) in 2015 to 658 Bcf in 2040. Heavy-duty vehicles and freight rail account for 33% of the natural gas used in the transportation sector in 2040 in the Reference case, and pipeline compressor stations account for most of the remainder.

In the residential sector, natural gas use for space heating declines, partially as a result of improvements in energy efficiency and population shifts to warmer regions. In the commercial sector, where growth in commercial floor space more than offsets improvements in energy efficiency, natural gas use rises gradually over the projection period.

Natural gas prices depend on oil prices, technology improvement, and resource recovery rates

Figure MT-42. Annual average Henry Hub natural gas spot market prices in five cases, 1990–2040 (2015 dollars per million Btu)



Across the AEO2016 cases, the average annual Henry Hub spot price for natural gas in 2040 (Figure MT-42) ranges from $2.40–$9.20/million British thermal units (Btu). In the Reference case, average annual U.S. natural gas prices at the Henry Hub remain at about $5.00/million Btu in 2015 dollars through 2040. Crude oil prices affect natural gas prices through changes in consumption and exports, although changes on the supply side, such as increased production of associated-dissolved gas, balance out those factors.

In the High Oil Price case, U.S. exports of liquefied natural gas (LNG) begin to exceed the Reference case total in 2024, and in 2030 they total 8.5 Tcf, or 3.3 Tcf more than in the Reference case. In response, the Henry Hub spot price begins to rise above Reference case levels in 2025, from more than $5.40/million Btu in 2025 to about $7.90/million Btu in 2030. The higher prices are sustained by increased consumption in the transportation sector, where a high price differential between oil and natural gas favors the use of natural gas over diesel. Natural gas use for gas-to-liquids production also increases over the projection period.

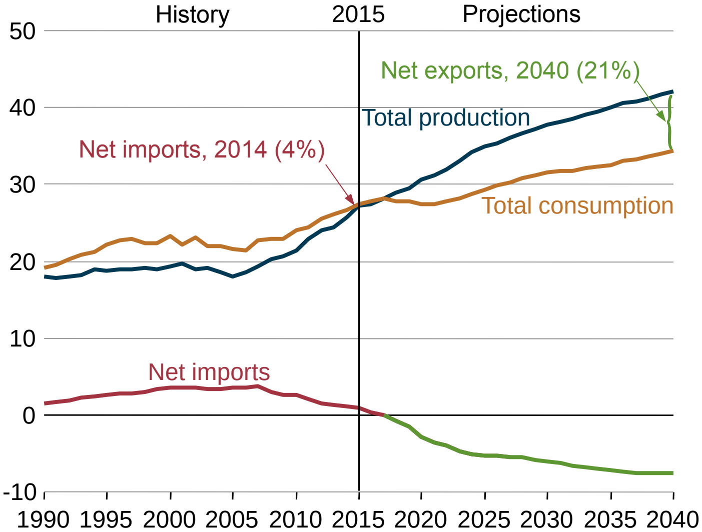
In the Low Oil Price case, the Henry Hub spot price averages about $0.50/million Btu lower than in the Reference case throughout the projection. Because of the relatively small price differential between crude oil and natural gas in the Low Oil Price case, U.S. exports of LNG from 2025–40 are about 50% lower in the Low Oil Price case than in the Reference case, and natural gas consumption is lower in both the industrial and transportation sectors.

Natural gas prices are affected by rates of resource recovery from oil and natural gas wells and by technology improvements, which affect total natural gas production and the associated costs. In the High Oil and Gas Resource and Technology case, with higher initial estimated ultimate recovery per well and more rapid technology improvements, total dry natural gas production in 2040 is 32% higher than in the Reference case. In the Low Oil and Gas Resource and Technology case, with slower rates of resource recovery and technology improvement, total dry natural gas production in 2040 is 37% less than in the Reference case. As a result, U.S. natural gas prices are lowest in the High Oil and Gas Resource and Technology case, ranging from about $2.45 to $3.50/million Btu over the projection period, and highest in the Low Oil and Gas Resource and Technology case, where prices rise quickly to more than $6.25/million Btu in 2020 and to just under $9.20/million Btu in 2040.

Natural gas supply

Ample natural gas supply is adequate to meet growth in both export and domestic markets

Figure MT-43. Natural gas production, consumption, and net imports and exports in the Reference case, 1990–2040 (trillion cubic feet)

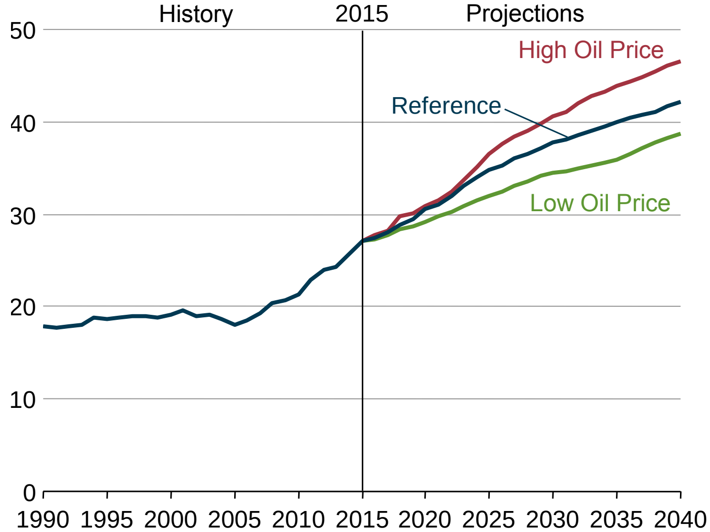


In the Reference case, U.S. natural gas production is sufficient to meet increases in demand for both domestic consumption and net exports through 2040, and Henry Hub spot prices remain relatively low (Figure MT-43). The United States transitions from being a net importer of 1.0 trillion cubic feet (Tcf) of natural gas in 2015, or 3% of U.S. total natural gas supply, to a net exporter in 2018. In 2040, net U.S. exports of natural gas total 7.5 Tcf, or 18% of dry natural gas production. Almost 50% (3.6 Tcf) of the growth in net exports occurs by 2021, as liquefied natural gas (LNG). Most of the LNG export capacity is already under construction. After 2021, U.S. net exports grow at a more moderate average rate of 4%/year.

Total U.S. natural gas consumption grows by 0.9%/year from 2015–40. After falling from 2017–21 as consumption in the electric power sector drops by 1.4 Tcf, total natural gas consumption rises steadily to 34.4 Tcf in 2040. Natural gas production increases in the reference case by an average of 1.8%/year, from 27.2 Tcf in 2015 to 42.1 Tcf in 2040. Technology improvements in the development of shale gas resources continue, which results in higher rates of recovery at lower costs. Production growth holds down natural gas prices, stimulating demand for U.S. natural gas in the United States (particularly in the electric power sector) and in overseas markets. Most U.S. natural gas exports to overseas markets are delivered as LNG. Through 2020, Mexico is also a rapidly growing market for U.S. natural gas. Canada continues to be a modest net exporter to the United States throughout the projection.

U.S. natural gas production, use, and exports are affected by oil prices

Figure MT-44. Natural gas production in three cases, 1990–2040 (trillion cubic feet)



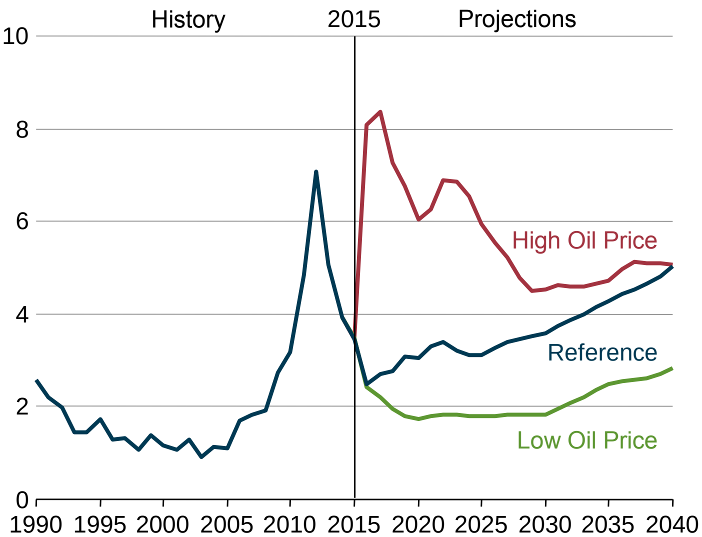
Crude oil prices affect U.S. natural gas production primarily through changes in natural gas consumption and exports. In 2040, total natural gas production varies by 7.8 trillion cubic feet (Tcf) across the oil price cases (Figure MT-44), liquefied natural gas (LNG) exports vary by 6.3 Tcf (plus 0.6 Tcf used for liquefaction), and natural gas use in the transportation sector varies by 1.4 Tcf.

In the High Oil Price case, the difference between the crude oil price and the natural gas price in 2022 is about $25/million British thermal unit (Btu), compared with $10/million Btu in the Reference case. The larger difference in the High Oil Price case creates more incentive for direct use of natural gas in transportation, and for conversion to LNG for export, than in the Reference case. The opposite occurs in the Low Oil Price case: the difference between the crude oil price and the natural gas price in 2033 is about $5/million Btu, and the smaller price difference results in virtually no incentive for additional natural gas consumption in the transportation sector or for more LNG exports.

Natural gas production levels are similar in the Reference and High Oil Price cases from 2015–23. In both cases, most LNG exports come from liquefaction plants currently under construction. Outside the United States—particularly in Australia—significant liquefaction capacity is coming online or is under construction. The near-term increase in LNG supply is expected to weaken the relationship between international oil and natural gas prices. As world demand for LNG grows, the economics of LNG exports from the United States are expected to improve in the Reference case. That transition is projected to occur more quickly in the High Oil Price case. In the Low Oil Price case, continued low oil prices act to hold down international natural gas prices, limiting U.S. LNG export capacity to the total under construction before 2035 and also limiting the utilization of existing capacity.

In all the AEO2016 cases, oil prices are higher than natural gas prices through 2040

Figure MT-45. Ratio of crude oil prices to U.S. natural gas prices on an energy-equivalent basis in three cases, 1990–2040



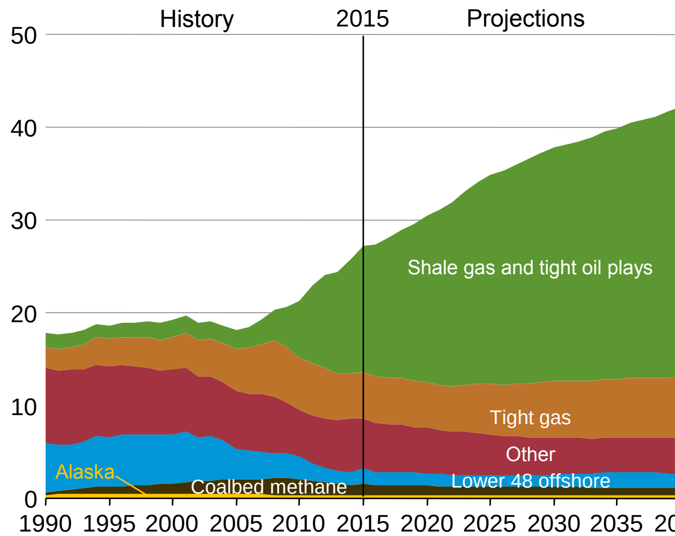
The oil-to-gas price ratio, on an energy-equivalent basis, is used as an indicator of the extent to which oil competes with natural gas in most applications. From 1990–2005, the downward trend in the oil-to-gas price ratio reflected declining crude oil prices and a gradual rise in natural gas prices. Natural gas use for electric power generation nearly doubled over that period. With stagnant domestic natural gas production, all incremental natural gas supply to the U.S. market came from imports. From 1995–2005, real prices for natural gas at the Henry Hub quadrupled.

After 2008, changes in the U.S. natural gas market resulted in a rapid and long-lasting decoupling of domestic crude oil prices from natural gas prices. As oil prices fell from their 2008 highs, natural gas prices declined even faster. When crude oil prices began to rise again, natural gas prices continued to decline, averaging about $2.85/million British thermal units (Btu) in 2012 compared with average crude oil prices at $20.10/million Btu. At that point, the oil-to-gas price ratio was 7.1 (Figure MT-45).

In the AEO2016 Reference case, the prices of liquid fuels continue to exceed natural gas prices from 2015–40. The disparity between Brent crude oil prices and Henry Hub natural gas prices on an energy-equivalent basis leads to a gradual increase in the oil-to-gas price ratio, from 3.5 in 2015 to 5.0 in 2040. In the High Oil Price case, the oil-to-gas price ratio grows to 8.3 in 2017 before declining gradually to 5.1 in 2040, as high oil prices spur U.S. crude oil development, which increases associated natural gas production and depresses natural gas prices in the short to medium term. Crude oil prices do not rebound in the Low Oil Price case but instead increase at a rate close to the inflation rate.

Natural gas production from shale gas and tight oil plays leads growth in U.S. natural gas supply

Figure MT-46. U.S. dry natural gas production by source in the Reference case, 1990–2040 (trillion cubic feet)



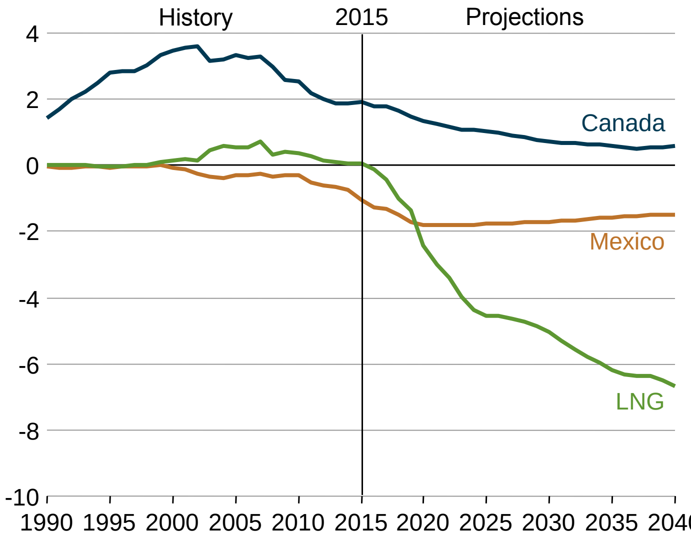
The 55% increase in dry natural gas production from 2015–40 in the AEO2016 Reference case results from increased development of shale gas and tight oil plays, tight gas, and offshore natural gas resources (Figure MT-46). Production from shale gas and tight oil plays is the largest contributor, growing by more than 15 trillion cubic feet (Tcf), from 13.6 Tcf in 2015 to 29.0 Tcf in 2040. The shale gas and tight oil play share of total U.S. dry natural gas production increases from 50% in 2015 to 69% in 2040. Although tight gas production increases by 31% from 2015 to 2040, its share of total production remains nearly constant.

Tight gas production is the second-largest source of domestic natural gas supply in the Reference case, providing 18% of total supply in 2015 and 16% of total supply in 2040. Lower 48 onshore production from all sources other than tight and shale gas formations declines from 6.6 Tcf in 2015 to 4.6 Tcf in 2040, when it accounts for about 11% of total domestic production, down from 24% in 2015.

Offshore natural gas production in the United States averages about 1.4 Tcf/year from 2015–20 before declining to 1.2 Tcf in 2027, reflecting declines in production from legacy offshore fields. Production of coalbed methane also declines. Offshore natural gas production increases to 1.7 Tcf in 2040 as new discoveries offset declines in legacy fields. Alaska's natural gas production remains relatively constant throughout the projection period, averaging 0.3 Tcf/year.

U.S. exports of liquefied natural gas increase to 4.6 trillion cubic feet in 2025 and to 6.7 trillion cubic feet in 2040

Figure MT-47. U.S. net imports of natural gas by source in the Reference case, 1990–2040 (trillion cubic feet)



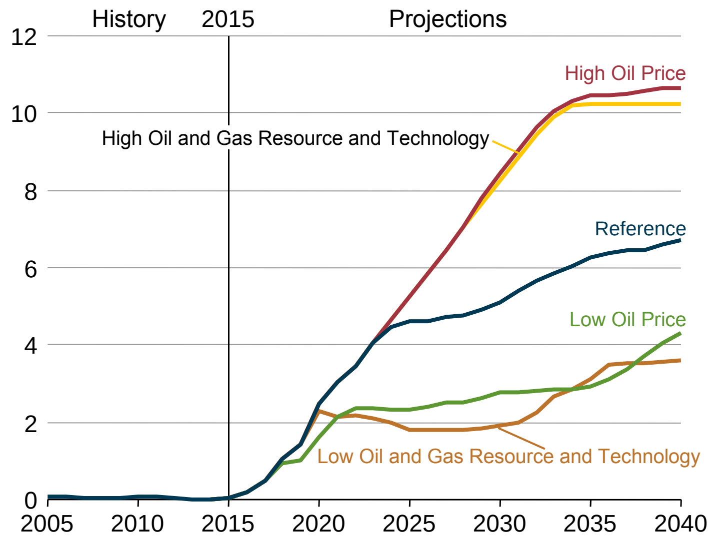
In the AEO2016 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports of 5.3 trillion cubic feet (Tcf) in 2025 and 7.5 Tcf in 2040. Liquefied natural gas (LNG) exports from the United States account for most of the growth (Figure MT-47). With the first LNG export terminal in the United States opening in 2016, LNG exports grow to 2.5 Tcf in 2020, 4.6 Tcf in 2025, and 6.7 Tcf in 2040. Although the five LNG export projects currently under construction in the Mid-Atlantic and Gulf Coast regions will provide total export capacity of 2.9 Tcf/year, additional capacity will be needed to meet the Reference case projection. U.S. natural gas is competitive in international markets, because Henry Hub spot natural gas prices are relatively low in comparison to international prices. However, the U.S. competitive advantage will also depend on world oil prices, growth of global LNG supply, international natural gas production, and international demand for natural gas, particularly in China and other key markets.

Natural gas pipeline exports from the United States to Mexico continue to increase in the near term in the Reference case, from 1.0 Tcf in 2015 to 1.8 Tcf in 2020. Although Mexico's domestic natural gas production is declining, its consumption is increasing, particularly in the electric power sector. Several pipeline projects currently under construction in Mexico are expected to come online between 2016 and 2018, opening new regional markets for natural gas use. After 2020, U.S. natural gas pipeline exports to Mexico decrease gradually to 1.5 Tcf in 2040, reflecting new oil and natural gas production projects and increases in the use of renewable energy for electric power generation in Mexico.

Net imports from Canada to the United States continue to decline in the Reference case, from 1.9 Tcf in 2015 to 0.6 Tcf in 2040. The United States maintains its current export volume of 0.7 Tcf, largely into eastern Canada, through 2040. Natural gas imports from western Canada to the United States decline in the Reference case as relatively low U.S. natural gas prices and Canada's proximity to major U.S. markets make natural gas produced in the United States more competitive.

Liquefied natural gas export growth depends on oil price and productivity assumptions

Figure MT-48. U.S. exports of liquefied natural gas in five cases, 2005–40 (trillion cubic feet)



In the AEO2016 Reference case, growing natural gas production from shale gas and tight oil formations at relatively low prices supports an increase in U.S. liquefied natural gas (LNG) exports of 6.7 trillion cubic feet (Tcf) from 2015–40, representing 93% of the total increase in U.S. natural gas exports over the period. In the United States, LNG exports surpass LNG imports beginning in 2016 and continue to increase through 2040. Prices increase rapidly until 2020 as the liquefaction facilities currently under construction begin operation, allowing rapid growth in natural gas exports, but the rate of increase slows somewhat from 2021–26 and more rapidly thereafter as growing LNG exports from the United States cause natural gas prices to decrease in the rest of the world.

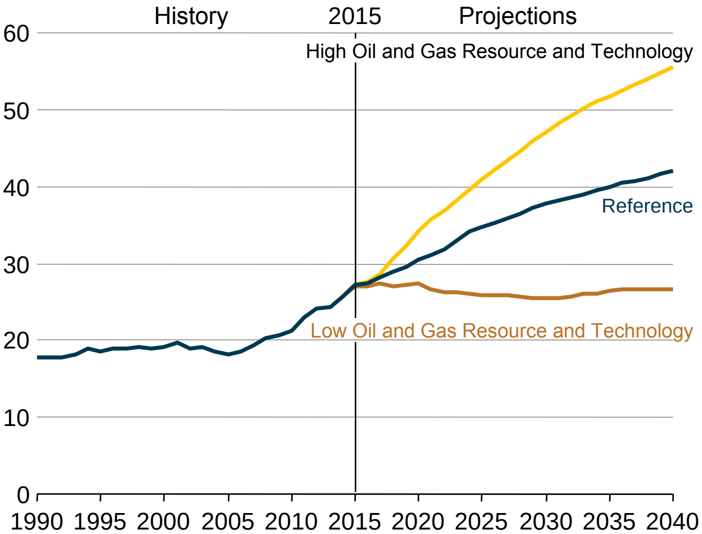
Exports of LNG from the United States vary significantly among the AEO2016 cases. In the High Oil Price case, both global LNG demand and LNG prices are higher than in the Reference case, and LNG exports from the United States increase to 10.5 Tcf in 2035 and remain near that level through 2040 (Figure MT-48). In the Low Oil Price case, gross LNG exports from the United States increase to 2.2 Tcf in 2021, remain above the export levels in the Low Oil and Gas Resource and Technology case through 2034, and then increase to 4.3 Tcf in 2040. In general, low oil prices reduce the incentive for expanding natural gas markets and result in decreasing global LNG prices; however, rising oil prices in the Low Oil Price case contribute to an eventual increase in LNG exports.

In the High Oil and Gas Resource and Technology case, large production increases at low costs result in decreasing U.S. natural gas prices, and LNG exports grow to 10.3 Tcf in 2035.

In the Low Oil and Gas Resource and Technology case, limited technology improvement results in lower natural gas production and higher domestic natural gas prices. Gross LNG exports increase to 2.3 Tcf in 2020 in the Low Oil and Gas Resource and Technology case but remain below export levels in the Low Oil Price case until 2035.

Natural gas production rates depend on resource availability and production costs

Figure MT-49. U.S. dry natural gas production in three cases, 1990–2040 (trillion cubic feet per year)

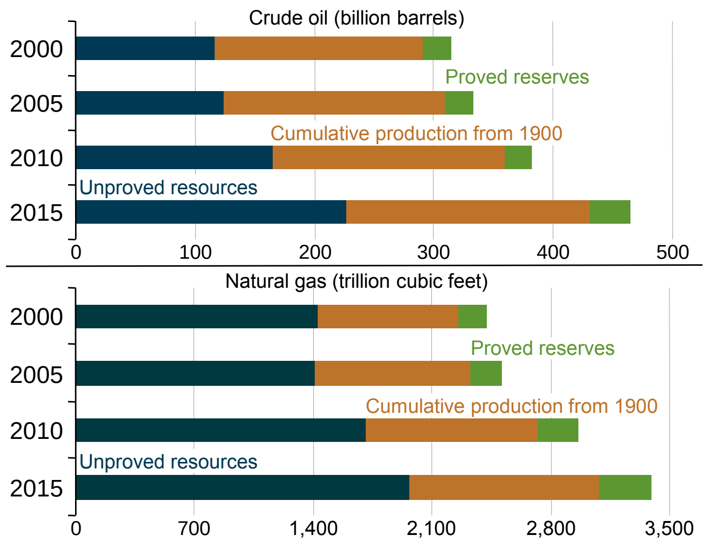


Prospects for natural gas production from tight oil and shale gas resources are uncertain because large portions of the formations have little or no production history and because future technology could increase well productivity while reducing costs. The High and Low Oil and Gas Resource and Technology cases illustrate potential impacts of changes in Reference case assumptions about technology advances and resource size and quality on natural gas demand, imports, and prices. These cases do not represent lower or upper bounds for production and do not have associated probabilities of occurrence.

The High Oil and Gas Resource and Technology case assumes higher estimates of unproved Alaska resources, offshore lower 48 resources, and onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case. These assumptions are based on higher initial estimated ultimate recovery per well, larger volumes of onshore lower 48 tight oil and shale gas resources, and higher rates of long-term technology improvement that lead to reductions in drilling and operating costs and higher production levels. Higher well productivity reduces development and production costs per unit, resulting in more resource development than in the Reference case. With more abundant shale gas resources at lower costs, cumulative dry gas production is 1,115 trillion cubic feet (Tcf) from 2015–40, compared with 920 Tcf in the Reference case. In the High Oil and Gas Resource and Technology case, dry natural gas production is nearly 56 Tcf in 2040, compared with 42 Tcf in the Reference case (Figure MT-49). In the Low Oil and Gas Resource and Technology case, which assumes lower tight oil, tight gas, and shale gas estimated ultimate recoveries (EURs) per well and lower rates of technology improvement than in the Reference case, total production of dry natural gas remains between 25 and 27 Tcf per year through 2040, while shale gas production increases to 15 Tcf in 2040 from 13.3 Tcf in 2015, and cumulative shale gas production is 383 Tcf over the 2015–40 period.

Crude oil and natural gas supply reflects new representation of technology advancement

Figure MT-50. Crude oil and natural gas resources and cumulative production by *Annual Energy Outlook* year (trillion cubic feet of natural gas, billion barrels of crude oil)



Note: U.S. technically recoverable resources and cumulative production are, as of January 1, two years before the "edition year" of the AEO (e.g., AEO2015 is as of 1/1/2013).

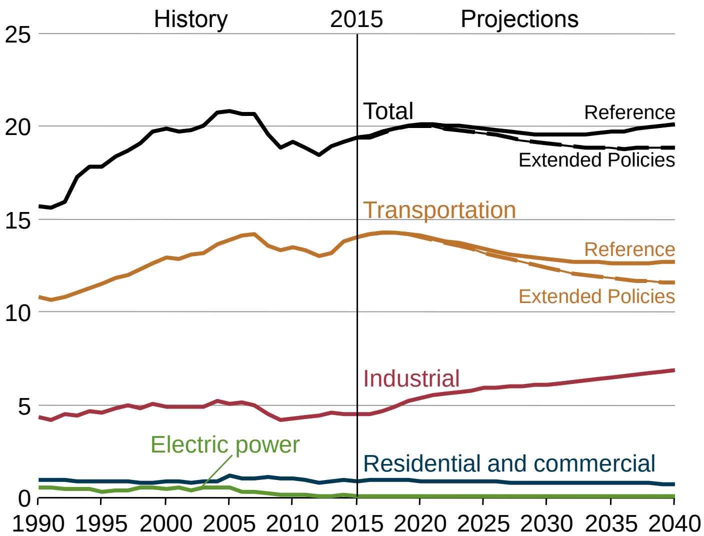
The AEO2016 Reference case uses a simplified approach to model the impacts of technology advances on U.S. oil and natural gas production. The Reference case includes assumptions about ongoing innovation in upstream technologies and reflects the average annual growth rate between AEO2000 and AEO2015 in natural gas and oil resources and the cumulative production from 1900 (Figure MT-50). The new representation of technology advances divides areas in tight oil, tight gas, and shale gas plays into two tiers with different technology change rate assumptions. Tier 1 encompasses areas within these plays that are under active development. The EUR per well for Tier 1 areas have a 1% annual growth rate. Tier 2 encompasses areas not yet developed and includes, for example, large areas of the Utica Shale in the Northeast. The EUR per well in Tier 2 areas has a 3% annual growth rate until development begins. Once development begins, the Tier 2 areas revert to a 1% annual EUR growth rate. These assumptions reflect the combined effects of diminishing returns per well from decreasing well spacing as development progresses, market penetration of technologies, and application of industry practices and technologies at the time of development.

Liquid fuels consumption

Annual EUR growth rates for conventional, enhanced oil recovery, and coalbed methane sources are 0.25%. Technology improvements also affect drilling and operating costs. Both Tier 1 and Tier 2 areas are assumed to have 1% annual declines in drilling costs and 0.5% annual declines in operating costs as a result of advances in technology and industry practices. Conventional oil recovery, enhanced oil recovery, and coalbed methane sources are assumed to have 0.25% annual declines in drilling costs and operating costs.

Petroleum and other liquids consumption is relatively level through 2040

Figure MT-51. U.S. consumption of petroleum and other liquids by sector in two cases, 1990–2040 (million barrels per day)

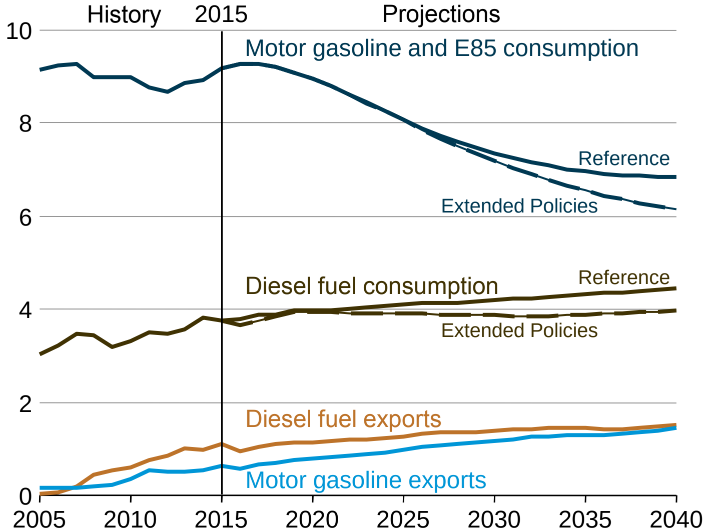


Total consumption of petroleum and other liquids in the AEO2016 Reference case remains relatively level through 2040, with decreases in transportation consumption offsetting increases in industrial consumption. The transportation sector continues to account for the largest share of total liquids consumption (Figure MT-51). However, with improvements in vehicle efficiency following incorporation of corporate average fuel economy standards for both light-duty vehicles and heavy-duty vehicles, the transportation share declines from 72% in 2015 to 63% in 2040. In the industrial sector, consumption of light chemical feedstocks—natural gas liquids and refinery olefins—increases by 1.5 million barrels/day (b/d) from 2015–40, largely as a result of increased supplies of hydrocarbon gas liquids from natural gas and crude oil production [*14*]. Transportation fuels—primarily motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel—can also include biofuels in their compositions.

Total motor gasoline consumption decreases by approximately 2.3 million b/d from 2015–40 in the Reference case, while total diesel fuel consumption grows by 0.7 million b/d from 2015–40. Ethanol consumption in both low-blend and high-blend gasoline is essentially flat throughout the projection, as gasoline consumption declines and the penetration of flex-fuel vehicles is limited.

Fuel consumption shares shift from motor gasoline toward diesel fuel in the Reference case

Figure MT-52. Consumption and gross exports of motor gasoline and diesel fuel in the Reference and Extended Policies cases, 2005–40 (million barrels per day)

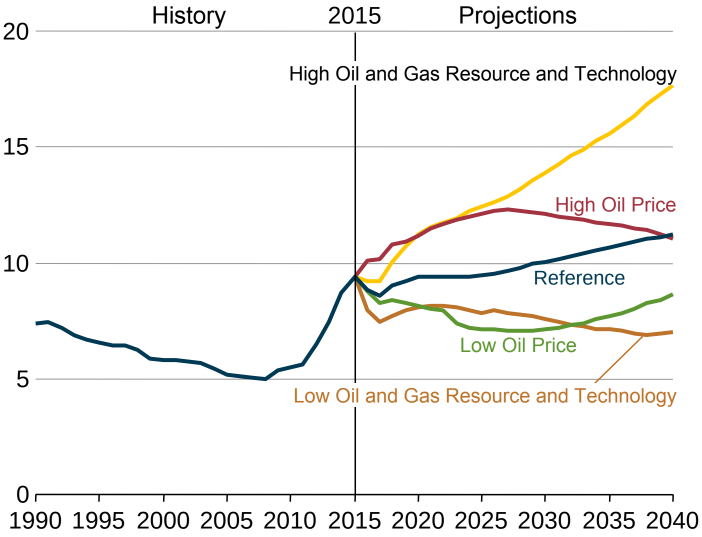


With corporate average fuel economy (CAFE) and greenhouse gas (GHG) emissions standards included in the Reference case, new light-duty vehicles (LDV) average 47 miles per gallon in 2025. The improvement in vehicle efficiency more than offsets an increase in total LDV vehicle miles traveled (VMT), which leads to a decline in motor gasoline consumption. In contrast, diesel fuel consumption continues to grow as VMT increases because of a smaller fuel efficiency improvement in freight trucks than in LDVs. Consumption of diesel fuel grows by about 0.7 million barrels per day (b/d) from 2015–40, while motor gasoline consumption falls by 2.3 million b/d (Figure MT-52). With motor gasoline and diesel fuel consumption trending in opposite directions, new refinery investment projects focus on shifting production from gasoline to distillate fuels. The Extended Policies case, which extends the CAFE and GHG emissions standards through 2040, results in higher average fuel efficiency for new LDVs and freight trucks, lower domestic consumption of motor gasoline and diesel fuel, and higher demand for electric and hybrid vehicles in 2040 compared with the Reference case.

As a result of refinery economics and slower growth in domestic demand, no new U.S. petroleum refinery crude-unit capacity is built in the Reference case, except for plants already under construction in 2015. Refineries continue to export finished products to international markets. Gross exports of total finished petroleum products, excluding hydrocarbon gas liquids, increase from 3.2 million b/d in 2015 to 5.2 million b/d in 2040 in the Reference case. Gasoline and diesel exports constitute about 74% of the increase. The United States became a net exporter of finished petroleum products in 2011 and remains a net exporter through 2040 in the Reference case. In the Extended Policies case, gross exports of total finished petroleum products remain near the same level as in the Reference case. However, in response to reduced domestic consumption of motor gasoline and diesel fuel, U.S. refinery utilization drops to 85% (reflected in a reduction of gross imports of crude oil).

U.S. crude oil production depends on market prices, resource availability, and production costs

Figure MT-53. Total U.S. crude oil production in five cases, 1990–2040 (million barrels per day)



Projections of U.S. tight oil production are uncertain because large portions of the known formations have little or no production history and because technology improvements could increase well productivity while reducing drilling, completion, and production costs. The High and Low Oil and Gas Resource and Technology cases apply different assumptions regarding technology advances, prices, and resource size and quality than used in the Reference case to examine the effects of higher and lower domestic supply on energy demand, imports, and prices.

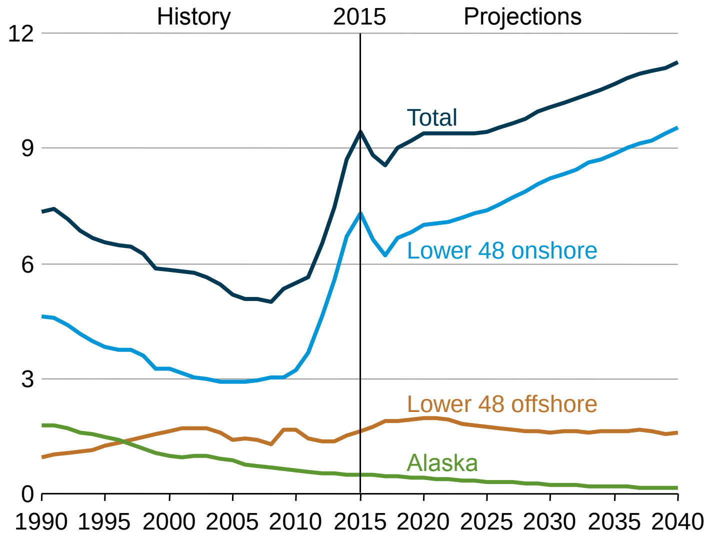
In the High Oil and Gas Resource and Technology case, higher well productivity and rates of technological progress reduce development and production costs per unit. The lower costs result in more and earlier development of oil and natural gas resources than in the Reference case (Figure MT-53), even after considering the effects that additional production would have on world markets for crude oil. U.S. crude oil production in this case increases to 17.7 million barrels per day (b/d) in 2040, compared with 11.3 million b/d in the Reference case, and cumulative production from 2015–40 is 126 billion barrels—about 32 billion barrels more than in the Reference case. In the Low Oil and Gas Resource and Technology case, U.S. crude oil production declines from 9.4 million b/d in 2015 to 7.0 million b/d in 2040, compared with 11.3 million b/d in the Reference case. Cumulative crude oil production from 2015–40 is 73 billion barrels, or about 21 billion barrels less than in the Reference case.

In the High Oil Price case, domestic crude oil production declines from 12.3 million b/d in 2027 to 11.0 million b/d in 2040. Cumulative production from 2015–40 is 109 billion barrels, compared with 94 billion barrels in the Reference case.

In the Low Oil Price case, production falls to 7.0 million b/d in 2028 and then increases to 8.6 million b/d in 2040. Cumulative production from 2015–40 is 74 billion barrels in the Low Oil Price case.

Lower 48 states onshore tight oil development increases U.S. crude oil production

Figure MT-54. Domestic crude oil production by source in the Reference case, 1990–2040 (million barrels per day)



In the Reference case, total U.S. crude oil production declines from 9.4 million barrels per day (b/d) in 2015 to 8.6 million b/d in 2017, then increases steadily to 11.3 million b/d in 2040 (Figure MT-54). With the average wellhead price of oil below $50 per barrel from 2015–17, lower 48 onshore production declines to 6.2 million b/d in 2017. After 2017, as crude oil prices rise, onshore crude oil production in the Lower 48 states increases to about 9.5 million b/d in 2040. The trend in Lower 48 states onshore crude oil production reflects the continued development of tight oil resources in the Bakken, the Western Gulf Basin (including the Eagle Ford play), and the Permian Basin. Tight oil production decreases to 4.2 million b/d in 2017 before increasing to 7.1 million b/d in 2040. The increase is primarily a result of higher oil prices and exploration and development programs that expand operator knowledge about producing reservoirs and lead to the identification of additional tight oil resources and development of new technologies that reduce costs and increase recovery.

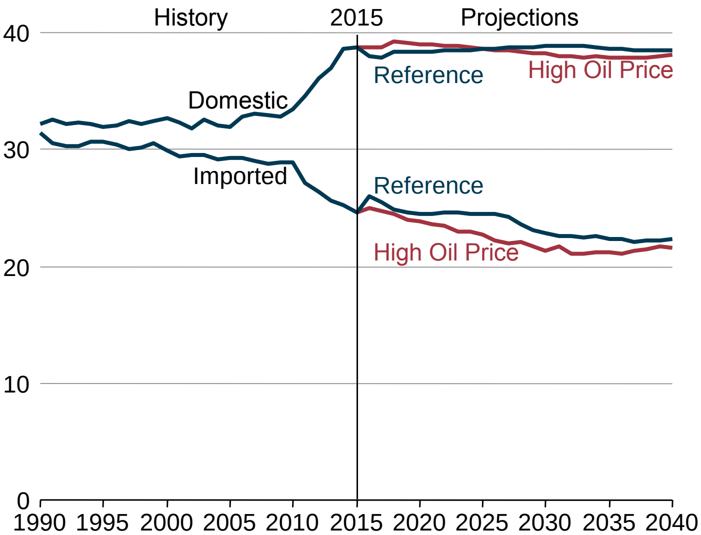
Offshore production in the Lower 48 states is less sensitive than onshore production to short-term price movements. With the startup and development of deepwater projects in the Gulf of Mexico—including the Heidelberg and Appomattox fields starting in 2016 and 2017—lower 48 offshore crude oil production increases to 2.0 million b/d in 2021 in the Reference case, declines to 1.6 million b/d in 2030, and continues at about the 2030 level through 2040, as production from newly developed fields is offset by declines in production from legacy fields.

Crude oil supply

Lower 48 onshore crude oil production that uses carbon dioxide-enhanced oil recovery increases from 0.3 million b/d in 2017 to 0.7 million b/d in 2040, as oil prices rise and affordable anthropogenic sources of carbon dioxide become available. In Alaska, production (both onshore and offshore) declines from nearly 0.5 million b/d in 2015 to less than 0.2 million b/d in 2040.

Domestic production of tight oil reduces imports of light sweet crude oil

Figure MT-55. Average API gravity of U.S. domestic and imported crude oil supplies in two cases, 1990–2040 (degrees API)



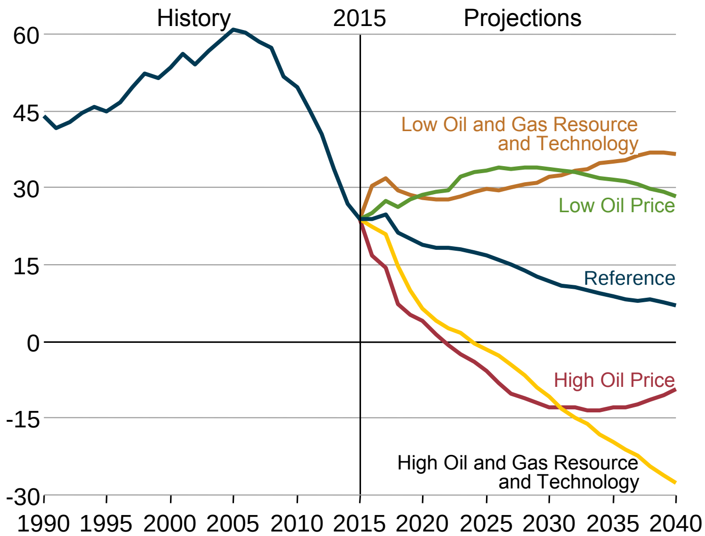
API gravity, as defined by the American Petroleum Institute (API), is a measure of the specific gravity, or relative density, of a liquid, expressed in degrees, with higher numbers indicating lower densities. Refineries generally process a mix of crude oils with a range of API gravities to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 32 degrees. As U.S. refiners run more domestic light crude oil produced from tight formations, they need less imported light crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the AEO2016 Reference case, the average API gravity of crude oil imports declines from 24.6 degrees in 2015 to 22.3 degrees in 2040 (Figure MT-55).

With total crude oil imports declining in the Reference case, imports of light crude oil are reduced further, resulting in a heavier slate of imported crude oil. The share of heavier crude oil imports grows through 2030 before stabilizing. The increase in demand for diesel fuel in the Reference case, from 3.8 million barrels/day (b/d) in 2015 to 4.4 million b/d in 2040, combined with a steady increase in exports of distillate fuel oil, from 1.2 million b/d in 2015 to 1.8 million b/d in 2040, strains the ability of refiners to switch from gasoline to distillate. As a result, distillate prices remain higher than gasoline prices through 2040.

In the High Oil Price case, domestic light crude oil production is higher than in the Reference case. With increased supplies of light crude oil available in domestic markets, light crude oil imports decline, and heavier crude oil imports become a larger share of total crude oil imports. As a result of the greater heavy crude oil share of total imports, the API gravity of crude oil imports is lower in the High Oil Price case than in the Reference case.

Increasing U.S. oil supply reduces net imports of petroleum and other liquid fuels

Figure MT-56. Net import share of U.S. petroleum and other liquid fuels consumption in five cases, 1990–2040 (percent)



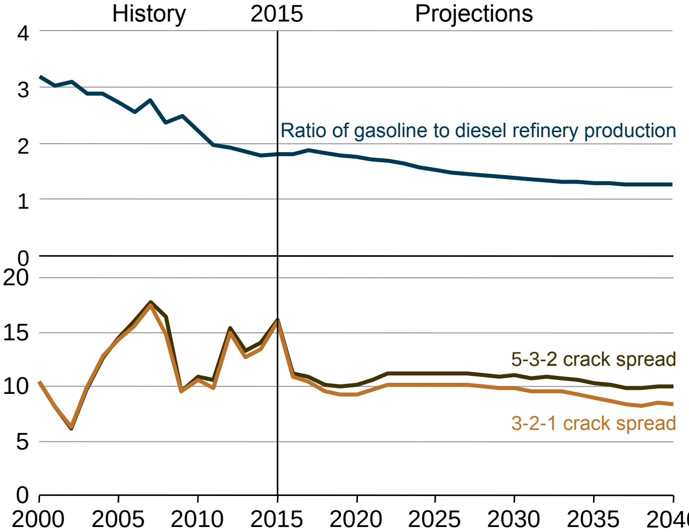
From the mid-1980s to 2005, the net crude oil and product imports share of U.S. petroleum and other liquid fuels consumption grew, and then from 2005–15 it fell steadily (Figure MT-56). In the Reference case, as tight oil production declines from 2015–17, the net import share of U.S. petroleum and other liquids consumption increases before resuming its decline to 7.4% in 2040, when U.S. net imports total 1.4 million barrels per day (b/d).

The outlook for net petroleum and other liquid fuel imports in the High and Low Oil Price and High and Low Oil and Gas Resource and Technology cases depends on U.S. oil production levels. Higher oil prices reduce consumption and encourage development of oil resources. In the High Oil Price case, with domestic liquids production rising and consumption declining, the United States becomes a net exporter of petroleum and other liquids. Total net exports in the High Oil Price case reach 2.4 million b/d in 2033 before declining to 1.7 million b/d in 2040. In the Low Oil Price case, the net import share of domestic consumption rises to 33.8% (6.0 million b/d) in 2028 before declining to 28.3% (6.1 million b/d) in 2040.

In the High Oil and Gas Resource and Technology case, with improvements in oil production technology beyond those in the Reference case and estimated ultimate recovery (EUR) 50% higher than in the Reference case, U.S. crude oil production increases to 17.7 million b/d in 2040. The United States transitions from a net importer of crude oil and petroleum products to a net exporter of 5.6 million b/d in 2040 in the High Oil and Gas Resource and Technology case. In the Low Oil and Gas Resource and Technology case, which assumes slower advances in production technology and a 50% lower EUR than in the Reference case, the net import share of U.S. crude oil and petroleum product consumption falls to 27.6% (5.5 million b/d) in 2022 before beginning a steady increase to 37.3% (7.4 million b/d) in 2040.

Petroleum refinery yields and crack spreads shift with changes in liquid fuels demand

Figure MT-57. U.S. refinery gasoline-to-diesel production ratio and crack spreads (dollars per barrel) in the Reference case, 2000–2040

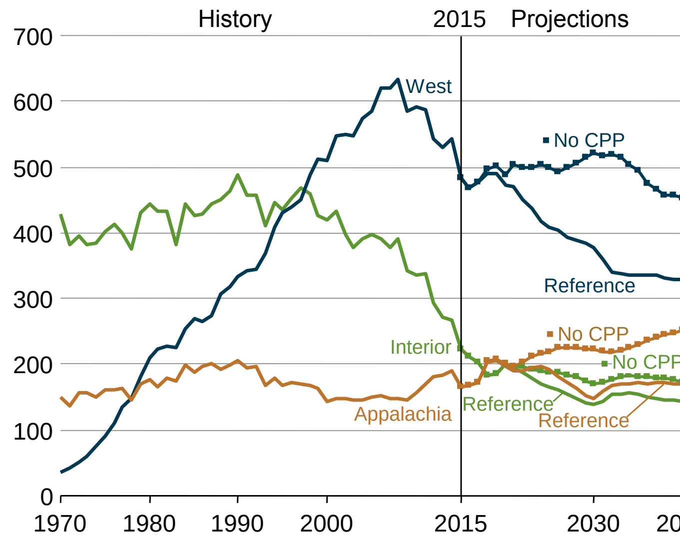


The transition to lower gasoline and higher diesel fuel production has a significant effect on petroleum refinery operations in the AEO2016 Reference case, with the ratio of gasoline to diesel production declining from 1.8 in 2015 to below 1.3 in 2040 (Figure MT-57, top). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units falls. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking calendar day capacity grows from 2.1 million barrels per day (b/d) in 2015 to 2.6 million b/d in 2040, indicating a shift from FCC to hydrocrackers to maximize diesel production.

Refinery profitability is affected by crude oil input costs, processing costs, and market prices for the end products. Profitability often is estimated from the crack spread, which is the difference between the price of crude oil and the price of finished products—typically, gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing three barrels of crude oil to produce two barrels of gasoline and one barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent crude oil prices) declines from $16/barrel in 2015 to $8/barrel in 2040 (2015 dollars) (Figure MT-57, bottom). A 5-3-2 crack spread, which estimates the profitability of processing five barrels of crude oil to produce three barrels of gasoline and two barrels of distillate, is more representative of the trend toward higher distillate production to meet market demands.

Western coal supply shows largest decline among regions with Clean Power Plan in effect

Figure MT-58. Coal production by region in the Reference and No CPP cases, 1970–2040 (million short tons)



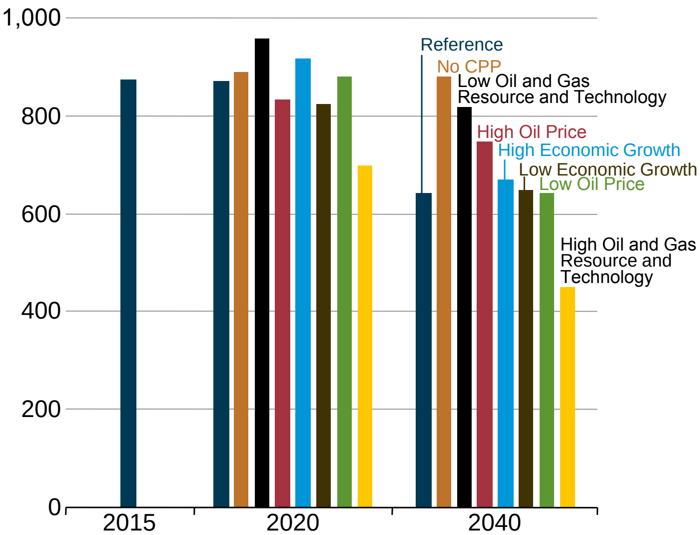
In the AEO2016 Reference case, total coal production decreases from 873 million short tons (MMst) in 2015 to 827 MMst in 2022 when the Clean Power Plan (CPP) takes effect, and to 643 MMst in 2040. The CPP affects coal supply differently in the West, Interior, and Appalachia regions because of differences in coal quality and markets served (Figure MT-58). Compared with the No CPP case, the West region accounts for the largest share of the decline in total coal production in the Reference case because its share of total domestic coal production is larger than in the other regions (about 55% in 2015), and most western coal is consumed in the electric power sector, which is subject to the CPP. The strongest markets for western coal (about 75% from the Wyoming Powder River basin) are in states where it was more economical to switch to low-sulfur western coal than to retrofit power plants to control sulfur emissions. In both the Reference and No CPP cases, competition from natural gas and renewables, coal plant retirements, and equipment retrofits early in the projection reduce consumption of western coal in those states.

Reduced coal demand in the Reference case delays expansion of coal production in the Interior region, with production in the Interior region declining by 0.7%/year from 2015–30. Starting in 2030, coal production in the Interior region grows before flattening out from 2033–40. In the No CPP case, coal production increases throughout the projection period, by 2.0%/year from 2015–30 and 1.2%/year from 2030–40, because power plants that were recently retrofitted with sulfur emission control equipment to comply with the Mercury and Air Toxics Standards (MATS) that took effect in 2015–16 can use higher sulfur Interior coal.

In the Appalachian region, the effects of the CPP in 2040 are less pronounced than in other regions because major cuts in coal production occurred over the past decade, and further cuts are expected to result from MATS and from fuel competition. In addition, exports and domestic metallurgical coal use, which together represented about 34% of Appalachia's coal production in 2015, are not directly affected by the CPP. As U.S. steam coal use declines, Appalachia's coal producers depend increasingly on exports and on domestic demand for metallurgical coal, which together account for 50% of the region's total coal production in 2040 in the Reference case.

Coal production falls in all AEO2016 cases except No CPP

Figure MT-59. U.S. coal production in eight cases, 2015, 2020, and 2040 (million short tons)

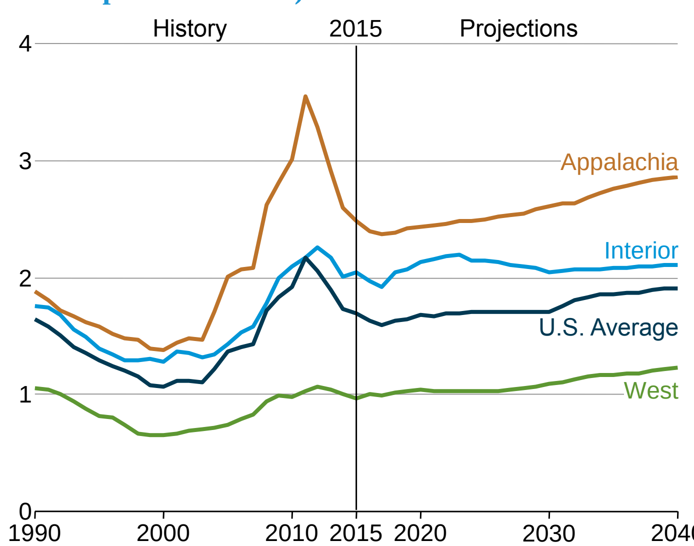


The No CPP case is the only AEO2016 case in which coal production in 2040 is higher than it was in 2015. Competition from natural gas and renewables, compliance with the Mercury Air Toxics Standard [*15*], and declining worldwide demand for coal contribute to lower production. In the No CPP case, as natural gas prices, electricity demand, and global coal demand rise, coal production increases from 873 million short tons (MMst) in 2015 to 890 MMst in 2020. After 2020, coal production stabilizes but declines slightly to 877 MMst in 2040 (compared with 643 MMst in 2040 in the Reference case). Production in the other cases varies between 192 MMst lower and 175 MMst higher in 2040 than in the Reference case. Among the cases shown in Figure MT-59, the Low Oil and Gas Resource and Technology case has the second-highest coal production in 2040 (818 MMst) because of higher natural gas prices. Before the Clean Power Plan (CPP) is implemented in 2022, coal production in the Low Oil and Gas Resource and Technology case is higher than in the No CPP case. After 2022, production declines, but it is still 175 MMst higher in 2040 than in the AEO2016 Reference case. The lowest level of coal production in 2040, at 450 MMst (about 52% of 2015 production), is in the High Oil and Gas Resource and Technology case, which has the lowest natural gas prices.

In the High Oil Price case, coal production in 2040 is 105 MMst higher than in the Reference case. In the High Oil Price case, beginning in 2025, rising demand at coal-to-liquids facilities contributes to higher levels of coal production. In the Low Oil Price case, coal production in 2040 varies little from the Reference case because electric power plants have limited ability to substitute oil for coal in electric power production. In the High and Low Economic Growth cases, coal production in 2020 is higher and lower, respectively, than in the Reference case. However, after implementation of the CPP, coal production in the Low Economic Growth case is nearly the same as in the Reference case because lower electricity sales deter investment in new generating capacity fueled by other energy sources, and existing coal plants in some regions are used to meet relatively low growth in demand for electric power. As a result, coal production in 2040 is slightly higher in both the High and Low Economic Growth cases than in the Reference case.

With declines in mining productivity, average minemouth coal prices increase

Figure MT-60. Average annual minemouth coal prices by region in the Reference case, 1990–2040 (2015 dollars per million Btu)



Average U.S. minemouth coal prices decline in the Reference case from 2015–17 as demand declines and less efficient higher-cost mines are closed. From 2017–30, the average minemouth coal price increases by 0.5%/year, as declines in coal mine productivity, which increase production costs, more than offset declines in coal demand, which reduce prices. Most of the production decline occurs before 2030, with domestic coal demand falling by 1.9%/year from 2015–30, and a smaller 0.7%/year from 2030–40. From 2030–40, the average minemouth coal price rises by 1.1%/year as average mine productivity continues to decline (Figure MT-60).

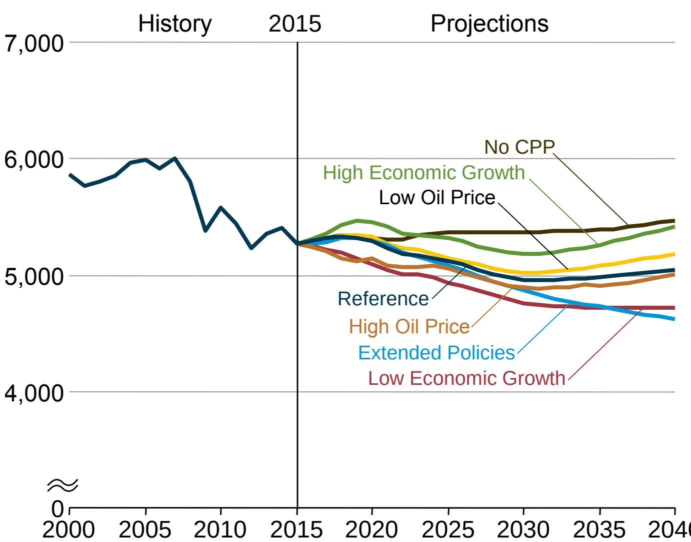
In the Appalachian region, average minemouth coal prices increase by 0.5%/year from 2015–40 as mine productivity declines. Appalachia's high-value coking coal continues to account for most of the coal supplied to U.S. steelmakers and exporters of coking coal. Coking coal is priced significantly higher than steam coal, and the price increases over the projection period. Appalachian coking coal provides 36% of the region's total production volume in 2040, compared with 29% in 2015, which contributes to a higher average coal price for the entire Appalachian region.

In the Interior region, previously unmarketable, but geologically favorable, high-sulfur coal reserves often can be mined with highly productive longwall equipment. While Interior region coal production and prices increase slowly from 2015 to about 2025 in the Reference case, Interior region coal production remains relatively constant over the entire projection period from 2015–40, and prices increase by an average of only 0.2%/year from 2015–40.

The West region has higher productivity improvement and lower mine costs than the other regions, but its productivity declines as Powder River Basin producers move to more westward reserves with thinner seams and thicker overburdens. As a result, the region's average minemouth coal price increases by an average of 1.3%/year from 2030–40 (compared with 0.1%/year from 2015–30). Powder River Basin coal production accounts for about 40% of total U.S. coal production over the 2030–40 period.

Energy-related carbon dioxide emissions projections depend on assumptions about economic growth, energy prices, resource availability, and policies

Figure MT-61. Energy-related carbon dioxide emissions in seven cases, 2000–2040 (million metric tons)



The AEO2016 Reference case assumes that current laws and regulations remain in effect through 2040. However, the status of the Clean Power Plan (CPP), which is on hold pending judicial review, is uncertain. The Reference case assumes implementation of the CPP as scheduled and uses mass-based standards that impose limits on carbon dioxide (CO2) emissions from fossil fuel-fired generators. The No CPP case assumes that no federal carbon reduction program is implemented. The No CPP case represents the upper end of the range of CO2 emissions (5,468 million metric tons) in 2040, but the range of projected energy-related CO2 emissions in 2040 is more than 800 million metric tons across the alternative cases included in AEO2016 (Figure MT-61). Projected emissions vary, depending on assumptions about economic growth, energy prices, and policies. In the High Economic Growth case, emissions in 2040 are close to emissions in the No CPP case—even though the High Economic Growth case includes the CPP—because emissions increase outside the electric power sector in response to higher economic growth.

The Extended Policies case represents the lower end of the emissions range, with CO2 emissions falling to 4,623 million metric tons in 2040, 23% below the 2005 level. The Extended Policies case assumes that existing policies and regulations remain in effect, or are extended beyond sunset dates specified in current regulation, and that existing tax credits that have scheduled reductions and sunset dates remain unchanged through 2040. Efficiency policies, including corporate average fuel economy standards, appliance standards, and building codes, are expanded beyond current provisions, and the CPP regulations that reduce CO2 emissions from electric power generation are tightened after 2030. The result is that, by 2040, energy-related CO2 emissions are 846 million metric tons lower in the Extended Policies case than in the No CPP case.

Variations in natural gas prices have less impact than the CPP requirements on total CO2 emissions. Because the limit that the CPP imposes on CO2 emissions in the electric power sector is met in all cases, differences in energy-related emissions occur only in the end-use sectors. As a result, CO2 emissions in 2040 in the Low Oil Price and High Oil Price cases fall within the range of emissions created by the No CPP and Extended Policies cases.

Endnotes for market trends

Links current as of July 2016

1. Labor productivity is measured as output per hour in private, nonfarm business.
2. As determined by the Business Cycle Dating Committee of the National Bureau of Economic Research, the most recent U.S. business contraction was from December 2007 to June 2009, the previous business expansion was from November 2001 to December 2007, and the current business expansion began in June 2009. See National Bureau of Economic Research, "US Business Cycle Expansions and Contractions," http://www.nber.org/cycles.html.
3. See U.S. Department of Labor, Bureau of Labor Statistics, "Multifactor Productivity Trends News Release" (Washington, DC: June 23, 2015), http://www.bls.gov/news.release/archives/prod3_06232015.htm.
4. Modified for EIA's energy prices and other key assumptions.
5. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
6. Value of shipments includes both final and intermediate products.
7. Drop-in fuels are those renewable fuels which can be blended with petroleum products, such as gasoline, and utilized in the current infrastructure of pumps, pipelines, and other existing equipment.
8. U.S. Senate and House of Representatives, "H.R. 6, Energy Independence and Security Act of 2007" (Washington, DC: January 4, 2007), https://www.gpo.gov/fdsys/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf, p. 86.
9. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Washington, DC: October 23, 2015), https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.
10. The AEO2016 Reference case includes only existing and announced standards and codes.
11. The NEMS Electricity Market Model regions are designed to replicate the power trading patterns in each market (see map in Appendix F).
12. Independent power producers are also known as nongovernment utilities and merchant generators. In 1978, the U.S. Congress passed the U.S. Public Utility Regulatory Policies Act, which established a class of nonutility generators called Qualifying Facilities permitted to produce power for resale.
13. W. Barber, "More nuclear power plant retirements forecast," Electric Light and Power (September 28, 2015), http://www.elp.com/articles/2015/09/more-nuclear-power-plant-retirements-forecast.html.
14. Hydrocarbon gas liquids include liquids produced from natural gas processing plants and fractionators and liquefied gases from crude oil refineries.
15. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)" (Washington, DC: June 8, 2016), https://www.epa.gov/mats.

Figure sources for market trends

Links current as of July 2016

Figure MT-1. Growth of real gross domestic product and hours worked in the Reference case, 1985–2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-2. Average annual growth rates for real gross domestic product and its major components in three cases, 2015–40: History: Bureau of Economic Analysis. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWMACRO.D032516A, and HIGHMACRO.D032516A.

Figure MT-3. Average annual growth rates of shipments from the U.S. industrial sector and its components in three cases, 2015–40: Projections: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWMACRO.D032516A, and HIGHMACRO.D032516A.

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990–2040: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2015 and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-6. World production of nonpetroleum liquids by type in the Reference case, 2015 and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-7. Energy use per capita and per dollar of gross domestic product and carbon dioxide emissions per dollar of gross domestic product in two cases, 1980–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-8. Primary energy consumption by end-use sector in two cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-9. Primary energy use by fuel in two cases, 2015, 2020, 2030, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-10. Residential delivered energy intensity in three cases, 2009–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, and TAXTENDED.D050216A.

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2015–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-12. Residential sector delivered energy consumption by fuel in the Reference case, 2004–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-13. Residential distributed electricity generation in two cases, 2010–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D050216A.

Figure MT-14. Commercial delivered energy intensity in the Reference case, 2005–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2015 and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-16. Efficiency gains for selected commercial equipment in two cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-17. Additions to commercial sector electricity generation capacity in two cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D050216A.

Figure MT-18. Industrial energy consumption by application in the Reference case, 2010–40: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-19. Industrial sector energy consumption by fuel in the Reference case, 2010–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-20. Industrial consumption of petroleum and other energy in three cases, 2015, 2025, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-21. Energy Consumption for pulp and paper production in three cases, 2015, 2025, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWMACRO.D032516A, and HIGHMACRO.D032516A.

Figure MT-22. Delivered energy consumption for transportation by mode in the Reference case, 2015 and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-23. Average fuel economy of new light-duty vehicles in the Reference case, 1980–2040: History: U.S. Department of Transportation, National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC: January 2016), http://www.nhtsa.gov/CAFE_PIC/CAFE_PIC_fleet_LIVE.html. **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-24. Vehicle miles traveled per licensed driver in the Reference case, 1995–2040: History: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2014* (Washington, DC: 2015), http://www.fhwa.dot.gov/policyinformation/statistics/2014/. **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-25. Sales of light-duty vehicles capable of using nongasoline technologies by type in the Reference case, 2015, 2025, and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-26. Transportation sector natural gas consumption by vehicle type in the Reference case, 1995–2040: Projections: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-27. U.S. gross domestic product growth and electricity demand growth rates, 1950–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-28. Net electricity generation by fuel in the Reference case, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-29. Net electricity generation by fuel in the No CPP case, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF_NO_CPP.D032316A.

Figure MT-30. Additions to electricity generation capacity by fuel in the Reference case, 2000–2040: History: Energy Information Administration, Form-860, "Annual Electric Generator Report." **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-31. Cumulative additions to electricity generation capacity by fuel in the No CPP case by period: AEO2016 National Energy Modeling System, run REF_NO_CPP.D032316A.

Figure MT-32. Electricity prices and natural gas prices to electricity generators in four cases, 2015–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWRT.D032516A, and HIGHRT.D032516A.

Figure MT-33. Electricity generation by fuel in three cases, 2015, 2020, 2030 and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, and HIGHRT.D032516A.

Figure MT-34. Natural gas-fired electricity generation in four cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWRT.D032516A, and HIGHRT.D032516A.

Figure MT-35. Cumulative nuclear generation capacity additions and retirements, 2016–20: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-36. Wind and solar electricity generation capacity additions in all sectors by energy source in two cases, 2016–20, 2021–30, and 2031–40: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-37. Renewable electricity generation by fuel type in all sectors in five cases, 2015 and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWRT.D032516A, HIGHRT.D032516A, and LOWPRICE.D041916A.

Figure MT-38. Nonhydropower renewable electricity generation in all sectors in two cases, 2020 and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-39. Levelized electricity costs with tax credits for new power plants in the Reference case, 2022 and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-40. Coal consumption and sulfur dioxide emissions in the Reference and No CPP cases, 2005–40: History: U.S. Environmental Protection Agency, Clean Air Markets Database, http://ampd.epa.gov/ampd/. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A.

Figure MT-41. Natural gas consumption by sector in the Reference case, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-42. Annual average Henry Hub natural gas spot market prices in five cases, 1990–2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC: September 2015). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE. D041916A, and HIGHPRICE.D041916A.

Figure MT-43. Natural gas production, consumption, and net imports and exports in the Reference case, 1990–2040: History, 1990–2014: U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC: September 2015). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-44. U.S. natural gas production in three cases, 1990–2040: History, 1990–2014: U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC: September 2015). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-45. Ratio of crude oil prices to U.S. natural gas prices on an energy-equivalent basis in three cases, 1990–2040: History, 1990–2014: U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC: September 2015). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-46. U.S. dry natural gas production by source in the Reference case, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-47. U.S. net imports of natural gas by source in the Reference case, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-48. U.S. exports of liquefied natural gas in five cases, 2005–40: History: 2005–14, U.S. Energy Information Administration, *Natural Gas Annual 2014,* DOE/EIA-0131(2014) (Washington, DC: September 2015). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-49. U.S. dry natural gas production in three cases, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, and HIGHRT.D032516A.

Figure MT-50. Crude oil and natural gas resources and cumulative production by *Annual Energy Outlook* year: Projections: AEO2000 National Energy Modeling System, run REF2K.D100199A; AEO2005 National Energy Modeling System, run REF2005. D102004A; AEO2010 National Energy Modeling System, run REF2010.D111809A; and AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-51. U.S. consumption of petroleum and other liquids by sector in two cases, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D050216A.

Figure MT-52. Consumption and gross exports of motor gasoline and diesel fuel in the Reference case and Extended Policies cases, 2005–40: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and TAXTENDED.D050216A.

Figure MT-53. Total U.S. crude oil production in five cases, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016. D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-54. Domestic crude oil production by source in the Reference case, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-55. Average API gravity of U.S. domestic and imported crude oil supplies in two cases, 1990–2040: History: U.S. Energy Information Administration, Crude Oil Input Qualities and Company Level Imports Archives, http://www.eia.gov/petroleum/imports/companylevel/archive/. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and HIGHPRICE.D041916A.

Figure MT-56. Net import share of U.S. petroleum and other liquid fuels consumption in five cases, 1990–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, LOWRT.D032516A, HIGHRT.D032516A, LOWPRICE.D041916A, and HIGHPRICE.D041916A.

Figure MT-57. U.S. refinery gasoline-to-diesel production ratio and crack spreads in the Reference case, 2000–2040: History: Crack spread calculated from national average New York Harbor (NYH) RBOB prices and ULSD spot prices (2006–15) and No. 2 heating oil spot prices (2000–05), http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm. Gasoline and diesel refinery production calculated from finished gasoline, motor gasoline blend components (net), and distillate fuel oil (15 ppm and 15–500 ppm), http://www.eia.gov/dnav/pet/pet_pnp_refp2_dc_nus_mbblpd_a.htm and http://www.eia.gov/dnav/pet/pet_pnp_intp2_dc_nus_mbblpd_a.htm. **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A.

Figure MT-58. Coal production by region in the Reference and No CPP cases, 1970–2040: History: 1970–90: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970–1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC: November 2002). **1991–2000:** U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001–14:** U.S. Energy Information Administration, *Annual Coal Report 2014,* DOE/EIA-0584(2014) (Washington, DC: March 2016) and previous issues. **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A and REF_NO_CPP.D032316A. Note: For 1989–2040, coal production includes waste coal.

Figure MT-59. U.S. coal production in eight cases, 2015, 2020, and 2040: AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWRT.D032516A, HIGHPRICE.D041916A, HIGHMACRO.D032516A, LOWMACRO.D032516A, LOWPRICE.D041916A, and HIGHRT.D032516A. **Note:** Coal production includes waste coal.

Figure MT-60. Average annual minemouth coal prices by region in the Reference case, 1990–2040: History (dollars per short ton): 1990–2000: U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001–14:** U.S. Energy Information Administration, *Annual Coal Report 2014,* DOE/EIA-0584(2014) (Washington, DC: March 2016), and previous issues. **History (conversion to dollars per million Btu): 1970–2014:** *Estimation Procedure:* Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Monthly Energy Review*. *Sources:* U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2016 National Energy Modeling System, run REF2016.D032416A. Note: Includes reported prices for both open-market and captive mines.

Figure MT-61. Energy-related carbon dioxide emissions in seven cases, 2000–2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* February 2016, DOE/EIA-0035(2016/02). **Projections:** AEO2016 National Energy Modeling System, runs REF2016.D032416A, REF_NO_CPP.D032316A, LOWPRICE.D041916A, HIGHPRICE.D041916A, LOWMACRO.D032516A, HIGHMACRO.D032516A, and TAXTENDED.D050216A.

Comparison with other projections

Energy Information Administration (EIA) and other contributors have 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. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.

Few organizations produce energy projections with details and time horizons comparable with those in the *Annual Energy Outlook 2016* (AEO2016). Other organizations do, however, address one or more aspects of the U.S. energy market. Projections from other organizations, which tend to focus on selected areas—such as economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal—are compared with the AEO2016 Reference case in the following sections.

CP1. Economic growth

The range of projected economic growth rates in the outlooks included in this comparison tends to be wider over the first 3 years of the projection than over longer periods because the group of variables that influence long-run economic growth—such as population, productivity, and labor force growth—is smaller than the group of variables that affect projections of short-run growth. The 5-year average annual growth rate of real gross domestic product (GDP) from 2015–20 ranges from 2.0% to 3.1% (Table CP1), and the 11-year average annual growth rate from 2015–26 ranges from 1.9% to 2.7%.

From 2015–20, real GDP growth averages 2.6%/year in the AEO2016 Reference case, lower than projected by the Social Security Administration (SSA) in *The 2015 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* and by ExxonMobil, but higher than projected by IHS Global Insight (IHSGI), the Congressional Budget Office (CBO), the Office of Management and Budget (OMB), the Interindustry Forecasting Project at the University of Maryland (INFORUM), Energy Ventures Analysis (EVA), the International Energy Agency (IEA) in its November 2015 *World Energy Outlook* Current Policies Scenario, and the Oxford Economics Group (OEG).

The average annual GDP growth of 2.4% in the AEO2016 Reference case from 2015–26 is identical to the mid-range of the outlooks, with IHSGI and CBO projecting 2.4% average growth; SSA and Exxon Mobil projecting higher average growth (2.7%/year and 2.6%/year, respectively); and OEG, OMB, INFORUM, and EVA projecting lower average growth (2.0%/year, 2.1%/year, 2.2%/year, and 1.9%/year, respectively).

There are few public or private projections of GDP growth for the United States that extend to 2040. The AEO2016 Reference case projects 2.2% average annual GDP growth from 2015–2040, consistent with trends in labor force and productivity growth. OEG, IEA, INFORUM, and EVA project lower GDP growth than in the AEO2016 Reference case, averaging 1.9%/year, 2.1%/year, 2.1%/year, and 2.0%/year, respectively. Exxon Mobil and SSA project higher GDP growth from 2015–40, both averaging 2.4%/year. IHSGI projects the same growth rate, at 2.2%/year, as in the AEO2016 Reference case.

CP2. Oil prices

In the AEO2016 Reference case, crude oil prices are represented by spot prices for North Sea Brent (Brent) crude oil and West Texas Intermediate (WTI) crude oil price, and by the imported U.S. refiner acquisition cost for crude oil (IRAC). The WTI price generally is lower than the North Sea Brent price. The historical record shows substantial variability in crude oil prices, and there is arguably even more uncertainty about prices in the long term. AEO2016 considers three crude oil price cases (Reference, Low Oil Price, and High Oil Price) to allow assessment of alternative views on the future course of crude oil prices (Table CP2).

In AEO2016, the North Sea Brent spot crude oil price is tracked as the main benchmark for world crude oil prices, because it better reflects the marginal price paid by refineries for imported light, sweet crude oil (used to produce petroleum products for

Table CP1. Comparisons of average annual economic growth projections, 2015–40

	Average annual percentage growth			
Projection	2015-20	2015-26	2026-40	2015-40
AEO2015 (Reference case)	2.6	2.5	2.3	2.4
AEO2016 (Reference case)	2.6	2.4	2.1	2.2
IHSGI (February 2016)	2.5	2.4	2.2	2.2
OMB (January 2016)[a]	2.2	2.1	--	--
CBO (January 2016)[a]	2.5	2.4	--	--
INFORUM (Spring 2016)	2.3	2.2	2.1	2.1
Social Security Administration (August 2015)	3.1	2.7	2.1	2.4
IEA (2015)[b]	2.5	--	2.0	2.1
Oxford Economics Group (February 2016)	2.2	2.0	1.9	1.9
ExxonMobil (growth calculated from 2014)[c]	2.7	2.6	2.3	2.4
EVA (growth calculated from 2014)[c]	2.0	1.9	2.0	2.0

-- = not reported or not applicable.
[a]OMB and CBO projections end in 2026, and growth rates cited are for 2015-26. AEO projections end in 2040.
[b]IEA publishes U.S. growth rates for certain intervals: 2013-20 growth is 2.5%, 2020-40 growth is 2.0%, and 2013-40 growth is 2.1%.
[c]ExxonMobil and EVA projections are calculated from 2014-20, 2014-25, 2025-40, and 2014-40.

consumers) than the West Texas Intermediate (WTI) crude oil price does. The WTI price has continued to trade at a discount relative to other world crude oil prices. In 2015, the WTI and North Sea Brent crude oil prices differed by $4 per barrel ($4/b). In the AEO2016 Reference case, the discount grows to $7/ b in 2040.

Spot crude oil prices in the other outlooks used in the comparison are based on either Brent, WTI, or IRAC prices, except for prices from the IEA, which are based on the average of crude oil import prices paid by members of the Organization for Economic Cooperation and Development (OECD) and prices from the Organization of Petroleum Exporting Countries (OPEC), which reflect the average price of a basket of crude oil sold by OPEC member countries.

The range of oil price projections in both the near term and the long term reflects current market conditions, including low prices due to crude oversupply in the near term and different assumptions about the future of the world economy. The wide range of the projections underscores the inherent uncertainty associated with future crude oil prices. With the exception of Strategic Energy & Economic Research (SEER)—which projects Brent prices remaining between $40/b and $45/b (2015 dollars)—the projections show crude oil prices rising over the entire projection period. On the other hand, the spread of the projections (again with the exception of SEER) is encompassed by the AEO2016 Low and High Oil Price cases, ranging from $49/b to $207/b for Brent in 2030 and from $73/b to $230/b in 2040. However, except for IEA (in 2030 and 2040) and IHSGI (in 2025), all the other projections in this comparison show lower crude oil prices than those in the AEO2016 Reference case for every year of the projection.

CP3. Total energy consumption

Three other organizations—ExxonMobil, BP, and IEA—provide projections of energy consumption by sector. IHSGI provides a projection of total primary energy consumption (but not consumption by sector) and projections of electricity sales, petroleum, and natural gas demand by end-use sector. To allow comparisons with the BP and IEA projections, AEO2016 Reference case projections for the residential and commercial sectors have been combined to produce a buildings sector projection (Table CP3). The IEA projections have a base year of 2013. ExxonMobil did not provide data for a base year. The BP projection extends through 2035, with a base year of 2014. The AEO2016 Reference case includes an unspecified sector, which has been combined with transportation for this comparison, in order to make it comparable with other projections.

Both IEA and ExxonMobil account for electricity generation from renewable energy sources at a conversion rate of 3,412 British thermal units (Btu) per kilowatthour (kWh) rather than a heat rate for displaced fossil fuel, as is used in the AEO2016 and other projections. As a result, their estimates for total energy consumption are lower. The BP projection appears to include the Clean Power Plan (CPP), with coal use for electricity generation showing the largest drop from 2020–25, as well as smaller declines in all other 5-year periods. The ExxonMobil projection does not include the CPP but assumes the implementation of unspecified environmental regulations related to carbon dioxide (CO2) emissions, which reduce demand for coal, particularly after 2030, whereas the CPP has a larger impact before 2030. Although the IEA New Policies Scenario includes the CPP, it is not included in

Table CP2. Comparisons of oil price projections, 2025, 2030, 2035, and 2040 (2015 dollars per barrel)

			Projections							
	2015		2025		2030		2035		2040	
	WTI	Brent	WTI	Brent	WTI	Brent	WTI	Brent	WTI	Brent
AEO2016 (Reference case)	48.67	52.32	85.41	91.59	97.06	104.00	112.45	119.64	129.11	136.21
AEO2016 (Low Oil Price case)	48.67	52.32	36.57	43.09	42.38	48.94	53.02	59.23	67.00	72.99
AEO2016 (High Oil Price case)	48.67	52.32	180.49	187.69	197.83	206.75	211.77	220.71	222.27	229.91
AEO2015 (Reference case)	54.58	57.58	88.02	94.34	102.98	109.37	120.34	126.51	140.45	146.26
ArrowHead Economics	58.00	58.00	66.00	66.00	68.00	69.00	71.00	73.00	75.00	77.00
Strategic Energy & Economic Research (SEER)[a]	--	--	--	40.40	--	40.40	--	43.44	--	45.46
Energy Security Analysis (ESAI)	--	52.45	--	80.00	--	80.00	--	87.10	--	94.10
IHS Global Insight (GI)[b]	48.83	-	95.41	--	96.26	-	95.62	--	95.15	--
ICF[a]	--	--	--	75.61	--	75.76	--	75.76	--	--
Energy Ventures Analysis (EVA)[a]	--	--	--	64.59	--	65.84	--	67.09	--	--
IEA (Current Policies Scenario)[c]	--	--	--	--	--	130.00	--	--	--	150.00
OPEC Reference Basket[d]	--	--	--	--	--	88.41	--	--	--	95.00

-- = No data reported.
[a]Inflated from 2014 to 2015 dollars using GDP chain-type price index from the AEO2016 Reference case.
[b]Deflated from nominal dollars using IHS Global Insight deflator.
[c]IEA mixed crude oil import prices are based on OECD member country reporting.
[d]OPEC uses a basket of crudes reflecting the mix of the crude markers of its member exporting countries.

this comparison because it assumes other new policies that are difficult to compare with the AEO2016 Reference case. IEA also includes scenarios that do not anticipate policies. The IEA Current Policies Scenario, which does not include the CPP and assumes that no new policies are added to those in place in mid-2015, is used for this comparison.

For all the years shown, ExxonMobil and IEA project lower total energy consumption than in the AEO2016 Reference case. Total energy consumption is higher in all years of the IHSGI projection than in the AEO2016 Reference case. IHSGI projects significantly higher total electricity sales than in the AEO2016 Reference case, which helps to explain much of the difference in total energy consumption between the two projections.

The use of unspecified CO2 emissions regulations instead of the CPP in the ExxonMobil projections results in a different path for energy use and lower total energy use in 2040 in the electric power sector than in the other projections. The AEO2016 Reference case shows switching from coal to natural gas and renewables in the electric power sector from 2020–25, with the CPP beginning in 2022. With the assumption of more general CO2 emissions regulations in the ExxonMobil projection, the transition away from coal begins in the 2030s and occurs more gradually. Both the AEO2016 Reference case and ExxonMobil projections show residential energy consumption slightly lower in 2040, commercial consumption growing slowly, and transportation consumption lower in 2040. Industrial consumption increases through 2040 in the AEO2016 Reference case, while ExxonMobil shows industrial consumption declining from 2030–40. The direction of the trends is relatively consistent, if not the timing, even with different assumptions for the timing of environmental regulations.

Table CP3. Comparisons of energy consumption projections by sector, 2015, 2020, 2030, 2035, and 2040 (quadrillion Btu)

Sector	AEO2016 Reference	ExxonMobil	BP[a]	IHSGI	IEA[a]
	2015 (except where noted)				
Residential	10.9	--	--	--	--
Commercial	8.8	--	--	--	--
Buildings Sector	***19.7***	**--**	***21.2[b]***	**--**	***19.3[c]***
Industrial	24.3	--	23.8[b]	--	23.0[c]
Transportation and unspecified[d]	27.6	--	23.8[b]	--	24.1[c]
Electric Power	37.8	--	37.5[b]	--	35.6[c]
Less: electricity demand[e]	12.7	--	15.1[b]	--	14.8[c]
Total primary energy	**96.7**	**--**	**91.2[b]**	**99.1**	**86.7[c]**
	2020				
Residential	10.9	10.6	--	--	--
Commercial	9.0	8.7	--	--	--
Buildings sector	***19.9***	***19.3***	***20.9***	**--**	***20.2***
Industrial	27.1	26.6	26.0	--	25.6
Transportation and unspecified[d]	27.7	27.8	24.5	--	24.4
Electric power	38.9	36.1	39.0	--	37.1
Less: electricity demand[e]	13.1	14.2	16.1	--	16.1
Total primary energy	**100.5**	**95.6**	**94.3**	**105.5**	**90.7**
	2030				
Residential	10.7	10.4	--	--	--
Commercial	9.5	8.9	--	--	--
Buildings sector	***20.2***	***19.3***	***21.4***	**--**	***21.5***
Industrial	30.1	29.2	26.9	--	25.9
Transportation and unspecified[d]	25.8	26.3	23.0	--	23.7
Electric power	39.4	36.5	39.6	--	39.0
Less: electricity demand[e]	14.0	15.5	16.7	--	17.5
Total primary energy	**101.5**	**95.9**	**94.1**	**109.8**	**92.2**

-- = No data reported.
See notes at end of table.

(continued on page CP-5)

The base year consumption figures used by BP are lower than the AEO2016 base year data, with most of the difference in transportation consumption. Part of the difference is that AEO2016 uses 2015 as a base year and BP uses 2014, but that does not account for all the difference. Base year consumption in the BP projection is about 7 quadrillion Btu less than in the AEO2016 Reference case, and the BP projections are about 10 quadrillion Btu lower in 2035. The gap widens in the 2030–35 period, due mainly to transportation consumption (which declines by a little more than 1 quadrillion Btu in the BP projection) and electric power consumption. Over the same period, transportation consumption remains relatively constant, and electric power consumption increase by about 1 quadrillion Btu, in the AEO2016 Reference case. The difference in accounting for renewable electricity generation could explain the variation in the electric power sector.

Total energy consumption in the IEA projection is higher in 2040 than in 2013 as a result of an increase of 3.5 quadrillion Btu in buildings sector energy consumption, including a 3.0 quadrillion Btu increase in buildings electricity use. IEA projects a small increase in energy use in the industrial sector of 0.4 quadrillion Btu from 2020–40 after a 10% increase from 2013–20. The increase through 2020 is similar to that in the AEO2016 Reference case, and it continues to grow through 2040 but at a slower rate than in the AEO2016 Reference case.

CP4. Electricity

Table CP4 compares AEO2016 Reference case projections for electricity with those from IEA, NREL, and EVA. The IEA and NREL projections for total electricity generation are similar to the AEO2016 Reference case projections for 2025, 2035, and 2040, whereas the EVA projections for total electricity generation are significantly higher than those of the other projections across all years. The AEO2016 Reference case projects total U.S. generation of 4,420 billion kWh in 2025, as compared with the EVA projection of 5,361 billion kWh, which is about 20% higher than AEO2016 and the highest among all of the projections compared. The EVA projection appears to be based on policy assumptions that are similar to those in the AEO2016 Reference case, including the CPP.

In the AEO2016 Reference case, as a result of the CPP, total generation from coal-fired power plants in 2025 is 217 billion kWh lower than generation from natural gas-fired plants. In the NREL projection, total coal-fired generation is 558 billion kWh higher

Table CP3. Comparisons of energy consumption projections by sector, 2015, 2020, 2030, 2035, and 2040 (quadrillion Btu) ***(continued)***

Sector	AEO2016 Reference	ExxonMobil	BP[a]	IHSGI	IEA[a]
			2035		
Residential	10.8	10.3	--	--	--
Commercial	9.9	8.9	--	--	--
Buildings sector	***20.6***	***19.2***	***21.5***	**--**	**--**
Industrial	31.4	28.9	27.6	--	--
Transportation and unspecified[d]	25.7	25.2	21.7	--	--
Electric power	40.6	36.4	39.6	--	--
Less: electricity demand[e]	14.5	15.9	16.9	--	--
Total primary energy	**103.9**	**93.9**	**93.4**	**111.2**	**--**
			2040		
Residential	10.9	10.2	--	--	--
Commercial	10.3	9.0	--	--	--
Buildings sector	***21.2***	***19.2***	**--**	**--**	***22.7***
Industrial	32.9	28.2	--	--	26.1
Transportation and unspecified[d]	26.2	24.5	--	--	23.6
Electric power	42.0	36.1	--	--	40.5
Less: electricity demand[e]	15.2	16.2	--	--	18.8
Total primary energy	**107.1**	**91.8**	**--**	**112.5**	**93.8**

-- = No data reported.
[a]Converted from million tons oil equivalent (mtoe), assuming 1 mtoe equals 0.03968 quadrillion Btu.
[b]BP data are for 2014.
[c]IEA data are for 2013.
[d]Unspecified sector consumption is that not attributed to the sectors listed.
[e]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

than natural gas-fired generation in 2025, even with the assumed implementation of both carbon taxes and carbon pollution standards for new power plants. The NREL projection shows a decline in total electricity generation from natural gas-fired power plants over the projection. In IEA's Current Policies scenario, which is based on current laws and regulations (excluding the CPP), electricity generation from natural gas-fired power plants does not surpass generation from coal-fired power plants until the later part of the 2030s. The EVA projection shows total natural gas-fired generation surpassing coal-fired generation in the early 2030s. One possible cause for the variation in projected timing of the transition (although no cause was suggested) may be differences in the IEA and EVA trends for natural gas and coal prices.

Electricity generation from U.S. nuclear power plants varies widely among the projections. In the AEO2016 Reference and No CPP cases, nuclear generation declines from 798 billion kWh in 2015 to 770 billion kWh in 2019 before rebounding to 789 billion kWh/year from 2022–40. In the IEA projection, nuclear generation grows by 5% (39 billion kWh) from 2013–20 and remains nearly constant through 2040. In the NREL projection, nuclear generation falls steadily, with an accelerated decline after 2025.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted)

Sector	2015	AEO2016 Reference	AEO2016 No CPP	IEA[h]	NREL	EVA
		2025				
Average end-use price (2015 cents per kilowatthour)[a]	10.3	10.7	10.6	--	--	--
Residential	12.4	13.2	13.1	--	--	--
Commercial	10.5	10.9	10.8	--	--	--
Industrial	6.9	7.3	7.2	--	--	--
Total generation plus net imports	**4,090**	**4,420**	**4,461**	**4,665**	**4,217**	**5,361**
Coal	1,355	1,179	1,432	1,692	1,425	1,433
Petroleum	26	13	14	24	0	0
Natural gas[b]	1,348	1,396	1,307	1,361	867	1,183
Nuclear	798	789	789	861	780	839
Hydroelectric/other[c]	336	419	417	413	431	325
Solar	38	170	113	68	163	71
Wind	190	453	388	247	551	372
Electricity sales	**3,729**	**3,986**	**4,025**	**--**	**--**	**--**
Residential	1,402	1,393	1,406	--	--	--
Commercial/other[d]	1,368	1,448	1,462	--	--	--
Industrial	959	1,145	1,156	--	--	--
Capacity, including CHP (gigawatts)[e]	**1,082**	**1,144**	**1,112**	**1,192**	**1,151**	**--**
Coal	284	196	215	281	249	--
Oil and natural gas	477	485	479	539	433	--
Nuclear	100	99	99	107	99	--
Hydroelectric/other[f]	120	124	124	130	122	--
Solar	25	96	70	44	96	--
Wind	76	144	125	91	151	--
Cumulative capacity retirements from 2016 (gigawatts)[g]	**--**	**145**	**116**	**--**	**--**	**--**
Coal	--	80	60	--	--	--
Oil and natural gas	--	60	50	--	--	--
Nuclear	--	5	5	--	--	--
Hydroelectric/other[f]	--	0	0	--	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-7)

EVA projects rising nuclear generation through 2025, followed by a decline. Across the projections, nuclear electricity generation in 2025 ranges from a low of 789 billion kWh in the AEO2016 Reference case to a high of 861 billion kWh in the IEA projection.

Generation from nonhydroelectric renewable resources accounts for a significant portion of the total increase in electricity generation, but its share of total generation varies across the projections. In the AEO2016 Reference case, wind and solar provide 10% and 4%, respectively, of total generation in 2025, compared with 9% and 3%, respectively, in the No CPP case. In the EVA projection, wind and solar energy provide the smallest share of total generation in 2025, 2035, and 2040. In the NREL projection, wind and solar have the largest shares of total generation in 2025, 2035, and 2040 of the projections compared. Differences among the projections may result from different assumptions about technology costs and performance or from different treatments of federal and state policies for renewable electricity generation (i.e., production tax credits, investment tax credits, renewable fuel standards, etc.).

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) *(continued)*

Sector	2015	AEO2016 Reference	AEO2016 No CPP	IEA[h]	NREL	EVA
				2035		
Average end-use price (2015 cents per kilowatthour)[a]	10.3	10.6	10.3	--	--	--
Residential	12.4	13.2	12.8	--	--	--
Commercial	10.5	10.7	10.4	--	--	--
Industrial	6.9	7.3	7.1	--	--	--
Total generation plus net imports	**4,090**	**4,795**	**4,910**	**5,065**	**4,477**	**5,943**
Coal	1,355	962	1,398	1,769	1,292	1,396
Petroleum	26	10	12	20	0	0
Natural gas[b]	1,348	1,768	1,599	1,496	820	1,500
Nuclear	798	789	789	864	581	704
Hydroelectric/other[c]	336	441	436	470	442	343
Solar	38	364	281	117	486	128
Wind	190	460	394	328	856	472
Electricity sales	**3,729**	**4,256**	**4,369**	**--**	**--**	**--**
Residential	1,402	1,457	1,494	--	--	--
Commercial/other[d]	1,368	1,601	1,657	--	--	--
Industrial	959	1,197	1,218	--	--	--
Capacity, including CHP (gigawatts)[e]	**1,082**	**1,277**	**1,254**	**1,281**	**1,388**	**--**
Coal	284	179	215	281	205	--
Oil and natural gas	477	536	536	560	483	--
Nuclear	100	99	99	107	74	--
Hydroelectric/other[f]	120	127	126	142	128	--
Solar	25	192	152	74	288	--
Wind	76	145	126	118	210	--
Cumulative capacity retirements from 2016 (gigawatts)[g]	**--**	**183**	**128**	**--**	**--**	**--**
Coal	--	97	60	--	--	--
Oil and natural gas	--	81	62	--	--	--
Nuclear	--	5	5	--	--	--
Hydroelectric/other[f]	--	0	0	--	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-8)

Total generating capacity (including combined heat and power) is similar across the projections, ranging from 1,112 gigawatts (GW) in 2025 in the AEO2016 No CPP case to 1,144 GW in the AEO2016 Reference case and 1,192 GW in the IEA projection. NREL projects slightly more growth in total generating capacity, corresponding to a higher projection of total generation from nonhydroelectric renewables, despite having the lowest projections for total generation in 2025, 2035, and 2040.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) *(continued)*

Sector	2015	AEO2016 Reference	AEO2016 No CPP	IEA[a]	NREL	EVA
		2040				
Average end-use price (2015 cents per kilowatthour)[b]	10.3	10.5	10.2	--	--	--
Residential	12.4	13.0	12.7	--	--	--
Commercial	10.5	10.5	10.2	--	--	--
Industrial	6.9	7.2	7.1	--	--	--
Total generation plus net imports	**4,090**	**5,060**	**5,180**	**5,451**	**4,638**	**6,416**
Coal	1,355	919	1,364	1,710	1,318	1,236
Petroleum	26	9	11	10	0	0
Natural gas[c]	1,348	1,942	1,784	1,752	763	1,785
Nuclear	798	789	789	865	461	679
Hydroelectric/other[d]	336	451	444	537	443	353
Solar	38	477	389	169	635	168
Wind	190	473	399	409	1,019	530
Electricity sales	**3,729**	**4,464**	**4,587**	**--**	**--**	**--**
Residential	1,402	1,523	1,557	--	--	--
Commercial/other[e]	1,368	1,692	1,761	--	--	--
Industrial	959	1,249	1,269	--	--	--
Capacity, including CHP (gigawatts)[f]	**1,082**	**1,374**	**1,342**	**1,343**	**1,539**	**--**
Coal	284	176	215	271	192	--
Oil and natural gas	477	576	570	572	534	--
Nuclear	100	99	99	107	58	--
Hydroelectric/other[g]	120	128	127	155	128	--
Solar	25	246	203	100	379	--
Wind	76	149	128	138	247	--
Cumulative capacity retirements from 2016 (gigawatts)[h]	**--**	**190**	**132**	**--**	**--**	**--**
Coal	--	100	60	--	--	--
Oil and natural gas	--	85	66	--	--	--
Nuclear	--	5	5	--	--	--
Hydroelectric/other[g]	--	0	0	--	--	--

-- = No data reported.
[a]Projections from IEA in the 2025 and 2035 comparison tables are in fact for 2020 and 2030 respectively. Since projections for year 2025 and 2035 under IEA WEO 2015 Current Policies Scenario (CPS) are not provided, projections from the closest years, 2020 and 2030, were used instead.
[b]Average end-use price includes the transportation sector.
[c]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.
[d]Other includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies.
[e]Other includes sales of electricity to government and other transportation services.
[f]EIA capacity is net summer capability, including CHP plants and end-use generators.
[g]Other includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, pumped storage, other gaseous fuels, refinery gas, still gas, and fuel cells.
[h]Retirements for AEO2016 reflect the electric power sector only.

The implied capacity utilization rate for coal-fired power plants in the AEO2016 Reference case (calculated from total coal-fired capacity and generation) is about 60% in both 2035 and 2040, which is lower than for any other projection. In comparison, IEA and NREL project more than 70% utilization of total U.S. coal-fired capacity in 2035 and 2040. For oil/natural gas, hydroelectric/other, and solar energy, however, the AEO2016 Reference case has the highest utilization rates among the projections, at about 38% for oil/natural gas, 40% for hydroelectric/other, and 22% for solar in 2035 and 2040. NREL projects the highest utilization rate for wind capacity in 2035 and 2040 (47%) and the lowest utilization rates for oil, natural gas, and nuclear capacity in the same years. IEA projects the highest utilization rate for nuclear capacity in 2035 and 2040 (92%) and the lowest for wind in both years. IEA also has the lowest utilization rates for hydroelectric/other and solar capacity in 2035, but the utilization rates for hydroelectric/other in 2040 are similar in all of the projections. IEA's utilization rate for solar in 2040 is lower than in the AEO2016 Reference case but similar to NREL's projection.

CP5. Natural gas

Projections for natural gas consumption, production, imports, and prices (Table CP5) differ significantly, largely as a result of different assumptions. For example, the AEO2016 Reference case assumes that current laws and regulations generally remain unchanged from 2015–40, whereas other projections may include assumptions about policy developments over the period. In particular, the AEO2016 Reference case does not incorporate any future changes in policies affecting carbon emissions or other environmental issues.

Production

All the outlooks shown in Table CP5 (with the exception of IHSGI, which did not provide production data) project increases in natural gas production from 2015, when production totaled 27.2 trillion cubic feet (Tcf). BP projects the largest production increase, to 42.0 Tcf in 2035, or 54% more than the 2015 level. BP is followed closely by ExxonMobil, which projects 40.8 Tcf of natural gas production in 2035 and 41.4 Tcf in 2040, or 50% and 53% above 2015 levels, respectively.

The AEO2016 Reference case, ICF, BP, and ExxonMobil all project larger increases in natural gas production before 2025 than in the later years. In the AEO2016 Reference case, natural gas production increases by 28% from 2015–25 and by 15% from 2025–35. ICF, BP, and ExxonMobil project production increases of more than 30% from 2015–25 and less than 20% from 2025–35. EVA projects roughly equal growth rates for natural gas production from 2015–25 and 2025–35. EVA projects production increases of 23% (to 33.4 Tcf) from 2015–25 and 22% (to 40.6 Tcf) from 2025–35.

Net imports/exports

The AEO2016 Reference case projection for growth in U.S. natural gas exports from 2015–40 is the largest among those reviewed here, from net imports of 1.0 Tcf in 2015 to net exports in 2018. U.S. export growth to 7.6 Tcf in 2040 consists mostly of liquefied natural gas (LNG) exports, along with a smaller increase in net pipeline exports to Mexico through 2020 and a reduction in net pipeline imports from Canada through 2040, which offsets a gradual decline in net pipeline exports to Mexico after 2020.

EVA, ICF, and BP also provide projections for net imports of natural gas that show the United States becoming a net exporter by 2020, but they differ from the AEO2016 Reference case in terms of export levels. ICF shows net exports growing early in the projection but declining through 2035, when net exports of 3.4 Tcf are less than one-half of those in the AEO2016 Reference case (7.2 Tcf). The decline of net natural gas exports in the ICF projection results from a decrease in net LNG exports, from 3.2 Tcf in 2025 to 2.6 Tcf in 2035. EVA and BP show continued growth in net exports, to 4.7 Tcf and 7.6 Tcf in 2035, respectively. The BP projection of 7.6 Tcf of net natural gas exports in 2035 is fairly close to the AEO2016 Reference case projection of 7.2 Tcf in 2035. EVA projects net pipeline imports of natural gas into the United States after 2020, rather than net pipeline exports, with U.S. gross pipeline imports of natural gas more than doubling from 2025–35.

Consumption

In the AEO2016 Reference case, total domestic natural gas consumption increases by 19% from 2015–35 and by 25% from 2015–40 to a total of 34.4 Tcf in 2040. The 5.1 Tcf increase in total domestic consumption in the AEO2016 Reference case from 2020–35 is 0.8 Tcf larger than the projected increase in net natural gas exports (4.3 Tcf). The domestic consumption share of total U.S. natural gas production declines in the Reference case from 90% in 2020 to 82% in 2035 and 2040. From 2015–35, natural gas consumption in the electric power sector grows by 16%, to a total of 11.1 Tcf, as compared with a 22% increase in the industrial sector, to 9.2 Tcf, and a 10% increase in the commercial sector, to 3.6 Tcf in 2035. In the residential sector, natural gas consumption remains constant at 4.6 Tcf from 2015 to 2035 in the Reference case.

EVA, ICF, BP, and ExxonMobil provided outlooks for domestic natural gas consumption at different levels of detail, with the ICF projections being the most comprehensive. BP provided separate projections for consumption in the industrial and electric power sectors—projections of residential and commercial sector consumption are included with projections of consumption in the transportation sector, for lease and plant operations, for liquefaction to LNG for export and for pipeline fuel. BP consistently shows higher projections than those in the AEO2016 Reference case for total natural gas consumption. BP shows increasing consumption of natural gas in all domestic sectors, led by consumption in the electric power sector, with ICF showing a greater increase than BP in electric power sector consumption from 2020–35. ICF projects 63% growth in power sector natural gas use, to 16.3 Tcf in 2035, which is higher than projected in the AEO2016 Reference case and the other outlooks. The AEO2016 projection for natural gas consumption in the electric power sector is lower than the others, and its projection for industrial sector natural gas consumption in 2035 is lower than the EVA, BP, and ExxonMobil projections.

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

Projection	2015	AEO2016 Reference	IHSGI	EVA	ICF	BP	ExxonMobil
		2025					
Dry gas production	**27.19**	**34.81**	**--**	**33.37**	**35.70**	**36.18**	**35.51**
Net imports	**0.95**	**-5.32**	**--**	**-2.86**	**-3.55**	**-4.42**	**--**
Pipeline	0.89	-0.76	--	0.16	-0.37	--	--
LNG	0.06	-4.56	--	-3.02	-3.18	--	--
Consumption	**27.47**	**29.35**	**--**	**28.19**	**31.70**	**31.75**	**--**
Residential	4.62	4.67	--	4.68	5.15	--	6.82[a]
Commercial	3.22	3.35	--	3.53	3.36	--	--
Industrial[b]	7.51	8.65	--	10.15	8.08	11.25	10.72
Electricity generation[c]	9.61	9.33	--	9.74	12.06	12.17	10.72
Other[d]	2.51	3.34	--	0.08[e]	3.04	8.34	--
Henry Hub spot market price (2012 dollars per million Btu)	**2.62**	**5.12**	**4.40[f]**	**4.70[g]**	**4.19[g]**	**--**	**--**
End-use prices (2012 dollars per thousand cubic feet)							
Residential	10.40	11.99	--	--	--	--	--
Commercial	7.92	10.39	--	--	--	--	--
Industrial	3.84	6.15	--	--	--	--	--
Electricity generation	3.35	5.55	--	--	--	--	--
		2035					
Dry gas production	**27.19**	**39.92**	**--**	**40.65**	**39.89**	**42.02**	**40.84**
Net imports	**0.95**	**-7.18**	**--**	**-4.70**	**-3.38**	**-7.61**	**--**
Pipeline	0.89	-0.99	--	0.51	-0.77	--	--
LNG	0.06	-6.19	--	-5.22	-2.61	--	--
Consumption	**27.47**	**32.59**	**--**	**31.02**	**36.15**	**34.41**	**--**
Residential	4.62	4.62	--	4.67	5.16	--	6.82[a]
Commercial	3.22	3.55	--	3.58	3.17	--	--
Industrial[b]	7.51	9.19	--	10.81	8.24	11.76	10.72
Electricity generation[c]	9.61	11.13	--	11.86	16.29	13.32	13.65
Other[d]	2.51	4.09	--	0.10[e]	3.28	9.33	1.00
Henry Hub spot market price (2012 dollars per million Btu)	**2.62**	**4.91**	**5.73[f]**	**5.93[g]**	**5.20[g]**	**--**	**--**
End-use prices (2012 dollars per thousand cubic feet)							
Residential	10.40	12.50	--	--	--	--	--
Commercial	7.92	10.66	--	--	--	--	--
Industrial	3.84	5.95	--	--	--	--	--
Electricity generation	3.35	5.54	--	--	--	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-11)

ICF shows the U.S. domestic sector consuming a steady share of U.S. natural gas production from 2020–35, varying from 89% to 92%. BP shows the share of production consumed in the United States declining from 88% in 2020 to 82% to 2035. In the AEO2016 Reference case, the share of production consumed in domestic markets falls from 90% in 2020 to 82% in 2035.

Although the EVA and ExxonMobil projections show lower volumes of natural gas consumption, they are not comparable with the other outlooks. EVA does not include natural gas consumed for lease and plant operations, liquefaction for export, or pipeline fuel. ExxonMobil does not include natural gas consumed in the commercial sector for transportation, lease and plant operations, liquefaction for export, and pipeline fuel. Also, ExxonMobil provides a combined projection for residential and commercial natural gas consumption. EVA differs from ExxonMobil in that it shows industrial consumption growing to 10.8 Tcf in 2035 (the second highest level among the projections), whereas ExxonMobil shows relatively flat consumption in the industrial sector. The ExxonMobil projections for total domestic consumption of natural gas through 2035 are higher than the EVA projections but lower than the AEO2016 Reference case projections.

Prices

Only IHSGI, EVA, and ICF provide projections for Henry Hub natural gas spot prices. All the price projections, including those in the AEO2016 Reference case, are in real 2015 dollars. Prices in the IHSGI, EVA, and ICF outlooks are lower than those in the AEO2016 Reference case from 2015–30. After 2030, the EVA, IHSGI, and ICF prices are above $5.00, in million British thermal unit (MMBtu), while, with the exception of 2031 and 2032, the price in the AEO2016 Reference case remains below $5.00/MMBtu throughout the projection period. EVA projects the highest Henry Hub prices through 2035, followed closely by IHSGI, with EVA having a projected 2035 spot natural gas price of $5.93/MMBtu, IHGSI $5.73/MMBtu, and ICF $5.20/MMBtu, all in real 2015

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) *(continued)*

Projection	2015	AEO2016 Reference	IHSGI	EVA	ICF	BP	ExxonMobil
		2040					
Dry gas production	**27.19**	**42.12**	**--**	**--**	**--**	**--**	**41.39**
Net imports	**0.95**	**-7.55**	**--**	**--**	**--**	**--**	**--**
Pipeline	0.89	-0.89	--	--	--	--	--
LNG	0.06	-6.66	--	--	--	--	--
Consumption	**27.47**	**34.42**	**--**	**--**	**--**	**--**	**--**
Residential	4.62	4.58	--	--	--	--	6.82[a]
Commercial	3.22	3.69	--	--	--	--	--
Industrial[b]	7.51	9.58	--	--	--	--	9.75
Electricity generation[c]	9.61	11.96	--	--	--	--	13.65
Other[d]	2.51	4.60	--	--	--	--	--
Henry Hub spot market price (2012 dollars per million Btu)	**2.62**	**4.86**	**6.82[f]**	**--**	**--**	**--**	**--**
End-use prices (2012 dollars per thousand cubic feet)							
Residential	10.40	12.74	--	--	--	--	--
Commercial	7.92	10.73	--	--	--	--	--
Industrial	3.84	5.89	--	--	--	--	--
Electricity generation	3.35	5.52	--	--	--	--	--
Electricity generation	3.35	5.54	--	--	--	--	--

-- = No data reported.
[a]Natural gas consumed in the residential and commercial sectors.
[b]Includes consumption for industrial CHP plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.
[c]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
[d]Includes lease, plant, and pipeline fuel, fuel consumed in natural gas vehicles, and fuel consumed in liquefaction for export.
[e]Does not include lease, plant, and pipeline fuel, and fuel consumed in liquefaction for export.
[f]Converted to 2015 dollars using IHS's GDP deflator for the IHS Reference case.
[g]Converted to 2015 dollars using EIA's GDP deflator.

dollars. IHSGI is the only other outlook that provides a projection in 2040, with a projected spot price of $6.82/MMBtu in 2040, 40% higher than projected in the AEO2016 Reference case.

In the AEO2016 Reference case, residential natural gas prices rise to $12.74/thousand cubic feet (Mcf) in real 2015 dollars in 2040. Commercial natural gas prices rise to $10.72/Mcf in 2030, and remain between $10.66 and $10.73/Mcf through 2040. Electric power and industrial natural gas prices rise to $6.15/Mcf in 2025 and $5.74/Mcf in 2030 in real 2015 dollars, respectively, before gradually declining to $5.52/Mcf and $5.89/Mcf, respectively, in 2040. EVA, and ICF did not project natural gas prices by sector.

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted)

Projection	2015	AEO2016 Reference	BP	EVA	ICF	IEA	ExxonMobil[a]	IHSGI[b]
					2025			
U.S. refiner imported acquisition cost of crude oil (2015 dollars per barrel)	46.42	83.45	--	--	75.63	--	--	87.35
Brent spot price (2015 dollars per barrel)	52.32	91.59	--	64.59	--	--	--	--
U.S. WTI crude oil price (2015 dollars per barrel)	48.67	85.41	--	64.61	--	--	--	95.41
Domestic production	**12.68**	**14.20**	**15.90**	**--**	**13.96**	**--**	**18.70**	**--**
Crude oil	9.42	9.43	10.20	--	8.88	12.00	--	--
Alaska	0.48	0.32	--	--	0.40	--	--	--
Natural gas liquids	3.25	4.77	5.70	--	5.08	--	11.00	--
Total net imports	**4.64**	**3.27**	**1.20**	**--**	**--**	**--**	**--**	**--**
Crude oil	6.88	6.95	--	--	--	--	--	--
Products	-2.24	-3.69	--	--	--	--	--	--
Petroleum and other liquids consumption	19.42	19.90	19.50	--	--	16.50	20.02	--
Net petroleum import share of liquids supplied (percent)	24.00	16.50	6.00	--	--	--	--	--
Biofuel production	1.01	1.02	1.20	--	--	--	--	--
					2035			
U.S. refiner imported acquisition cost of crude oil (2015 dollars per barrel)	46.42	109.70	--	--	75.78	--	--	91.00
Brent spot price (2015 dollars per barrel)	52.32	119.64	--	67.09	--	--	--	--
U.S. WTI crude oil price (2015 dollars per barrel)	48.67	112.45	--	67.29	--	--	--	95.62
Domestic production	**12.68**	**15.62**	**17.30**	**--**	**13.99**	**--**	**19.10**	**--**
Crude oil	9.42	10.66	10.50	--	8.52	11.40	--	--
Alaska	0.48	0.19	--	--	0.38	--	--	--
Natural gas liquids	3.25	4.95	6.90	--	5.47	--	--	--
Total net imports	**4.64**	**1.72**	**-1.90**	**--**	**--**	**--**	**--**	**--**
Crude oil	6.88	6.24	--	--	--	--	--	--
Products	-2.24	-4.52	--	--	--	--	--	--
Petroleum and other liquids consumption	19.42	19.69	18.10	--	--	14.20	19.09	--
Net petroleum import share of liquids supplied (percent)	24.00	9.00	-9.00	--	--	--	--	--
Biofuel production	1.01	1.03	1.40	--	--	--	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-13)

CP6. Petroleum and other liquid fuels

In the AEO2016 Reference case, the North Sea Brent spot crude oil price (in 2015 dollars) increases from about $52/barrel (b) in 2015 to $92/b in 2025 and then continues rising to $120/b in 2035 and $136/b in 2040 (Table CP6). North Sea Brent spot crude oil prices are relatively flat in the Energy Ventures Analysis (EVA) projection, rising from $65/b in 2025 to $67/b in 2035. In the AEO2016 projection, the U.S. imported refiner acquisition cost (IRAC) of crude oil (in 2015 dollars) increases from $46/b in 2015 to about $83/b in 2025, and then increases to $110/b in 2035 and $126/b in 2040. IRAC prices in the International Energy Agency (IEA) projection are similar but rise faster, increasing from $46/b in 2015 to $152/b in 2040, while IHS-Global Insight (IHSGI) project that IRAC prices will increase from $46/b in 2015 to $87/b in 2025 and then gradually to $91/b in 2035 and $93/b in 2040. IRAC prices in the ICF projection are relatively flat after increasing from 2015 levels, averaging $76/b in both 2025 and 2035. BP and ExxonMobil did not report projections of North Sea Brent or IRAC crude oil prices.

In the AEO2016 Reference Case, domestic crude oil production decreases from about 9.4 million barrels/day (b/d) in 2015 to 8.6 million b/d in 2017, before growing to 9.4 million b/d in 2025, 10.7 million b/d in 2035, and 11.3 million b/d by 2040. Overall, the production level in 2040 is about 20% higher than in 2015. Production in the BP projection grows from 9.4 million b/d in 2015 to 10.2 million b/d in 2025 and then grows modestly to 10.5 million b/d in 2035. The ICF projection shows production falling from the 9.4 million b/d produced in 2015 to 8.9 million b/d in 2025 and to 8.5 million b/d in 2035. Production increases from 2015 levels in the IEA projection to 12.0 million b/d in 2025 before falling to 10.6 million b/d in 2040. The ExxonMobil projection includes only total domestic production of crude oil and natural gas liquids, which is higher than in the AEO2016 Reference Case. Total production in the ExxonMobil projection increases from 2015 levels of 12.7 million b/d to 18.7 million b/d in 2025 before increasing to 19.1 million b/d in 2035, and then falling again to 18.0 million b/d in 2040. These levels are all higher than in the AEO2016 projection where production falls to 14.2 million b/d in 2025 before rising to 15.6 million b/d in 2035 and 16.3 million b/d in 2040.

With rapid growth in U.S. crude oil production, net imports fall in the AEO2016 Reference case and other projections. In the Reference case, total net imports of crude oil and products fall from 4.6 million b/d in 2015 to 3.3 million b/d in 2025, 1.7 million b/d in 2035, and 1.4 million b/d in 2040. In the BP projection, total net imports are even lower than in the AEO2016 Reference Case, falling to 1.2 million b/d in 2025. By 2035, the United States is a net exporter of 1.9 million b/d of crude oil and products.

Biofuel production increases to about 1.0 million b/d in 2025 and remains at roughly that level through 2040 in the AEO2016 Reference case. In the BP projection, biofuel production on an energy-equivalent basis increases to 1.2 million b/d in 2025 and 1.4 million b/d in 2035. Biofuels production is not explicitly included in the EVA, ICF, IEA, ExxonMobil, and IHSGI projections.

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) *(continued)*

Projection	2015	AEO2016 Reference	BP	EVA	ICF	IEA	ExxonMobil[a]	IHSGI[b]
		2040						
U.S. refiner imported acquisition cost of crude oil (2015 dollars per barrel)	46.42	125.93	--	--	--	151.57	--	92.53
Brent spot price (2015 dollars per barrel)	52.32	136.21	--	--	--	--	--	--
U.S. WTI crude oil price (2015 dollars per barrel)	48.67	129.11	--	--	--	--	--	95.15
Domestic production	**12.68**	**16.25**	**--**	**--**	**--**	**--**	**18.00**	**--**
Crude oil	9.42	11.26	--	--	--	10.60	--	--
Alaska	0.48	0.15	--	--	--	--	--	--
Natural gas liquids	3.25	4.99	--	--	--	--	--	--
Total net imports	**4.64**	**1.44**	**--**	**--**	**--**	**--**	**--**	**--**
Crude oil	6.88	6.10	--	--	--	--	--	--
Products	-2.24	-4.66	--	--	--	--	--	--
Petroleum and other liquids consumption	19.42	20.14	--	--	--	17.30	18.43	--
Net petroleum import share of liquids supplied (percent)	24.00	7.00	--	--	--	--	--	--
Biofuel production	1.01	1.06	--	--	--	--	--	--

-- = No data reported.
[a]ExxonMobil liquids demand data converted from quadrillion Btu to barrels assuming 187.9 million barrels per quadrillion Btu.
[b]Deflated from nominal dollars using IHS Global Insight deflator.
Note: 2014 dollars per barrel converted to 2015 dollars per barrel using the AEO2016 Reference case GDP Chain-type price deflator.

CP7. Coal

Projections for U.S. coal production, consumption, exports, and prices vary widely in the AEO2016 Reference case and the projections from EVA, Wood Mackenzie (WoodMac), SNL Energy, IEA, and BP (Table CP7). The range of projections implies significant differences in analysts' views on how CO2 emissions and other environmental regulations will be implemented and how U.S. coal mining regions will compete with each other, with alternative energy sources, and with coal from other parts of the world. Most of the projections point to an overall downward trend for total coal consumption and production; however, the size and pace of the expected declines in coal consumption and production, as well as expectations for coal imports, vary even among projections with similar regulatory assumptions.

The projections generally noted the environmental regulations or programs considered; however, the respondents did not provide details for how the environmental regulations and programs were implemented in the projections, such as the assumed start dates for rules currently in litigation. WoodMac incorporated the CPP, Carbon Pollution Standards for new plants, regional carbon programs that constrain CO2 emissions, and rules that limit conventional air emissions. EVA and SNL Energy excluded the CPP but included everything else mentioned above, including CO2 emissions standards for new coal-fired power plants. IEA's Current Policies Scenario took into account only policies formally enacted as of mid-2015, implying that it excludes regulations that would limit coal use the most, such as the CPP [*1*].

Collectively, the projections demonstrate the profound impact of the CPP on coal consumption in the electricity sector. Compared with 2015, coal consumption is projected to decline by 13% in 2025 and 30% in 2035 in the AEO2016 Reference case, as compared with 17% in 2025 and 42% in 2035 in the WoodMac projection [*2*]. BP projects the most significant drop from 2015 levels with

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted)

		AEO2016 Reference case		Other projections				
				EVA[a]	Wood Mackenzie[b]	SNL Energy[c]	IEA[d]	BP[e]
Projection	2015	(million short tons)	(quadrillion Btu)	(million short tons)			(quadrillion Btu)	
		2025						
Production	**873**	**766**	**15.35**	**921**	**713**	**857**	**--**	**16.37**
Appalachia	223	165	--	232	104	173	--	--
Interior	165	193	--	200	143	194	--	--
West	484	408	--	489	465	490	--	--
Consumption								
Electric power	739	643	12.12	812	612	742	--	10.90
Coke plants	19	16	0.45	15	--	16	--	--
Coal-to-liquids	--	--	--	--	--	--	--	--
Other industrial/buildings	40	44	1.37[f]	40	--	34	--	--
Total consumption (quadrillion Btu)	**15.48**	**--**	**13.49**	**--**	**--**	**--**	**--**	**12.00**
Total consumption (million short tons)	**801**	**705**	**--**	**867**	**--**	**792**	**--**	**--**
Net coal exports (million short tons)	**63**	**70**	**1.80**	**72**	**103**	**65**	**--**	**4.37[g]**
Exports	75[h]	70	--	82	105	72	--	--
Imports	11	0	--	10	2	7	--	--
Minemouth price								
2015 dollars per ton	33.80	33.99	--	--	--	26.95[i]	--	--
2015 dollars per Btu	1.69	1.71	--	--	--	1.32[i]	--	--
Average delivered price to electricity generators								
2015 dollars per ton	41.62	42.69	--	--	--	40.43[i]	--	--
2015 dollars per Btu	2.19	2.26	--	--	--	1.98[i]	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-15)

coal consumption falling by 7.4 quadrillion Btu by 2035, compared with a 4.3 quadrillion Btu decline in the AEO2016 Reference case [*3*]. In the EVA projection, consumption declines between 2014 and 2020, recovers in the following five years, and then drops by 12% from 2025–40 [*4*]. Coal consumption for electricity generation in 2025 is slightly higher in the SNL Energy projection and remains nearly constant before 2030 in the IEA Current Policies Scenario. The EVA, SNL Energy, and IEA projections do not include the CPP.

The key difference among the projections for end-use (residential, commercial, industrial, and transportation sectors) coal use is in the other industrial/buildings sector. In the AEO2016 Reference case, the largest share of coal use in the other industrial/buildings sector is in combined heat and power plants and small on-site generating plants. Coal consumption in those applications increases throughout the 2015–40 projection period in the AEO2016 Reference case. Coking plants account for the remaining coal consumption. Only EVA and SNL Energy provide projections for coal consumption at coking plants, and both projections are largely in line with the AEO2016 Reference case, with coal use at coking plants declining steadily throughout the projection. Total end-use coal consumption, including coal use in the other industrial/buildings sector and at coking plants, remains largely constant through 2040 in the AEO2016 Reference case, while all the other projections show steady declines in end-use coal consumption resulting from declines in both the other industrial/building sector and at coking plants. The decline in total domestic coal consumption through 2040 significantly outweighs the impact of any changes in net coal exports, resulting in declines in total coal production in all of the projections. From 2015–35, the reductions in coal production range from 24% (EIA) to 31% (WoodMac), based on tonnage, and from 22% (EIA) to 34% (BP), based on energy content.

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) *(continued)*

Projection	2015	AEO2016 Reference case (million short tons)	AEO2016 Reference case (quadrillion Btu)	EVA[a] (million short tons)	Wood Mackenzie[b] (million short tons)	SNL Energy[c] (million short tons)	IEA[d] (quadrillion Btu)	BP[e] (quadrillion Btu)
		2035						
Production	**873**	**661**	**13.44**	**890**	**606**	**--**	**--**	**12.10**
Appalachia	223	154	--	226	83	--	--	--
Interior	165	172	--	195	150	--	--	--
West	484	335	--	469	373	--	--	--
Consumption								
Electric power	739	520	9.82	787	432	--	--	7.65
Coke plants	19	15	0	14	--	--	--	--
Coal-to-liquids	--	--	--	--	--	--	--	--
Other industrial/buildings	40	45	1.38	37	--	--	--	--
Total consumption (quadrillion Btu)	**15.48**	**--**	**11.21**	**--**	**--**	**--**	**--**	**8.60**
Total consumption (million short tons)	**801**	**583**	**--**	**838**	**--**	**--**	**--**	**--**
Net coal exports (million short tons)	**63**	**87**	**2.19**	**69**	**189**	**--**	**--**	**3.50[g]**
Exports	75[h]	87	--	79	191	--	--	--
Imports	11	0	--	10	2	--	--	--
Minemouth price								
2015 dollars per ton	33.80	37.58	--	--	--	--	--	--
2015 dollars per Btu	1.69	1.86	--	--	--	--	--	--
Average delivered price to electricity generators								
2015 dollars per ton	41.62	43.79	--	--	--	--	--	--
2015 dollars per Btu	2.19	2.32	--	--	--	--	--	--

-- = No data reported.
See notes at end of table.

(continued on page CP-16)

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) *(continued)*

		AEO2016 Reference case		Other projections				
Projection	2015	(million short tons)	(quadrillion Btu)	EVA[a] (million short tons)	Wood Mackenzie[b] (million short tons)	SNL Energy[c] (million short tons)	IEA[d] (quadrillion Btu)	BP[e] (quadrillion Btu)
		2040						
Production	**873**	**643**	**13.11**	**814**	**--**	**--**	**--**	**--**
Appalachia	223	144	--	187	--	--	--	--
Interior	165	170	--	182	--	--	--	--
West	484	329	--	445	--	--	--	--
Consumption								
Electric power	739	494	9.36	711	--	--	14.64	--
Coke plants	19	14	0.40	14	--	--	--	--
Coal-to-liquids	--	--	--	--	--	--	--	--
Other industrial/buildings	40	47	1.38f	36	--	--	0.74	--
Total consumption (quadrillion Btu)	**15.48**	**--**	**10.75**	**--**	**--**	**--**	**16.30**	**--**
Total consumption (million short tons)	**801**	**557**	**--**	**761**	**--**	**--**	**--**	**--**
Net coal exports (million short tons)	**63**	**94**	**2.32**	**69**	**--**	**--**	**--**	**--**
Exports	75[h]	94	--	78	--	--	--	--
Imports	11	0	--	9	--	--	--	--
Minemouth price								
2015 dollars per ton	33.80	38.68	--	--	--	--	--	--
2015 dollars per Btu	1.69	1.91	--	--	--	--	--	--
Average delivered price to electricity generators								
2015 dollars per ton	41.62	45.17	--	--	--	--	--	--
2015 dollars per Btu	2.19	2.38	--	--	--	--	--	--

-- = No data reported.

[a]Regulations known to be accounted for in the EVA projections include the Carbon Pollution Standard for new plants, Regional Greenhouse Gas Initiative (RGGI), California carbon tax (California AB32), Cross-State Air Pollution Rule (CSAPR, with allowances reaching zero between the mid- and late 2020s), regulations for cooling water intake structures under Section 316(b) of the Clean Water Act (all plants must achieve compliance by 2018), regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act (compliance by 2022), Regional Haze Program, and Effluent Limitation Guidelines (compliance by 2022).

[b]Regulations known to be accounted for in the Wood Mackenzie projections include interconnect-level, mass-based CPP with new source complement, Carbon Pollution Standards for new plants, RGGI, California AB32, CSAPR, MATS, regulations for cooling water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act and the Regional Haze Program.

[c]Regulations known to be accounted for in the SNL Energy projections include RGGI, California AB32, Carbon Pollution Standards for new plants, CSAPR (with Phase I budgets applied through the end of 2016 and Phase II budgets starting in 2017), MATS, California cooling water regulations and ban on once-through cooling, and Regional Haze Program.

[d]International Energy Agency, *World Energy Outlook 2015,* Current Policies Scenario.

[e]BP generally assumes continued evolution of policies and regulations that constrain CO2 emissions and support renewables (the CPP is included in the *BP Energy Outlook,* 2016 edition). Values were converted from million metric tons oil equivalent to quadrillion Btu, using a conversion factor of 39.653 million Btu per metric ton oil equivalent.

[f]Represents coal consumed in both the other industrial/buildings sector and at coke plants, to facilitate comparison of the AEO2016 and IEA projections, because IEA provided projections for total end-use coal consumption with no breakout for coke plants.

[g]Net coal exports in the BP projection are calculated as production minus consumption.

[h]Preliminary estimate. Finalized as 74 million tons in EIA's *Quarterly Coal Report – October-December 2015,* https://www.eia.gov/coal/production/quarterly/pdf/t7p01p1.pdf.

[i]Converted from 2014 dollars to 2015 dollars using an inflator of 1.0322.

There are also differences among the projections of coal production by region, especially for the Appalachian and West regions. All of the projections suggest that Appalachian coal production will be lower in 2040 than in 2015. In the AEO2016 Reference case and WoodMac projections most of the decline occurs before 2030, compared with after 2035 in the EVA projection. The projections also disagree on how much the Appalachian region's production will shrink, with WoodMac projecting a decline to 83 million tons in 2035, compared with 154 million tons in the AEO2016 Reference case. Coal production in the West region declines rapidly in the AEO2016 Reference case, beginning in 2020, and falls to 335 million tons in 2035. In the WoodMac projection, coal production declines rapidly from 2025–2030 before leveling off at about 373 million tons through 2040. EVA projects only moderate declines before 2035, with 2040 production at approximately 445 million tons. Compared with Appalachia and the West, production in the Interior region is relatively flat in all of the projections, ranging from about 150 million tons (WoodMac) to 200 million tons (EVA). Production in the AEO2016 Reference case falls within that range.

Coal exports increase from 75 million tons in 2015 to 94 million tons in 2040 in the AEO2016 Reference case. In comparison, WoodMac projects a more substantial increase in coal exports, to 191 million tons in 2035. EVA projects an increase to 82 million tons in 2025, followed by a decline to 78 million tons in 2040. BP does not project coal exports and imports separately, but the difference between its projections for production and consumption suggests a significant increase in net exports from 2015–25, by 2.1 quadrillion Btu, compared with an increase of 0.1 quadrillion Btu over the same period in the AEO2016 Reference case. Net exports decline in the BP projection by 0.9 quadrillion Btu from 2025–35, as compared with an increase of 0.4 quadrillion Btu from 2025–35 in the AEO2016 Reference case.

All the projections show coal imports declining over time. The largest reduction is in the AEO2016 Reference case, with imports declining from 11 million tons in 2015 to 55,000 tons in 2020 and remaining at that level through 2040. EVA projects that imports will remain at a level of about 10 million tons through 2040, and SNL projects that imports will remain at about 7 million tons from 2020–25. In the WoodMac projection, imports decline to 6 million tons in 2020, then drop to 2 million tons in 2025 and remain at that level through 2040.

The only projection for coal prices that can be compared with the EIA projections is from SNL Energy, which shows coal prices declining from 2015–20 and remaining relatively flat from 2020–25. In the AEO2016 Reference case, both minemouth prices and delivered prices to power plants increase moderately from 2015–40.

Endnotes for comparisons with other projections

Links current as of July 2016

1. International Energy Agency, *World Energy Outlook 2015,* http://www.worldenergyoutlook.org/weo2015/.
2. The ranges of percentages are based on the tonnage of coal.
3. BP, *Energy Outlook 2016,* http://www.bp.com/en/global/corporate/energy-economics/energy-outlook-2035/energy-outlook-downloads.html.
4. All changes over time in this section are calculated based on projections provided to EIA starting 2020 and in 5-year increments. Values for 2020 and 2030 are not shown in Table CP7. When values for 2015 are available in a projection provided to EIA, they are used in calculations for the projection but not shown in Table CP7; when they are not available, EIA data for 2015 are used to calculation changes from 2015.

Table sources for comparisons with other projections

Links current as of July 2016

Table CP1. Comparisons of average annual economic growth projections, 2015–40: AEO2016 (Reference case): AEO2016 National Energy Modeling System, run REF2016.D032416A. **AEO2015 (Reference case):** AEO2015 National Energy Modeling System, run REF2015.D021915A. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA: February 2016), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **OMB:** Office of Management and Budget, *Fiscal Year 2017 Budget of the U.S. Government* (Washington, DC: January 2016), http://www.whitehouse.gov/sites/default/files/omb/budget/fy2017/assets/budget.pdf. **CBO:** Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2016 to 2026* (Washington, DC: February 2016), http://www.cbo.gov/publication/51129. **INFORUM:** "INFORUM Spring 2016 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD: February 2016), http://inforumweb.umd.edu/services/models/lift.html. **SSA:** Social Security Administration, *The 2015 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (Washington, DC: U.S. Government Printing Office, August 2015), http://www.ssa.gov/oact/tr/2015/2015_Long-Range_Economic_Assumptions.pdf. **IEA (New Policies Scenario):** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/. **Oxford Economics Group:** Oxford Economics, Ltd., *2016 Long Term Forecast* (Oxford, United Kingdom: February 2016), http://www.OxfordEconomics.com (subscription site). **ExxonMobil:** ExxonMobil Corporation, *The Outlook for Energy: A View to 2040* (Irving, TX: 2016), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016).

Table CP2. Comparisons of oil price projections, 2025, 2030, 2035, and 2040: AEO2016 (Reference case): AEO2016 National Energy Modeling System, run REF2016.D032416A. **AEO2016 (Low Oil Price case):** AEO2016 National Energy Modeling System, run LOWPRICE.D041916A. **AEO2016 (High Oil Price case):** AEO2016 National Energy Modeling System, run HIGHPRICE.D041916A. **AEO2015 (Reference case):** AEO2015 National Energy Modeling System, run REF2015.D021915A. **Arrowhead:** ArrowHead Economics LLC, email from Dale Nesbitt (March 17, 2016). **SEER:** Strategic Energy & Economic Research, email from Michael Lynch (March 14, 2016). **ESAI:** Energy Security Analysis, Inc., "ESAI Energy 2016 Long Term Crude Price Forecast," email from Sarah Emerson (March 17, 2016). **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA: February 2016), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **ICF:** ICForecast Natural Gas Strategic Outlook (Fairfax, VA: 1st Quarter 2016), email from Hua Fang (March 28, 2016). **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016). **IEA (New Policies Scenario):** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/. **OPEC:** Organization of the Petroleum Exporting Countries, *2015 World Oil Outlook* (Vienna, Austria: October 2015), http://woo.opec.org/images/woo/WOO_2015.pdf.

Table CP3. Comparisons of energy consumption projections by sector, 2015, 2020, 2035, and 2040: AEO2016 (Reference case): AEO2016 National Energy Modeling System, run REF2016.D032416A.AEO2016. **AEO2016 (No CPP case):** AEO2016 National Energy Modeling System, run REF_NO_CPP.D032316A. **ExxonMobil:** ExxonMobil Corporation, *The Outlook for Energy: A View to 2040* (Irving, TX: 2016), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **BP:** BP p.l.c., *BP Energy Outlook 2035* (London, United Kingdom: February 2015), http://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2015/bp-energy-outlook-2035-booklet.pdf. **IHSGI:** IHS Global Insight, "30-year U.S. Economic Forecast" (Lexington, MA: February 2016), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **IEA:** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040: AEO2016 (Reference case): AEO2016 National Energy Modeling System, run REF2016.D032416A. **AEO2016 (No CPP case):** AEO2016 National Energy Modeling System, run REF_NO_CPP.D032316A. **IEA (New Policies Scenario):** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/. **NREL (Regional Energy Deployment System model reference case):** T. Mai, W. Cole, E. Lantz, C. Marcy, and B. Sigrin, *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions,* NREL/TP-6A20-65571 (Golden, CO: National Renewable Energy Laboratory, February 2016), http://www.nrel.gov/docs/fy16osti/65571.pdf. **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016).

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A. **IHSGI:** IHS Global Insight, "30-year U.S. Economic Forecast" (Lexington, MA: February 2016), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016). **ICF:** ICForecast Natural Gas Strategic Outlook (Fairfax, VA: 1st Quarter 2016), email from Hua Fang (March 28, 2016). **ExxonMobil:** ExxonMobil Corporation, *The Outlook for Energy: A View to 2040* (Irving, TX: 2016), http://www.exxonmobil.com/Corporate/energy_outlook.aspx.

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A. **BP:** BP p.l.c., *BP Energy Outlook 2035* (London, United Kingdom: February 2015), http://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2015/bp-energy-outlook-2035-booklet.pdf. **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016). **ICF:** ICForecast Natural Gas Strategic Outlook (Fairfax, VA: 1st Quarter 2016), email from Hua Fang (March 28, 2016). **IEA (New Policies Scenario):** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/. **ExxonMobil:** ExxonMobil Corporation, *The Outlook for Energy: A View to 2040* (Irving, TX: 2016), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **IHSGI:** IHS Global Insight, "30-year U.S. Economic Forecast" (Lexington, MA: February 2016), http://www.ihs.com/products/global-insight/index.aspx (subscription site).

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040: AEO2016 National Energy Modeling System, run REF2016.D032416A. **EVA:** Energy Ventures Analysis, Inc., email from Wes Mitchell (April 12, 2016). **Wood Mackenzie:** Wood Mackenzie, Inc., email from Shane Mathers (April 22, 2016). **SNL Energy:** S&P Global Market Intelligence, email from Steve Piper (March 29, 2016). **IEA (New Policies Scenario):** International Energy Agency, *World Energy Outlook 2015* (Paris, France: November 2015), http://www.worldenergyoutlook.org/weo2015/. **BP:** BP p.l.c., *BP Energy Outlook 2035* (London, United Kingdom: February 2015), http://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2015/bp-energy-outlook-2035-booklet.pdf.

List of acronyms

AB 32	California Assembly Bill 32, the Global Warming Solutions Act of 2006
ACEEE	American Council for an Energy-Efficient Economy
ACP	alternative compliance payment
AEO	Annual Energy Outlook
AEO2016	Annual Energy Outlook 2016
ACU	atmospheric cracking unit
API	American Petroleum Institute
ARRA	American Recovery and Reinvestment Act
ASHRAE	American Society of Heating, Refrigeration and Air-Conditioning Engineers
ATPZEV	advanced technology partial zero-emission vehicle
b	barrel
b/d	barrels per day
BAT	best available technology
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BF	blast furnace
BOF	basic oxygen furnace
BSER	best system of emission reduction
BTL	biomass-to-liquids
Btu	British thermal unit
Btu/scf	Btu per standard cubic foot
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resource Board
CBTL	coal-and-biomass-to-liquids
CCR	Coal Combustion Residual rule
CCS	carbon capture and storage
CHP	combined heat and power
CMM	Coal Market Module
CNG	compressed natural gas
CO2	carbon dioxide
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
CT	combustion turbine
CTL	coal-to-liquids
CWA	Clean Water Act
DG	distributed generation
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
DOT	U.S. Department of Transportation
DRI	direct reduced iron
DSI	dry sorbent injection
DSIRE	Database of State Incentives for Renewables & Efficiency
EAER	equivalent all-electric range
EAF	electric arc furnace
ECAs	U.S. Emission Control Areas
ECP	Electricity Capacity Planning
EE	energy efficiency
EEPS	energy efficiency portfolio standard
EERS	energy efficiency resource standard
EFD	Electricity Fuel Dispatch
EG	Steam Electric Power Generating Effluent Guidelines and Standards
EGUs	electric generating units
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA	Energy Independence and Security Act of 2007
EMM	Electricity Market Module
EM&V	energy measurement and verification
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
EUR	estimated ultimate recovery
FCC	fluid catalytic cracking
FHWA	Federal Highway Administration
GDP	gross domestic product
GEM	Greenhouse Gas Emissions Model
GHG	greenhouse gas
GTL	gas-to-liquids
GVWR	gross vehicle weight rating
GW	gigawatt
HB2001	West Virginia House Bill 2001
HB40	Vermont House Bill 40
HB623	Hawaii House Bill 623
HD	heavy-duty
HDV	heavy-duty vehicle
HGL	hydrocarbon gas liquids
HVAC	heating, ventilation, and air conditioning
IDM	Industrial Demand Module
IEM	International Energy Module
IMO	International Maritime Organization
IOU	investor-owned utility
ITC	investment tax credit
kWh	kilowatthour
LACE	levelized avoided cost of electricity
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LCOE	levelized cost of electricity
LDV	light-duty vehicle
LFG	landfill gas
LFMM	Liquid Fuels Market Module
LIPA	Long Island Power Authority
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAM	Macroeconomic Activity Module
MARPOL	International Convention for the Prevention of Pollution from Ships

MATS	Mercury Air Toxics Standard
MDV	medium-duty vehicle
MECS	Manufacturing Energy Consumption Survey
MGO	marine gas oil
MMST	million metric short tons
MMT	million metric tons
MOU	memorandum of understanding
mpg	miles per gallon
MSW	municipal solid waste
MT	metric ton
MW	megawatt
MWh	megawatthour
MY	model year
NAICS	North American Industry Classification System
NEEP	Northeast Energy Efficiency Partnerships
NEMS	National Energy Modeling System
NGPL	natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	U.S. National Highway Traffic Safety Administration
NOx	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NYPA	New York Power Authority
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PM2.5	fine particulate matter
POU	publicly owned utility
PRB	Wyoming Powder River Basin
PTC	production tax credit
PUC	public utility commission
PV	solar photovoltaic
PZEV	partial zero-emission vehicle
RECs	Renewable Energy Certificates
RFM	Renewable Fuels Module
RFS	Renewable Fuels Standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
SB91	Kansas Senate Bill 91
SB310	Ohio Senate Bill 310
SB350	California Senate Bill 350
SEU	Sustainable Energy Utility
SOx	sulfur oxide
SO2	sulfur dioxide
SPR	Strategic Petroleum Reserve
SPR	Stream Protection Rule
STEO	Short-Term Energy Outlook
Tcf	trillion cubic feet
TZEV	transitional zero-emission vehicle
VIUS	Vehicle Inventory and Use Survey
VMT	vehicle miles traveled
WTI	West Texas Intermediate
ZEV	zero-emission vehicle

Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	18.4	19.7	19.6	19.7	21.0	22.3	23.5	0.7%
Natural gas plant liquids	4.1	4.4	6.1	6.4	6.5	6.6	6.7	1.6%
Dry natural gas	26.5	28.0	31.4	35.9	38.9	41.2	43.4	1.8%
Coal[1]	20.6	17.2	17.5	15.4	13.3	13.4	13.1	-1.1%
Nuclear / uranium[2]	8.3	8.3	8.1	8.2	8.2	8.2	8.2	0.0%
Conventional hydroelectric power	2.5	2.3	2.8	2.8	2.8	2.8	2.8	0.8%
Biomass[3]	4.4	4.1	4.2	4.3	4.4	4.4	4.6	0.4%
Other renewable energy[4]	2.5	2.6	4.6	6.1	6.6	7.8	8.8	5.0%
Other[5]	1.0	0.5	0.9	1.0	0.9	0.9	1.0	2.8%
Total	**88.4**	**87.3**	**95.4**	**99.8**	**102.7**	**107.7**	**112.2**	**1.0%**
Imports								
Crude oil	16.3	16.1	16.8	16.8	16.0	15.8	15.9	-0.1%
Petroleum and other liquids[6]	3.9	3.9	4.5	4.5	4.3	4.2	4.3	0.4%
Natural gas[7]	2.8	2.8	2.1	1.8	1.6	1.4	1.4	-2.6%
Other imports[8]	0.4	0.4	0.2	0.2	0.2	0.2	0.2	-3.9%
Total	**23.3**	**23.2**	**23.6**	**23.2**	**22.0**	**21.5**	**21.8**	**-0.3%**
Exports								
Petroleum and other liquids[9]	8.2	9.0	11.6	12.5	13.5	14.4	15.2	2.1%
Natural gas[10]	1.5	1.8	5.0	7.1	7.6	8.6	9.0	6.7%
Coal	2.5	2.0	1.9	1.8	1.9	2.2	2.3	0.7%
Total	**12.2**	**12.8**	**18.5**	**21.4**	**23.0**	**25.2**	**26.6**	**3.0%**
Discrepancy[11]	**1.4**	**1.0**	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**- -**
Consumption								
Petroleum and other liquids[12]	36.0	36.5	37.8	37.3	36.6	36.8	37.5	0.1%
Natural gas	27.5	28.3	28.3	30.2	32.5	33.5	35.4	0.9%
Coal[13]	17.9	15.5	15.6	13.5	11.3	11.2	10.7	-1.4%
Nuclear / uranium[2]	8.3	8.3	8.1	8.2	8.2	8.2	8.2	0.0%
Conventional hydroelectric power	2.5	2.3	2.8	2.8	2.8	2.8	2.8	0.8%
Biomass[14]	3.0	2.8	2.8	2.9	3.0	3.0	3.1	0.5%
Other renewable energy[4]	2.5	2.6	4.6	6.1	6.6	7.8	8.8	5.0%
Other[15]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1%
Total	**98.1**	**96.7**	**100.5**	**101.6**	**101.5**	**103.9**	**107.1**	**0.4%**
Prices (2015 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	100	52	77	92	104	120	136	3.9%
West Texas Intermediate	94	49	71	85	97	112	129	4.0%
Natural gas at Henry Hub (dollars per million Btu)	4.44	2.62	4.43	5.12	5.06	4.91	4.86	2.5%
Coal (dollars per ton)								
at the minemouth[16]	35.2	33.8	33.6	34.0	33.8	37.6	38.7	0.5%
Coal (dollars per million Btu)								
at the minemouth[16]	1.73	1.69	1.68	1.71	1.71	1.86	1.91	0.5%
Average end-use[17]	2.52	2.37	2.43	2.49	2.55	2.61	2.68	0.5%
Average electricity (cents per kilowatthour)	10.5	10.3	10.5	10.7	10.9	10.6	10.5	0.1%

Table A1. Total energy supply, disposition, and price summary *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	99	52	85	112	141	181	229	6.1%
West Texas Intermediate	93	49	79	105	131	170	217	6.2%
Natural gas at Henry Hub (dollars per million Btu)	4.39	2.62	4.90	6.27	6.84	7.42	8.17	4.7%
Coal (dollars per ton)								
at the minemouth[16]	34.9	33.8	37.1	41.6	45.8	56.8	65.1	2.7%
Coal (dollars per million Btu)								
at the minemouth[16]	1.71	1.69	1.86	2.09	2.31	2.81	3.21	2.6%
Average end-use[17]	2.49	2.37	2.69	3.05	3.45	3.94	4.50	2.6%
Average electricity (cents per kilowatthour)	10.4	10.3	11.6	13.1	14.7	16.1	17.6	2.2%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 natural gas supply values: EIA, *Natural Gas Monthly*, July 2015. 2014 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*. 2014 petroleum supply values: EIA, *Petroleum Supply Annual 2014*. 2014 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2014 coal values: *Quarterly Coal Report, October-December 2014*. Other 2014: EIA, *Monthly Energy Review*, February 2016. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.50	0.43	0.42	0.40	0.38	0.36	0.34	-0.9%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-2.6%
Distillate fuel oil	0.55	0.50	0.43	0.38	0.34	0.30	0.27	-2.4%
Petroleum and other liquids subtotal	1.05	0.93	0.86	0.78	0.72	0.66	0.61	-1.7%
Natural gas	5.25	4.77	4.87	4.82	4.80	4.77	4.73	0.0%
Renewable energy[1]	0.59	0.44	0.42	0.41	0.39	0.38	0.37	-0.7%
Electricity	4.80	4.78	4.76	4.75	4.83	4.97	5.20	0.3%
Delivered energy	**11.70**	**10.92**	**10.90**	**10.77**	**10.74**	**10.78**	**10.91**	**0.0%**
Electricity related losses	9.72	9.44	9.37	9.03	8.77	8.93	9.15	-0.1%
Total	**21.42**	**20.37**	**20.27**	**19.79**	**19.50**	**19.71**	**20.05**	**-0.1%**
Commercial								
Propane	0.15	0.17	0.18	0.19	0.19	0.20	0.20	0.7%
Motor gasoline[2]	0.04	0.04	0.06	0.06	0.06	0.07	0.07	2.1%
Kerosene	0.00	0.00	0.00	0.00	0.01	0.01	0.01	5.0%
Distillate fuel oil	0.36	0.37	0.36	0.34	0.32	0.30	0.29	-1.0%
Residual fuel oil	0.02	0.07	0.11	0.10	0.10	0.10	0.10	1.2%
Petroleum and other liquids subtotal	0.57	0.66	0.70	0.69	0.68	0.67	0.67	0.1%
Natural gas	3.58	3.32	3.45	3.46	3.53	3.66	3.81	0.5%
Coal	0.05	0.06	0.05	0.05	0.05	0.05	0.05	-0.4%
Renewable energy[3]	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.0%
Electricity	4.61	4.64	4.69	4.86	5.09	5.33	5.62	0.8%
Delivered energy	**8.95**	**8.81**	**9.03**	**9.20**	**9.49**	**9.86**	**10.28**	**0.6%**
Electricity related losses	9.34	9.16	9.23	9.23	9.23	9.57	9.89	0.3%
Total	**18.29**	**17.97**	**18.26**	**18.43**	**18.72**	**19.43**	**20.17**	**0.5%**
Industrial[4]								
Liquefied petroleum gases and other[5]	2.44	2.38	3.10	3.50	3.66	3.92	4.22	2.3%
Motor gasoline[2]	0.27	0.27	0.28	0.27	0.27	0.27	0.27	0.0%
Distillate fuel oil	1.36	1.34	1.44	1.45	1.44	1.45	1.47	0.4%
Residual fuel oil	0.03	0.04	0.04	0.06	0.06	0.05	0.05	1.6%
Petrochemical feedstocks	0.70	0.66	0.96	1.21	1.31	1.47	1.66	3.8%
Other petroleum[6]	3.19	3.38	3.59	3.71	3.82	3.95	4.15	0.8%
Petroleum and other liquids subtotal	7.99	8.07	9.40	10.19	10.55	11.13	11.82	1.5%
Natural gas	7.84	7.75	8.55	8.93	9.13	9.49	9.89	1.0%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.55	1.63	1.76	1.94	2.06	2.19	2.31	1.4%
Natural gas liquefaction for export[8]	0.00	0.00	0.26	0.48	0.53	0.64	0.69	- -
Natural gas subtotal	9.40	9.38	10.57	11.34	11.72	12.32	12.89	1.3%
Metallurgical coal	0.58	0.54	0.41	0.45	0.47	0.43	0.40	-1.2%
Other industrial coal	0.87	0.82	0.82	0.86	0.88	0.89	0.93	0.5%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	-0.02	-0.02	-0.01	0.00	0.00	0.01	0.01	- -
Coal subtotal	1.43	1.34	1.23	1.31	1.35	1.33	1.34	0.0%
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Renewable energy[9]	1.52	1.48	1.48	1.59	1.67	1.70	1.79	0.8%
Electricity	3.40	3.27	3.61	3.91	3.98	4.08	4.26	1.1%
Delivered energy	**24.49**	**24.33**	**27.11**	**29.14**	**30.07**	**31.38**	**32.94**	**1.2%**
Electricity related losses	6.89	6.46	7.11	7.42	7.22	7.34	7.50	0.6%
Total	**31.38**	**30.79**	**34.22**	**36.56**	**37.29**	**38.72**	**40.44**	**1.1%**

Table A2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Transportation								
Propane	0.01	0.01	0.01	0.01	0.01	0.01	0.02	3.3%
Motor gasoline[2]	16.78	17.01	16.79	15.05	13.62	12.84	12.55	-1.2%
of which: E85[10]	0.03	0.05	0.04	0.12	0.22	0.27	0.28	7.3%
Jet fuel[11]	2.82	2.84	2.99	3.14	3.32	3.46	3.56	0.9%
Distillate fuel oil[12]	6.40	6.67	6.99	7.28	7.49	7.77	8.01	0.7%
Residual fuel oil	0.44	0.45	0.37	0.40	0.42	0.44	0.45	0.1%
Other petroleum[13]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.1%
Petroleum and other liquids subtotal	26.61	27.14	27.32	26.04	25.01	24.68	24.75	-0.4%
Pipeline fuel natural gas	0.87	0.89	0.83	0.89	0.94	1.00	1.07	0.7%
Compressed / liquefied natural gas	0.06	0.07	0.08	0.10	0.17	0.31	0.59	9.2%
Liquid hydrogen	0.00	0.00	0.01	0.03	0.04	0.05	0.06	22.9%
Electricity	0.03	0.03	0.05	0.08	0.11	0.14	0.15	6.7%
Delivered energy	**27.56**	**28.13**	**28.29**	**27.13**	**26.28**	**26.18**	**26.63**	**-0.2%**
Electricity related losses	0.05	0.06	0.09	0.15	0.20	0.24	0.27	6.2%
Total	**27.61**	**28.19**	**28.38**	**27.28**	**26.48**	**26.42**	**26.90**	**-0.2%**
Unspecified sector[14]	**-0.57**	**-0.58**	**-0.58**	**-0.52**	**-0.46**	**-0.43**	**-0.42**	**-1.3%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases and other[5]	3.09	2.99	3.71	4.09	4.24	4.49	4.79	1.9%
Motor gasoline[2]	16.51	16.96	16.55	14.87	13.49	12.74	12.47	-1.2%
of which: E85[10]	0.03	0.05	0.04	0.12	0.22	0.27	0.28	7.3%
Jet fuel[11]	3.04	3.18	3.22	3.38	3.58	3.72	3.83	0.7%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.3%
Distillate fuel oil	8.45	8.33	8.98	9.19	9.33	9.56	9.77	0.6%
Residual fuel oil	0.50	0.56	0.52	0.56	0.57	0.59	0.60	0.3%
Petrochemical feedstocks	0.70	0.66	0.96	1.21	1.31	1.47	1.66	3.8%
Other petroleum[15]	3.35	3.54	3.75	3.87	3.98	4.12	4.31	0.8%
Petroleum and other liquids subtotal	35.65	36.23	37.70	37.18	36.51	36.71	37.44	0.1%
Natural gas	16.73	15.90	16.95	17.31	17.63	18.23	19.02	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.55	1.63	1.76	1.94	2.06	2.19	2.31	1.4%
Natural gas liquefaction for export[8]	0.00	0.00	0.26	0.48	0.53	0.64	0.69	- -
Pipeline fuel natural gas	0.87	0.89	0.83	0.89	0.94	1.00	1.07	0.7%
Natural gas subtotal	19.15	18.43	19.80	20.61	21.16	22.06	23.09	0.9%
Metallurgical coal	0.58	0.54	0.41	0.45	0.47	0.43	0.40	-1.2%
Other coal	0.92	0.88	0.88	0.92	0.93	0.95	0.98	0.5%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	-0.02	-0.02	-0.01	0.00	0.00	0.01	0.01	- -
Coal subtotal	1.48	1.40	1.28	1.36	1.40	1.39	1.39	0.0%
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Renewable energy[16]	2.24	2.06	2.03	2.13	2.19	2.22	2.29	0.4%
Liquid hydrogen	0.00	0.00	0.01	0.03	0.04	0.05	0.06	22.9%
Electricity	12.84	12.72	13.11	13.60	14.01	14.52	15.23	0.7%
Delivered energy	**72.12**	**71.62**	**74.75**	**75.73**	**76.12**	**77.77**	**80.34**	**0.5%**
Electricity related losses	26.01	25.12	25.80	25.83	25.41	26.09	26.81	0.3%
Total	**98.13**	**96.74**	**100.55**	**101.56**	**101.54**	**103.85**	**107.15**	**0.4%**
Electric power[17]								
Distillate fuel oil	0.09	0.09	0.09	0.08	0.06	0.06	0.05	-2.0%
Residual fuel oil	0.22	0.17	0.06	0.05	0.04	0.04	0.03	-6.6%
Petroleum and other liquids subtotal	0.31	0.26	0.15	0.13	0.11	0.10	0.09	-4.4%
Natural gas	8.38	9.89	8.50	9.60	11.34	11.46	12.31	0.9%
Steam coal	16.42	14.08	14.34	12.12	9.92	9.82	9.36	-1.6%
Nuclear / uranium[18]	8.33	8.34	8.12	8.25	8.25	8.25	8.25	0.0%
Renewable energy[19]	5.01	4.86	7.37	8.91	9.41	10.60	11.67	3.6%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.18	0.19	0.19	0.20	0.17	0.16	0.15	-1.1%
Total	**38.86**	**37.85**	**38.90**	**39.43**	**39.42**	**40.61**	**42.04**	**0.4%**

Table A2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases and other[5]	3.09	2.99	3.71	4.09	4.24	4.49	4.79	1.9%
Motor gasoline[2]	16.51	16.96	16.55	14.87	13.49	12.74	12.47	-1.2%
of which: E85[10]	0.03	0.05	0.04	0.12	0.22	0.27	0.28	7.3%
Jet fuel[11]	3.04	3.18	3.22	3.38	3.58	3.72	3.83	0.7%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.3%
Distillate fuel oil	8.54	8.42	9.07	9.27	9.40	9.62	9.82	0.6%
Residual fuel oil	0.72	0.73	0.58	0.61	0.62	0.63	0.64	-0.5%
Petrochemical feedstocks	0.70	0.66	0.96	1.21	1.31	1.47	1.66	3.8%
Other petroleum[15]	3.35	3.54	3.75	3.87	3.98	4.12	4.31	0.8%
Petroleum and other liquids subtotal	35.96	36.49	37.85	37.31	36.62	36.81	37.52	0.1%
Natural gas	25.11	25.79	25.45	26.91	28.97	29.69	31.33	0.8%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.55	1.63	1.76	1.94	2.06	2.19	2.31	1.4%
Natural gas liquefaction for export[8]	0.00	0.00	0.26	0.48	0.53	0.64	0.69	- -
Pipeline fuel natural gas	0.87	0.89	0.83	0.89	0.94	1.00	1.07	0.7%
Natural gas subtotal	27.53	28.31	28.30	30.22	32.51	33.52	35.39	0.9%
Metallurgical coal	0.58	0.54	0.41	0.45	0.47	0.43	0.40	-1.2%
Other coal	17.34	14.96	15.22	13.04	10.86	10.77	10.34	-1.5%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	-0.02	-0.02	-0.01	0.00	0.00	0.01	0.01	- -
Coal subtotal	17.90	15.48	15.62	13.49	11.32	11.21	10.75	-1.4%
Nuclear / uranium[18]	8.33	8.34	8.12	8.25	8.25	8.25	8.25	0.0%
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Renewable energy[20]	7.26	6.92	9.40	11.04	11.60	12.82	13.96	2.8%
Liquid hydrogen	0.00	0.00	0.01	0.03	0.04	0.05	0.06	22.9%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.18	0.19	0.19	0.20	0.17	0.16	0.15	-1.1%
Total	**98.13**	**96.74**	**100.55**	**101.56**	**101.54**	**103.85**	**107.15**	**0.4%**
Energy use and related statistics								
Delivered energy use	72.12	71.62	74.75	75.73	76.12	77.77	80.34	0.5%
Total energy use	98.13	96.74	100.55	101.56	101.54	103.85	107.15	0.4%
Ethanol consumed in motor gasoline and E85	1.14	1.18	1.19	1.13	1.12	1.14	1.24	0.2%
Population (millions)	319	322	335	348	360	371	381	0.7%
Gross domestic product (billion 2009 dollars)	15,962	16,349	18,555	20,765	23,113	25,598	28,397	2.2%
Carbon dioxide emissions (million metric tons)	5,406	5,273	5,289	5,115	4,961	4,980	5,044	-0.2%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[8]Fuel used in facilities that liquefy natural gas for export.
[9]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Diesel fuel for on- and off- road use.
[13]Includes aviation gasoline and lubricants.
[14]Represents consumption unattributed to the sectors above.
[15]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[16]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[17]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[18]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[20]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 consumption, carbon dioxide emissions, and emission factors based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2014 population and gross domestic product: IHS Economics, Industry and Employment models, November 2015. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A3. Energy prices by sector and source
(2015 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Residential								
Propane	23.3	16.9	20.2	21.4	22.4	24.0	25.6	1.7%
Distillate fuel oil	26.9	19.3	22.4	25.5	27.8	30.8	33.8	2.3%
Natural gas	10.7	10.1	10.7	11.6	12.0	12.1	12.3	0.8%
Electricity	37.1	36.3	37.7	38.8	39.4	38.7	38.1	0.2%
Commercial								
Propane	20.6	15.1	17.9	18.9	19.8	21.2	22.5	1.6%
Distillate fuel oil	26.4	17.0	19.7	22.2	24.4	27.4	30.5	2.4%
Residual fuel oil	16.7	6.9	11.0	13.5	15.3	17.6	19.9	4.3%
Natural gas	9.0	7.7	9.3	10.1	10.4	10.3	10.4	1.2%
Electricity	31.8	30.6	31.5	32.0	32.3	31.4	30.7	0.0%
Industrial[1]								
Propane	18.8	12.2	15.6	16.8	17.8	19.5	21.1	2.2%
Distillate fuel oil	27.1	17.0	19.7	22.2	24.4	27.4	30.5	2.4%
Residual fuel oil	15.0	6.8	11.3	14.2	15.9	18.2	20.6	4.6%
Natural gas[2]	5.4	3.7	5.4	6.0	6.0	5.8	5.7	1.7%
Metallurgical coal	5.3	5.4	6.0	6.5	7.0	7.2	7.3	1.2%
Other industrial coal	3.2	3.4	3.4	3.4	3.4	3.5	3.6	0.2%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	21.0	20.3	20.9	21.5	22.1	21.5	21.2	0.2%
Transportation								
Propane	24.4	18.0	21.2	22.4	23.4	25.0	26.6	1.6%
E85[3]	33.3	23.3	32.0	31.2	30.8	32.3	35.0	1.6%
Motor gasoline[4]	28.4	20.9	22.7	24.7	26.5	28.9	31.8	1.7%
Jet fuel[5]	20.8	12.0	16.2	19.0	21.3	24.5	27.7	3.4%
Diesel fuel (distillate fuel oil)[6]	27.8	19.8	23.1	25.8	28.0	31.0	34.1	2.2%
Residual fuel oil	14.6	8.1	11.7	13.4	15.0	17.0	19.2	3.5%
Natural gas[7]	18.4	16.6	16.6	16.4	15.5	15.4	15.9	-0.2%
Electricity	32.2	29.5	33.0	36.0	37.4	36.4	35.5	0.7%
Electric power[8]								
Distillate fuel oil	23.8	15.0	18.4	21.2	23.5	26.4	29.4	2.7%
Residual fuel oil	18.3	10.2	13.8	16.3	18.1	20.2	22.4	3.2%
Natural gas	5.1	3.3	4.7	5.4	5.6	5.4	5.4	2.0%
Steam coal	2.4	2.2	2.3	2.3	2.3	2.3	2.4	0.3%
Average price to all users[9]								
Propane	21.2	14.9	18.0	19.2	20.1	21.6	23.2	1.8%
E85[3]	33.3	23.3	32.0	31.2	30.8	32.3	35.0	1.6%
Motor gasoline[4]	28.4	20.9	22.7	24.7	26.5	28.9	31.8	1.7%
Jet fuel[5]	20.8	12.0	16.2	19.0	21.3	24.5	27.7	3.4%
Distillate fuel oil	27.5	19.1	22.3	25.1	27.3	30.3	33.3	2.2%
Residual fuel oil	15.8	8.4	11.7	13.8	15.4	17.4	19.6	3.4%
Natural gas	6.9	5.3	6.7	7.4	7.4	7.3	7.4	1.4%
Metallurgical coal	5.3	5.4	6.0	6.5	7.0	7.2	7.3	1.2%
Other coal	2.4	2.3	2.3	2.4	2.4	2.4	2.5	0.4%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	30.9	30.1	30.8	31.4	31.9	31.2	30.6	0.1%
Non-renewable energy expenditures by sector (billion 2015 dollars)								
Residential	261	239	250	259	266	268	274	0.6%
Commercial	193	178	193	205	216	221	230	1.0%
Industrial[1]	231	168	232	276	301	330	369	3.2%
Transportation	707	514	586	615	640	698	777	1.7%
Total non-renewable expenditures	1,391	1,099	1,260	1,355	1,423	1,517	1,650	1.6%
Transportation renewable expenditures	1	1	1	4	7	9	10	9.1%
Total expenditures	**1,393**	**1,100**	**1,262**	**1,359**	**1,430**	**1,526**	**1,660**	**1.7%**

Table A3. Energy prices by sector and source *(continued)*
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Residential								
Propane	23.1	16.9	22.3	26.2	30.3	36.2	43.0	3.8%
Distillate fuel oil	26.7	19.3	24.7	31.2	37.6	46.5	56.9	4.4%
Natural gas	10.6	10.1	11.9	14.2	16.3	18.3	20.8	2.9%
Electricity	36.7	36.3	41.7	47.5	53.3	58.4	64.2	2.3%
Commercial								
Propane	20.4	15.1	19.8	23.2	26.8	31.9	37.9	3.8%
Distillate fuel oil	26.1	17.0	21.8	27.2	33.1	41.4	51.2	4.5%
Residual fuel oil	16.5	6.9	12.1	16.5	20.7	26.5	33.6	6.5%
Natural gas	8.9	7.7	10.3	12.3	14.1	15.6	17.5	3.4%
Electricity	31.5	30.6	34.8	39.2	43.7	47.4	51.7	2.1%
Industrial[1]								
Propane	18.7	12.2	17.2	20.6	24.1	29.4	35.6	4.4%
Distillate fuel oil	26.8	17.0	21.8	27.2	33.1	41.4	51.3	4.5%
Residual fuel oil	14.8	6.8	12.4	17.4	21.6	27.5	34.7	6.8%
Natural gas[2]	5.3	3.7	5.9	7.3	8.1	8.7	9.6	3.9%
Metallurgical coal	5.3	5.4	6.7	8.0	9.4	10.9	12.2	3.3%
Other industrial coal	3.2	3.4	3.7	4.2	4.6	5.2	6.0	2.4%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.8	20.3	23.1	26.3	29.9	32.5	35.7	2.3%
Transportation								
Propane	24.1	18.0	23.4	27.5	31.7	37.8	44.8	3.7%
E85[3]	32.9	23.3	35.4	38.2	41.7	48.8	58.8	3.8%
Motor gasoline[4]	28.1	20.9	25.1	30.2	35.9	43.7	53.6	3.8%
Jet fuel[5]	20.6	12.0	17.9	23.2	28.8	37.0	46.6	5.6%
Diesel fuel (distillate fuel oil)[6]	27.5	19.8	25.5	31.6	37.9	46.7	57.3	4.3%
Residual fuel oil	14.5	8.1	12.9	16.5	20.3	25.7	32.3	5.7%
Natural gas[7]	18.2	16.6	18.4	20.0	21.0	23.2	26.7	1.9%
Electricity	31.8	29.5	36.5	44.1	50.5	55.0	59.8	2.9%
Electric power[8]								
Distillate fuel oil	23.5	15.0	20.4	26.0	31.8	39.9	49.4	4.9%
Residual fuel oil	18.1	10.2	15.2	19.9	24.4	30.5	37.8	5.4%
Natural gas	5.0	3.3	5.2	6.6	7.5	8.1	9.0	4.2%
Steam coal	2.4	2.2	2.5	2.8	3.1	3.5	4.0	2.5%

Table A3. Energy prices by sector and source *(continued)*
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	21.0	14.9	19.9	23.5	27.2	32.6	39.0	3.9%
E85[3]	32.9	23.3	35.4	38.2	41.7	48.8	58.8	3.8%
Motor gasoline[4]	28.1	20.9	25.1	30.2	35.9	43.7	53.6	3.8%
Jet fuel[5]	20.6	12.0	17.9	23.2	28.8	37.0	46.6	5.6%
Distillate fuel oil	27.2	19.1	24.7	30.7	36.9	45.7	56.1	4.4%
Residual fuel oil	15.7	8.4	13.0	16.8	20.8	26.2	32.9	5.6%
Natural gas	6.9	5.3	7.4	9.0	10.0	11.1	12.4	3.5%
Metallurgical coal	5.3	5.4	6.7	8.0	9.4	10.9	12.2	3.3%
Other coal	2.4	2.3	2.6	2.9	3.2	3.7	4.2	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	30.6	30.1	34.1	38.4	43.1	47.0	51.6	2.2%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	258	239	276	317	360	405	462	2.7%
Commercial	191	178	213	251	292	334	387	3.2%
Industrial[1]	229	168	256	338	407	498	620	5.4%
Transportation	699	514	647	753	866	1,054	1,307	3.8%
Total non-renewable expenditures	1,377	1,099	1,392	1,659	1,925	2,291	2,776	3.8%
Transportation renewable expenditures	1	1	1	5	9	13	17	11.4%
Total expenditures	**1,378**	**1,100**	**1,394**	**1,663**	**1,934**	**2,304**	**2,793**	**3.8%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, January 2105-December 2015. 2014 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, July 2015. 2015 transportation sector natural gas delivered prices derived from: U.S. Department of Energy, Clean Cities Alternative Fuel Price Report. 2014 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, February 2016. 2014 electric power sector natural gas prices: EIA, *Electric Power Monthly*, April 2014 and April 2015, Table 4.2, and EIA, *State Energy Data Report 2013*. 2014 coal prices based on: EIA, *Quarterly Coal Report, October-December 2014* and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. 2014 electricity prices: EIA, *Monthly Energy Review*, February 2016. 2014 E85 prices derived from: U.S. Department of Energy, Clean Cities Alternative Fuel Price Report. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Key indicators								
Households (millions)								
Single-family	80.1	80.6	84.4	88.5	92.2	95.5	99.0	0.8%
Multifamily	28.6	28.9	30.5	32.3	34.0	35.8	37.5	1.1%
Mobile homes	6.1	6.0	5.5	5.3	5.1	4.9	4.8	-0.9%
Total	**114.8**	**115.4**	**120.4**	**126.0**	**131.3**	**136.3**	**141.4**	**0.8%**
Average house square footage	**1,686**	**1,694**	**1,733**	**1,768**	**1,799**	**1,828**	**1,857**	**0.4%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	101.9	94.6	90.5	85.4	81.8	79.1	77.1	-0.8%
Total energy consumption	186.6	176.5	168.3	157.1	148.5	144.6	141.8	-0.9%
(thousand Btu per square foot)								
Delivered energy consumption	60.4	55.9	52.3	48.3	45.5	43.2	41.6	-1.2%
Total energy consumption	110.7	104.2	97.1	88.9	82.6	79.1	76.4	-1.2%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating	0.43	0.33	0.36	0.35	0.34	0.34	0.33	0.0%
Space cooling	0.65	0.80	0.74	0.75	0.79	0.84	0.89	0.4%
Water heating	0.45	0.45	0.46	0.47	0.47	0.48	0.48	0.2%
Refrigeration	0.36	0.36	0.34	0.33	0.33	0.34	0.36	0.0%
Cooking	0.11	0.11	0.11	0.12	0.13	0.14	0.14	1.1%
Clothes dryers	0.20	0.21	0.21	0.22	0.23	0.24	0.26	0.9%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.51	0.50	0.43	0.37	0.30	0.25	0.23	-3.0%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.09	0.09	0.10	0.10	0.11	0.12	0.13	1.2%
Televisions and related equipment[2]	0.30	0.29	0.26	0.25	0.26	0.29	0.32	0.4%
Computers and related equipment[3]	0.11	0.11	0.09	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.14	0.11	0.12	0.12	0.11	0.11	0.10	-0.5%
Other uses[4]	1.34	1.32	1.43	1.50	1.60	1.70	1.82	1.3%
Delivered energy	**4.80**	**4.78**	**4.76**	**4.75**	**4.83**	**4.97**	**5.20**	**0.3%**
Natural gas								
Space heating	3.52	3.03	3.11	3.04	3.01	2.98	2.95	-0.1%
Space cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.9%
Water heating	1.21	1.21	1.23	1.25	1.27	1.27	1.25	0.1%
Cooking	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.3%
Clothes dryers	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.7%
Other uses[5]	0.25	0.25	0.24	0.24	0.23	0.23	0.22	-0.5%
Delivered energy	**5.25**	**4.77**	**4.87**	**4.82**	**4.80**	**4.77**	**4.73**	**0.0%**
Distillate fuel oil								
Space heating	0.49	0.45	0.40	0.35	0.31	0.28	0.25	-2.3%
Water heating	0.05	0.04	0.03	0.02	0.02	0.02	0.01	-4.7%
Other uses[6]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.6%
Delivered energy	**0.55**	**0.50**	**0.43**	**0.38**	**0.34**	**0.30**	**0.27**	**-2.4%**
Propane								
Space heating	0.37	0.29	0.30	0.27	0.26	0.24	0.22	-1.1%
Water heating	0.06	0.06	0.05	0.05	0.04	0.03	0.03	-2.7%
Cooking	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-0.8%
Other uses[6]	0.04	0.04	0.05	0.05	0.05	0.06	0.06	1.4%
Delivered energy	**0.50**	**0.43**	**0.42**	**0.40**	**0.38**	**0.36**	**0.34**	**-0.9%**
Marketed renewables (wood)[7]	0.59	0.44	0.42	0.41	0.39	0.38	0.37	-0.7%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-2.6%

Table A4. Residential sector key indicators and consumption *(continued)*

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	5.40	4.55	4.58	4.43	4.31	4.22	4.13	-0.4%
Space cooling	0.67	0.83	0.76	0.77	0.81	0.86	0.91	0.4%
Water heating	1.76	1.77	1.78	1.79	1.81	1.79	1.78	0.0%
Refrigeration	0.36	0.36	0.34	0.33	0.33	0.34	0.36	0.0%
Cooking	0.34	0.34	0.35	0.36	0.37	0.38	0.39	0.5%
Clothes dryers	0.25	0.26	0.27	0.28	0.29	0.30	0.32	0.9%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.51	0.50	0.43	0.37	0.30	0.25	0.23	-3.0%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.09	0.09	0.10	0.10	0.11	0.12	0.13	1.2%
Televisions and related equipment[2]	0.30	0.29	0.26	0.25	0.26	0.29	0.32	0.4%
Computers and related equipment[3]	0.11	0.11	0.09	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.14	0.11	0.12	0.12	0.11	0.11	0.10	-0.5%
Other uses[8]	1.64	1.62	1.73	1.80	1.89	1.99	2.11	1.1%
Delivered energy	**11.70**	**10.92**	**10.90**	**10.77**	**10.74**	**10.78**	**10.91**	**0.0%**
Electricity related losses	**9.72**	**9.44**	**9.37**	**9.03**	**8.77**	**8.93**	**9.15**	**-0.1%**
Total energy consumption by end use								
Space heating	6.27	5.20	5.29	5.10	4.94	4.83	4.72	-0.4%
Space cooling	1.98	2.41	2.21	2.20	2.24	2.36	2.48	0.1%
Water heating	2.67	2.66	2.69	2.69	2.67	2.65	2.62	-0.1%
Refrigeration	1.09	1.06	1.01	0.96	0.93	0.95	0.98	-0.3%
Cooking	0.56	0.56	0.58	0.59	0.60	0.62	0.64	0.5%
Clothes dryers	0.67	0.66	0.69	0.70	0.71	0.74	0.77	0.6%
Freezers	0.23	0.22	0.21	0.20	0.18	0.18	0.18	-1.0%
Lighting	1.54	1.47	1.29	1.07	0.85	0.69	0.64	-3.3%
Clothes washers[1]	0.08	0.08	0.07	0.05	0.05	0.04	0.05	-2.3%
Dishwashers[1]	0.29	0.28	0.29	0.29	0.31	0.33	0.35	0.9%
Televisions and related equipment[2]	0.91	0.85	0.77	0.73	0.74	0.81	0.88	0.1%
Computers and related equipment[3]	0.35	0.33	0.28	0.23	0.20	0.17	0.14	-3.3%
Furnace fans and boiler circulation pumps	0.43	0.34	0.36	0.34	0.31	0.29	0.28	-0.8%
Other uses[8]	4.36	4.23	4.55	4.65	4.79	5.05	5.32	0.9%
Total	**21.42**	**20.37**	**20.27**	**19.79**	**19.50**	**19.71**	**20.05**	**-0.1%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.8%
Solar hot water heating	0.01	0.01	0.01	0.02	0.02	0.02	0.02	3.4%
Solar photovoltaic	0.05	0.08	0.30	0.43	0.57	0.71	0.86	10.2%
Wind	0.01	0.02	0.03	0.03	0.03	0.03	0.03	2.0%
Total	**0.08**	**0.11**	**0.35**	**0.50**	**0.63**	**0.78**	**0.94**	**8.8%**
Heating degree days[10]	**4,549**	**4,084**	**4,173**	**4,106**	**4,041**	**3,977**	**3,914**	**-0.2%**
Cooling degree days[10]	**1,299**	**1,488**	**1,456**	**1,503**	**1,551**	**1,599**	**1,648**	**0.4%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills, exterior lights, pool heaters, spa heaters, and backup electricity generators.
[6]Includes such appliances as pool heaters, spa heaters, and backup electricity generators.
[7]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2009*.
[8]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[9]Consumption determined by using the fossil fuel equivalent of 9,541 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2014 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case 2014	2015	2020	2025	2030	2035	2040	Annual growth 2015-2040 (percent)
Key indicators								
Total floorspace (billion square feet)								
Surviving	81.6	82.2	86.7	91.9	97.1	102.3	107.5	1.1%
New additions	1.5	1.7	2.1	2.1	2.2	2.3	2.3	1.4%
Total	**83.1**	**83.8**	**88.7**	**94.0**	**99.3**	**104.6**	**109.8**	**1.1%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	107.6	105.1	101.8	97.8	95.6	94.3	93.6	-0.5%
Electricity related losses	112.4	109.3	104.0	98.2	92.9	91.5	90.0	-0.8%
Total energy consumption	220.0	214.3	205.8	196.0	188.5	185.8	183.7	-0.6%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.16	0.14	0.14	0.13	0.13	0.13	0.13	-0.4%
Space cooling[1]	0.48	0.55	0.52	0.52	0.53	0.55	0.57	0.1%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.08	0.08	-0.3%
Ventilation	0.51	0.52	0.54	0.56	0.57	0.58	0.61	0.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Lighting	0.89	0.88	0.87	0.83	0.81	0.76	0.74	-0.7%
Refrigeration	0.37	0.36	0.33	0.31	0.30	0.30	0.31	-0.6%
Office equipment (PC)	0.09	0.08	0.06	0.05	0.04	0.03	0.02	-4.8%
Office equipment (non-PC)	0.22	0.22	0.24	0.26	0.30	0.34	0.38	2.2%
Other uses[2]	1.79	1.76	1.88	2.08	2.30	2.53	2.76	1.8%
Delivered energy	**4.61**	**4.64**	**4.69**	**4.86**	**5.09**	**5.33**	**5.62**	**0.8%**
Natural gas								
Space heating[1]	1.92	1.74	1.75	1.70	1.66	1.64	1.62	-0.3%
Space cooling[1]	0.03	0.04	0.04	0.04	0.04	0.04	0.04	-0.6%
Water heating[1]	0.54	0.55	0.56	0.57	0.60	0.63	0.66	0.8%
Cooking	0.20	0.21	0.22	0.22	0.23	0.25	0.26	0.9%
Other uses[3]	0.89	0.79	0.89	0.93	1.01	1.11	1.22	1.8%
Delivered energy	**3.58**	**3.32**	**3.45**	**3.46**	**3.53**	**3.66**	**3.81**	**0.5%**
Distillate fuel oil								
Space heating[1]	0.16	0.16	0.15	0.14	0.13	0.11	0.10	-1.6%
Water heating[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Other uses[4]	0.18	0.19	0.18	0.18	0.18	0.17	0.17	-0.6%
Delivered energy	**0.36**	**0.37**	**0.36**	**0.34**	**0.32**	**0.30**	**0.29**	**-1.0%**
Marketed renewables (biomass)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.0%
Other fuels[5]	0.26	0.34	0.40	0.41	0.42	0.42	0.43	0.9%
Delivered energy consumption by end use								
Space heating[1]	2.24	2.03	2.04	1.97	1.92	1.89	1.85	-0.4%
Space cooling[1]	0.51	0.60	0.56	0.56	0.57	0.58	0.60	0.0%
Water heating[1]	0.64	0.66	0.67	0.68	0.70	0.73	0.77	0.6%
Ventilation	0.51	0.52	0.54	0.56	0.57	0.58	0.61	0.6%
Cooking	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.8%
Lighting	0.89	0.88	0.87	0.83	0.81	0.76	0.74	-0.7%
Refrigeration	0.37	0.36	0.33	0.31	0.30	0.30	0.31	-0.6%
Office equipment (PC)	0.09	0.08	0.06	0.05	0.04	0.03	0.02	-4.8%
Office equipment (non-PC)	0.22	0.22	0.24	0.26	0.30	0.34	0.38	2.2%
Other uses[6]	3.26	3.23	3.49	3.74	4.03	4.36	4.72	1.5%
Delivered energy	**8.95**	**8.81**	**9.03**	**9.20**	**9.49**	**9.86**	**10.28**	**0.6%**

Table A5. Commercial sector key indicators and consumption *(continued)*

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Electricity related losses	**9.34**	**9.16**	**9.23**	**9.23**	**9.23**	**9.57**	**9.89**	**0.3%**
Total energy consumption by end use								
Space heating[1]	2.57	2.32	2.32	2.22	2.16	2.12	2.08	-0.4%
Space cooling[1]	1.47	1.69	1.59	1.56	1.53	1.57	1.60	-0.2%
Water heating[1]	0.83	0.83	0.84	0.84	0.86	0.89	0.91	0.4%
Ventilation	1.55	1.54	1.61	1.62	1.60	1.63	1.67	0.3%
Cooking	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.6%
Lighting	2.68	2.62	2.58	2.41	2.27	2.12	2.04	-1.0%
Refrigeration	1.11	1.08	0.97	0.89	0.84	0.85	0.85	-0.9%
Office equipment (PC)	0.27	0.25	0.18	0.14	0.10	0.08	0.07	-5.1%
Office equipment (non-PC)	0.65	0.65	0.70	0.76	0.85	0.96	1.05	1.9%
Other uses[6]	6.88	6.71	7.19	7.70	8.20	8.90	9.57	1.4%
Total	**18.29**	**17.97**	**18.26**	**18.43**	**18.72**	**19.43**	**20.17**	**0.5%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.09	0.09	0.10	0.10	0.11	0.11	1.0%
Solar photovoltaic	0.06	0.07	0.09	0.12	0.19	0.27	0.35	6.5%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%
Total	**0.15**	**0.16**	**0.18**	**0.22**	**0.29**	**0.38**	**0.47**	**4.4%**
Heating degree days								
New England	6,674	6,526	6,099	6,004	5,909	5,813	5,716	-0.5%
Middle Atlantic	6,203	5,781	5,533	5,459	5,385	5,312	5,240	-0.4%
East North Central	7,194	6,168	6,207	6,182	6,158	6,133	6,109	0.0%
West North Central	7,304	6,090	6,521	6,508	6,492	6,476	6,459	0.2%
South Atlantic	2,952	2,492	2,628	2,593	2,559	2,526	2,494	0.0%
East South Central	3,931	3,227	3,440	3,433	3,426	3,419	3,411	0.2%
West South Central	2,422	2,087	2,031	1,995	1,959	1,923	1,888	-0.4%
Mountain	4,742	4,593	4,877	4,819	4,757	4,691	4,622	0.0%
Pacific	2,772	2,867	3,366	3,334	3,302	3,271	3,240	0.5%
United States	**4,549**	**4,084**	**4,173**	**4,106**	**4,041**	**3,977**	**3,914**	**-0.2%**
Cooling degree days								
New England	419	557	561	589	618	647	676	0.8%
Middle Atlantic	596	799	778	810	843	875	906	0.5%
East North Central	610	728	790	804	818	832	846	0.6%
West North Central	814	942	985	999	1,014	1,028	1,043	0.4%
South Atlantic	2,008	2,390	2,169	2,205	2,241	2,278	2,313	-0.1%
East South Central	1,493	1,717	1,686	1,709	1,731	1,754	1,777	0.1%
West South Central	2,474	2,741	2,809	2,875	2,941	3,007	3,073	0.5%
Mountain	1,432	1,484	1,547	1,594	1,644	1,697	1,751	0.7%
Pacific	1,068	1,095	956	994	1,032	1,069	1,107	0.0%
United States	**1,299**	**1,488**	**1,456**	**1,503**	**1,551**	**1,599**	**1,648**	**0.4%**

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[3]Includes miscellaneous uses, such as emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, propane, coal, motor gasoline, and kerosene.
[6]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,541 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2014 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A6. Industrial sector key indicators and consumption

Shipments, prices, and consumption	Reference case 2014	2015	2020	2025	2030	2035	2040	Annual growth 2015-2040 (percent)
Key indicators								
Value of shipments (billion 2009 dollars)								
Manufacturing	5,208	5,299	5,858	6,527	7,066	7,734	8,528	1.9%
Agriculture, mining, and construction	1,957	1,931	2,493	2,620	2,710	2,828	2,955	1.7%
Total	**7,165**	**7,229**	**8,351**	**9,146**	**9,776**	**10,562**	**11,483**	**1.9%**
Energy prices								
(2015 dollars per million Btu)								
Propane	18.8	12.2	15.6	16.8	17.8	19.5	21.1	2.2%
Motor gasoline	27.5	20.4	22.5	24.7	26.6	28.9	31.8	1.8%
Distillate fuel oil	27.1	17.0	19.7	22.2	24.4	27.4	30.5	2.4%
Residual fuel oil	15.0	6.8	11.3	14.2	15.9	18.2	20.6	4.6%
Asphalt and road oil	9.0	3.3	7.7	10.3	11.7	13.5	15.3	6.3%
Natural gas heat and power	5.2	3.5	5.2	5.8	5.8	5.6	5.6	1.8%
Natural gas feedstocks	5.6	3.9	5.5	6.1	6.1	5.9	5.8	1.6%
Metallurgical coal	5.3	5.4	6.0	6.5	7.0	7.2	7.3	1.2%
Other industrial coal	3.2	3.4	3.4	3.4	3.4	3.5	3.6	0.2%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	21.0	20.3	20.9	21.5	22.1	21.5	21.2	0.2%
(nominal dollars per million Btu)								
Propane	18.7	12.2	17.2	20.6	24.1	29.4	35.6	4.4%
Motor gasoline	27.2	20.4	24.9	30.2	35.9	43.7	53.6	3.9%
Distillate fuel oil	26.8	17.0	21.8	27.2	33.1	41.4	51.3	4.5%
Residual fuel oil	14.8	6.8	12.4	17.4	21.6	27.5	34.7	6.8%
Asphalt and road oil	8.9	3.3	8.5	12.6	15.9	20.4	25.8	8.5%
Natural gas heat and power	5.1	3.5	5.7	7.1	7.8	8.5	9.4	4.0%
Natural gas feedstocks	5.5	3.9	6.1	7.5	8.2	8.9	9.8	3.8%
Metallurgical coal	5.3	5.4	6.7	8.0	9.4	10.9	12.2	3.3%
Other industrial coal	3.2	3.4	3.7	4.2	4.6	5.2	6.0	2.4%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.8	20.3	23.1	26.3	29.9	32.5	35.7	2.3%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Propane heat and power	0.42	0.35	0.37	0.38	0.37	0.37	0.38	0.3%
Liquefied petroleum gas and other feedstocks[2]	2.00	2.02	2.73	3.13	3.29	3.55	3.85	2.6%
Motor gasoline	0.27	0.27	0.28	0.27	0.27	0.27	0.27	0.0%
Distillate fuel oil	1.36	1.34	1.44	1.45	1.44	1.45	1.47	0.4%
Residual fuel oil	0.03	0.03	0.04	0.06	0.06	0.05	0.05	1.9%
Petrochemical feedstocks	0.70	0.66	0.96	1.21	1.31	1.47	1.66	3.8%
Petroleum coke	0.12	0.16	0.22	0.23	0.23	0.23	0.23	1.4%
Asphalt and road oil	0.79	0.83	0.89	0.93	1.05	1.18	1.31	1.8%
Miscellaneous petroleum[3]	0.30	0.40	0.42	0.50	0.52	0.53	0.55	1.3%
Petroleum and other liquids subtotal	5.99	6.08	7.34	8.15	8.53	9.11	9.76	1.9%
Natural gas heat and power	5.74	5.61	5.94	6.19	6.33	6.59	6.87	0.8%
Natural gas feedstocks	0.63	0.68	1.22	1.41	1.45	1.52	1.59	3.5%
Lease and plant fuel[4]	1.55	1.63	1.76	1.94	2.06	2.19	2.31	1.4%
Natural gas liquefaction for export[5]	0.00	0.00	0.26	0.48	0.53	0.64	0.69	- -
Natural gas subtotal	7.92	7.92	9.17	10.01	10.38	10.94	11.45	1.5%
Metallurgical coal and coke[6]	0.56	0.52	0.40	0.45	0.47	0.44	0.41	-1.0%
Other industrial coal	0.85	0.79	0.82	0.86	0.88	0.89	0.93	0.6%
Coal subtotal	1.41	1.31	1.23	1.31	1.35	1.33	1.34	0.1%
Renewables[7]	1.52	1.48	1.48	1.59	1.67	1.70	1.79	0.8%
Purchased electricity	3.21	3.07	3.42	3.73	3.81	3.91	4.08	1.1%
Delivered energy	**20.04**	**19.87**	**22.65**	**24.79**	**25.73**	**26.99**	**28.42**	**1.4%**
Electricity related losses	6.49	6.07	6.74	7.09	6.91	7.03	7.18	0.7%
Total	**26.53**	**25.94**	**29.38**	**31.87**	**32.64**	**34.02**	**35.60**	**1.3%**

Table A6. Industrial sector key indicators and consumption *(continued)*

Shipments, prices, and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gas heat and power[2]	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.53	0.50	0.36	0.36	0.35	0.35	0.36	-1.3%
Still gas	1.45	1.48	1.70	1.68	1.67	1.67	1.69	0.6%
Miscellaneous petroleum[3]	0.01	0.01	0.00	0.00	0.00	0.00	0.01	1.9%
Petroleum and other liquids subtotal	2.00	2.00	2.06	2.04	2.02	2.02	2.06	0.1%
Natural gas heat and power	1.29	1.25	1.09	1.04	1.04	1.06	1.10	-0.5%
Natural gas feedstocks	0.19	0.22	0.31	0.30	0.31	0.32	0.34	1.8%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.48	1.46	1.39	1.33	1.35	1.39	1.44	-0.1%
Other industrial coal	0.02	0.02	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	0.02	0.02	0.00	0.00	0.00	0.00	0.00	- -
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Purchased electricity	0.20	0.20	0.19	0.18	0.17	0.17	0.18	-0.4%
Delivered energy	**4.45**	**4.47**	**4.46**	**4.36**	**4.34**	**4.39**	**4.52**	**0.0%**
Electricity related losses	0.40	0.39	0.37	0.33	0.31	0.31	0.32	-0.8%
Total	**4.85**	**4.86**	**4.84**	**4.69**	**4.65**	**4.70**	**4.84**	**0.0%**
Total industrial sector consumption								
Liquefied petroleum gas heat and power[2]	0.43	0.36	0.37	0.38	0.37	0.37	0.38	0.2%
Liquefied petroleum gas and other feedstocks[2]	2.00	2.02	2.73	3.13	3.29	3.55	3.85	2.6%
Motor gasoline	0.27	0.27	0.28	0.27	0.27	0.27	0.27	0.0%
Distillate fuel oil	1.36	1.34	1.44	1.45	1.44	1.45	1.47	0.4%
Residual fuel oil	0.03	0.04	0.04	0.06	0.06	0.05	0.05	1.6%
Petrochemical feedstocks	0.70	0.66	0.96	1.21	1.31	1.47	1.66	3.8%
Petroleum coke	0.65	0.67	0.57	0.59	0.58	0.58	0.59	-0.5%
Asphalt and road oil	0.79	0.83	0.89	0.93	1.05	1.18	1.31	1.8%
Still gas	1.45	1.48	1.70	1.68	1.67	1.67	1.69	0.6%
Miscellaneous petroleum[3]	0.30	0.41	0.42	0.50	0.52	0.53	0.56	1.3%
Petroleum and other liquids subtotal	7.99	8.07	9.40	10.19	10.55	11.13	11.82	1.5%
Natural gas heat and power	7.03	6.85	7.03	7.23	7.37	7.65	7.96	0.6%
Natural gas feedstocks	0.81	0.90	1.52	1.70	1.76	1.84	1.93	3.1%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[4]	1.55	1.63	1.76	1.94	2.06	2.19	2.31	1.4%
Natural gas liquefaction for export[5]	0.00	0.00	0.26	0.48	0.53	0.64	0.69	- -
Natural gas subtotal	9.40	9.38	10.57	11.34	11.72	12.32	12.89	1.3%
Metallurgical coal and coke[6]	0.56	0.52	0.40	0.45	0.47	0.44	0.41	-1.0%
Other industrial coal	0.87	0.82	0.82	0.86	0.88	0.89	0.93	0.5%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	1.43	1.34	1.23	1.31	1.35	1.33	1.34	0.0%
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Renewables[7]	1.52	1.48	1.48	1.59	1.67	1.70	1.79	0.8%
Purchased electricity	3.40	3.27	3.61	3.91	3.98	4.08	4.26	1.1%
Delivered energy	**24.49**	**24.33**	**27.11**	**29.14**	**30.07**	**31.38**	**32.94**	**1.2%**
Electricity related losses	6.89	6.46	7.11	7.42	7.22	7.34	7.50	0.6%
Total	**31.38**	**30.79**	**34.22**	**36.56**	**37.29**	**38.72**	**40.44**	**1.1%**

Table A6. Industrial sector key indicators and consumption *(continued)*

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2009 dollar)								
Petroleum and other liquids	1.12	1.12	1.13	1.11	1.08	1.05	1.03	-0.3%
Natural gas	1.31	1.30	1.27	1.24	1.20	1.17	1.12	-0.6%
Coal	0.20	0.19	0.15	0.14	0.14	0.13	0.12	-1.8%
Renewable fuels[7]	0.32	0.31	0.28	0.26	0.25	0.24	0.23	-1.2%
Purchased electricity	0.48	0.45	0.43	0.43	0.41	0.39	0.37	-0.8%
Delivered energy	**3.42**	**3.37**	**3.25**	**3.19**	**3.08**	**2.97**	**2.87**	**-0.6%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	25.7	25.8	27.0	28.9	31.5	34.3	36.0	1.3%
Generation (billion kilowatthours)	138	139	158	168	182	196	206	1.6%

[1]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes lubricants and miscellaneous petroleum products.
[4]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[5]Fuel used in facilities that liquefy natural gas for export.
[6]Includes net coal coke imports.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, January 2105-December 2015. 2014 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2013*. 2014 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2014* and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. 2014 electricity prices: EIA, *Monthly Energy Review*, February 2016. 2014 natural gas prices: *Natural Gas Monthly*, July 2015. 2014 refining consumption based on: *Petroleum Supply Annual 2014*. Other 2014 consumption values are based on: EIA, *Monthly Energy Review*, February 2016. 2014 shipments: IHS Economics, Industry model, November 2015. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,665	2,752	3,031	3,126	3,232	3,336	3,438	0.9%
Commercial light trucks[1]	94	96	110	118	125	133	143	1.6%
Freight trucks greater than 10,000 pounds	270	280	304	329	349	375	407	1.5%
(billion seat miles available)								
Air	1,053	1,070	1,168	1,261	1,364	1,452	1,531	1.4%
(billion ton miles traveled)								
Rail	1,690	1,690	1,810	1,956	2,006	2,054	2,128	0.9%
Domestic shipping	497	482	453	423	404	402	407	-0.7%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	30.9	31.5	36.2	46.1	46.4	46.6	46.9	1.6%
New car[2]	34.9	36.0	43.7	54.3	54.3	54.3	54.3	1.7%
New light truck[2]	26.9	27.9	30.9	39.5	39.5	39.5	39.5	1.4%
Compliance new light-duty vehicle[3]	31.6	31.7	37.0	46.5	47.2	47.6	47.8	1.7%
New car[3]	36.0	36.3	44.2	54.6	55.1	55.2	55.1	1.7%
New light truck[3]	27.3	28.0	31.8	40.1	40.4	40.5	40.4	1.5%
Tested new light-duty vehicle[4]	30.8	30.9	36.9	46.5	47.2	47.6	47.8	1.8%
New car[4]	35.6	35.9	44.2	54.6	55.1	55.2	55.1	1.7%
New light truck[4]	26.1	27.0	31.7	40.0	40.4	40.5	40.4	1.6%
On-road new light-duty vehicle[5]	24.9	25.0	29.8	37.6	38.2	38.5	38.6	1.8%
New car[5]	29.1	29.3	36.1	44.6	45.0	45.1	45.0	1.7%
New light truck[5]	20.9	21.6	25.4	32.1	32.3	32.4	32.3	1.6%
Light-duty stock[6]	21.4	21.7	24.1	27.6	31.5	34.4	36.3	2.1%
New commercial light truck[1]	17.0	17.3	19.5	23.7	24.0	24.1	24.0	1.3%
Stock commercial light truck[1]	14.8	15.0	16.6	18.7	20.8	22.2	23.2	1.7%
Freight truck	6.9	6.9	7.3	7.6	7.8	7.9	8.0	0.6%
(seat miles per gallon)								
Aircraft	65.9	66.1	67.5	68.7	70.1	71.9	74.1	0.5%
(ton miles per thousand Btu)								
Rail	3.5	3.5	3.6	3.8	3.9	4.1	4.2	0.7%
Domestic shipping	4.8	4.8	5.0	5.2	5.4	5.6	5.8	0.8%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.60	15.86	15.73	14.12	12.82	12.10	11.83	-1.2%
Commercial light trucks[1]	0.80	0.80	0.82	0.79	0.75	0.75	0.77	-0.1%
Bus transportation	0.26	0.26	0.27	0.28	0.29	0.30	0.31	0.6%
Freight trucks	5.39	5.57	5.76	5.96	6.16	6.52	6.98	0.9%
Rail, passenger	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.9%
Rail, freight	0.49	0.48	0.50	0.52	0.51	0.51	0.51	0.2%
Shipping, domestic	0.11	0.10	0.09	0.08	0.08	0.07	0.07	-1.4%
Shipping, international	0.64	0.73	0.64	0.68	0.70	0.73	0.74	0.1%
Recreational boats	0.24	0.25	0.27	0.28	0.29	0.29	0.30	0.8%
Air	2.35	2.37	2.52	2.66	2.82	2.93	3.00	0.9%
Military use	0.65	0.65	0.65	0.66	0.69	0.73	0.78	0.8%
Lubricants	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.2%
Pipeline fuel	0.87	0.89	0.83	0.89	0.94	1.00	1.07	0.7%
Total	**27.56**	**28.14**	**28.28**	**27.11**	**26.24**	**26.13**	**26.57**	**-0.2%**

Table A7. Transportation sector key indicators and delivered energy consumption *(continued)*

Key indicators and consumption	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.45	8.60	8.52	7.66	6.98	6.60	6.47	-1.1%
Commercial light trucks[1]	0.42	0.42	0.43	0.41	0.39	0.39	0.40	-0.2%
Bus transportation	0.13	0.13	0.13	0.14	0.14	0.14	0.15	0.6%
Freight trucks	2.59	2.67	2.77	2.87	2.96	3.14	3.36	0.9%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.9%
Rail, freight	0.23	0.23	0.24	0.25	0.24	0.24	0.24	0.2%
Shipping, domestic	0.05	0.05	0.04	0.04	0.04	0.03	0.03	-1.4%
Shipping, international	0.29	0.33	0.29	0.31	0.31	0.33	0.34	0.1%
Recreational boats	0.13	0.13	0.14	0.15	0.16	0.16	0.16	0.8%
Air	1.14	1.15	1.22	1.29	1.36	1.42	1.45	0.9%
Military use	0.31	0.31	0.31	0.31	0.33	0.35	0.38	0.8%
Lubricants	0.06	0.06	0.07	0.06	0.07	0.07	0.07	0.2%
Pipeline fuel	0.41	0.42	0.39	0.42	0.44	0.47	0.51	0.7%
Total	**14.23**	**14.52**	**14.57**	**13.92**	**13.45**	**13.36**	**13.58**	**-0.3%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016; EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; Federal Highway Administration, *Highway Statistics 2012*; Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 34*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* June 2015; U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV; EIA, U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009*; and United States Department of Defense, Defense Fuel Supply Center, Factbook January, 2010. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Net generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,549	1,320	1,355	1,145	938	928	884	-1.6%
Petroleum	26	23	13	11	9	8	7	-4.6%
Natural gas[3]	911	1,114	947	1,129	1,412	1,460	1,618	1.5%
Nuclear power	797	798	777	789	789	789	789	0.0%
Pumped storage/other[4]	1	3	3	3	3	3	3	0.1%
Renewable sources[5]	505	493	757	918	969	1,094	1,205	3.6%
Distributed generation (natural gas)	0	0	0	1	1	1	2	- -
Total	**3,790**	**3,751**	**3,853**	**3,996**	**4,121**	**4,284**	**4,508**	**0.7%**
Combined heat and power[6]								
Coal	20	23	21	21	21	21	21	-0.4%
Petroleum	2	1	1	1	1	1	1	0.0%
Natural gas	120	136	143	143	147	142	139	0.1%
Renewable sources	4	4	4	4	4	4	4	0.1%
Total	**150**	**164**	**168**	**169**	**173**	**169**	**165**	**0.0%**
Total net electric power sector generation	**3,939**	**3,915**	**4,021**	**4,165**	**4,294**	**4,452**	**4,673**	**0.7%**
Less direct use	16	18	18	17	17	17	17	-0.1%
Net available to the grid	**3,924**	**3,897**	**4,004**	**4,148**	**4,276**	**4,435**	**4,656**	**0.7%**
End-use sector[7]								
Coal	12	12	12	13	13	13	14	0.6%
Petroleum	2	2	1	1	1	1	2	-0.4%
Natural gas	97	99	111	124	143	165	183	2.5%
Other gaseous fuels[8]	11	11	21	21	21	21	21	2.5%
Renewable sources[9]	45	49	75	93	115	139	165	5.0%
Other[10]	3	3	3	3	3	3	3	0.0%
Total end-use sector net generation	**170**	**176**	**223**	**255**	**296**	**343**	**387**	**3.2%**
Less direct use	121	127	181	210	246	286	324	3.8%
Total sales to the grid	**49**	**49**	**42**	**45**	**51**	**57**	**63**	**1.0%**
Total net electricity generation by fuel								
Coal	1,582	1,355	1,388	1,179	972	962	919	-1.5%
Petroleum	30	26	15	13	11	10	9	-4.0%
Natural gas	1,129	1,348	1,201	1,396	1,702	1,768	1,942	1.5%
Nuclear power	797	798	777	789	789	789	789	0.0%
Renewable sources[5,9]	554	546	836	1,015	1,088	1,238	1,374	3.8%
Other[11]	18	17	27	27	27	27	27	1.8%
Total net electricity generation	**4,109**	**4,090**	**4,244**	**4,420**	**4,590**	**4,795**	**5,060**	**0.9%**
Net generation to the grid	**3,972**	**3,946**	**4,046**	**4,193**	**4,327**	**4,492**	**4,719**	**0.7%**
Net imports	**52**	**57**	**57**	**58**	**50**	**46**	**43**	**-1.1%**
Electricity sales by sector								
Residential	1,407	1,402	1,395	1,393	1,416	1,457	1,523	0.3%
Commercial	1,352	1,360	1,374	1,425	1,491	1,562	1,647	0.8%
Industrial	998	959	1,059	1,145	1,166	1,197	1,249	1.1%
Transportation	8	9	13	23	32	40	45	6.7%
Total	**3,765**	**3,729**	**3,841**	**3,986**	**4,105**	**4,256**	**4,464**	**0.7%**
Direct use	137	144	199	227	263	303	341	3.5%
Total electricity use	**3,902**	**3,873**	**4,039**	**4,213**	**4,368**	**4,559**	**4,805**	**0.9%**

Table A8. Electricity supply, disposition, prices, and emissions *(continued)*
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
End-use prices								
(2015 cents per kilowatthour)								
Residential	12.7	12.4	12.9	13.2	13.4	13.2	13.0	0.2%
Commercial	10.9	10.5	10.7	10.9	11.0	10.7	10.5	0.0%
Industrial	7.2	6.9	7.1	7.3	7.5	7.3	7.2	0.2%
Transportation	11.0	10.1	11.3	12.3	12.7	12.4	12.1	0.7%
All sectors average	**10.5**	**10.3**	**10.5**	**10.7**	**10.9**	**10.6**	**10.5**	**0.1%**
(nominal cents per kilowatthour)								
Residential	12.5	12.4	14.2	16.2	18.2	19.9	21.9	2.3%
Commercial	10.7	10.5	11.9	13.4	14.9	16.2	17.6	2.1%
Industrial	7.1	6.9	7.9	9.0	10.2	11.1	12.2	2.3%
Transportation	10.9	10.1	12.5	15.1	17.2	18.8	20.4	2.9%
All sectors average	**10.4**	**10.3**	**11.6**	**13.1**	**14.7**	**16.1**	**17.6**	**2.2%**
Prices by service category								
(2015 cents per kilowatthour)								
Generation	6.8	6.4	6.4	6.8	7.3	6.8	6.6	0.1%
Transmission	1.0	1.1	1.2	1.2	1.3	1.3	1.3	0.7%
Distribution	2.7	2.8	3.0	2.7	2.3	2.6	2.6	-0.3%
(nominal cents per kilowatthour)								
Generation	6.7	6.4	7.0	8.4	9.9	10.3	11.1	2.2%
Transmission	1.0	1.1	1.3	1.5	1.7	1.9	2.2	2.8%
Distribution	2.7	2.8	3.3	3.3	3.2	3.9	4.4	1.8%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	4.05	3.57	1.20	1.07	0.77	0.84	0.79	-5.9%
Nitrogen oxide (million short tons)	1.63	1.41	1.16	1.00	0.91	0.90	0.88	-1.9%
Mercury (short tons)	26.77	23.74	5.55	4.62	3.76	3.82	3.57	-7.3%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and that have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2015 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016, and supporting databases. 2014 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2014 electricity prices by service category: EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections**: EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal[4]	290.8	277.7	208.4	189.3	177.0	172.2	169.5	-2.0%
Oil and natural gas steam[4,5]	91.9	91.0	89.9	65.6	54.0	52.4	52.4	-2.2%
Combined cycle	198.1	202.3	220.6	231.5	267.7	287.9	318.7	1.8%
Combustion turbine/diesel	138.7	138.3	140.1	137.4	134.2	136.8	141.8	0.1%
Nuclear power[6]	99.1	99.8	99.1	99.1	99.1	99.1	99.1	0.0%
Pumped storage	22.6	22.6	22.6	22.6	22.6	22.6	22.6	0.0%
Fuel cells	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0%
Renewable sources[7]	162.1	176.2	237.7	287.3	304.3	356.1	398.4	3.3%
Distributed generation (natural gas)[8]	0.0	0.0	0.2	0.5	1.0	1.8	2.9	- -
Total	**1,003.4**	**1,007.8**	**1,018.7**	**1,033.4**	**1,060.0**	**1,128.9**	**1,205.3**	**0.7%**
Combined heat and power[9]								
Coal	3.8	3.7	3.3	3.3	3.3	3.3	3.3	-0.4%
Oil and natural gas steam[5]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined cycle	25.1	25.0	26.8	26.7	26.7	26.7	26.7	0.3%
Combustion turbine/diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	0.0%
Renewable sources[7]	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.0%
Total	**33.1**	**32.9**	**34.4**	**34.3**	**34.3**	**34.3**	**34.3**	**0.2%**
Cumulative planned additions[10]								
Coal	- -	- -	0.3	0.3	0.3	0.3	0.3	- -
Oil and natural gas steam[5]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	- -	- -	21.5	21.5	21.5	21.5	21.5	- -
Combustion turbine/diesel	- -	- -	5.0	5.0	5.0	5.0	5.0	- -
Nuclear power	- -	- -	4.4	4.4	4.4	4.4	4.4	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	19.7	19.7	19.7	19.7	19.7	- -
Distributed generation[8]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Total	**- -**	**- -**	**50.8**	**50.8**	**50.8**	**50.8**	**50.8**	**- -**
Cumulative unplanned additions[10]								
Coal	- -	- -	0.2	0.2	0.2	0.2	0.2	- -
Oil and natural gas steam[5]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	- -	- -	5.2	26.0	63.4	85.1	117.2	- -
Combustion turbine/diesel	- -	- -	2.3	2.4	3.0	7.0	14.5	- -
Nuclear power	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	42.3	91.8	108.9	160.7	203.1	- -
Distributed generation[8]	- -	- -	0.2	0.5	1.0	1.8	2.9	- -
Total	**- -**	**- -**	**50.3**	**121.0**	**176.6**	**254.8**	**337.8**	**- -**
Cumulative electric power sector additions[10]	**- -**	**- -**	**101.1**	**171.8**	**227.4**	**305.6**	**388.6**	**- -**
Cumulative retirements[11]								
Coal	- -	- -	61.6	79.7	92.1	96.9	99.6	- -
Oil and natural gas steam[5]	- -	- -	9.7	34.9	46.4	48.1	48.1	- -
Combined cycle	- -	- -	6.5	16.5	17.7	19.2	20.5	- -
Combustion turbine/diesel	- -	- -	5.5	8.3	12.2	13.5	16.0	- -
Nuclear power	- -	- -	5.2	5.2	5.2	5.2	5.2	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	0.4	0.4	0.4	0.5	0.5	- -
Total	**- -**	**- -**	**88.9**	**144.9**	**174.0**	**183.3**	**189.8**	**- -**
Total electric power sector capacity	**1,037**	**1,041**	**1,053**	**1,068**	**1,094**	**1,163**	**1,240**	**0.7%**

Table A9. Electricity generating capacity *(continued)*
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
End-use generators[12]								
Coal	2.9	2.9	2.9	3.0	3.1	3.2	3.3	0.5%
Petroleum	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.0%
Natural gas	16.2	16.5	17.4	19.7	22.9	26.6	29.5	2.4%
Other gaseous fuels[13]	2.4	2.4	3.0	3.0	3.0	3.0	3.0	1.0%
Renewable sources[7]	15.0	18.4	36.6	49.1	63.6	80.3	97.4	6.9%
Other[14]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**37.8**	**41.3**	**61.1**	**76.0**	**93.9**	**114.4**	**134.5**	**4.8%**
Cumulative capacity additions[10]	**- -**	**- -**	**21.0**	**35.9**	**53.8**	**74.2**	**94.3**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes plants that only produce electricity and that have a regulatory status. Includes capacity increases (uprates) at existing units.
[4]Total coal and oil and natural gas steam capacity account for the conversion of coal capacity to gas steam capacity, but the conversions are not included explicitly as additions or retirements. The totals reflect 8.8 gigawatts of planned conversions as well as additional model-projected conversions.
[5]Includes oil-, gas-, and dual-fired capacity.
[6]Nuclear capacity includes 0.1 gigawatts of uprates.
[7]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[8]Primarily peak load capacity fueled by natural gas.
[9]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[10]Cumulative additions after December 31, 2015.
[11]Cumulative retirements after December 31, 2015.
[12]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]Includes refinery gas and still gas.
[14]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A10. Electricity trade

(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Interregional electricity trade								
Gross domestic sales								
Firm power	105	102	95	92	73	53	49	-2.9%
Economy	165	233	216	257	239	226	222	-0.2%
Total	**271**	**336**	**311**	**349**	**312**	**278**	**270**	**-0.9%**
Gross domestic sales (million 2015 dollars)								
Firm power	6,761	6,568	6,088	5,871	4,683	3,375	3,120	-2.9%
Economy	8,385	7,704	9,139	12,921	13,756	11,896	11,460	1.6%
Total	**15,147**	**14,273**	**15,227**	**18,792**	**18,439**	**15,270**	**14,580**	**0.1%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	20.3	28.3	29.5	28.5	26.6	23.2	20.2	-1.4%
Economy	45.3	37.5	41.0	43.8	37.6	36.0	35.9	-0.2%
Total	**65.6**	**65.9**	**70.5**	**72.4**	**64.2**	**59.2**	**56.1**	**-0.6%**
Exports to Canada and Mexico								
Firm power	2.6	1.8	1.8	1.8	0.9	0.0	0.0	- -
Economy	10.6	7.5	11.9	12.7	13.0	13.2	13.2	2.3%
Total	**13.3**	**9.3**	**13.7**	**14.5**	**13.9**	**13.2**	**13.2**	**1.4%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2014 interregional firm electricity trade data: Federal Energy Regulatory Commission, Form 1, “Electric Utility Annual Report”, and 2014 seasonal reliability assessments from North American Electric Reliability Council regional entities and Independent System Operators, and Federal Energy Regulatory Commission, Form 1. 2014 interregional economy electricity trade are model results. 2014 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2014*. 2014 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2014*. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A11. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Crude oil								
Domestic crude production[1]	8.71	9.42	9.38	9.43	10.06	10.66	11.26	0.7%
Alaska	0.50	0.48	0.41	0.32	0.24	0.19	0.15	-4.7%
Lower 48 states	8.21	8.94	8.96	9.12	9.82	10.48	11.11	0.9%
Net imports	6.99	6.88	6.97	6.95	6.57	6.24	6.10	-0.5%
Gross imports	7.35	7.28	7.60	7.58	7.20	7.07	7.12	-0.1%
Exports	0.35	0.40	0.63	0.63	0.63	0.83	1.02	3.8%
Other crude supply[2]	0.15	-0.11	0.01	0.07	0.00	0.00	0.00	- -
Total crude supply	**15.85**	**16.19**	**16.36**	**16.46**	**16.63**	**16.91**	**17.36**	**0.3%**
Net product imports	-1.90	-2.24	-3.26	-3.69	-4.32	-4.52	-4.66	3.0%
Gross refined product imports[3]	0.78	0.66	1.11	1.24	1.30	1.44	1.63	3.7%
Unfinished oil imports	0.55	0.55	0.53	0.50	0.46	0.43	0.39	-1.4%
Blending component imports	0.55	0.67	0.58	0.52	0.45	0.35	0.30	-3.2%
Exports	3.76	4.12	5.48	5.95	6.52	6.74	6.98	2.1%
Refinery processing gain[4]	1.08	1.03	1.05	1.01	0.98	0.97	0.99	-0.2%
Product stock withdrawal	-0.18	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas plant liquids	3.02	3.25	4.57	4.77	4.90	4.95	4.99	1.7%
Supply from renewable sources	0.96	1.01	1.08	1.03	1.03	1.05	1.12	0.4%
Ethanol	0.86	0.89	0.89	0.85	0.84	0.86	0.93	0.2%
Domestic production	0.91	0.94	0.90	0.87	0.87	0.88	0.91	-0.1%
Net imports	-0.05	-0.05	-0.01	-0.03	-0.03	-0.03	0.02	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biodiesel	0.10	0.11	0.15	0.10	0.10	0.10	0.10	-0.5%
Domestic production	0.08	0.08	0.11	0.06	0.06	0.06	0.06	-1.6%
Net imports	0.02	0.03	0.04	0.04	0.04	0.04	0.04	1.7%
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.04	0.09	0.09	0.09	0.09	18.1%
Domestic production	0.00	0.00	0.04	0.09	0.09	0.09	0.09	18.1%
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other[6]	0.21	0.21	0.28	0.28	0.30	0.31	0.32	1.7%
Total primary supply[7]	**19.04**	**19.46**	**20.08**	**19.87**	**19.52**	**19.66**	**20.12**	**0.1%**
Product supplied								
by fuel								
Liquefied petroleum gases and other[8]	2.45	2.46	2.90	3.22	3.34	3.55	3.80	1.8%
Motor gasoline[9]	8.94	9.18	8.97	8.08	7.35	6.96	6.84	-1.2%
of which: E85[10]	0.02	0.03	0.03	0.09	0.15	0.18	0.19	7.3%
Jet fuel[11]	1.47	1.54	1.56	1.64	1.73	1.80	1.86	0.8%
Distillate fuel oil[12]	4.04	3.96	4.31	4.40	4.46	4.57	4.67	0.7%
of which: Diesel	3.83	3.76	3.97	4.10	4.19	4.32	4.43	0.7%
Residual fuel oil	0.26	0.26	0.25	0.27	0.27	0.28	0.28	0.2%
Other[13]	2.01	2.02	2.11	2.29	2.39	2.53	2.70	1.2%
by sector								
Residential and commercial	0.93	0.90	0.89	0.84	0.80	0.77	0.74	-0.8%
Industrial[14]	4.46	4.47	5.35	5.88	6.10	6.46	6.89	1.8%
Transportation	13.76	14.04	14.11	13.40	12.84	12.65	12.69	-0.4%
Electric power[15]	0.14	0.12	0.07	0.06	0.05	0.04	0.04	-4.3%
Unspecified sector[16]	-0.31	-0.30	-0.31	-0.28	-0.25	-0.23	-0.23	-1.1%
Total product supplied	**19.16**	**19.42**	**20.11**	**19.90**	**19.54**	**19.69**	**20.14**	**0.1%**
Discrepancy[17]	-0.12	0.04	-0.03	-0.03	-0.03	-0.03	-0.03	- -

Table A11. Petroleum and other liquids supply and disposition *(continued)*
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[18]	17.9	18.0	19.0	19.0	19.0	19.0	19.0	0.2%
Capacity utilization rate (percent)[19]	90.4	91.1	87.7	88.2	88.9	90.2	92.5	0.1%
Net import share of product supplied (percent)	26.6	23.7	18.6	16.5	11.6	8.8	7.4	-4.5%
Net expenditures for imported crude oil and petroleum products (billion 2015 dollars)	262	128	207	250	268	303	348	4.1%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. Other 2014 data: EIA, *Petroleum Supply Annual 2014*. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A12. Petroleum and other liquids prices
(2015 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Crude oil prices (2015 dollars per barrel)								
Brent spot	100	52	77	92	104	120	136	3.9%
West Texas Intermediate spot	94	49	71	85	97	112	129	4.0%
Average imported refiners acquisition cost[1]	91	46	69	83	95	110	126	4.1%
Brent / West Texas Intermediate spread	5.8	3.7	5.4	6.2	6.9	7.2	7.1	2.7%
Delivered sector product prices								
Residential								
Propane	2.13	1.55	1.84	1.95	2.04	2.19	2.33	1.7%
Distillate fuel oil	3.71	2.66	3.08	3.51	3.82	4.23	4.65	2.3%
Commercial								
Distillate fuel oil	3.63	2.34	2.71	3.05	3.36	3.77	4.19	2.4%
Residual fuel oil	2.50	1.04	1.64	2.02	2.29	2.63	2.98	4.3%
Residual fuel oil (2015 dollars per barrel)	105	44	69	85	96	110	125	4.3%
Industrial[2]								
Propane	1.72	1.12	1.42	1.54	1.63	1.78	1.93	2.2%
Distillate fuel oil	3.72	2.34	2.71	3.05	3.36	3.76	4.19	2.4%
Residual fuel oil	2.24	1.01	1.68	2.13	2.39	2.73	3.08	4.6%
Residual fuel oil (2015 dollars per barrel)	94	42	71	89	100	115	130	4.6%
Transportation								
Propane	2.23	1.64	1.94	2.05	2.14	2.28	2.43	1.6%
E85[3]	3.15	2.21	3.05	2.97	2.93	3.08	3.33	1.6%
Ethanol wholesale price	2.25	2.22	2.77	2.38	2.28	2.39	2.60	0.6%
Motor gasoline[4]	3.42	2.52	2.74	2.97	3.19	3.47	3.81	1.7%
Jet fuel[5]	2.81	1.62	2.18	2.56	2.87	3.30	3.74	3.4%
Diesel fuel (distillate fuel oil)[6]	3.82	2.72	3.18	3.55	3.85	4.25	4.68	2.2%
Residual fuel oil	2.19	1.21	1.75	2.01	2.25	2.54	2.87	3.5%
Residual fuel oil (2015 dollars per barrel)	92	51	73	85	94	107	121	3.5%
Electric power[7]								
Distillate fuel oil	3.27	2.07	2.53	2.92	3.23	3.63	4.04	2.7%
Residual fuel oil	2.73	1.53	2.06	2.43	2.70	3.03	3.36	3.2%
Residual fuel oil (2015 dollars per barrel)	115	64	87	102	114	127	141	3.2%
Average prices, all sectors[8]								
Propane	1.94	1.36	1.65	1.75	1.83	1.97	2.12	1.8%
Motor gasoline[4]	3.42	2.52	2.74	2.97	3.19	3.47	3.81	1.7%
Jet fuel[5]	2.81	1.62	2.18	2.56	2.87	3.30	3.74	3.4%
Distillate fuel oil	3.78	2.63	3.07	3.44	3.75	4.16	4.58	2.2%
Residual fuel oil	2.37	1.26	1.76	2.06	2.30	2.60	2.93	3.4%
Residual fuel oil (2015 dollars per barrel)	99	53	74	87	97	109	123	3.4%
Average	**3.12**	**2.18**	**2.44**	**2.65**	**2.85**	**3.13**	**3.42**	**1.8%**

Table A12. Petroleum and other liquids prices *(continued)*

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Crude oil prices (nominal dollars per barrel)								
Brent spot	99	52	85	112	141	181	229	6.1%
West Texas Intermediate spot	93	49	79	105	131	170	217	6.2%
Average imported refiners acquisition cost[1]	90	46	76	102	128	166	212	6.3%
Delivered sector product prices								
Residential								
Propane	2.11	1.55	2.03	2.39	2.76	3.30	3.93	3.8%
Distillate fuel oil	3.67	2.66	3.40	4.29	5.16	6.39	7.83	4.4%
Commercial								
Distillate fuel oil	3.59	2.34	2.99	3.74	4.54	5.69	7.04	4.5%
Residual fuel oil	2.47	1.04	1.81	2.47	3.09	3.97	5.02	6.5%
Residual fuel oil (nominal dollars per barrel)	104	44	76	104	130	167	211	6.5%
Industrial[2]								
Propane	1.70	1.12	1.57	1.88	2.20	2.69	3.25	4.4%
Distillate fuel oil	3.68	2.34	2.99	3.74	4.54	5.69	7.04	4.5%
Residual fuel oil	2.22	1.01	1.86	2.60	3.23	4.12	5.19	6.8%
Residual fuel oil (nominal dollars per barrel)	93	42	78	109	136	173	218	6.8%
Transportation								
Propane	2.21	1.64	2.14	2.51	2.89	3.45	4.09	3.7%
E85[3]	3.12	2.21	3.37	3.63	3.97	4.65	5.60	3.8%
Ethanol wholesale price	2.23	2.22	3.06	2.91	3.09	3.62	4.38	2.8%
Motor gasoline[4]	3.38	2.52	3.02	3.64	4.32	5.25	6.40	3.8%
Jet fuel[5]	2.78	1.62	2.41	3.14	3.89	4.99	6.29	5.6%
Diesel fuel (distillate fuel oil)[6]	3.78	2.72	3.51	4.34	5.21	6.43	7.88	4.3%
Residual fuel oil	2.17	1.21	1.93	2.46	3.04	3.84	4.83	5.7%
Residual fuel oil (nominal dollars per barrel)	91	51	81	103	128	161	203	5.7%
Electric power[7]								
Distillate fuel oil	3.24	2.07	2.80	3.57	4.37	5.48	6.79	4.9%
Residual fuel oil	2.71	1.53	2.28	2.98	3.66	4.57	5.65	5.4%
Residual fuel oil (nominal dollars per barrel)	114	64	96	125	154	192	237	5.4%
Average prices, all sectors[8]								
Propane	1.92	1.36	1.82	2.14	2.48	2.98	3.56	3.9%
Motor gasoline[4]	3.38	2.52	3.02	3.64	4.32	5.24	6.40	3.8%
Jet fuel[5]	2.78	1.62	2.41	3.14	3.89	4.99	6.29	5.6%
Distillate fuel oil	3.75	2.63	3.39	4.22	5.08	6.28	7.71	4.4%
Residual fuel oil	2.34	1.26	1.94	2.52	3.11	3.93	4.93	5.6%
Residual fuel oil (nominal dollars per barrel)	98	53	81	106	131	165	207	5.6%
Average	**3.09**	**2.18**	**2.70**	**3.25**	**3.86**	**4.72**	**5.76**	**4.0%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2014 average imported crude oil price: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2014 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, January 2105-December 2015. 2014 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2014 electric power prices based on: EIA, *Monthly Energy Review*, February 2016. 2014 E85 prices derived from: U.S. Department of Energy, Clean Cities Alternative Fuel Price Report. 2014 wholesale ethanol prices derived from Bloomberg U.S. average rack price. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.
Projections: EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Supply								
Dry gas production[1]	25.73	27.19	30.50	34.81	37.76	39.92	42.12	1.8%
Supplemental natural gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.3%
Net imports	1.18	0.95	-2.89	-5.32	-6.02	-7.18	-7.55	- -
Pipeline[3]	1.14	0.89	-0.48	-0.76	-0.97	-0.99	-0.89	- -
Liquefied natural gas	0.04	0.06	-2.42	-4.56	-5.06	-6.19	-6.66	- -
Total supply	**26.97**	**28.20**	**27.67**	**29.55**	**31.80**	**32.80**	**34.63**	**0.8%**
Consumption by sector								
Residential	5.09	4.62	4.71	4.67	4.65	4.62	4.58	0.0%
Commercial	3.47	3.22	3.34	3.35	3.42	3.55	3.69	0.5%
Industrial[4]	7.60	7.51	8.29	8.65	8.85	9.19	9.58	1.0%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	8.14	9.61	8.26	9.33	11.02	11.13	11.96	0.9%
Transportation[8]	0.06	0.06	0.09	0.14	0.22	0.38	0.66	9.8%
Pipeline fuel	0.84	0.86	0.81	0.86	0.91	0.97	1.04	0.7%
Lease and plant fuel[9]	1.50	1.58	1.71	1.88	2.00	2.12	2.24	1.4%
Liquefaction for export[10]	0.00	0.00	0.25	0.46	0.51	0.63	0.67	- -
Total consumption	**26.70**	**27.47**	**27.46**	**29.35**	**31.59**	**32.59**	**34.42**	**0.9%**
Discrepancy[11]	**0.27**	**0.73**	**0.21**	**0.21**	**0.21**	**0.21**	**0.21**	**- -**
Natural gas spot price at Henry Hub								
(2015 dollars per million Btu)	**4.44**	**2.62**	**4.43**	**5.12**	**5.06**	**4.91**	**4.86**	**2.5%**
(nominal dollars per million Btu)	**4.39**	**2.62**	**4.90**	**6.27**	**6.84**	**7.42**	**8.17**	**4.7%**
Delivered prices								
(2015 dollars per thousand cubic feet)								
Residential	11.08	10.40	11.08	11.99	12.41	12.50	12.74	0.8%
Commercial	9.24	7.92	9.58	10.39	10.72	10.66	10.73	1.2%
Industrial[4]	5.57	3.84	5.53	6.15	6.14	5.95	5.89	1.7%
Electric power[7]	5.20	3.35	4.83	5.55	5.74	5.54	5.52	2.0%
Transportation[12]	19.03	17.18	17.18	16.90	16.05	15.87	16.37	-0.2%
Average[13]	**7.15**	**5.42**	**6.95**	**7.58**	**7.65**	**7.55**	**7.59**	**1.4%**
(nominal dollars per thousand cubic feet)								
Residential	10.96	10.40	12.24	14.67	16.78	18.87	21.44	2.9%
Commercial	9.15	7.92	10.59	12.72	14.51	16.09	18.05	3.4%
Industrial[4]	5.51	3.84	6.11	7.53	8.31	8.98	9.91	3.9%
Electric power[7]	5.15	3.35	5.33	6.80	7.76	8.36	9.29	4.2%
Transportation[12]	18.83	17.18	18.98	20.68	21.71	23.96	27.54	1.9%
Average[13]	**7.08**	**5.42**	**7.67**	**9.28**	**10.35**	**11.40**	**12.77**	**3.5%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Fuel used in facilities that liquefy natural gas for export.
[11]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2014 and 2015 values include net storage injections.
[12]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, July 2015. Other 2014 consumption based on: EIA, *Monthly Energy Review*, February 2016. 2014 natural gas spot price at Henry Hub: Thomson Reuters. 2014 electric power prices: EIA, *Electric Power Monthly*, April 2014 and April 2015, Table 4.2, and EIA, *State Energy Data Report 2013*. 2014 transportation sector delivered prices derived from: U.S. Department of Energy, Clean Cities Alternative Fuel Price Report. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Crude oil								
Lower 48 average wellhead price[1]								
(2015 dollars per barrel)	**88**	**49**	**74**	**88**	**99**	**114**	**130**	**4.0%**
Production (million barrels per day)[2]								
United States total	8.71	9.42	9.38	9.43	10.06	10.66	11.26	0.7%
Lower 48 onshore	6.71	7.30	6.99	7.38	8.22	8.85	9.53	1.1%
Tight oil[3]	4.28	4.89	5.08	5.51	6.25	6.72	7.08	1.5%
Carbon dioxide enhanced oil recovery	0.28	0.28	0.32	0.43	0.55	0.63	0.72	3.8%
Other	2.15	2.13	1.59	1.44	1.41	1.50	1.73	-0.8%
Lower 48 offshore	1.50	1.64	1.98	1.74	1.60	1.63	1.58	-0.2%
State	0.07	0.07	0.05	0.04	0.04	0.03	0.03	-3.6%
Federal	1.43	1.57	1.92	1.69	1.57	1.60	1.55	0.0%
Alaska	0.50	0.48	0.41	0.32	0.24	0.19	0.15	-4.7%
Onshore	0.40	0.41	0.28	0.22	0.17	0.14	0.11	-5.0%
State offshore	0.10	0.07	0.13	0.10	0.07	0.05	0.03	-3.2%
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-10.7%
Natural gas plant liquids production								
(million barrels per day)								
United States total	3.02	3.25	4.57	4.77	4.90	4.96	4.99	1.7%
Lower 48 onshore	2.65	2.86	4.15	4.39	4.50	4.51	4.54	1.9%
Lower 48 offshore	0.34	0.37	0.40	0.36	0.39	0.44	0.44	0.8%
Alaska	0.03	0.03	0.02	0.02	0.01	0.01	0.01	-4.9%
Natural gas								
Natural gas spot price at Henry Hub								
(2015 dollars per million Btu)	4.44	2.62	4.43	5.12	5.06	4.91	4.86	2.5%
Dry production (trillion cubic feet)[4]								
United States total	25.73	27.19	30.50	34.81	37.76	39.92	42.12	1.8%
Lower 48 onshore	24.05	25.20	28.82	33.31	36.15	37.99	40.18	1.9%
Tight gas	4.81	5.00	4.92	5.43	6.08	6.30	6.55	1.1%
Shale gas and tight oil plays[3]	12.29	13.64	17.96	22.50	25.16	27.04	29.00	3.1%
Coalbed methane	1.16	1.24	1.04	1.02	0.94	0.85	0.78	-1.9%
Other	5.79	5.32	4.90	4.36	3.97	3.79	3.85	-1.3%
Lower 48 offshore	1.36	1.70	1.39	1.21	1.33	1.65	1.67	-0.1%
State	0.10	0.14	0.07	0.04	0.03	0.02	0.02	-7.3%
Federal	1.25	1.56	1.32	1.17	1.30	1.63	1.64	0.2%
Alaska	0.32	0.29	0.29	0.29	0.28	0.28	0.28	-0.2%
Onshore	0.32	0.29	0.29	0.29	0.28	0.28	0.28	-0.2%
State offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Supplemental gas supplies (trillion cubic feet)[5]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.3%**
Total lower 48 wells drilled (thousands)	**47.4**	**32.3**	**32.3**	**36.8**	**41.8**	**44.6**	**47.4**	**1.5%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, January 2105-December 2015. 2014 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2014*. 2014 natural gas spot price at Henry Hub: Thomson Reuters. 2014 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, July 2015. Other 2014: EIA, Office of Energy Analysis. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A15. Coal supply, disposition, and prices
(million short tons, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Production[1]								
Appalachia	270	223	202	165	138	154	144	-1.7%
Interior	190	165	197	193	148	172	170	0.1%
West	542	484	473	408	378	335	329	-1.5%
East of the Mississippi	413	346	351	307	243	281	276	-0.9%
West of the Mississippi	590	526	521	460	422	380	367	-1.4%
Total	**1,002**	**873**	**872**	**766**	**664**	**661**	**643**	**-1.2%**
Waste coal supplied[2]	**9**	**9**	**11**	**9**	**9**	**8**	**9**	**-0.3%**
Net imports								
Imports[3]	11	11	0	0	0	0	0	-19.2%
Exports	97	75	70	70	74	87	94	0.9%
Total	**-86**	**-63**	**-70**	**-70**	**-74**	**-87**	**-94**	**1.6%**
Total supply[4]	**925**	**819**	**813**	**705**	**599**	**583**	**557**	**-1.5%**
Consumption by sector								
Commercial and institutional	2	3	2	2	2	2	2	-0.4%
Coke plants	20	19	14	16	16	15	14	-1.2%
Other industrial[5]	43	40	42	44	45	45	47	0.6%
Coal-to-liquids heat and power	0	0	0	0	0	0	0	- -
Coal to liquids production	0	0	0	0	0	0	0	- -
Electric power[6]	852	739	754	643	536	520	494	-1.6%
Total	**917**	**801**	**813**	**705**	**599**	**583**	**557**	**-1.4%**
Discrepancy and stock change[7]	**8**	**17**	**0**	**0**	**0**	**0**	**0**	**- -**
Average minemouth price[8]								
(2015 dollars per short ton)	35.2	33.8	33.6	34.0	33.8	37.6	38.7	0.5%
(2015 dollars per million Btu)	1.73	1.69	1.68	1.71	1.71	1.86	1.91	0.5%
Delivered prices[9]								
(2015 dollars per short ton)								
Commercial and institutional	91.2	85.6	85.0	86.0	85.7	87.2	89.2	0.2%
Coke plants	153.0	153.7	173.4	186.8	200.2	207.3	208.1	1.2%
Other industrial[5]	68.9	69.7	70.6	71.5	71.2	72.3	74.9	0.3%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(2015 dollars per short ton)	46.1	41.6	43.1	42.7	41.8	43.8	45.2	0.3%
(2015 dollars per million Btu)	2.38	2.19	2.26	2.26	2.26	2.32	2.38	0.3%
Average	**49.7**	**45.8**	**47.0**	**47.8**	**48.5**	**50.4**	**51.9**	**0.5%**
Exports[10]	85.3	86.7	84.0	81.7	81.2	84.8	83.9	-0.1%

Table A15. Coal supply, disposition, and prices *(continued)*
(million short tons, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	34.9	33.8	37.1	41.6	45.8	56.8	65.1	2.7%
(nominal dollars per million Btu)	1.71	1.69	1.86	2.09	2.31	2.81	3.21	2.6%
Delivered prices[9]								
(nominal dollars per short ton)								
Commercial and institutional	90.3	85.6	93.9	105.2	116.0	131.6	150.0	2.3%
Coke plants	151.4	153.7	191.6	228.7	270.9	313.1	350.2	3.3%
Other industrial[5]	68.2	69.7	78.0	87.5	96.3	109.2	126.0	2.4%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(nominal dollars per short ton)	45.7	41.6	47.6	52.3	56.5	66.1	76.0	2.4%
(nominal dollars per million Btu)	2.35	2.19	2.50	2.77	3.05	3.50	4.01	2.5%
Average	**49.2**	**45.8**	**51.9**	**58.6**	**65.5**	**76.1**	**87.3**	**2.6%**
Exports[10]	84.4	86.7	92.8	100.0	109.8	128.0	141.2	2.0%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[9]Prices weighted by consumption; weighted average excludes commercial and institutional prices, and export free-alongside-ship prices.
[10]Free-alongside-ship price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2013*; EIA, *Quarterly Coal Report, October-December 2014*; and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydroelectric power	79.0	79.2	79.8	80.0	80.1	80.1	80.4	0.1%
Geothermal[2]	2.5	2.5	3.1	4.5	5.6	6.7	7.2	4.3%
Municipal waste[3]	3.7	3.8	3.9	3.9	3.9	3.9	3.9	0.0%
Wood and other biomass[4]	3.4	3.4	3.6	3.6	3.6	3.7	4.1	0.7%
Solar thermal	1.9	2.0	2.5	2.5	2.5	2.5	2.5	0.8%
Solar photovoltaic[5]	8.4	11.7	25.5	52.5	67.6	117.6	155.6	10.9%
Wind	64.1	74.4	120.4	141.3	142.0	142.6	145.7	2.7%
Offshore wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total electric power sector capacity	**163.0**	**177.1**	**238.7**	**288.2**	**305.2**	**357.0**	**399.4**	**3.3%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	262.3	245.5	292.7	293.7	294.2	294.8	296.3	0.8%
Geothermal[2]	15.9	16.7	21.5	32.6	42.3	51.4	55.5	4.9%
Biogenic municipal waste[6]	17.6	19.4	20.9	20.8	20.8	21.7	21.9	0.5%
Wood and other biomass	15.1	6.2	9.4	13.1	14.8	13.8	17.7	4.3%
Dedicated plants	14.0	5.4	8.7	12.4	14.1	13.1	17.0	4.7%
Cofiring	1.1	0.7	0.7	0.7	0.7	0.7	0.7	-0.3%
Solar thermal	2.5	3.3	4.5	4.6	4.6	4.7	4.8	1.5%
Solar photovoltaic[5]	15.0	18.8	47.8	107.5	143.5	256.2	345.0	12.3%
Wind	180.9	187.5	364.5	449.9	453.1	456.0	468.3	3.7%
Offshore wind	0.0	0.0	0.1	0.1	0.1	0.1	0.1	- -
Total electric power sector generation	**509.2**	**497.4**	**761.4**	**922.2**	**973.4**	**1,098.6**	**1,209.5**	**3.6%**
End-use sectors[7]								
Net summer capacity								
Conventional hydroelectric power	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0%
Biomass	4.7	4.7	4.7	4.9	5.0	5.0	5.0	0.3%
Solar photovoltaic[5]	8.6	11.2	28.7	41.0	55.1	71.5	88.3	8.6%
Wind	0.9	1.6	2.3	2.4	2.6	2.9	3.2	2.8%
Total end-use sector capacity	**15.0**	**18.4**	**36.6**	**49.1**	**63.6**	**80.3**	**97.4**	**6.9%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	1.3	1.3	1.3	1.3	1.3	1.3	1.3	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	4.1	4.1	4.1	4.1	4.1	4.1	4.1	0.0%
Biomass	26.1	26.0	25.9	26.6	27.4	27.4	27.6	0.2%
Solar photovoltaic[5]	11.8	15.5	40.2	58.1	78.7	102.7	127.2	8.8%
Wind	1.2	2.1	3.1	3.1	3.5	3.9	4.3	3.0%
Total end-use sector generation	**44.5**	**49.0**	**74.6**	**93.2**	**115.0**	**139.4**	**164.6**	**5.0%**

Table A16. Renewable energy generating capacity and generation *(continued)*

(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydroelectric power	79.3	79.5	80.1	80.3	80.3	80.4	80.7	0.1%
Geothermal	2.5	2.5	3.1	4.5	5.6	6.7	7.2	4.3%
Municipal waste	4.3	4.4	4.4	4.4	4.4	4.4	4.4	0.0%
Wood and other biomass[4]	8.1	8.1	8.3	8.4	8.6	8.7	9.1	0.5%
Solar[5]	18.9	24.9	56.6	95.9	125.3	191.6	246.4	9.6%
Wind	65.0	76.0	122.7	143.7	144.6	145.5	149.0	2.7%
Total capacity, all sectors	**178.1**	**195.4**	**275.3**	**337.3**	**368.8**	**437.3**	**496.8**	**3.8%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	263.6	246.8	294.1	295.0	295.6	296.1	297.6	0.8%
Geothermal	15.9	16.7	21.5	32.6	42.3	51.4	55.5	4.9%
Municipal waste	21.7	23.5	25.0	24.9	24.9	25.8	26.0	0.4%
Wood and other biomass	41.2	32.1	35.3	39.7	42.2	41.2	45.2	1.4%
Solar[5]	29.3	37.6	92.5	170.1	226.8	363.6	477.1	10.7%
Wind	182.1	189.6	367.6	453.2	456.7	459.9	472.8	3.7%
Total generation, all sectors	**553.7**	**546.4**	**836.0**	**1,015.5**	**1,088.4**	**1,238.1**	**1,374.1**	**3.8%**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2015, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2015, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2015 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2014 generation: EIA, *Monthly Energy Review*, February 2016. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case 2014	2015	2020	2025	2030	2035	2040	Annual growth 2015-2040 (percent)
Marketed renewable energy[1]								
Residential (wood)	**0.59**	**0.44**	**0.42**	**0.41**	**0.39**	**0.38**	**0.37**	**-0.7%**
Commercial (biomass)	**0.14**	**0.14**	**0.14**	**0.14**	**0.14**	**0.14**	**0.14**	**0.0%**
Industrial[2]	**2.26**	**2.26**	**2.30**	**2.39**	**2.47**	**2.52**	**2.63**	**0.6%**
Conventional hydroelectric power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Municipal waste[3]	0.19	0.20	0.22	0.23	0.23	0.24	0.26	1.1%
Biomass	1.32	1.29	1.25	1.35	1.43	1.46	1.53	0.7%
Biofuels heat and coproducts	0.75	0.78	0.83	0.80	0.81	0.81	0.84	0.3%
Transportation	**1.30**	**1.38**	**1.53**	**1.48**	**1.47**	**1.50**	**1.59**	**0.6%**
Ethanol used in E85[4]	0.02	0.03	0.03	0.08	0.14	0.18	0.18	7.3%
Ethanol used in gasoline blending	1.09	1.12	1.12	1.01	0.94	0.93	1.01	-0.4%
Biodiesel used in distillate blending	0.19	0.22	0.30	0.19	0.19	0.19	0.19	-0.5%
Biobutanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from biomass	0.00	0.00	0.00	0.00	0.01	0.01	0.01	- -
Renewable diesel and gasoline[5]	0.00	0.00	0.08	0.19	0.19	0.19	0.19	17.9%
Electric power[6]	**5.01**	**4.86**	**7.37**	**8.91**	**9.41**	**10.60**	**11.67**	**3.6%**
Conventional hydroelectric power	2.50	2.34	2.79	2.80	2.81	2.81	2.83	0.8%
Geothermal	0.15	0.16	0.21	0.31	0.41	0.49	0.53	4.9%
Biogenic municipal waste[7]	0.24	0.25	0.28	0.28	0.28	0.29	0.29	0.6%
Biomass	0.23	0.10	0.15	0.21	0.24	0.22	0.27	3.9%
Dedicated plants	0.15	0.06	0.09	0.13	0.15	0.14	0.18	4.7%
Cofiring	0.08	0.05	0.06	0.08	0.09	0.08	0.09	2.7%
Solar thermal	0.02	0.03	0.04	0.04	0.04	0.04	0.05	1.5%
Solar photovoltaic	0.14	0.18	0.46	1.03	1.37	2.44	3.29	12.3%
Wind	1.73	1.79	3.43	4.24	4.27	4.30	4.41	3.7%
Total marketed renewable energy	**9.31**	**9.08**	**11.76**	**13.32**	**13.88**	**15.13**	**16.40**	**2.4%**
Sources of ethanol								
from corn and other starch	1.18	1.21	1.16	1.12	1.12	1.13	1.17	-0.1%
from cellulose	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.4%
Net imports	-0.07	-0.06	-0.01	-0.04	-0.04	-0.03	0.02	- -
Total	**1.11**	**1.15**	**1.15**	**1.09**	**1.09**	**1.11**	**1.20**	**0.2%**

Table A17. Renewable energy consumption by sector and source *(continued)*
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.08**	**0.11**	**0.35**	**0.50**	**0.63**	**0.78**	**0.94**	**8.8%**
Solar hot water heating	0.01	0.01	0.01	0.02	0.02	0.02	0.02	3.4%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.8%
Solar photovoltaic	0.05	0.08	0.30	0.43	0.57	0.71	0.86	10.2%
Wind	0.01	0.02	0.03	0.03	0.03	0.03	0.03	2.0%
Commercial	**0.15**	**0.16**	**0.18**	**0.22**	**0.29**	**0.38**	**0.47**	**4.4%**
Solar thermal	0.08	0.09	0.09	0.10	0.10	0.11	0.11	1.0%
Solar photovoltaic	0.06	0.07	0.09	0.12	0.19	0.27	0.35	6.5%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2. Actual heat rates used to determine fuel consumption for all renewable fuels except hydroelectric, geothermal, solar, and wind. Consumption at hydroelectric, solar, and wind facilities is determined by using the fossil fuel equivalent of 9,541 Btu per kilowatthour.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2015 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 ethanol: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2014 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2014 values: EIA, Office of Energy Analysis. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Residential								
Petroleum	69	64	59	53	49	45	41	-1.7%
Natural gas	278	253	258	256	255	253	251	0.0%
Electricity[1]	765	711	664	586	538	531	529	-1.2%
Total residential	**1,112**	**1,028**	**981**	**895**	**841**	**829**	**821**	**-0.9%**
Commercial								
Petroleum	39	47	50	49	49	48	47	0.0%
Natural gas	189	176	183	184	188	194	202	0.5%
Coal	5	6	5	5	5	5	5	-0.4%
Electricity[1]	735	690	654	599	566	569	572	-0.7%
Total commercial	**968**	**918**	**893**	**836**	**807**	**817**	**826**	**-0.4%**
Industrial[2]								
Petroleum	341	378	410	431	434	443	458	0.8%
Natural gas[3]	476	478	524	560	579	609	636	1.2%
Coal	138	130	120	128	131	130	131	0.0%
Electricity[1]	542	486	504	481	443	436	434	-0.5%
Total industrial	**1,497**	**1,472**	**1,558**	**1,600**	**1,587**	**1,618**	**1,660**	**0.5%**
Transportation								
Petroleum[4]	1,777	1,800	1,802	1,720	1,652	1,629	1,628	-0.4%
Natural gas[5]	48	51	49	55	62	74	93	2.4%
Electricity[1]	4	5	6	10	12	15	16	5.1%
Total transportation	**1,829**	**1,855**	**1,857**	**1,784**	**1,726**	**1,717**	**1,737**	**-0.3%**
Electric power[6]								
Petroleum	26	20	11	10	8	7	6	-4.4%
Natural gas	444	524	451	509	602	608	653	0.9%
Coal	1,570	1,340	1,360	1,150	943	930	885	-1.6%
Other[7]	6	6	6	6	6	6	6	0.0%
Total electric power	**2,046**	**1,891**	**1,829**	**1,675**	**1,559**	**1,551**	**1,551**	**-0.8%**
Total by fuel								
Petroleum[4]	2,252	2,309	2,332	2,262	2,191	2,171	2,181	-0.2%
Natural gas	1,434	1,482	1,466	1,563	1,685	1,737	1,835	0.9%
Coal	1,713	1,476	1,485	1,283	1,079	1,065	1,021	-1.5%
Other[7]	6	6	6	6	6	6	6	0.0%
Total	**5,406**	**5,273**	**5,289**	**5,115**	**4,961**	**4,980**	**5,044**	**-0.2%**
Carbon dioxide emissions (tons per person)	**16.9**	**16.4**	**15.8**	**14.7**	**13.8**	**13.4**	**13.3**	**-0.8%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2015, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See Table A19, "Energy-Related Carbon Dioxide Emissions by End Use", for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case 2014	2015	2020	2025	2030	2035	2040	Annual growth 2015-2040 (percent)
Residential								
Space heating	314	262	263	248	237	230	223	-0.6%
Space cooling	104	120	104	94	89	90	92	-1.1%
Water heating	143	139	136	129	124	121	118	-0.6%
Refrigeration	57	53	47	41	37	36	36	-1.5%
Cooking	30	29	29	28	27	28	28	-0.1%
Clothes dryers	35	33	33	30	29	29	29	-0.5%
Freezers	12	11	10	8	7	7	6	-2.2%
Lighting	81	74	60	45	33	26	24	-4.4%
Clothes washers[1]	4	4	3	2	2	2	2	-3.4%
Dishwashers[1]	15	14	13	12	12	13	13	-0.3%
Televisions and related equipment[2]	48	42	36	31	29	31	32	-1.1%
Computers and related equipment[3]	18	17	13	10	8	7	5	-4.4%
Furnace fans and boiler circulation pumps	23	17	17	14	12	11	10	-2.0%
Other uses[4]	230	213	216	201	194	198	202	-0.2%
Discrepancy[5]	-3	0	0	0	0	0	0	-0.9%
Total residential	**1,112**	**1,028**	**981**	**895**	**841**	**829**	**821**	**-0.9%**
Commercial								
Space heating[6]	139	125	124	117	112	109	107	-0.6%
Space cooling[6]	78	85	75	67	61	60	60	-1.4%
Water heating[6]	44	44	43	42	43	44	45	0.1%
Ventilation	82	77	76	69	63	62	62	-0.9%
Cooking	14	14	15	15	15	16	16	0.5%
Lighting	141	131	121	103	90	81	75	-2.2%
Refrigeration	58	54	46	38	33	32	32	-2.1%
Office equipment (PC)	14	12	9	6	4	3	2	-6.3%
Office equipment (non-PC)	34	33	33	32	34	37	39	0.7%
Other uses[7]	362	343	352	349	352	372	389	0.5%
Total commercial	**968**	**918**	**893**	**836**	**807**	**817**	**826**	**-0.4%**
Industrial[8]								
Manufacturing								
Refining	261	257	247	238	233	235	241	-0.3%
Food products	99	94	97	96	97	100	104	0.4%
Paper products	79	72	65	65	64	61	60	-0.7%
Bulk chemicals	249	238	300	326	325	338	351	1.6%
Glass	15	16	17	17	17	17	17	0.1%
Cement and lime	24	24	30	32	32	34	38	1.8%
Iron and steel	115	108	94	106	105	104	107	0.0%
Aluminum	42	40	44	42	40	38	35	-0.5%
Fabricated metal products	33	33	31	29	27	28	29	-0.5%
Machinery	19	19	19	21	20	21	22	0.6%
Computers and electronics	19	18	18	17	17	18	19	0.3%
Transportation equipment	40	40	38	36	34	35	36	-0.4%
Electrical equipment	9	9	10	11	11	11	11	1.0%
Wood products	14	13	15	15	14	14	15	0.5%
Plastics	34	33	34	33	31	32	32	0.0%
Balance of manufacturing	137	131	127	122	117	116	116	-0.5%
Total manufacturing	**1,190**	**1,144**	**1,186**	**1,205**	**1,186**	**1,202**	**1,233**	**0.3%**
Nonmanufacturing								
Agriculture	86	85	82	79	76	74	72	-0.7%
Construction	69	64	83	83	81	82	82	1.0%
Mining	123	111	115	115	114	117	120	0.3%
Total nonmanufacturing	**277**	**261**	**281**	**277**	**271**	**272**	**274**	**0.2%**
Discrepancy[5]	29	67	92	117	130	144	153	3.3%
Total industrial	**1,497**	**1,472**	**1,558**	**1,600**	**1,587**	**1,618**	**1,660**	**0.5%**

Table A19. Energy-related carbon dioxide emissions by end use *(continued)*
(million metric tons)

Sector and end use	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Transportation								
Light-duty vehicles	1,043	1,050	1,040	929	837	785	759	-1.3%
Commercial light trucks[9]	54	54	55	53	51	51	52	-0.2%
Bus transportation	18	18	18	18	18	18	18	0.1%
Freight trucks	379	389	396	410	424	448	477	0.8%
Rail, passenger	6	5	5	5	5	5	5	0.0%
Rail, freight	34	34	34	36	35	33	33	-0.2%
Shipping, domestic	8	7	6	6	5	5	5	-1.5%
Shipping, international	49	55	48	50	52	54	56	0.1%
Recreational boats	16	17	18	19	19	20	20	0.7%
Air	166	168	178	189	200	207	212	0.9%
Military use	46	46	46	46	49	52	56	0.8%
Lubricants	5	5	5	5	5	5	5	0.2%
Pipeline fuel	46	47	44	47	50	53	57	0.7%
Discrepancy[5]	-40	-40	-37	-30	-24	-20	-17	-3.4%
Total transportation	**1,829**	**1,855**	**1,857**	**1,784**	**1,726**	**1,717**	**1,737**	**-0.3%**
Biogenic energy combustion[10]								
Biomass	214	185	184	198	206	205	216	0.6%
Electric power sector	21	10	14	19	22	20	25	3.9%
Other sectors	193	175	169	178	184	185	191	0.3%
Biogenic waste	22	23	25	25	25	26	27	0.6%
Biofuels heat and coproducts	70	73	77	75	76	76	79	0.3%
Ethanol	76	79	79	75	74	76	82	0.2%
Biodiesel	14	16	22	14	14	14	14	-0.5%
Liquids from biomass	0	0	0	0	0	1	1	- -
Renewable diesel and gasoline	0	0	6	14	14	14	14	17.9%
Total	**396**	**376**	**393**	**401**	**409**	**413**	**432**	**0.6%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[6]Includes emissions related to fuel consumption for district services.
[7]Includes emissions related to (but not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[10]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, February 2016. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A20. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2014	2015	2020	2025	2030	2035	2040	Annual growth 2015-2040 (percent)
Real gross domestic product	**15,962**	**16,349**	**18,555**	**20,765**	**23,113**	**25,598**	**28,397**	**2.2%**
Components of real gross domestic product								
Real consumption	10,876	11,221	12,861	14,348	16,092	17,881	19,870	2.3%
Real investment	2,718	2,842	3,513	4,068	4,520	5,051	5,661	2.8%
Real government spending	2,838	2,860	2,967	3,056	3,222	3,396	3,602	0.9%
Real exports	2,086	2,119	2,615	3,374	4,178	5,105	6,113	4.3%
Real imports	2,529	2,662	3,374	4,032	4,824	5,721	6,683	3.8%
Energy intensity (thousand Btu per 2009 dollar of GDP)								
Delivered energy	4.52	4.38	4.03	3.65	3.29	3.04	2.83	-1.7%
Total energy	6.15	5.92	5.42	4.89	4.39	4.06	3.77	-1.8%
Price indices								
GDP chain-type price index (2009=1.000)	1.09	1.10	1.21	1.34	1.49	1.66	1.85	2.1%
Consumer price index (1982-4=1.00)								
All-urban	2.37	2.37	2.65	2.99	3.35	3.78	4.27	2.4%
Energy commodities and services	2.43	2.02	2.41	2.87	3.34	3.92	4.61	3.4%
Wholesale price index (1982=1.00)								
All commodities	2.05	1.91	2.14	2.37	2.59	2.87	3.16	2.0%
Fuel and power	2.10	1.60	2.10	2.53	2.91	3.39	3.92	3.7%
Metals and metal products	2.15	2.01	2.15	2.35	2.55	2.80	3.06	1.7%
Industrial commodities excluding energy	1.98	1.94	2.13	2.33	2.53	2.76	3.01	1.8%
Interest rates (percent, nominal)								
Federal funds rate	0.09	0.13	3.32	3.22	3.24	3.23	3.08	- -
10-year treasury note	2.54	2.14	3.83	3.66	3.77	3.82	3.72	- -
AA utility bond rate	4.19	4.01	5.87	5.41	5.73	5.85	5.71	- -
Value of shipments (billion 2009 dollars)								
Non-industrial and service sectors	23,338	24,085	26,750	29,265	32,042	34,833	37,701	1.8%
Total industrial	7,165	7,229	8,351	9,146	9,776	10,562	11,483	1.9%
Agriculture, mining, and construction	1,957	1,931	2,493	2,620	2,710	2,828	2,955	1.7%
Manufacturing	5,208	5,299	5,858	6,527	7,066	7,734	8,528	1.9%
Energy-intensive	1,718	1,704	1,892	2,046	2,147	2,267	2,417	1.4%
Non-energy-intensive	3,490	3,594	3,967	4,481	4,920	5,467	6,111	2.1%
Total shipments	**30,504**	**31,314**	**35,101**	**38,411**	**41,818**	**45,396**	**49,184**	**1.8%**
Population and employment (millions)								
Population, with armed forces overseas	319	322	335	348	360	371	381	0.7%
Population, aged 16 and over	254	257	269	281	292	302	311	0.8%
Population, aged 65 and over	46	48	57	66	74	79	82	2.2%
Employment, nonfarm	138	142	150	156	161	165	170	0.7%
Employment, manufacturing	12.2	12.5	13.1	13.4	13.0	12.6	12.3	-0.1%
Key labor indicators								
Labor force (millions)	156	157	167	171	177	183	188	0.7%
Nonfarm labor productivity (2009=1.00)	1.05	1.06	1.15	1.25	1.37	1.50	1.63	1.7%
Unemployment rate (percent)	6.15	5.31	4.72	4.90	4.78	4.76	4.78	- -
Key indicators for energy demand								
Real disposable personal income	11,836	12,225	14,197	15,888	17,826	19,689	21,789	2.3%
Housing starts (millions)	1.06	1.18	1.74	1.71	1.66	1.66	1.65	1.3%
Commercial floorspace (billion square feet)	83.1	83.8	88.7	94.0	99.3	104.6	109.8	1.1%
Unit sales of light-duty vehicles (millions)	16.4	17.4	17.1	17.3	17.7	18.2	19.0	0.4%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2014 and 2015: IHS Economics, Industry and Employment models, November 2015. **Projections:** U.S. Energy Information Administration, AEO2016 National Energy Modeling System run ref2016.d032416a.

Table A21. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Crude oil spot prices								
(2015 dollars per barrel)								
Brent	100	52	77	92	104	120	136	3.9%
West Texas Intermediate	94	49	71	85	97	112	129	4.0%
(nominal dollars per barrel)								
Brent	99	52	85	112	141	181	229	6.1%
West Texas Intermediate	93	49	79	105	131	170	217	6.2%
Petroleum and other liquids consumption[1]								
OECD								
United States (50 states)	19.16	19.42	20.11	19.90	19.54	19.69	20.14	0.1%
United States territories	0.30	0.30	0.31	0.32	0.34	0.36	0.38	1.0%
Canada	2.41	2.39	2.39	2.38	2.39	2.44	2.51	0.2%
Mexico and Chile	2.29	2.30	2.38	2.36	2.50	2.67	2.87	0.9%
OECD Europe[2]	13.66	13.83	13.70	13.57	13.65	13.79	13.98	0.0%
Japan	4.30	4.14	3.91	3.75	3.66	3.56	3.40	-0.8%
South Korea	2.35	2.38	2.41	2.42	2.44	2.48	2.55	0.3%
Australia and New Zealand	1.24	1.28	1.35	1.39	1.41	1.45	1.53	0.7%
Total OECD consumption	**45.71**	**46.03**	**46.56**	**46.08**	**45.93**	**46.44**	**47.35**	**0.1%**
Non-OECD								
Russia	3.56	3.35	3.65	3.79	3.75	3.73	3.59	0.3%
Other Europe and Eurasia[3]	2.04	2.07	2.18	2.34	2.43	2.48	2.53	0.8%
China	10.85	11.18	12.71	13.81	14.81	15.65	16.36	1.5%
India	3.78	3.97	4.54	5.19	5.94	6.97	8.26	3.0%
Other Asia[4]	8.04	8.15	9.40	10.35	11.42	12.73	14.29	2.3%
Middle East	8.13	8.29	9.96	10.42	11.28	12.31	13.23	1.9%
Africa	3.71	3.86	4.54	5.06	5.50	6.08	6.93	2.4%
Brazil	3.15	3.15	3.41	3.74	4.06	4.39	4.71	1.6%
Other Central and South America	3.83	3.85	4.11	4.28	4.41	4.60	4.89	1.0%
Total non-OECD consumption	**47.08**	**47.87**	**54.49**	**58.99**	**63.60**	**68.93**	**74.79**	**1.8%**
Total consumption	**92.79**	**93.90**	**101.05**	**105.06**	**109.52**	**115.37**	**122.14**	**1.1%**
Petroleum and other liquids production								
OPEC[5]								
Middle East	26.66	27.76	30.87	32.33	34.29	36.87	39.38	1.4%
North Africa	2.24	2.13	1.99	2.12	2.32	2.58	2.94	1.3%
West Africa	4.18	4.21	4.35	4.41	4.58	4.72	5.07	0.8%
South America	3.24	3.24	2.96	3.10	3.33	3.60	3.88	0.7%
Total OPEC production	**36.33**	**37.33**	**40.17**	**41.96**	**44.52**	**47.75**	**51.28**	**1.3%**
Non-OPEC								
OECD								
United States (50 states)	14.01	14.95	16.33	16.52	17.26	17.93	18.62	0.9%
Canada	4.39	4.54	5.43	5.39	5.55	5.73	6.01	1.1%
Mexico and Chile	2.84	2.64	2.46	2.56	2.58	2.83	3.24	0.8%
OECD Europe[2]	3.66	3.79	3.44	3.32	3.10	2.92	2.78	-1.2%
Japan and South Korea	0.22	0.22	0.20	0.21	0.21	0.22	0.22	0.0%
Australia and New Zealand	0.52	0.51	0.66	0.63	0.61	0.69	0.76	1.7%
Total OECD production	**25.63**	**26.65**	**28.51**	**28.63**	**29.31**	**30.32**	**31.63**	**0.7%**
Non-OECD								
Russia	10.85	10.95	10.62	10.99	11.22	11.51	12.21	0.4%
Other Europe and Eurasia[3]	3.21	3.23	3.69	4.34	4.63	4.68	4.50	1.3%
China	4.60	4.69	4.90	5.23	5.44	5.91	6.24	1.1%
Other Asia[4]	3.94	4.03	3.92	3.75	3.65	3.61	3.62	-0.4%
Middle East	1.17	1.14	1.02	0.91	0.83	0.76	0.69	-2.0%
Africa	2.33	2.33	2.48	2.58	2.73	2.79	2.83	0.8%
Brazil	2.97	3.15	3.59	4.59	5.00	5.46	6.15	2.7%
Other Central and South America	2.18	2.18	2.15	2.10	2.19	2.58	2.99	1.3%
Total non-OECD production	**31.25**	**31.70**	**32.37**	**34.48**	**35.69**	**37.30**	**39.23**	**0.9%**
Total petroleum and other liquids production	**93.21**	**95.68**	**101.05**	**105.06**	**109.52**	**115.37**	**122.14**	**1.0%**
OPEC market share (percent)	39.0	39.0	39.8	39.9	40.7	41.4	42.0	- -

Table A21. International petroleum and other liquids supply, disposition, and prices *(continued)*

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2015-2040 (percent)
	2014	2015	2020	2025	2030	2035	2040	
Selected world production subtotals:								
Crude oil and equivalents[6]	77.98	80.13	82.77	85.71	89.12	93.95	99.74	0.9%
Tight oil	4.69	5.34	5.44	5.85	6.96	8.50	10.35	2.7%
Bitumen[7]	2.25	2.32	3.08	3.12	3.18	3.24	3.31	1.4%
Refinery processing gain[8]	2.50	2.45	2.53	2.62	2.73	2.84	2.94	0.7%
Natural gas plant liquids	10.07	10.37	12.32	12.88	13.24	13.58	13.88	1.2%
Liquids from renewable sources[9]	2.26	2.32	2.54	2.88	3.31	3.71	4.11	2.3%
Liquids from coal[10]	0.20	0.25	0.27	0.16	0.26	0.36	0.50	2.8%
Liquids from natural gas[11]	0.27	0.29	0.32	0.52	0.57	0.62	0.65	3.3%
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.7%
Crude oil production[6]								
OPEC[5]								
Middle East	23.32	24.38	27.07	28.31	30.10	32.42	34.74	1.4%
North Africa	1.89	1.78	1.61	1.71	1.82	1.97	2.20	0.9%
West Africa	4.16	4.19	4.28	4.34	4.51	4.64	4.99	0.7%
South America	3.06	3.05	2.75	2.85	3.09	3.35	3.64	0.7%
Total OPEC production	**32.43**	**33.40**	**35.72**	**37.22**	**39.52**	**42.38**	**45.57**	**1.3%**
Non-OPEC								
OECD								
United States (50 states)	8.71	9.42	9.38	9.43	10.06	10.66	11.26	0.7%
Canada	3.61	3.72	4.57	4.42	4.53	4.69	4.96	1.2%
Mexico and Chile	2.48	2.31	2.16	2.27	2.29	2.55	2.96	1.0%
OECD Europe[2]	2.82	2.95	2.31	2.15	1.88	1.65	1.47	-2.7%
Japan and South Korea	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.2%
Australia and New Zealand	0.39	0.39	0.53	0.51	0.49	0.56	0.64	1.9%
Total OECD production	**18.01**	**18.81**	**18.96**	**18.78**	**19.24**	**20.12**	**21.29**	**0.5%**
Non-OECD								
Russia	10.11	10.17	9.84	10.23	10.49	10.81	11.53	0.5%
Other Europe and Eurasia[3]	2.99	3.00	3.43	4.07	4.36	4.40	4.23	1.4%
China	4.20	4.28	4.34	4.46	4.40	4.63	4.67	0.3%
Other Asia[4]	3.10	3.18	2.98	2.73	2.52	2.38	2.25	-1.4%
Middle East	1.14	1.11	1.00	0.89	0.81	0.74	0.67	-2.0%
Africa	1.94	1.94	2.01	2.10	2.25	2.30	2.34	0.8%
Brazil	2.25	2.43	2.77	3.58	3.78	4.07	4.67	2.7%
Other Central and South America	1.80	1.81	1.72	1.65	1.75	2.12	2.52	1.3%
Total non-OECD production	**27.54**	**27.92**	**28.09**	**29.72**	**30.36**	**31.45**	**32.87**	**0.7%**
Total crude oil production[6]	**77.98**	**80.13**	**82.77**	**85.71**	**89.12**	**93.95**	**99.74**	**0.9%**
OPEC market share (percent)	41.6	41.7	43.2	43.4	44.3	45.1	45.7	- -

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2014 are model results and may differ from official EIA data reports.
Sources: 2014 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2015: EIA, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System run ref2016.d032416a and EIA, Generate World Oil Balance application.

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2015	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	19.7	19.5	19.6	19.6	20.8	21.0	21.2	23.3	23.5	23.8
Natural gas plant liquids	4.4	6.0	6.1	6.2	6.4	6.5	6.5	6.5	6.7	6.7
Dry natural gas	28.0	30.9	31.4	31.7	37.9	38.9	38.8	42.5	43.4	44.0
Coal[1]	17.2	16.6	17.5	18.5	13.6	13.3	13.7	13.3	13.1	13.8
Nuclear / uranium[2]	8.3	8.1	8.1	8.1	8.2	8.2	8.2	8.2	8.2	8.2
Conventional hydroelectric power	2.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9
Biomass[3]	4.1	4.2	4.2	4.4	4.3	4.4	4.7	4.1	4.6	5.4
Other renewable energy[4]	2.6	4.9	4.6	4.9	5.6	6.6	9.6	6.4	8.8	13.3
Other[5]	0.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.1
Total	**87.3**	**93.9**	**95.4**	**97.0**	**100.4**	**102.7**	**106.5**	**107.9**	**112.2**	**119.1**
Imports										
Crude oil	16.1	16.0	16.8	17.7	14.0	16.0	18.0	12.5	15.9	18.5
Petroleum and other liquids[6]	3.9	4.5	4.5	4.6	4.2	4.3	4.4	4.1	4.3	4.7
Natural gas[7]	2.8	2.1	2.1	2.2	1.5	1.6	1.6	1.4	1.4	1.5
Other imports[8]	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Total	**23.2**	**22.7**	**23.6**	**24.7**	**19.8**	**22.0**	**24.2**	**18.1**	**21.8**	**24.9**
Exports										
Petroleum and other liquids[9]	9.0	11.7	11.6	11.6	13.4	13.5	13.5	15.1	15.2	15.2
Natural gas[10]	1.8	5.0	5.0	5.0	8.1	7.6	7.2	9.7	9.0	8.3
Coal	2.0	1.9	1.9	1.9	1.9	1.9	1.8	2.3	2.3	2.3
Total	**12.8**	**18.5**	**18.5**	**18.4**	**23.4**	**23.0**	**22.5**	**27.1**	**26.6**	**25.8**
Discrepancy[11]	**1.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**0.3**	**0.3**
Consumption										
Petroleum and other liquids[12]	36.5	36.8	37.8	39.0	34.2	36.6	39.0	33.5	37.5	41.1
Natural gas	28.3	27.7	28.3	28.6	31.0	32.5	32.8	33.7	35.4	36.8
Coal[13]	15.5	14.6	15.6	16.5	11.7	11.3	11.9	10.9	10.7	11.4
Nuclear / uranium[2]	8.3	8.1	8.1	8.1	8.2	8.2	8.2	8.2	8.2	8.2
Conventional hydroelectric power	2.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9
Biomass[14]	2.8	2.7	2.8	2.9	2.8	3.0	3.3	2.8	3.1	3.8
Other renewable energy[4]	2.6	4.9	4.6	4.9	5.6	6.6	9.6	6.4	8.8	13.3
Other[15]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**96.7**	**98.1**	**100.5**	**103.3**	**96.7**	**101.5**	**108.0**	**98.7**	**107.1**	**117.9**
Prices (2015 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	52	76	77	77	102	104	106	133	136	139
West Texas Intermediate	49	70	71	72	96	97	99	125	129	132
Natural gas at Henry Hub (dollars per million Btu)	2.62	4.24	4.43	4.58	4.70	5.06	4.96	4.54	4.86	5.04
Coal (dollars per ton) at the minemouth[16]	33.8	33.9	33.6	33.9	34.1	33.8	34.0	39.7	38.7	40.0
Coal (dollars per million Btu) at the minemouth[16]	1.69	1.70	1.68	1.69	1.73	1.71	1.71	1.95	1.91	1.96
Average end-use[17]	2.37	2.42	2.43	2.48	2.58	2.55	2.62	2.70	2.68	2.79
Average electricity (cents per kilowatthour)	10.3	10.7	10.5	10.5	10.9	10.9	10.8	10.5	10.5	10.5

Table B1. Total energy supply, disposition, and price summary *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2015	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	52	86	85	84	160	141	140	294	229	230
West Texas Intermediate	49	80	79	78	150	131	131	276	217	218
Natural gas at Henry Hub (dollars per million Btu)	2.62	4.82	4.90	4.99	7.36	6.84	6.58	10.00	8.17	8.32
Coal (dollars per ton) at the minemouth[16]	33.8	38.5	37.1	37.0	53.4	45.8	45.0	87.4	65.1	66.1
Coal (dollars per million Btu) at the minemouth[16]	1.69	1.93	1.86	1.85	2.70	2.31	2.27	4.30	3.21	3.24
Average end-use[17]	2.37	2.75	2.69	2.70	4.04	3.45	3.47	5.95	4.50	4.62
Average electricity (cents per kilowatthour)	10.3	12.1	11.6	11.5	17.1	14.7	14.3	23.2	17.6	17.3

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowmacro.d032516a, ref2016.d032416a, and highmacro.d032516a.

Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Propane	0.43	0.42	0.42	0.43	0.37	0.38	0.39	0.32	0.34	0.36
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Distillate fuel oil	0.50	0.43	0.43	0.43	0.34	0.34	0.34	0.27	0.27	0.27
Petroleum and other liquids subtotal	0.93	0.86	0.86	0.87	0.71	0.72	0.73	0.59	0.61	0.64
Natural gas	4.77	4.80	4.87	4.92	4.57	4.80	5.08	4.30	4.73	5.20
Renewable energy[1]	0.44	0.41	0.42	0.42	0.38	0.39	0.40	0.35	0.37	0.38
Electricity	4.78	4.64	4.76	4.85	4.53	4.83	5.21	4.66	5.20	5.90
Delivered energy	**10.92**	**10.72**	**10.90**	**11.05**	**10.18**	**10.74**	**11.42**	**9.91**	**10.91**	**12.12**
Electricity related losses	9.44	9.14	9.37	9.56	8.44	8.77	9.50	8.38	9.15	10.44
Total	**20.37**	**19.85**	**20.27**	**20.62**	**18.62**	**19.50**	**20.92**	**18.28**	**20.05**	**22.56**
Commercial										
Propane	0.17	0.18	0.18	0.18	0.19	0.19	0.20	0.19	0.20	0.21
Motor gasoline[2]	0.04	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07
Kerosene	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	0.37	0.36	0.36	0.36	0.32	0.32	0.32	0.29	0.29	0.29
Residual fuel oil	0.07	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Petroleum and other liquids subtotal	0.66	0.70	0.70	0.71	0.67	0.68	0.69	0.65	0.67	0.68
Natural gas	3.32	3.45	3.45	3.45	3.51	3.53	3.60	3.77	3.81	3.87
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Electricity	4.64	4.65	4.69	4.71	4.96	5.09	5.19	5.41	5.62	5.80
Delivered energy	**8.81**	**8.99**	**9.03**	**9.05**	**9.34**	**9.49**	**9.67**	**10.02**	**10.28**	**10.54**
Electricity related losses	9.16	9.15	9.23	9.29	9.24	9.23	9.47	9.72	9.89	10.28
Total	**17.97**	**18.14**	**18.26**	**18.34**	**18.58**	**18.72**	**19.13**	**19.74**	**20.17**	**20.82**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.38	3.00	3.10	3.21	3.46	3.66	3.80	3.96	4.22	4.22
Motor gasoline[2]	0.27	0.27	0.28	0.28	0.26	0.27	0.28	0.26	0.27	0.29
Distillate fuel oil	1.34	1.36	1.44	1.51	1.33	1.44	1.53	1.35	1.47	1.60
Residual fuel oil	0.04	0.04	0.04	0.05	0.05	0.06	0.06	0.05	0.05	0.06
Petrochemical feedstocks	0.66	0.94	0.96	1.00	1.24	1.31	1.36	1.55	1.66	1.64
Other petroleum[6]	3.38	3.39	3.59	3.78	3.45	3.82	4.15	3.59	4.15	4.63
Petroleum and other liquids subtotal	8.07	9.00	9.40	9.82	9.80	10.55	11.19	10.75	11.82	12.45
Natural gas	7.75	8.35	8.55	8.84	8.67	9.13	9.78	9.16	9.89	10.93
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.63	1.73	1.76	1.77	2.02	2.06	2.06	2.26	2.31	2.33
Natural gas liquefaction for export[8]	0.00	0.26	0.26	0.26	0.57	0.53	0.49	0.75	0.69	0.62
Natural gas subtotal	9.38	10.34	10.57	10.87	11.25	11.72	12.33	12.16	12.89	13.89
Metallurgical coal	0.54	0.39	0.41	0.52	0.47	0.47	0.60	0.37	0.40	0.59
Other industrial coal	0.82	0.79	0.82	0.87	0.81	0.88	1.00	0.82	0.93	1.16
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	0.00	0.01	0.02
Coal subtotal	1.34	1.16	1.23	1.36	1.26	1.35	1.59	1.19	1.34	1.78
Biofuels heat and coproducts	0.78	0.81	0.83	0.83	0.81	0.81	0.82	0.74	0.84	0.90
Renewable energy[9]	1.48	1.40	1.48	1.58	1.49	1.67	1.94	1.53	1.79	2.34
Electricity	3.27	3.45	3.61	3.82	3.69	3.98	4.36	3.86	4.26	4.90
Delivered energy	**24.33**	**26.16**	**27.11**	**28.28**	**28.31**	**30.07**	**32.25**	**30.23**	**32.94**	**36.26**
Electricity related losses	6.46	6.79	7.11	7.52	6.88	7.22	7.96	6.94	7.50	8.69
Total	**30.79**	**32.95**	**34.22**	**35.80**	**35.19**	**37.29**	**40.21**	**37.17**	**40.44**	**44.95**

Table B2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections 2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Transportation										
Propane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03
Motor gasoline[2]	17.01	16.52	16.79	17.05	12.65	13.62	14.35	10.57	12.55	13.77
of which: E85[10]	0.05	0.04	0.04	0.04	0.33	0.22	0.19	0.36	0.28	0.30
Jet fuel[11]	2.84	2.92	2.99	3.06	3.18	3.32	3.49	3.40	3.56	3.74
Distillate fuel oil[12]	6.67	6.66	6.99	7.38	6.93	7.49	8.28	7.21	8.01	9.54
Residual fuel oil	0.45	0.36	0.37	0.38	0.40	0.42	0.43	0.42	0.45	0.49
Other petroleum[13]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.15	0.16	0.17
Petroleum and other liquids subtotal	27.14	26.64	27.32	28.04	23.33	25.01	26.72	21.76	24.75	27.73
Pipeline fuel natural gas	0.89	0.82	0.83	0.84	0.91	0.94	0.95	1.04	1.07	1.10
Compressed / liquefied natural gas	0.07	0.08	0.08	0.09	0.16	0.17	0.18	0.57	0.59	0.73
Liquid hydrogen	0.00	0.01	0.01	0.01	0.04	0.04	0.05	0.05	0.06	0.07
Electricity	0.03	0.05	0.05	0.05	0.10	0.11	0.12	0.13	0.15	0.17
Delivered energy	**28.13**	**27.59**	**28.29**	**29.02**	**24.54**	**26.28**	**28.01**	**23.56**	**26.63**	**29.79**
Electricity related losses	0.06	0.09	0.09	0.09	0.19	0.20	0.21	0.24	0.27	0.29
Total	**28.19**	**27.68**	**28.38**	**29.11**	**24.74**	**26.48**	**28.23**	**23.80**	**26.90**	**30.08**
Unspecified sector[14]	**-0.58**	**-0.57**	**-0.58**	**-0.60**	**-0.41**	**-0.46**	**-0.50**	**-0.33**	**-0.42**	**-0.50**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	2.99	3.61	3.71	3.83	4.03	4.24	4.40	4.49	4.79	4.82
Motor gasoline[2]	16.96	16.28	16.55	16.80	12.55	13.49	14.21	10.54	12.47	13.66
of which: E85[10]	0.05	0.04	0.04	0.04	0.33	0.22	0.19	0.36	0.28	0.30
Jet fuel[11]	3.18	3.15	3.22	3.30	3.43	3.58	3.76	3.66	3.83	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.33	8.59	8.98	9.44	8.68	9.33	10.20	8.87	9.77	11.39
Residual fuel oil	0.56	0.51	0.52	0.53	0.55	0.57	0.59	0.56	0.60	0.65
Petrochemical feedstocks	0.66	0.94	0.96	1.00	1.24	1.31	1.36	1.55	1.66	1.64
Other petroleum[15]	3.54	3.55	3.75	3.94	3.61	3.98	4.32	3.74	4.31	4.80
Petroleum and other liquids subtotal	36.23	36.63	37.70	38.84	34.10	36.51	38.84	33.43	37.44	41.00
Natural gas	15.90	16.68	16.95	17.29	16.91	17.63	18.64	17.79	19.02	20.73
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.63	1.73	1.76	1.77	2.02	2.06	2.06	2.26	2.31	2.33
Pipeline natural gas	0.00	0.26	0.26	0.26	0.57	0.53	0.49	0.75	0.69	0.62
Natural gas liquefaction for export[8]	0.89	0.82	0.83	0.84	0.91	0.94	0.95	1.04	1.07	1.10
Natural gas subtotal	18.43	19.49	19.80	20.16	20.41	21.16	22.13	21.84	23.09	24.79
Metallurgical coal	0.54	0.39	0.41	0.52	0.47	0.47	0.60	0.37	0.40	0.59
Other coal	0.88	0.84	0.88	0.93	0.86	0.93	1.05	0.88	0.98	1.22
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	0.00	0.01	0.02
Coal subtotal	1.40	1.21	1.28	1.42	1.32	1.40	1.65	1.24	1.39	1.83
Biofuels heat and coproducts	0.78	0.81	0.83	0.83	0.81	0.81	0.82	0.74	0.84	0.90
Renewable energy[16]	2.06	1.95	2.03	2.13	2.01	2.19	2.48	2.01	2.29	2.86
Liquid hydrogen	0.00	0.01	0.01	0.01	0.04	0.04	0.05	0.05	0.06	0.07
Electricity	12.72	12.78	13.11	13.42	13.28	14.01	14.88	14.07	15.23	16.77
Delivered energy	**71.62**	**72.89**	**74.75**	**76.81**	**71.96**	**76.12**	**80.85**	**73.38**	**80.34**	**88.21**
Electricity related losses	25.12	25.17	25.80	26.46	24.76	25.41	27.14	25.28	26.81	29.70
Total	**96.74**	**98.06**	**100.55**	**103.27**	**96.72**	**101.54**	**107.99**	**98.66**	**107.15**	**117.91**
Electric power[17]										
Distillate fuel oil	0.09	0.08	0.09	0.09	0.07	0.06	0.07	0.06	0.05	0.06
Residual fuel oil	0.17	0.06	0.06	0.06	0.04	0.04	0.05	0.03	0.03	0.03
Petroleum and other liquids subtotal	0.26	0.14	0.15	0.15	0.11	0.11	0.11	0.09	0.09	0.09
Natural gas	9.89	8.18	8.50	8.44	10.56	11.34	10.70	11.85	12.31	12.01
Steam coal	14.08	13.42	14.34	15.13	10.33	9.92	10.22	9.64	9.36	9.56
Nuclear / uranium[18]	8.34	8.12	8.12	8.12	8.25	8.25	8.25	8.25	8.25	8.25
Renewable energy[19]	4.86	7.67	7.37	7.62	8.40	9.41	12.34	9.15	11.67	16.18
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.19	0.19	0.19	0.20	0.17	0.17	0.17	0.15	0.15	0.15
Total	**37.85**	**37.95**	**38.90**	**39.89**	**38.04**	**39.42**	**42.02**	**39.35**	**42.04**	**46.47**

Table B2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections 2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Total energy consumption										
Liquefied petroleum gases and other[5]	2.99	3.61	3.71	3.83	4.03	4.24	4.40	4.49	4.79	4.82
Motor gasoline[2]	16.96	16.28	16.55	16.80	12.55	13.49	14.21	10.54	12.47	13.66
of which: E85[10]	0.05	0.04	0.04	0.04	0.33	0.22	0.19	0.36	0.28	0.30
Jet fuel[11]	3.18	3.15	3.22	3.30	3.43	3.58	3.76	3.66	3.83	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.42	8.67	9.07	9.53	8.75	9.40	10.26	8.93	9.82	11.44
Residual fuel oil	0.73	0.57	0.58	0.59	0.59	0.62	0.64	0.59	0.64	0.68
Petrochemical feedstocks	0.66	0.94	0.96	1.00	1.24	1.31	1.36	1.55	1.66	1.64
Other petroleum[15]	3.54	3.55	3.75	3.94	3.61	3.98	4.32	3.74	4.31	4.80
Petroleum and other liquids subtotal	36.49	36.77	37.85	38.99	34.21	36.62	38.96	33.51	37.52	41.09
Natural gas	25.79	24.87	25.45	25.73	27.47	28.97	29.33	29.64	31.33	32.74
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.63	1.73	1.76	1.77	2.02	2.06	2.06	2.26	2.31	2.33
Natural gas liquefaction for export[8]	0.00	0.26	0.26	0.26	0.57	0.53	0.49	0.75	0.69	0.62
Pipeline natural gas	0.89	0.82	0.83	0.84	0.91	0.94	0.95	1.04	1.07	1.10
Natural gas subtotal	28.31	27.67	28.30	28.60	30.96	32.51	32.83	33.69	35.39	36.80
Metallurgical coal	0.54	0.39	0.41	0.52	0.47	0.47	0.60	0.37	0.40	0.59
Other coal	14.96	14.26	15.22	16.06	11.20	10.86	11.28	10.52	10.34	10.78
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	0.00	0.01	0.02
Coal subtotal	15.48	14.63	15.62	16.54	11.65	11.32	11.87	10.89	10.75	11.39
Nuclear / uranium[18]	8.34	8.12	8.12	8.12	8.25	8.25	8.25	8.25	8.25	8.25
Biofuels heat and coproducts	0.78	0.81	0.83	0.83	0.81	0.81	0.82	0.74	0.84	0.90
Renewable energy[20]	6.92	9.62	9.40	9.75	10.41	11.60	14.82	11.17	13.96	19.05
Liquid hydrogen	0.00	0.01	0.01	0.01	0.04	0.04	0.05	0.05	0.06	0.07
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.19	0.19	0.19	0.20	0.17	0.17	0.17	0.15	0.15	0.15
Total	**96.74**	**98.06**	**100.55**	**103.27**	**96.72**	**101.54**	**107.99**	**98.66**	**107.15**	**117.91**
Energy use and related statistics										
Delivered energy use	71.62	72.89	74.75	76.81	71.96	76.12	80.85	73.38	80.34	88.21
Total energy use	96.74	98.06	100.55	103.27	96.72	101.54	107.99	98.66	107.15	117.91
Ethanol consumed in motor gasoline and E85	1.18	1.17	1.19	1.20	1.12	1.12	1.16	1.12	1.24	1.35
Population (millions)	322	334	335	336	355	360	364	371	381	391
Gross domestic product (billion 2009 dollars)	16,349	17,576	18,555	19,499	20,749	23,113	25,606	24,511	28,397	32,967
Carbon dioxide emissions (million metric tons)	5,273	5,098	5,289	5,458	4,762	4,961	5,176	4,720	5,044	5,417

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[8]Fuel used in facilities that liquefy natural gas for export.
[9]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Diesel fuel for on- and off- road use.
[13]Includes aviation gasoline and lubricants.
[14]Represents consumption unattributed to the sectors above.
[15]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[16]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[17]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[18]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[20]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowmacro.d032516a, ref2016.d032416a, and highmacro.d032516a.

Table B3. Energy prices by sector and source
(2015 dollars per million Btu, unless otherwise noted)

Sector and source	2015	2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Residential										
Propane	16.9	20.1	20.2	20.3	22.2	22.4	22.6	25.5	25.6	26.1
Distillate fuel oil	19.3	22.2	22.4	22.6	27.3	27.8	28.3	33.0	33.8	34.6
Natural gas	10.1	10.5	10.7	11.0	11.5	12.0	12.2	11.7	12.3	13.0
Electricity	36.3	38.5	37.7	37.7	40.0	39.4	39.0	38.9	38.1	37.8
Commercial										
Propane	15.1	17.9	17.9	18.0	19.7	19.8	20.0	22.5	22.5	23.0
Distillate fuel oil	17.0	19.5	19.7	19.9	24.1	24.4	24.9	29.8	30.5	31.3
Residual fuel oil	6.9	10.8	11.0	11.1	15.0	15.3	15.6	19.4	19.9	20.4
Natural gas	7.7	9.1	9.3	9.5	10.0	10.4	10.4	9.9	10.4	10.8
Electricity	30.6	31.7	31.5	31.7	32.3	32.3	32.4	30.8	30.7	31.1
Industrial[1]										
Propane	12.2	15.5	15.6	15.7	17.7	17.8	18.1	21.1	21.1	21.7
Distillate fuel oil	17.0	19.5	19.7	19.9	24.2	24.4	24.9	29.9	30.5	31.3
Residual fuel oil	6.8	11.1	11.3	11.4	15.7	15.9	16.2	20.0	20.6	21.1
Natural gas[2]	3.7	5.2	5.4	5.5	5.6	6.0	5.9	5.4	5.7	5.9
Metallurgical coal	5.4	6.0	6.0	6.1	7.0	7.0	7.0	7.2	7.3	7.3
Other industrial coal	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.6	3.6	3.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.3	21.0	20.9	21.0	21.7	22.1	22.1	21.0	21.2	21.6
Transportation										
Propane	18.0	21.2	21.2	21.4	23.3	23.4	23.7	26.6	26.6	27.2
E85[3]	23.3	31.7	32.0	31.6	27.4	30.8	31.7	30.1	35.0	36.0
Motor gasoline[4]	20.9	22.5	22.7	22.8	26.1	26.5	26.9	30.4	31.8	32.6
Jet fuel[5]	12.0	16.0	16.2	16.4	20.9	21.3	21.9	27.2	27.7	28.4
Diesel fuel (distillate fuel oil)[6]	19.8	22.9	23.1	23.3	27.8	28.0	28.5	33.4	34.1	34.8
Residual fuel oil	8.1	11.5	11.7	11.8	14.8	15.0	15.3	18.8	19.2	19.7
Natural gas[7]	16.6	16.4	16.6	16.9	15.0	15.5	15.6	15.3	15.9	16.3
Electricity	29.5	33.3	33.0	33.2	37.1	37.4	37.0	35.4	35.5	35.6
Electric power[8]										
Distillate fuel oil	15.0	18.2	18.4	18.7	23.0	23.5	24.0	28.6	29.4	30.2
Residual fuel oil	10.2	13.6	13.8	13.9	17.8	18.1	18.4	21.8	22.4	23.0
Natural gas	3.3	4.5	4.7	4.8	5.2	5.6	5.4	5.1	5.4	5.5
Steam coal	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
Average price to all users[9]										
Propane	14.9	18.0	18.0	18.1	20.0	20.1	20.3	23.1	23.2	23.7
E85[3]	23.3	31.7	32.0	31.6	27.4	30.8	31.7	30.1	35.0	36.0
Motor gasoline[4]	20.9	22.5	22.7	22.8	26.1	26.5	26.9	30.4	31.8	32.6
Jet fuel[5]	12.0	16.0	16.2	16.4	20.9	21.3	21.9	27.2	27.7	28.4
Distillate fuel oil	19.1	22.1	22.3	22.5	27.1	27.3	27.8	32.8	33.3	34.2
Residual fuel oil	8.4	11.6	11.7	11.8	15.1	15.4	15.7	19.1	19.6	20.1
Natural gas	5.3	6.6	6.7	6.9	7.1	7.4	7.4	7.0	7.4	7.7
Metallurgical coal	5.4	6.0	6.0	6.1	7.0	7.0	7.0	7.2	7.3	7.3
Other coal	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.6
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	30.1	31.3	30.8	30.8	32.0	31.9	31.7	30.8	30.6	30.7
Non-renewable energy expenditures by sector (billion 2015 dollars)										
Residential	239	247	250	256	251	266	284	249	274	309
Commercial	178	192	193	195	210	216	221	221	230	241
Industrial[1]	168	220	232	247	275	301	325	332	369	411
Transportation	514	566	586	605	585	640	697	660	777	894
Total non-renewable expenditures	1,099	1,225	1,260	1,302	1,321	1,423	1,526	1,462	1,650	1,855
Transportation renewable expenditures	1	1	1	1	9	7	6	11	10	11
Total expenditures	**1,100**	**1,226**	**1,262**	**1,303**	**1,330**	**1,430**	**1,532**	**1,472**	**1,660**	**1,866**

Table B3. Energy prices by sector and source *(continued)*
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2015	Projections 2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Residential										
Propane	16.9	22.8	22.3	22.2	34.8	30.3	30.0	56.3	43.0	43.1
Distillate fuel oil	19.3	25.2	24.7	24.7	42.6	37.6	37.4	72.8	56.9	57.2
Natural gas	10.1	12.0	11.9	12.0	18.0	16.3	16.1	25.7	20.8	21.4
Electricity	36.3	43.7	41.7	41.1	62.5	53.3	51.7	85.8	64.2	62.4
Commercial										
Propane	15.1	20.3	19.8	19.7	30.8	26.8	26.5	49.6	37.9	38.0
Distillate fuel oil	17.0	22.1	21.8	21.7	37.7	33.1	33.0	65.6	51.2	51.6
Residual fuel oil	6.9	12.3	12.1	12.1	23.5	20.7	20.7	42.7	33.6	33.7
Natural gas	7.7	10.4	10.3	10.4	15.6	14.1	13.8	21.9	17.5	17.8
Electricity	30.6	36.0	34.8	34.5	50.5	43.7	42.9	67.8	51.7	51.4
Industrial[1]										
Propane	12.2	17.6	17.2	17.2	27.7	24.1	24.0	46.5	35.6	35.8
Distillate fuel oil	17.0	22.1	21.8	21.7	37.8	33.1	33.0	65.8	51.3	51.6
Residual fuel oil	6.8	12.6	12.4	12.4	24.5	21.6	21.5	44.2	34.7	34.8
Natural gas[2]	3.7	5.9	5.9	6.1	8.8	8.1	7.8	11.9	9.6	9.7
Metallurgical coal	5.4	6.9	6.7	6.6	10.9	9.4	9.2	15.9	12.2	12.0
Other industrial coal	3.4	3.9	3.7	3.7	5.4	4.6	4.5	7.9	6.0	6.1
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.3	23.8	23.1	23.0	34.0	29.9	29.3	46.2	35.7	35.7
Transportation										
Propane	18.0	24.0	23.4	23.3	36.4	31.7	31.3	58.6	44.8	44.9
E85[3]	23.3	36.0	35.4	34.4	42.9	41.7	42.0	66.3	58.8	59.5
Motor gasoline[4]	20.9	25.6	25.1	24.8	40.8	35.9	35.6	67.1	53.6	53.9
Jet fuel[5]	12.0	18.2	17.9	17.9	32.7	28.8	29.0	59.9	46.6	46.9
Diesel fuel (distillate fuel oil)[6]	19.8	26.0	25.5	25.4	43.5	37.9	37.7	73.7	57.3	57.5
Residual fuel oil	8.1	13.1	12.9	12.8	23.2	20.3	20.3	41.4	32.3	32.5
Natural gas[7]	16.6	18.6	18.4	18.5	23.5	21.0	20.6	33.7	26.7	26.9
Electricity	29.5	37.9	36.5	36.2	58.1	50.5	49.0	78.0	59.8	58.7
Electric power[8]										
Distillate fuel oil	15.0	20.7	20.4	20.4	35.9	31.8	31.8	63.1	49.4	49.9
Residual fuel oil	10.2	15.5	15.2	15.2	27.8	24.4	24.4	48.1	37.8	37.9
Natural gas	3.3	5.1	5.2	5.3	8.1	7.5	7.2	11.2	9.0	9.2
Steam coal	2.2	2.6	2.5	2.5	3.6	3.1	3.0	5.4	4.0	4.0

Table B3. Energy prices by sector and source *(continued)*

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2015	Projections 2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[9]										
Propane	14.9	20.5	19.9	19.8	31.3	27.2	26.9	51.0	39.0	39.1
E85[3]	23.3	36.0	35.4	34.4	42.9	41.7	42.0	66.3	58.8	59.5
Motor gasoline[4]	20.9	25.6	25.1	24.8	40.8	35.9	35.6	67.1	53.6	53.8
Jet fuel[5]	12.0	18.2	17.9	17.9	32.7	28.8	29.0	59.9	46.6	46.9
Distillate fuel oil	19.1	25.1	24.7	24.6	42.3	36.9	36.8	72.2	56.1	56.5
Residual fuel oil	8.4	13.1	13.0	12.9	23.7	20.8	20.7	42.2	32.9	33.1
Natural gas	5.3	7.4	7.4	7.6	11.1	10.0	9.8	15.4	12.4	12.7
Metallurgical coal	5.4	6.9	6.7	6.6	10.9	9.4	9.2	15.9	12.2	12.0
Other coal	2.3	2.6	2.6	2.6	3.8	3.2	3.2	5.6	4.2	4.2
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	30.1	35.5	34.1	33.6	50.1	43.1	42.0	67.9	51.6	50.7
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	239	281	276	279	393	360	376	548	462	510
Commercial	178	217	213	213	328	292	293	487	387	398
Industrial[1]	168	250	256	269	431	407	430	732	620	678
Transportation	514	643	647	659	915	866	923	1,455	1,307	1,477
Total non-renewable expenditures	1,099	1,391	1,392	1,420	2,066	1,925	2,022	3,223	2,776	3,063
Transportation renewable expenditures	1	2	1	1	14	9	8	24	17	18
Total expenditures	**1,100**	**1,393**	**1,394**	**1,422**	**2,081**	**1,934**	**2,030**	**3,246**	**2,793**	**3,081**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowmacro.d032516a, ref2016.d032416a, and highmacro.d032516a.

Table B4. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	2015	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**16,349**	**17,576**	**18,555**	**19,499**	**20,749**	**23,113**	**25,606**	**24,511**	**28,397**	**32,967**
Components of real gross domestic product										
Real consumption	11,221	12,197	12,861	13,436	14,356	16,092	17,863	16,827	19,870	22,954
Real investment	2,842	3,094	3,513	3,939	3,758	4,520	5,283	4,591	5,661	6,935
Real government spending	2,860	2,906	2,967	3,026	3,079	3,222	3,369	3,360	3,602	3,899
Real exports	2,119	2,475	2,615	2,733	3,635	4,178	4,692	4,954	6,113	7,595
Real imports	2,662	3,069	3,374	3,602	4,013	4,824	5,499	5,070	6,683	8,171
Energy intensity (thousand Btu per 2009 dollar of GDP)										
Delivered energy	4.38	4.15	4.03	3.94	3.47	3.29	3.16	2.99	2.83	2.68
Total energy	5.92	5.58	5.42	5.30	4.66	4.39	4.22	4.02	3.77	3.58
Price indices										
GDP chain-type price index (2009=1.000)	1.10	1.25	1.21	1.20	1.72	1.49	1.45	2.42	1.85	1.81
Consumer price index (1982-4=1.00)										
All-urban	2.37	2.73	2.65	2.62	3.88	3.35	3.27	5.62	4.27	4.18
Energy commodities and services	2.02	2.48	2.41	2.39	3.83	3.34	3.29	5.93	4.61	4.61
Wholesale price index (1982=1.00)										
All commodities	1.91	2.20	2.14	2.13	3.02	2.59	2.54	4.19	3.16	3.15
Fuel and power	1.60	2.14	2.10	2.10	3.30	2.91	2.87	5.04	3.92	3.96
Metals and metal products	2.01	2.20	2.15	2.18	2.93	2.55	2.55	3.92	3.06	3.24
Industrial commodities excluding energy	1.94	2.20	2.13	2.12	2.97	2.53	2.48	4.03	3.01	2.99
Interest rates (percent, nominal)										
Federal funds rate	0.13	4.91	3.32	2.88	6.10	3.24	2.97	6.20	3.08	3.12
10-year treasury note	2.14	5.55	3.83	3.44	6.66	3.77	3.50	6.87	3.72	3.53
AA utility bond rate	4.01	7.94	5.87	5.07	9.14	5.73	5.02	9.48	5.71	4.67
Value of shipments (billion 2009 dollars)										
Non-industrial and service sectors	24,085	25,327	26,750	28,025	28,651	32,042	35,673	32,130	37,701	44,520
Total industrial	7,229	7,861	8,351	8,889	8,969	9,776	10,707	10,365	11,483	13,187
Agriculture, mining, and construction	1,931	2,270	2,493	2,715	2,408	2,710	2,970	2,604	2,955	3,320
Manufacturing	5,299	5,591	5,858	6,174	6,561	7,066	7,736	7,761	8,528	9,868
Energy-intensive	1,704	1,829	1,892	1,965	2,018	2,147	2,315	2,222	2,417	2,682
Non-energy-intensive	3,594	3,763	3,967	4,208	4,543	4,920	5,421	5,539	6,111	7,186
Total shipments	**31,314**	**33,188**	**35,101**	**36,914**	**37,620**	**41,818**	**46,380**	**42,494**	**49,184**	**57,707**
Population and employment (millions)										
Population, with armed forces overseas	322	334	335	336	355	360	364	371	381	391
Population, aged 16 and over	257	269	269	270	288	292	295	304	311	319
Population, aged 65 and over	48	57	57	57	74	74	75	83	82	84
Employment, nonfarm	142	146	150	154	154	161	168	163	170	180
Employment, manufacturing	12.5	13.0	13.1	13.5	12.2	13.0	13.2	11.2	12.3	12.7
Key labor indicators										
Labor force (millions)	157	166	167	167	174	177	180	182	188	194
Non-farm labor productivity (2009=1.00)	1.06	1.11	1.15	1.18	1.28	1.37	1.43	1.46	1.63	1.74
Unemployment rate (percent)	5.31	5.12	4.72	4.66	4.98	4.78	4.53	5.01	4.78	4.33
Key indicators for energy demand										
Real disposable personal income	12,225	13,577	14,197	14,748	16,684	17,826	19,420	20,033	21,789	24,273
Housing starts (millions)	1.18	1.24	1.74	2.34	0.97	1.66	2.50	0.85	1.65	2.77
Commercial floorspace (billion square feet)	83.8	88.1	88.7	89.3	96.8	99.3	101.4	105.5	109.8	113.6
Unit sales of light-duty vehicles (millions)	17.4	15.7	17.1	18.3	15.5	17.7	18.7	14.8	19.0	21.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2015: IHS Economics, Industry and Employment models, November 2015. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowmacro.d032516a, ref2016.d032416a, and highmacro.d032516a.

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Price case comparisons

Table C1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	19.7	17.0	19.6	23.3	14.8	21.0	25.4	18.0	23.5	23.1
Natural gas plant liquids	4.4	5.8	6.1	6.4	5.8	6.5	6.9	6.1	6.7	7.0
Dry natural gas	28.0	30.1	31.4	31.8	35.6	38.9	41.8	40.0	43.4	48.0
Coal[1]	17.2	17.4	17.5	17.0	13.2	13.3	15.7	13.0	13.1	15.2
Nuclear / uranium[2]	8.3	8.1	8.1	8.1	8.2	8.2	8.2	8.2	8.2	8.2
Conventional hydroelectric power	2.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9
Biomass[3]	4.1	4.2	4.2	4.4	4.2	4.4	4.6	4.3	4.6	4.9
Other renewable energy[4]	2.6	4.4	4.6	5.5	6.2	6.6	8.7	8.6	8.8	10.8
Other[5]	0.5	0.8	0.9	0.9	0.8	0.9	0.9	0.9	1.0	1.0
Total	**87.3**	**90.6**	**95.4**	**100.2**	**91.7**	**102.7**	**115.2**	**101.9**	**112.2**	**121.2**
Imports										
Crude oil	16.1	15.8	16.8	15.8	17.3	16.0	13.5	18.9	15.9	16.7
Petroleum and other liquids[6]	3.9	5.1	4.5	4.2	5.7	4.3	3.6	5.8	4.3	3.4
Natural gas[7]	2.8	2.0	2.1	2.1	1.5	1.6	1.8	1.3	1.4	2.1
Other imports[8]	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.5
Total	**23.2**	**23.1**	**23.6**	**22.2**	**24.6**	**22.0**	**19.0**	**26.2**	**21.8**	**22.7**
Exports										
Petroleum and other liquids[9]	9.0	7.1	11.6	16.0	7.2	13.5	19.5	10.5	15.2	21.0
Natural gas[10]	1.8	4.2	5.0	5.0	5.5	7.6	10.8	6.9	9.0	12.7
Coal	2.0	1.9	1.9	1.7	2.1	1.9	1.7	2.4	2.3	1.9
Total	**12.8**	**13.1**	**18.5**	**22.7**	**14.7**	**23.0**	**32.0**	**19.8**	**26.6**	**35.6**
Discrepancy[11]	**1.0**	**0.1**	**0.0**	**-0.1**	**0.2**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**
Consumption										
Petroleum and other liquids[12]	36.5	38.8	37.8	36.3	38.4	36.6	33.7	40.5	37.5	33.9
Natural gas	28.3	27.7	28.3	28.6	31.3	32.5	31.5	34.0	35.4	35.3
Coal[13]	15.5	15.5	15.6	15.1	11.1	11.3	13.5	10.5	10.7	13.1
Nuclear / uranium[2]	8.3	8.1	8.1	8.1	8.2	8.2	8.2	8.2	8.2	8.2
Conventional hydroelectric power	2.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9
Biomass[14]	2.8	2.7	2.8	2.9	2.8	3.0	3.2	2.9	3.1	3.4
Other renewable energy[4]	2.6	4.4	4.6	5.5	6.2	6.6	8.7	8.6	8.8	10.8
Other[15]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**96.7**	**100.5**	**100.5**	**99.7**	**101.4**	**101.5**	**102.0**	**108.1**	**107.1**	**108.0**
Prices (2015 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	52	38	77	152	49	104	207	73	136	230
West Texas Intermediate	49	32	71	145	42	97	198	67	129	222
Natural gas at Henry Hub (dollars per million Btu)	2.62	3.85	4.43	4.40	4.65	5.06	7.92	4.54	4.86	7.74
Coal (dollars per ton) at the minemouth[16]	33.8	30.8	33.6	36.7	32.3	33.8	36.8	36.3	38.7	42.0
Coal (dollars per million Btu) at the minemouth[16]	1.69	1.57	1.68	1.82	1.63	1.71	1.86	1.80	1.91	2.08
Average end-use[17]	2.37	2.31	2.43	2.62	2.34	2.55	2.78	2.45	2.68	2.85
Average electricity (cents per kilowatthour)	10.3	10.3	10.5	10.6	10.6	10.9	11.6	10.3	10.5	11.3

Table C1. Total energy supply, disposition, and price summary *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	52	42	85	166	66	141	284	121	229	397
West Texas Intermediate	49	35	79	159	58	131	272	111	217	384
Natural gas at Henry Hub (dollars per million Btu)	2.62	4.25	4.90	4.83	6.31	6.84	10.90	7.54	8.17	13.36
Coal (dollars per ton) at the minemouth[16]	33.8	34.0	37.1	40.3	43.8	45.8	50.6	60.2	65.1	72.5
Coal (dollars per million Btu) at the minemouth[16]	1.69	1.73	1.86	1.99	2.21	2.31	2.55	2.99	3.21	3.59
Average end-use[17]	2.37	2.55	2.69	2.87	3.18	3.45	3.82	4.06	4.50	4.92
Average electricity (cents per kilowatthour)	10.3	11.4	11.6	11.7	14.4	14.7	16.0	17.1	17.6	19.5

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Energy consumption										
Residential										
Propane	0.43	0.44	0.42	0.39	0.41	0.38	0.33	0.37	0.34	0.29
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Distillate fuel oil	0.50	0.46	0.43	0.39	0.37	0.34	0.30	0.30	0.27	0.24
Petroleum and other liquids subtotal	0.93	0.91	0.86	0.79	0.78	0.72	0.63	0.67	0.61	0.54
Natural gas	4.77	4.90	4.87	4.87	4.83	4.80	4.72	4.76	4.73	4.62
Renewable energy[1]	0.44	0.34	0.42	0.54	0.30	0.39	0.51	0.29	0.37	0.45
Electricity	4.78	4.80	4.76	4.70	4.89	4.83	4.72	5.26	5.20	5.04
Delivered energy	**10.92**	**10.95**	**10.90**	**10.90**	**10.81**	**10.74**	**10.58**	**10.99**	**10.91**	**10.65**
Electricity related losses	9.44	9.43	9.37	9.27	8.85	8.77	8.93	9.25	9.15	9.32
Total	**20.37**	**20.37**	**20.27**	**20.17**	**19.66**	**19.50**	**19.50**	**20.24**	**20.05**	**19.97**
Commercial										
Propane	0.17	0.20	0.18	0.15	0.22	0.19	0.16	0.23	0.20	0.18
Motor gasoline[2]	0.04	0.07	0.06	0.05	0.08	0.06	0.05	0.08	0.07	0.06
Kerosene	0.00	0.01	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.00
Distillate fuel oil	0.37	0.40	0.36	0.31	0.38	0.32	0.27	0.34	0.29	0.25
Residual fuel oil	0.07	0.17	0.11	0.07	0.16	0.10	0.07	0.13	0.10	0.08
Petroleum and other liquids subtotal	0.66	0.84	0.70	0.58	0.84	0.68	0.56	0.79	0.67	0.57
Natural gas	3.32	3.49	3.45	3.47	3.59	3.53	3.41	3.85	3.81	3.60
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Electricity	4.64	4.71	4.69	4.66	5.13	5.09	4.99	5.67	5.62	5.50
Delivered energy	**8.81**	**9.23**	**9.03**	**8.91**	**9.74**	**9.49**	**9.14**	**10.51**	**10.28**	**9.86**
Electricity related losses	9.16	9.25	9.23	9.19	9.29	9.23	9.43	9.97	9.89	10.16
Total	**17.97**	**18.48**	**18.26**	**18.09**	**19.03**	**18.72**	**18.58**	**20.48**	**20.17**	**20.01**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.38	3.05	3.10	3.03	3.59	3.66	3.57	4.17	4.22	4.06
Motor gasoline[2]	0.27	0.27	0.28	0.28	0.26	0.27	0.26	0.27	0.27	0.26
Distillate fuel oil	1.34	1.50	1.44	1.39	1.46	1.44	1.38	1.49	1.47	1.38
Residual fuel oil	0.04	0.08	0.04	0.03	0.09	0.06	0.05	0.07	0.05	0.05
Petrochemical feedstocks	0.66	0.92	0.96	0.94	1.28	1.31	1.28	1.63	1.66	1.59
Other petroleum[6]	3.38	3.64	3.59	3.73	3.75	3.82	3.71	4.23	4.15	3.97
Petroleum and other liquids subtotal	8.07	9.46	9.40	9.39	10.42	10.55	10.26	11.85	11.82	11.31
Natural gas	7.75	7.84	8.55	8.71	8.50	9.13	9.17	9.47	9.89	9.72
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.08	0.00	0.00	0.84	0.00	0.00	1.60
Lease and plant fuel[7]	1.63	1.69	1.76	1.79	1.87	2.06	2.21	2.11	2.31	2.54
Natural gas liquefaction for export[8]	0.00	0.17	0.26	0.26	0.29	0.53	0.87	0.45	0.69	1.10
Natural gas subtotal	9.38	9.70	10.57	10.83	10.65	11.72	13.08	12.03	12.89	14.95
Metallurgical coal	0.54	0.40	0.41	0.50	0.34	0.47	0.50	0.30	0.40	0.33
Other industrial coal	0.82	0.80	0.82	0.86	0.81	0.88	0.91	0.84	0.93	0.97
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.65	0.00	0.00	0.75
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	-0.01	0.01	0.00
Coal subtotal	1.34	1.17	1.23	1.34	1.13	1.35	2.05	1.13	1.34	2.04
Biofuels heat and coproducts	0.78	0.84	0.83	0.82	0.80	0.81	0.83	0.81	0.84	0.92
Renewable energy[9]	1.48	1.44	1.48	1.53	1.53	1.67	1.71	1.62	1.79	1.85
Electricity	3.27	3.54	3.61	3.71	3.77	3.98	4.05	4.08	4.26	4.28
Delivered energy	**24.33**	**26.16**	**27.11**	**27.62**	**28.31**	**30.07**	**31.99**	**31.51**	**32.94**	**35.37**
Electricity related losses	6.46	6.96	7.11	7.32	6.82	7.22	7.66	7.16	7.50	7.92
Total	**30.79**	**33.12**	**34.22**	**34.94**	**35.13**	**37.29**	**39.65**	**38.67**	**40.44**	**43.28**

Table C2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Transportation										
Propane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Motor gasoline[2]	17.01	17.51	16.79	15.39	15.55	13.62	11.48	15.18	12.55	10.19
of which: E85[10]	0.05	0.04	0.04	0.18	0.08	0.22	0.56	0.14	0.28	0.63
Jet fuel[11]	2.84	3.02	2.99	2.95	3.34	3.32	3.28	3.58	3.56	3.53
Distillate fuel oil[12]	6.67	6.97	6.99	7.04	7.30	7.49	7.10	8.24	8.01	7.28
Residual fuel oil	0.45	0.38	0.37	0.36	0.41	0.42	0.43	0.45	0.45	0.47
Other petroleum[13]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	27.14	28.05	27.32	25.91	26.77	25.01	22.46	27.64	24.75	21.66
Pipeline fuel natural gas	0.89	0.80	0.83	0.85	0.86	0.94	1.07	0.94	1.07	1.27
Compressed / liquefied natural gas	0.07	0.08	0.08	0.13	0.07	0.17	0.75	0.09	0.59	1.58
Liquid hydrogen	0.00	0.01	0.01	0.01	0.05	0.04	0.04	0.07	0.06	0.05
Electricity	0.03	0.05	0.05	0.05	0.11	0.11	0.11	0.16	0.15	0.15
Delivered energy	**28.13**	**28.98**	**28.29**	**26.95**	**27.86**	**26.28**	**24.43**	**28.90**	**26.63**	**24.72**
Electricity related losses	0.06	0.09	0.09	0.10	0.21	0.20	0.21	0.29	0.27	0.28
Total	**28.19**	**29.07**	**28.38**	**27.04**	**28.07**	**26.48**	**24.64**	**29.19**	**26.90**	**25.00**
Unspecified sector[14]	**-0.58**	**-0.60**	**-0.58**	**-0.53**	**-0.52**	**-0.46**	**-0.36**	**-0.52**	**-0.42**	**-0.30**
Delivered energy consumption for all Sectors										
Liquefied petroleum gases and other[5]	2.99	3.69	3.71	3.57	4.22	4.24	4.07	4.79	4.79	4.55
Motor gasoline[2]	16.96	17.25	16.55	15.20	15.35	13.49	11.42	15.01	12.47	10.18
of which: E85[10]	0.05	0.04	0.04	0.18	0.08	0.22	0.56	0.14	0.28	0.63
Jet fuel[11]	3.18	3.26	3.22	3.17	3.60	3.58	3.53	3.85	3.83	3.80
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.33	9.09	8.98	8.89	9.26	9.33	8.82	10.09	9.77	8.91
Residual fuel oil	0.56	0.63	0.52	0.46	0.66	0.57	0.55	0.65	0.60	0.60
Petrochemical feedstocks	0.66	0.92	0.96	0.94	1.28	1.31	1.28	1.63	1.66	1.59
Other petroleum[15]	3.54	3.81	3.75	3.88	3.91	3.98	3.87	4.39	4.31	4.13
Petroleum and other liquids subtotal	36.23	38.66	37.70	36.14	38.29	36.51	33.55	40.43	37.44	33.77
Natural gas	15.90	16.30	16.95	17.19	16.99	17.63	18.04	18.18	19.02	19.51
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.08	0.00	0.00	0.84	0.00	0.00	1.60
Lease and plant fuel[7]	1.63	1.69	1.76	1.79	1.87	2.06	2.21	2.11	2.31	2.54
Natural gas liquefaction for export[8]	0.00	0.17	0.26	0.26	0.29	0.53	0.87	0.45	0.69	1.10
Pipeline natural gas	0.89	0.80	0.83	0.85	0.86	0.94	1.07	0.94	1.07	1.27
Natural gas subtotal	18.43	18.96	19.80	20.17	20.00	21.16	23.02	21.67	23.09	26.02
Metallurgical coal	0.54	0.40	0.41	0.50	0.34	0.47	0.50	0.30	0.40	0.33
Other coal	0.88	0.85	0.88	0.91	0.86	0.93	0.97	0.90	0.98	1.02
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.65	0.00	0.00	0.75
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	-0.01	0.01	0.00
Coal subtotal	1.40	1.23	1.28	1.39	1.18	1.40	2.11	1.19	1.39	2.10
Biofuels heat and coproducts	0.78	0.84	0.83	0.82	0.80	0.81	0.83	0.81	0.84	0.92
Renewable energy[16]	2.06	1.92	2.03	2.20	1.97	2.19	2.36	2.05	2.29	2.44
Liquid hydrogen	0.00	0.01	0.01	0.01	0.05	0.04	0.04	0.07	0.06	0.05
Electricity	12.72	13.10	13.11	13.12	13.90	14.01	13.87	15.18	15.23	14.97
Delivered energy	**71.62**	**74.73**	**74.75**	**73.85**	**76.20**	**76.12**	**75.77**	**81.40**	**80.34**	**80.28**
Electricity related losses	25.12	25.73	25.80	25.88	25.17	25.41	26.23	26.66	26.81	27.68
Total	**96.74**	**100.45**	**100.55**	**99.72**	**101.38**	**101.54**	**102.01**	**108.05**	**107.15**	**107.96**
Electric power[17]										
Distillate fuel oil	0.09	0.09	0.09	0.08	0.06	0.06	0.07	0.05	0.05	0.06
Residual fuel oil	0.17	0.06	0.06	0.06	0.04	0.04	0.04	0.03	0.03	0.03
Petroleum and other liquids subtotal	0.26	0.15	0.15	0.14	0.11	0.11	0.11	0.09	0.09	0.09
Natural gas	9.89	8.76	8.50	8.40	11.33	11.34	8.44	12.30	12.31	9.28
Steam coal	14.08	14.25	14.34	13.74	9.94	9.92	11.36	9.36	9.36	10.97
Nuclear / uranium[18]	8.34	8.12	8.12	8.12	8.25	8.25	8.25	8.25	8.25	8.25
Renewable energy[19]	4.86	7.13	7.37	8.17	9.05	9.41	11.55	11.47	11.67	13.70
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.19	0.19	0.19	0.19	0.17	0.17	0.17	0.15	0.15	0.15
Total	**37.85**	**38.83**	**38.90**	**39.00**	**39.08**	**39.42**	**40.10**	**41.84**	**42.04**	**42.65**

Table C2. Energy consumption by sector and source *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2015	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Total energy consumption										
Liquefied petroleum gases and other[5]	2.99	3.69	3.71	3.57	4.22	4.24	4.07	4.79	4.79	4.55
Motor gasoline[2]	16.96	17.25	16.55	15.20	15.35	13.49	11.42	15.01	12.47	10.18
of which: E85[10]	0.05	0.04	0.04	0.18	0.08	0.22	0.56	0.14	0.28	0.63
Jet fuel[11]	3.18	3.26	3.22	3.17	3.60	3.58	3.53	3.85	3.83	3.80
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.42	9.18	9.07	8.98	9.33	9.40	8.88	10.14	9.82	8.97
Residual fuel oil	0.73	0.69	0.58	0.52	0.70	0.62	0.59	0.68	0.64	0.63
Petrochemical feedstocks	0.66	0.92	0.96	0.94	1.28	1.31	1.28	1.63	1.66	1.59
Other petroleum[15]	3.54	3.81	3.75	3.88	3.91	3.98	3.87	4.39	4.31	4.13
Petroleum and other liquids subtotal	36.49	38.81	37.85	36.28	38.40	36.62	33.66	40.52	37.52	33.86
Natural gas	25.79	25.06	25.45	25.59	28.32	28.97	26.47	30.48	31.33	28.79
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.08	0.00	0.00	0.84	0.00	0.00	1.60
Lease and plant fuel[7]	1.63	1.69	1.76	1.79	1.87	2.06	2.21	2.11	2.31	2.54
Natural gas liquefaction for export[8]	0.00	0.17	0.26	0.26	0.29	0.53	0.87	0.45	0.69	1.10
Pipeline natural gas	0.89	0.80	0.83	0.85	0.86	0.94	1.07	0.94	1.07	1.27
Natural gas subtotal	28.31	27.72	28.30	28.57	31.33	32.51	31.46	33.98	35.39	35.30
Metallurgical coal	0.54	0.40	0.41	0.50	0.34	0.47	0.50	0.30	0.40	0.33
Other coal	14.96	15.10	15.22	14.65	10.81	10.86	12.33	10.26	10.34	11.99
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.65	0.00	0.00	0.75
Net coal coke imports	-0.02	-0.03	-0.01	-0.03	-0.02	0.00	-0.01	-0.01	0.01	0.00
Coal subtotal	15.48	15.48	15.62	15.13	11.13	11.32	13.47	10.55	10.75	13.06
Nuclear / uranium[18]	8.34	8.12	8.12	8.12	8.25	8.25	8.25	8.25	8.25	8.25
Biofuels heat and coproducts	0.78	0.84	0.83	0.82	0.80	0.81	0.83	0.81	0.84	0.92
Renewable energy[20]	6.92	9.05	9.40	10.38	11.02	11.60	13.90	13.52	13.96	16.14
Liquid hydrogen	0.00	0.01	0.01	0.01	0.05	0.04	0.04	0.07	0.06	0.05
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.19	0.19	0.19	0.19	0.17	0.17	0.17	0.15	0.15	0.15
Total	**96.74**	**100.45**	**100.55**	**99.72**	**101.38**	**101.54**	**102.01**	**108.05**	**107.15**	**107.96**
Energy use and related statistics										
Delivered energy use	71.62	74.73	74.75	73.85	76.20	76.12	75.77	81.40	80.34	80.28
Total energy use	96.74	100.45	100.55	99.72	101.38	101.54	102.01	108.05	107.15	107.96
Ethanol consumed in motor gasoline and E85	1.18	1.22	1.19	1.18	1.13	1.12	1.17	1.14	1.24	1.06
Population (millions)	322	335	335	335	360	360	360	381	381	381
Gross domestic product (billion 2009 dollars)	16,349	18,768	18,555	18,420	23,076	23,113	23,021	28,506	28,397	28,246
Carbon dioxide emissions (million metric tons)	5,273	5,327	5,289	5,145	5,018	4,961	4,888	5,181	5,044	5,001

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[8]Fuel used in facilities that liquefy natural gas for export.
[9]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Diesel fuel for on- and off- road use.
[13]Includes aviation gasoline and lubricants.
[14]Represents consumption unattributed to the sectors above.
[15]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[16]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[17]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[18]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[20]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a.

Table C3. Energy prices by sector and source
(2012 dollars per million Btu, unless otherwise noted)

Sector and source	2015	2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil Price	2040 Reference	2040 High oil price
Residential										
Propane	16.9	16.1	20.2	29.2	17.0	22.4	33.6	19.4	25.6	34.5
Distillate fuel oil	19.3	14.9	22.4	36.4	17.2	27.8	46.7	21.8	33.8	50.9
Natural gas	10.1	10.3	10.7	10.6	11.6	12.0	13.6	11.9	12.3	14.4
Electricity	36.3	36.9	37.7	38.4	38.2	39.4	42.1	37.3	38.1	40.9
Commercial										
Propane	15.1	14.4	17.9	25.6	15.1	19.8	29.5	17.2	22.5	30.3
Distillate fuel oil	17.0	12.2	19.7	33.7	13.9	24.4	43.4	18.5	30.5	47.6
Residual fuel oil	6.9	4.6	11.0	21.8	6.6	15.3	30.1	10.9	19.9	33.5
Natural gas	7.7	8.9	9.3	9.1	9.9	10.4	12.0	10.0	10.4	12.4
Electricity	30.6	30.9	31.5	31.8	31.3	32.3	34.7	30.0	30.7	33.4
Industrial[1]										
Propane	12.2	11.4	15.6	24.8	12.3	17.8	29.4	14.8	21.1	30.3
Distillate fuel oil	17.0	12.2	19.7	33.6	13.9	24.4	43.4	18.5	30.5	47.6
Residual fuel oil	6.8	4.9	11.3	22.0	7.3	15.9	30.8	11.6	20.6	34.1
Natural gas[2]	3.7	5.0	5.4	5.2	5.6	6.0	7.7	5.4	5.7	7.5
Metallurgical coal	5.4	6.0	6.0	6.0	7.0	7.0	7.0	7.3	7.3	7.3
Other industrial coal	3.4	3.3	3.4	3.6	3.2	3.4	3.7	3.3	3.6	3.9
Coal to liquids	- -	- -	- -	- -	- -	- -	2.0	- -	- -	2.1
Electricity	20.3	20.5	20.9	21.1	21.4	22.1	24.0	20.8	21.2	23.5
Transportation										
Propane	18.0	17.1	21.2	30.2	18.0	23.4	34.7	20.4	26.6	35.6
E85[3]	23.3	24.1	32.0	38.1	25.4	30.8	39.3	28.5	35.0	42.2
Motor gasoline[4]	20.9	16.1	22.7	35.6	16.9	26.5	43.0	21.0	31.8	47.0
Jet fuel[5]	12.0	8.6	16.2	29.6	10.9	21.3	40.1	16.0	27.7	44.7
Diesel fuel (distillate fuel oil)[6]	19.8	15.7	23.1	37.0	17.5	28.0	46.9	22.0	34.1	51.2
Residual fuel oil	8.1	4.9	11.7	21.6	5.6	15.0	28.3	10.9	19.2	31.2
Natural gas[7]	16.6	16.4	16.6	16.4	16.1	15.5	18.8	15.5	15.9	18.5
Electricity	29.5	32.5	33.0	33.5	36.5	37.4	39.5	35.0	35.5	37.9
Electric power[8]										
Distillate fuel oil	15.0	10.9	18.4	32.4	12.9	23.5	42.5	17.4	29.4	46.6
Residual fuel oil	10.2	7.4	13.8	24.6	9.4	18.1	32.9	13.4	22.4	36.0
Natural gas	3.3	4.4	4.7	4.5	5.2	5.6	7.1	5.0	5.4	7.1
Steam coal	2.2	2.1	2.3	2.4	2.1	2.3	2.6	2.2	2.4	2.7
Average price to all users[9]										
Propane	14.9	13.9	18.0	26.9	14.8	20.1	31.1	17.1	23.2	31.9
E85[3]	23.3	24.1	32.0	38.1	25.4	30.8	39.3	28.5	35.0	42.2
Motor gasoline[4]	20.9	16.1	22.7	35.6	16.9	26.5	43.0	21.0	31.8	47.0
Jet fuel[5]	12.0	8.6	16.2	29.6	10.9	21.3	40.1	16.0	27.7	44.7
Distillate fuel oil	19.1	14.8	22.3	36.3	16.7	27.3	46.2	21.4	33.3	50.5
Residual fuel oil	8.4	5.0	11.7	22.0	6.3	15.4	29.0	11.1	19.6	31.9
Natural gas	5.3	6.4	6.7	6.6	7.0	7.4	9.4	6.9	7.4	9.6
Metallurgical coal	5.4	6.0	6.0	6.0	7.0	7.0	7.0	7.3	7.3	7.3
Other coal	2.3	2.2	2.3	2.5	2.2	2.4	2.7	2.3	2.5	2.8
Coal to liquids	- -	- -	- -	- -	- -	- -	2.0	- -	- -	2.1
Electricity	30.1	30.3	30.8	31.1	31.1	31.9	34.1	30.1	30.6	33.1
Non-renewable energy expenditures by sector (billion 2015 dollars)										
Residential	239	242	250	258	256	266	288	267	274	296
Commercial	178	186	193	198	208	216	235	223	230	251
Industrial[1]	168	184	232	309	222	301	444	275	369	509
Transportation	514	411	586	885	426	640	956	559	777	1,023
Total non-renewable expenditures	1,099	1,023	1,260	1,650	1,112	1,423	1,923	1,324	1,650	2,079
Transportation renewable expenditures	1	1	1	7	2	7	22	4	10	26
Total expenditures	**1,100**	**1,024**	**1,262**	**1,657**	**1,114**	**1,430**	**1,945**	**1,328**	**1,660**	**2,106**

Table C3. Energy prices by sector and source *(continued)*
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Propane	16.9	17.8	22.3	32.0	23.1	30.3	46.3	32.2	43.0	59.6
Distillate fuel oil	19.3	16.4	24.7	39.9	23.3	37.6	64.2	36.2	56.9	88.0
Natural gas	10.1	11.4	11.9	11.6	15.7	16.3	18.8	19.8	20.8	24.9
Electricity	36.3	40.7	41.7	42.1	51.8	53.3	57.9	61.9	64.2	70.7
Commercial										
Propane	15.1	15.9	19.8	28.1	20.6	26.8	40.6	28.6	37.9	52.3
Distillate fuel oil	17.0	13.5	21.8	36.9	18.8	33.1	59.7	30.7	51.2	82.2
Residual fuel oil	6.9	5.1	12.1	23.9	9.0	20.7	41.4	18.1	33.6	57.8
Natural gas	7.7	9.8	10.3	10.0	13.5	14.1	16.5	16.6	17.5	21.4
Electricity	30.6	34.1	34.8	34.9	42.5	43.7	47.7	49.9	51.7	57.6
Industrial[1]										
Propane	12.2	12.6	17.2	27.2	16.7	24.1	40.5	24.6	35.6	52.4
Distillate fuel oil	17.0	13.5	21.8	36.9	18.9	33.1	59.7	30.7	51.3	82.2
Residual fuel oil	6.8	5.4	12.4	24.1	9.9	21.6	42.3	19.2	34.7	58.9
Natural gas[2]	3.7	5.5	5.9	5.7	7.6	8.1	10.6	9.0	9.6	13.0
Metallurgical coal	5.4	6.7	6.7	6.6	9.5	9.4	9.7	12.0	12.2	12.6
Other industrial coal	3.4	3.6	3.7	4.0	4.4	4.6	5.1	5.5	6.0	6.7
Coal to liquids	- -	- -	- -	- -	- -	- -	2.8	- -	- -	3.6
Electricity	20.3	22.7	23.1	23.2	29.1	29.9	33.0	34.6	35.7	40.5
Transportation										
Propane	18.0	18.9	23.4	33.2	24.5	31.7	47.7	34.0	44.8	61.4
E85[3]	23.3	26.6	35.4	41.8	34.5	41.7	54.0	47.3	58.8	72.8
Motor gasoline[4]	20.9	17.8	25.1	39.0	23.0	35.9	59.2	34.9	53.6	81.1
Jet fuel[5]	12.0	9.5	17.9	32.5	14.8	28.8	55.1	26.5	46.6	77.2
Diesel fuel (distillate fuel oil)[6]	19.8	17.3	25.5	40.6	23.7	37.9	64.6	36.6	57.3	88.4
Residual fuel oil	8.1	5.4	12.9	23.7	7.6	20.3	38.9	18.1	32.3	53.9
Natural gas[7]	16.6	18.1	18.4	18.0	21.9	21.0	25.8	25.7	26.7	31.9
Electricity	29.5	35.9	36.5	36.8	49.6	50.5	54.4	58.2	59.8	65.5
Electric power[8]										
Distillate fuel oil	15.0	12.1	20.4	35.6	17.5	31.8	58.4	28.9	49.4	80.5
Residual fuel oil	10.2	8.2	15.2	27.0	12.7	24.4	45.2	22.2	37.8	62.1
Natural gas	3.3	4.8	5.2	4.9	7.0	7.5	9.7	8.3	9.0	12.2
Steam coal	2.2	2.4	2.5	2.7	2.8	3.1	3.5	3.7	4.0	4.7

Table C3. Energy prices by sector and source *(continued)*
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Average price to all users[9]										
Propane	14.9	15.4	19.9	29.5	20.1	27.2	42.8	28.4	39.0	55.1
E85[3]	23.3	26.6	35.4	41.8	34.5	41.7	54.0	47.3	58.8	72.8
Motor gasoline[4]	20.9	17.8	25.1	39.0	23.0	35.9	59.2	34.9	53.6	81.1
Jet fuel[5]	12.0	9.5	17.9	32.5	14.8	28.8	55.1	26.5	46.6	77.2
Distillate fuel oil	19.1	16.4	24.7	39.8	22.7	36.9	63.6	35.5	56.1	87.2
Residual fuel oil	8.4	5.6	13.0	24.1	8.6	20.8	39.9	18.4	32.9	55.1
Natural gas	5.3	7.0	7.4	7.2	9.6	10.0	12.9	11.5	12.4	16.6
Metallurgical coal	5.4	6.7	6.7	6.6	9.5	9.4	9.7	12.0	12.2	12.6
Other coal	2.3	2.4	2.6	2.7	3.0	3.2	3.7	3.8	4.2	4.8
Coal to liquids	- -	- -	- -	- -	- -	- -	2.8	- -	- -	3.6
Electricity	30.1	33.4	34.1	34.2	42.2	43.1	47.0	50.0	51.6	57.2
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	239	267	276	283	347	360	396	443	462	510
Commercial	178	206	213	217	282	292	323	370	387	434
Industrial[1]	168	203	256	340	301	407	611	457	620	879
Transportation	514	454	647	972	579	866	1,315	929	1,307	1,767
Total non-renewable expenditures	1,099	1,130	1,392	1,811	1,509	1,925	2,645	2,199	2,776	3,590
Transportation renewable expenditures	1	1	1	7	3	9	30	7	17	46
Total expenditures	**1,100**	**1,131**	**1,394**	**1,819**	**1,512**	**1,934**	**2,676**	**2,205**	**2,793**	**3,636**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a.

Table C4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil										
Domestic crude production[1]	9.42	8.13	9.38	11.16	7.10	10.06	12.14	8.62	11.26	11.02
Alaska	0.48	0.41	0.41	0.41	0.00	0.24	0.24	0.00	0.15	0.15
Lower 48 states	8.94	7.72	8.96	10.75	7.09	9.82	11.90	8.61	11.11	10.88
Net imports	6.88	6.51	6.97	6.49	7.13	6.57	4.47	7.86	6.10	5.54
Gross imports	7.28	7.14	7.60	7.12	7.76	7.20	6.04	8.49	7.12	7.47
Exports	0.40	0.63	0.63	0.63	0.63	0.63	1.57	0.63	1.02	1.93
Other crude supply[2]	-0.11	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**16.19**	**14.65**	**16.36**	**17.66**	**14.23**	**16.63**	**16.61**	**16.48**	**17.36**	**16.56**
Net product imports	-2.24	-0.71	-3.26	-5.83	-0.28	-4.32	-6.83	-1.76	-4.66	-7.24
Gross refined product imports[3]	0.66	1.13	1.11	0.79	1.71	1.30	0.82	1.91	1.63	1.10
Unfinished oil imports	0.55	0.64	0.53	0.54	0.65	0.46	0.45	0.66	0.39	0.35
Blending component imports	0.67	0.72	0.58	0.62	0.63	0.45	0.45	0.53	0.30	0.32
Exports	4.12	3.21	5.48	7.78	3.28	6.52	8.56	4.86	6.98	9.01
Refinery processing gain[4]	1.03	0.97	1.05	1.14	0.92	0.98	0.95	1.03	0.99	0.94
Product stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas plant liquids	3.25	4.33	4.57	4.82	4.32	4.90	5.17	4.53	4.99	5.25
Supply from renewable sources	1.01	1.11	1.08	1.08	1.03	1.03	1.08	1.04	1.12	1.22
Ethanol	0.89	0.92	0.89	0.89	0.84	0.84	0.88	0.85	0.93	0.79
Domestic production	0.94	0.93	0.90	0.89	0.88	0.87	0.89	0.89	0.91	0.69
Net imports	-0.05	-0.01	-0.01	0.00	-0.04	-0.03	-0.01	-0.03	0.02	0.11
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.11	0.15	0.15	0.16	0.04	0.10	0.16	0.04	0.10	0.16
Domestic production	0.08	0.11	0.11	0.12	0.00	0.06	0.12	0.00	0.06	0.12
Net imports	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.04	0.04	0.04	0.14	0.09	0.04	0.14	0.09	0.27
Domestic production	0.00	0.04	0.04	0.04	0.14	0.09	0.04	0.14	0.09	0.27
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	0.00	0.00	0.00	0.04	0.00	0.00	0.45	0.00	0.00	0.85
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.28
Other[6]	0.21	0.22	0.28	0.30	0.24	0.30	0.32	0.28	0.32	0.35
Total primary supply[7]	**19.46**	**20.56**	**20.08**	**19.22**	**20.45**	**19.52**	**17.98**	**21.60**	**20.12**	**18.21**
Product supplied										
by fuel										
Liquefied petroleum gases and other[8]	2.46	2.88	2.90	2.80	3.32	3.34	3.22	3.76	3.80	3.61
Motor gasoline[9]	9.18	9.35	8.97	8.26	8.33	7.35	6.28	8.15	6.84	5.65
of which: E85[10]	0.03	0.03	0.03	0.12	0.06	0.15	0.39	0.10	0.19	0.43
Jet fuel[11]	1.54	1.58	1.56	1.54	1.74	1.73	1.71	1.87	1.86	1.84
Distillate fuel oil[12]	3.96	4.36	4.31	4.26	4.43	4.46	4.22	4.82	4.67	4.27
of which: Diesel	3.76	3.99	3.97	3.96	4.13	4.19	3.98	4.56	4.43	4.06
Residual fuel oil	0.26	0.30	0.25	0.23	0.31	0.27	0.26	0.30	0.28	0.27
Other[13]	2.02	2.12	2.11	2.16	2.34	2.39	2.33	2.73	2.70	2.59
by sector										
Residential and commercial	0.90	0.98	0.89	0.78	0.92	0.80	0.68	0.84	0.74	0.64
Industrial[14]	4.47	5.36	5.35	5.33	6.01	6.10	5.94	6.85	6.89	6.60
Transportation	14.04	14.51	14.11	13.37	13.78	12.84	11.53	14.18	12.69	11.11
Electric power[15]	0.12	0.07	0.07	0.07	0.05	0.05	0.05	0.04	0.04	0.04
Unspecified sector[16]	-0.30	-0.32	-0.31	-0.29	-0.28	-0.25	-0.19	-0.28	-0.23	-0.16
Total product supplied	**19.42**	**20.59**	**20.11**	**19.26**	**20.47**	**19.54**	**18.01**	**21.63**	**20.14**	**18.24**
Discrepancy[17]	0.04	-0.03	-0.03	-0.03	-0.02	-0.03	-0.03	-0.03	-0.03	-0.03

Table C4. Petroleum and other liquids supply and disposition *(continued)*
(million barrels per day, unless otherwise noted)

Supply and disposition	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[18]	18.0	19.0	19.0	19.2	19.0	19.0	19.3	19.0	19.0	19.3
Capacity utilization rate (percent)[19]	91.1	79.2	87.7	93.8	77.0	88.9	87.5	88.8	92.5	86.9
Net import share of product supplied (percent)	23.7	28.3	18.6	3.6	33.5	11.6	-13.0	28.3	7.4	-8.5
Net expenditures for imported crude oil and petroleum products (billion 2015 dollars)	128	88	207	399	126	268	455	221	348	609

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a.

Table C5. Petroleum and other liquids prices
(2015 dollars per gallon, unless otherwise noted)

Sector and fuel	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2015 dollars per barrel)										
Brent spot	52	38	77	152	49	104	207	73	136	230
West Texas Intermediate spot	49	32	71	145	42	97	198	67	129	222
Average imported refiners acquisition cost[1]	46	30	69	142	40	95	191	66	126	213
Brent / West Texas Intermediate spread	3.7	6.1	5.4	7.1	6.6	6.9	8.9	6.0	7.1	7.6
Delivered sector product prices										
Residential										
Propane	1.55	1.47	1.84	2.66	1.55	2.04	3.07	1.77	2.33	3.15
Distillate fuel oil	2.66	2.05	3.08	5.00	2.35	3.82	6.42	2.99	4.65	7.00
Commercial										
Distillate fuel oil	2.34	1.68	2.71	4.63	1.90	3.36	5.96	2.53	4.19	6.54
Residual fuel oil	1.04	0.69	1.64	3.26	0.99	2.29	4.51	1.63	2.98	5.01
Residual fuel oil (2015 dollars per barrel)	44	29	69	137	41	96	189	68	125	210
Industrial[2]										
Propane	1.12	1.04	1.42	2.27	1.12	1.63	2.69	1.35	1.93	2.77
Distillate fuel oil	2.34	1.68	2.71	4.62	1.90	3.36	5.96	2.53	4.19	6.54
Residual fuel oil	1.01	0.73	1.68	3.29	1.09	2.39	4.60	1.73	3.08	5.11
Residual fuel oil (2015 dollars per barrel)	42	31	71	138	46	100	193	73	130	214
Transportation										
Propane	1.64	1.57	1.94	2.76	1.65	2.14	3.17	1.87	2.43	3.25
E85[3]	2.21	2.30	3.05	3.62	2.42	2.93	3.74	2.71	3.33	4.01
Ethanol wholesale price	2.22	2.74	2.77	2.78	2.11	2.28	2.55	2.29	2.60	2.93
Motor gasoline[4]	2.52	1.94	2.74	4.28	2.04	3.19	5.17	2.53	3.81	5.61
Jet fuel[5]	1.62	1.16	2.18	3.99	1.47	2.87	5.41	2.15	3.74	6.04
Diesel fuel (distillate fuel oil)[6]	2.72	2.15	3.18	5.09	2.40	3.85	6.45	3.03	4.68	7.04
Residual fuel oil	1.21	0.73	1.75	3.23	0.84	2.25	4.23	1.63	2.87	4.67
Residual fuel oil (2015 dollars per barrel)	51	31	73	136	35	94	178	69	121	196
Electric power[7]										
Distillate fuel oil	2.07	1.50	2.53	4.45	1.77	3.23	5.84	2.39	4.04	6.41
Residual fuel oil	1.53	1.12	2.06	3.68	1.40	2.70	4.92	2.00	3.36	5.38
Residual fuel oil (2015 dollars per barrel)	64	47	87	154	59	114	207	84	141	226
Average prices, all sectors[8]										
Propane	1.36	1.27	1.65	2.46	1.35	1.83	2.84	1.56	2.12	2.91
Motor gasoline[4]	2.52	1.94	2.74	4.28	2.04	3.19	5.17	2.53	3.81	5.61
Jet fuel[5]	1.62	1.16	2.18	3.99	1.47	2.87	5.41	2.15	3.74	6.04
Distillate fuel oil	2.63	2.04	3.07	4.99	2.30	3.75	6.36	2.93	4.58	6.94
Residual fuel oil	1.26	0.75	1.76	3.29	0.94	2.30	4.35	1.66	2.93	4.78
Residual fuel oil (2015 dollars per barrel)	53	32	74	138	40	97	183	70	123	201
Average	**2.18**	**1.65**	**2.44**	**3.97**	**1.75**	**2.85**	**4.82**	**2.21**	**3.42**	**5.16**

Table C5. Petroleum and other liquids prices *(continued)*
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Brent spot	52	42	85	166	66	141	284	121	229	397
West Texas Intermediate spot	49	35	79	159	58	131	272	111	217	384
Average imported refiners acquisition cost[1]	46	33	76	156	55	128	263	109	212	369
Delivered sector product prices										
Residential										
Propane	1.55	1.62	2.03	2.92	2.11	2.76	4.22	2.94	3.93	5.44
Distillate fuel oil	2.66	2.26	3.40	5.49	3.20	5.16	8.83	4.97	7.83	12.09
Commercial										
Distillate fuel oil	2.34	1.85	2.99	5.08	2.58	4.54	8.20	4.21	7.04	11.30
Residual fuel oil	1.04	0.76	1.81	3.58	1.34	3.09	6.20	2.70	5.02	8.65
Industrial[2]										
Propane	1.12	1.15	1.57	2.49	1.53	2.20	3.69	2.24	3.25	4.78
Distillate fuel oil	2.34	1.85	2.99	5.08	2.59	4.54	8.20	4.21	7.04	11.30
Residual fuel oil	1.01	0.81	1.86	3.61	1.49	3.23	6.33	2.88	5.19	8.82
Transportation										
Propane	1.64	1.73	2.14	3.03	2.24	2.89	4.36	3.10	4.09	5.61
E85[3]	2.21	2.53	3.37	3.98	3.28	3.97	5.14	4.51	5.60	6.93
Ethanol wholesale price	2.22	3.02	3.06	3.05	2.86	3.09	3.50	3.80	4.38	5.06
Motor gasoline[4]	2.52	2.14	3.02	4.70	2.77	4.32	7.11	4.20	6.40	9.68
Jet fuel[5]	1.62	1.28	2.41	4.38	2.00	3.89	7.44	3.58	6.29	10.42
Diesel fuel (distillate fuel oil)[6]	2.72	2.38	3.51	5.59	3.26	5.21	8.88	5.03	7.88	12.15
Residual fuel oil	1.21	0.80	1.93	3.55	1.14	3.04	5.82	2.71	4.83	8.06
Electric power[7]										
Distillate fuel oil	2.07	1.66	2.80	4.89	2.41	4.37	8.04	3.97	6.79	11.06
Residual fuel oil	1.53	1.23	2.28	4.04	1.90	3.66	6.77	3.32	5.65	9.30
Average prices, all sectors[8]										
Propane	1.36	1.40	1.82	2.70	1.83	2.48	3.91	2.60	3.56	5.03
Motor gasoline[4]	2.52	2.14	3.02	4.70	2.77	4.32	7.11	4.20	6.40	9.68
Jet fuel[5]	1.62	1.28	2.41	4.38	2.00	3.89	7.44	3.58	6.29	10.42
Distillate fuel oil	2.63	2.25	3.39	5.47	3.12	5.08	8.75	4.87	7.71	11.98
Residual fuel oil (nominal dollars per barrel)	53	35	81	152	54	131	251	116	207	347
Average	**2.18**	**1.82**	**2.70**	**4.35**	**2.37**	**3.86**	**6.64**	**3.68**	**5.76**	**8.91**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a.

Table C6. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2015	2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Crude oil spot prices										
(2015 dollars per barrel)										
Brent	52	38	77	152	49	104	207	73	136	230
West Texas Intermediate	49	32	71	145	42	97	198	67	129	222
(nominal dollars per barrel)										
Brent	52	42	85	166	66	141	284	121	229	397
West Texas Intermediate	49	35	79	159	58	131	272	111	217	384
Petroleum and other liquids consumption[1]										
OECD										
United States (50 states)	19.42	20.59	20.11	19.26	20.47	19.54	18.01	21.63	20.14	18.24
United States territories	0.30	0.31	0.31	0.31	0.34	0.34	0.34	0.38	0.38	0.38
Canada	2.39	2.45	2.39	2.32	2.48	2.39	2.39	2.64	2.51	2.57
Mexico and Chile	2.30	2.48	2.38	2.27	2.61	2.50	2.44	3.05	2.87	2.84
OECD Europe[2]	13.83	13.98	13.70	13.28	13.98	13.65	13.36	14.43	13.98	13.60
Japan	4.14	4.02	3.91	3.69	3.80	3.66	3.48	3.60	3.40	3.33
South Korea	2.38	2.50	2.41	2.25	2.54	2.44	2.32	2.67	2.55	2.49
Australia and New Zealand	1.28	1.37	1.35	1.32	1.43	1.41	1.40	1.55	1.53	1.55
Total OECD consumption	**46.03**	**47.70**	**46.56**	**44.69**	**47.65**	**45.93**	**43.73**	**49.94**	**47.35**	**45.01**
Non-OECD										
Russia	3.35	3.68	3.65	3.51	3.77	3.75	3.68	3.58	3.59	3.58
Other Europe and Eurasia[3]	2.07	2.22	2.18	2.11	2.46	2.43	2.39	2.56	2.53	2.53
China	11.18	12.87	12.71	12.43	14.65	14.81	14.95	15.53	16.36	17.15
India	3.97	4.67	4.54	4.32	6.07	5.94	5.59	8.35	8.26	7.41
Other Asia[4]	8.15	9.67	9.40	9.01	11.74	11.42	10.76	14.41	14.29	13.46
Middle East	8.29	10.31	9.96	9.76	11.42	11.28	11.47	13.21	13.23	14.09
Africa	3.86	4.64	4.54	4.40	5.62	5.50	5.43	7.03	6.93	6.99
Brazil	3.15	3.52	3.41	3.24	4.14	4.06	3.93	4.80	4.71	4.58
Other Central and South America	3.85	4.23	4.11	3.98	4.57	4.41	4.18	5.00	4.89	4.65
Total non-OECD consumption	**47.87**	**55.82**	**54.49**	**52.77**	**64.43**	**63.60**	**62.38**	**74.45**	**74.79**	**74.44**
Total consumption	**93.90**	**103.51**	**101.05**	**97.46**	**112.08**	**109.52**	**106.11**	**124.39**	**122.14**	**119.44**
Petroleum and other liquids production										
OPEC[5]										
Middle East	27.76	32.44	30.87	27.42	36.70	34.29	29.33	41.63	39.38	31.71
North Africa	2.13	3.51	1.99	2.12	3.73	2.32	2.11	4.03	2.94	2.28
West Africa	4.21	4.51	4.35	4.08	5.04	4.58	3.53	6.21	5.07	3.57
South America	3.24	4.17	2.96	2.59	5.46	3.33	2.85	6.76	3.88	3.21
Total OPEC production	**37.33**	**44.63**	**40.17**	**36.21**	**50.93**	**44.52**	**37.81**	**58.63**	**51.28**	**40.77**
Non-OPEC										
OECD										
United States (50 states)	14.95	14.73	16.33	18.51	13.60	17.26	20.32	15.49	18.62	19.76
Canada	4.54	5.11	5.43	5.14	4.68	5.55	6.16	4.63	6.01	8.25
Mexico and Chile	2.64	2.54	2.46	2.75	2.69	2.58	3.35	3.11	3.24	5.06
OECD Europe[2]	3.79	3.47	3.44	3.40	3.11	3.10	3.03	2.86	2.78	2.80
Japan and South Korea	0.22	0.17	0.20	0.16	0.19	0.21	0.17	0.20	0.22	0.18
Australia and New Zealand	0.51	0.67	0.66	0.75	0.60	0.61	1.08	0.56	0.76	1.53
Total OECD production	**26.65**	**26.68**	**28.51**	**30.71**	**24.87**	**29.31**	**34.12**	**26.84**	**31.63**	**37.58**
Non-OECD										
Russia	10.95	10.44	10.62	9.68	11.75	11.22	9.80	12.56	12.21	11.17
Other Europe and Eurasia[3]	3.23	3.78	3.69	3.18	4.93	4.63	4.03	5.12	4.50	5.75
China	4.69	4.91	4.90	4.86	5.36	5.44	5.65	5.70	6.24	6.78
Other Asia[4]	4.03	3.91	3.92	3.88	3.63	3.65	3.65	3.60	3.62	3.68
Middle East	1.14	1.04	1.02	1.02	0.84	0.83	0.83	0.70	0.69	0.70
Africa	2.33	2.42	2.48	2.46	2.46	2.73	2.56	2.56	2.83	2.75
Brazil	3.15	3.57	3.59	3.21	5.25	5.00	4.73	6.45	6.15	6.03
Other Central and South America	2.18	2.14	2.15	2.25	2.06	2.19	2.93	2.22	2.99	4.24
Total non-OECD production	**31.70**	**32.20**	**32.37**	**30.55**	**36.28**	**35.69**	**34.18**	**38.92**	**39.23**	**41.09**
Total petroleum and other liquids production	**95.68**	**103.51**	**101.05**	**97.46**	**112.08**	**109.52**	**106.11**	**124.39**	**122.14**	**119.44**
OPEC market share (percent)	39.0	43.1	39.8	37.2	45.4	40.7	35.6	47.1	42.0	34.1

Table C6. International petroleum and other liquids supply, disposition, and prices *(continued)*
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2015	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Selected world production subtotals:										
Crude oil and equivalents[6]	80.13	86.11	82.77	78.52	93.24	89.12	83.45	103.39	99.74	92.92
Tight oil	5.34	4.19	5.44	7.73	4.17	6.96	10.17	5.55	10.35	12.84
Bitumen[7]	2.32	2.99	3.08	3.08	2.88	3.18	3.68	2.99	3.31	4.80
Refinery processing gain[8]	2.45	2.46	2.53	2.55	2.78	2.73	2.67	3.23	2.94	2.95
Natural gas plant liquids	10.37	11.74	12.32	12.87	12.67	13.24	14.34	13.82	13.88	15.69
Liquids from renewable sources[9]	2.32	2.42	2.54	2.54	2.99	3.31	3.35	3.55	4.11	4.13
Liquids from coal[10]	0.25	0.25	0.27	0.31	0.04	0.26	0.88	0.00	0.50	1.48
Liquids from natural gas[11]	0.29	0.31	0.32	0.37	0.11	0.57	1.10	0.12	0.65	1.92
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Crude oil production[6]										
OPEC[5]										
Middle East	24.38	29.14	27.07	23.60	33.28	30.10	25.10	38.06	34.74	27.03
North Africa	1.78	2.95	1.61	1.63	3.03	1.82	1.46	3.18	2.20	1.46
West Africa	4.19	4.37	4.28	3.93	4.91	4.51	3.36	6.09	4.99	3.37
South America	3.05	3.88	2.75	2.38	5.11	3.09	2.60	6.42	3.64	2.96
Total OPEC production	**33.40**	**40.34**	**35.72**	**31.54**	**46.33**	**39.52**	**32.51**	**53.75**	**45.57**	**34.83**
Non-OPEC										
OECD										
United States (50 states)	9.42	8.13	9.38	11.16	7.10	10.06	12.14	8.62	11.26	11.02
Canada	3.72	4.42	4.57	4.34	3.95	4.53	5.33	3.89	4.96	7.40
Mexico and Chile	2.31	2.19	2.16	2.46	2.35	2.29	3.07	2.77	2.96	4.78
OECD Europe[2]	2.95	2.36	2.31	2.29	1.90	1.88	1.81	1.51	1.47	1.44
Japan and South Korea	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Australia and New Zealand	0.39	0.53	0.53	0.62	0.46	0.49	0.96	0.41	0.64	1.39
Total OECD production	**18.81**	**17.63**	**18.96**	**20.88**	**15.77**	**19.24**	**23.30**	**17.20**	**21.29**	**26.04**
Non-OECD										
Russia	10.17	9.84	9.84	8.79	10.90	10.49	8.51	11.28	11.53	9.21
Other Europe and Eurasia[3]	3.00	3.48	3.43	2.90	4.49	4.36	3.62	4.46	4.23	5.11
China	4.28	4.38	4.34	4.27	4.57	4.40	4.23	4.68	4.67	4.49
Other Asia[4]	3.18	3.01	2.98	2.95	2.57	2.52	2.52	2.28	2.25	2.25
Middle East	1.11	0.99	1.00	0.99	0.80	0.81	0.81	0.67	0.67	0.67
Africa	1.94	1.94	2.01	1.99	2.15	2.25	2.02	2.26	2.34	2.05
Brazil	2.43	2.80	2.77	2.39	4.07	3.78	3.46	5.08	4.67	4.52
Other Central and South America	1.81	1.69	1.72	1.80	1.58	1.75	2.46	1.73	2.52	3.75
Total non-OECD production	**27.92**	**28.15**	**28.09**	**26.10**	**31.14**	**30.36**	**27.64**	**32.44**	**32.87**	**32.05**
Total crude oil production[6]	**80.13**	**86.11**	**82.77**	**78.52**	**93.24**	**89.12**	**83.45**	**103.39**	**99.74**	**92.92**
OPEC market share (percent)	41.7	46.8	43.2	40.2	49.7	44.3	39.0	52.0	45.7	37.5

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** Energy Information Administration (EIA), AEO2016 National Energy Modeling System runs lowprice.d041916a, ref2016.d032416a, and highprice.d041916a; and EIA, Generate World Oil Balance application.

Table D1. Key results for Clean Power Plan cases

Capacity, generation, prices, consumption, and emissions	2015	2020 Reference	2020 CPP Rate	2020 CPP Interregional Trading	2020 CPP Hybrid	2020 CPP Allocation to Generators	2020 CPP Extended
Net summer capacity (gigawatts)[1]							
Capacity							
Electric power sector[2]	1,040.8	1,053.0	1,053.2	1,054.4	1,052.6	1,054.8	1,048.5
Coal[3]	281.4	211.7	211.7	212.1	211.8	212.3	205.9
Oil and natural gas steam[3,4]	91.4	90.3	90.3	91.2	90.5	91.0	90.9
Combined cycle	227.3	247.5	247.1	247.5	246.4	247.4	248.5
Combustion turbine/diesel	141.2	142.9	143.4	142.9	143.2	143.3	143.1
Nuclear power	99.8	99.1	99.1	99.1	99.1	99.1	99.1
Solar[5]	13.8	28.0	28.1	28.0	28.1	28.1	27.5
Wind	74.4	120.4	120.4	120.4	120.4	120.4	120.4
Other renewable energy[6]	89.0	90.3	90.3	90.3	90.3	90.3	90.3
Other[7]	22.6	22.9	22.9	22.9	22.9	22.9	22.9
End-use sector[8]	41.3	61.1	61.1	61.2	61.1	61.2	62.0
Total capacity	**1,082.1**	**1,114.2**	**1,114.4**	**1,115.5**	**1,113.8**	**1,115.9**	**1,110.6**
Capacity additions (gigawatts)[9]							
Electric power sector[2]	- -	101.1	101.0	101.3	101.0	101.3	102.4
Coal[3]	- -	0.5	0.5	0.5	0.5	0.5	0.5
Combined cycle	- -	26.7	26.3	26.8	26.3	26.7	28.1
Combustion turbine/diesel	- -	7.3	7.4	7.3	7.4	7.3	7.7
Nuclear power	- -	4.4	4.4	4.4	4.4	4.4	4.4
Solar[5]	- -	14.2	14.4	14.2	14.4	14.4	13.8
Wind	- -	46.1	46.1	46.1	46.1	46.1	46.1
Other renewable energy[6]	- -	1.7	1.7	1.7	1.7	1.7	1.7
Other[7]	- -	0.2	0.3	0.2	0.3	0.2	0.2
End-use sector[8]	- -	21.0	21.0	21.0	21.0	21.0	21.1
Total capacity additions	**- -**	**122.1**	**122.1**	**122.3**	**122.1**	**122.3**	**123.5**
Capacity retirements (gigawatts)[9]							
Electric power sector[2]	- -	88.9	88.6	87.7	89.2	87.4	94.7
Coal[3]	- -	61.6	61.6	61.2	61.5	61.0	67.4
Oil and natural gas steam[3,4]	- -	9.7	9.7	8.8	9.5	9.0	9.1
Combined cycle	- -	6.5	6.5	6.6	7.2	6.6	6.9
Combustion turbine/diesel	- -	5.5	5.3	5.6	5.4	5.2	5.8
Nuclear power	- -	5.2	5.2	5.2	5.2	5.2	5.2
Renewable energy[10]	- -	0.4	0.4	0.4	0.4	0.4	0.4
Fuel cells	- -	0.0	0.0	0.0	0.0	0.0	0.0
End-use sector[8]	- -	1.2	1.2	1.2	1.2	1.2	0.4
Total capacity retirements	**- -**	**90.1**	**89.9**	**89.0**	**90.5**	**88.6**	**95.1**
Total net electricity generation by fuel (billion kilowatthours)							
Coal	1,355	1,388	1,389	1,389	1,389	1,388	1,366
Petroleum	26	15	15	15	15	15	15
Natural gas	1,348	1,201	1,199	1,199	1,199	1,201	1,220
Nuclear power	798	777	777	777	777	777	777
Solar[5]	38	93	93	93	93	93	92
Wind	190	368	368	368	367	368	368
Other renewable energy[6]	319	376	375	376	375	376	376
Other[11]	17	27	27	27	27	27	27
Total net electricity generation	**4,090**	**4,244**	**4,243**	**4,244**	**4,243**	**4,245**	**4,240**
Fuel prices to the electric power sector[2] (2015 dollars per million Btu)							
Natural gas	3.26	4.69	4.69	4.68	4.69	4.68	4.76
Steam coal	2.19	2.26	2.26	2.26	2.26	2.26	2.27
Electricity prices (2015 cents per kilowatthour)							
Residential	12.4	12.9	12.9	12.9	12.9	12.9	12.9
Commercial	10.5	10.7	10.7	10.7	10.7	10.7	10.8
Industrial	6.9	7.1	7.1	7.1	7.1	7.1	7.2
Transportation	10.1	11.3	11.3	11.3	11.3	11.3	11.3
All sectors average price	**10.3**	**10.5**	**10.5**	**10.5**	**10.5**	**10.5**	**10.6**

2030						2040					
Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended	Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended
1,094.2	1,139.1	1,107.1	1,138.9	1,088.9	1,107.9	1,239.6	1,252.2	1,259.0	1,251.4	1,242.6	1,250.4
180.3	186.6	185.6	188.2	179.4	174.9	172.8	186.6	178.9	188.2	172.3	152.7
54.5	66.0	52.7	62.8	53.4	52.1	52.8	63.3	50.0	60.7	49.8	49.6
294.5	259.0	280.1	258.6	290.9	294.9	345.4	303.5	331.4	302.0	340.5	352.9
137.0	137.1	139.9	136.2	138.2	135.1	144.6	147.9	145.5	146.8	146.3	141.5
99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1
70.1	109.6	90.2	112.2	69.0	90.2	158.1	164.0	189.0	166.9	166.9	184.5
142.0	164.6	142.9	164.6	142.1	144.6	145.8	167.2	144.3	167.2	146.9	149.4
93.1	93.7	92.9	93.6	93.1	93.3	95.5	95.6	95.4	95.5	95.4	95.7
23.7	23.5	23.6	23.5	23.6	23.6	25.5	25.1	25.4	25.1	25.4	25.0
93.9	94.0	94.0	93.9	95.0	94.6	134.5	135.0	134.3	135.0	136.6	136.3
1,188.1	**1,233.1**	**1,201.0**	**1,232.8**	**1,184.0**	**1,202.5**	**1,374.1**	**1,387.2**	**1,393.2**	**1,386.4**	**1,379.2**	**1,386.6**
227.4	249.2	234.5	252.4	223.9	252.9	388.6	367.7	402.5	369.6	393.8	432.4
0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
84.9	44.3	70.2	44.6	82.4	86.1	138.6	89.8	123.6	89.1	133.6	150.4
8.0	8.0	9.1	8.2	8.0	9.5	19.5	20.3	19.2	20.3	19.9	21.6
4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
56.4	95.8	76.4	98.5	55.3	76.5	144.3	150.3	175.2	153.2	153.1	170.7
67.7	90.3	68.6	90.3	67.8	70.3	71.5	92.9	70.1	92.9	72.7	75.2
4.5	5.0	4.3	5.0	4.5	4.7	6.9	7.0	6.8	6.9	6.8	7.1
1.0	0.9	0.9	0.9	0.9	1.0	2.9	2.5	2.8	2.4	2.7	2.4
53.8	53.9	53.8	53.8	54.9	53.7	94.3	94.9	94.1	94.9	96.5	95.3
281.1	**303.1**	**288.3**	**306.2**	**278.8**	**306.5**	**482.9**	**462.6**	**496.6**	**464.6**	**490.2**	**527.7**
174.0	151.0	168.3	154.4	175.8	185.9	189.8	156.3	184.4	159.1	192.0	222.9
92.1	85.8	86.7	84.2	92.9	97.4	99.6	85.8	93.5	84.2	100.1	119.7
46.4	34.9	48.2	38.1	47.5	48.8	48.1	37.6	50.9	40.2	51.1	51.3
17.7	12.5	17.4	13.3	18.8	18.5	20.5	13.6	19.5	14.4	20.4	24.9
12.2	12.2	10.4	13.2	11.0	15.6	16.0	13.7	14.8	14.6	14.8	21.3
5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.2	1.2	1.2	1.2	1.2	0.4	1.2	1.2	1.2	1.2	1.2	0.4
175.2	**152.2**	**169.5**	**155.6**	**177.0**	**186.2**	**191.0**	**157.6**	**185.6**	**160.3**	**193.2**	**223.2**
972	995	1,029	997	979	987	919	1,080	980	1,081	931	653
11	11	12	11	11	11	9	10	10	10	9	8
1,702	1,531	1,607	1,524	1,680	1,650	1,942	1,723	1,829	1,712	1,896	2,097
789	789	789	789	789	789	789	789	789	789	789	789
227	302	267	306	226	266	477	482	546	491	498	538
457	528	459	528	457	466	473	541	467	540	477	487
405	407	404	407	405	405	424	422	423	421	422	427
27	27	27	27	27	27	27	27	27	27	27	27
4,590	**4,591**	**4,594**	**4,591**	**4,574**	**4,601**	**5,060**	**5,074**	**5,071**	**5,071**	**5,050**	**5,025**
5.57	5.32	5.42	5.31	5.57	5.33	5.36	5.07	5.14	5.07	5.35	5.58
2.26	2.29	2.27	2.29	2.28	2.26	2.38	2.46	2.37	2.46	2.40	2.26
13.4	13.5	13.4	13.4	13.6	13.3	13.0	13.0	12.9	13.0	13.1	13.4
11.0	11.0	11.0	11.0	11.2	10.9	10.5	10.5	10.4	10.5	10.6	10.8
7.5	7.6	7.5	7.5	7.7	7.4	7.2	7.2	7.2	7.2	7.3	7.5
12.7	12.7	12.7	12.6	13.0	12.6	12.1	12.0	12.0	12.0	12.2	12.5
10.9	**10.9**	**10.9**	**10.9**	**11.1**	**10.8**	**10.5**	**10.5**	**10.4**	**10.4**	**10.6**	**10.8**

Table D1. Key results for Clean Power Plan cases *(continued)*

Capacity, generation, prices, consumption, and emissions	2015	2020					
		Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended
Energy consumption (quadrillion Btu)							
Residential							
Petroleum and other liquids[12]	0.93	0.86	0.86	0.86	0.86	0.86	0.86
Natural gas	4.77	4.87	4.87	4.87	4.87	4.87	4.86
Renewable energy[13]	0.44	0.42	0.42	0.42	0.42	0.42	0.42
Electricity	4.78	4.76	4.76	4.76	4.76	4.76	4.76
Total residential	**10.92**	**10.90**	**10.90**	**10.90**	**10.90**	**10.90**	**10.89**
Nonmarketed residential renewable energy[14]	0.11	0.35	0.35	0.35	0.35	0.35	0.35
Commercial							
Petroleum and other liquids[15]	0.66	0.70	0.70	0.70	0.70	0.70	0.70
Natural gas	3.32	3.45	3.45	3.45	3.45	3.45	3.45
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[16]	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Electricity	4.64	4.69	4.69	4.69	4.69	4.69	4.68
Total commercial	**8.81**	**9.03**	**9.03**	**9.03**	**9.03**	**9.03**	**9.03**
Nonmarketed commercial renewable energy[14]	0.16	0.18	0.18	0.18	0.18	0.18	0.18
Industrial[8]							
Petroleum and other liquids[17]	8.07	9.40	9.40	9.40	9.39	9.40	9.39
Natural gas	9.38	10.57	10.57	10.57	10.57	10.57	10.56
Coal	1.34	1.23	1.23	1.23	1.23	1.23	1.22
Renewable energy[18]	2.26	2.30	2.30	2.30	2.30	2.30	2.30
Electricity	3.27	3.61	3.61	3.61	3.61	3.61	3.61
Total industrial	**24.33**	**27.11**	**27.11**	**27.10**	**27.10**	**27.11**	**27.08**
Transportation							
Petroleum and other liquids[19]	27.14	27.32	27.32	27.32	27.32	27.32	27.31
Pipeline fuel natural gas	0.89	0.83	0.83	0.83	0.83	0.83	0.83
Compressed / liquefied natural gas	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Liquid hydrogen	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Electricity	0.03	0.05	0.05	0.05	0.05	0.05	0.05
Total transportation	**28.13**	**28.29**	**28.29**	**28.29**	**28.29**	**28.29**	**28.28**
Unspecified sector[20]	**-0.58**	**-0.58**	**-0.58**	**-0.58**	**-0.58**	**-0.58**	**-0.58**
Electric power[2]							
Petroleum and other liquids[21]	0.26	0.15	0.15	0.15	0.15	0.15	0.15
Natural gas	9.89	8.50	8.49	8.49	8.49	8.50	8.59
Steam coal	14.08	14.34	14.36	14.36	14.37	14.35	14.09
Nuclear / uranium[22]	8.34	8.12	8.12	8.12	8.12	8.12	8.12
Renewable energy[23]	4.86	7.37	7.34	7.37	7.36	7.37	7.36
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.19	0.19	0.20	0.20	0.20	0.19	0.20
Total electric power	**37.85**	**38.90**	**38.89**	**38.91**	**38.91**	**38.91**	**38.73**
Total marketed energy consumption							
Petroleum and other liquids	36.49	37.85	37.85	37.85	37.85	37.85	37.83
Natural gas	28.31	28.30	28.29	28.29	28.29	28.30	28.38
Coal	15.48	15.62	15.64	15.64	15.65	15.63	15.36
Nuclear / uranium[22]	8.34	8.12	8.12	8.12	8.12	8.12	8.12
Renewable energy[24]	7.71	10.22	10.20	10.23	10.21	10.23	10.22
Other[25]	0.42	0.43	0.43	0.43	0.43	0.43	0.43
Total marketed energy consumption	**96.74**	**100.55**	**100.54**	**100.56**	**100.55**	**100.55**	**100.34**

2030						2040					
Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended	Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended
0.72	0.72	0.72	0.72	0.72	0.72	0.61	0.61	0.61	0.61	0.61	0.61
4.80	4.81	4.81	4.81	4.80	4.81	4.73	4.75	4.74	4.75	4.73	4.72
0.39	0.39	0.39	0.39	0.39	0.39	0.37	0.37	0.37	0.37	0.37	0.37
4.83	4.82	4.83	4.83	4.81	4.84	5.20	5.19	5.21	5.20	5.18	5.16
10.74	**10.74**	**10.75**	**10.75**	**10.72**	**10.76**	**10.91**	**10.92**	**10.93**	**10.93**	**10.89**	**10.86**
0.63	0.63	0.63	0.63	0.64	0.63	0.94	0.94	0.93	0.94	0.95	0.94
0.68	0.68	0.68	0.68	0.68	0.68	0.67	0.67	0.67	0.67	0.67	0.67
3.53	3.55	3.55	3.55	3.54	3.56	3.81	3.84	3.83	3.84	3.83	3.81
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
5.09	5.08	5.08	5.08	5.06	5.09	5.62	5.62	5.63	5.62	5.60	5.58
9.49	**9.50**	**9.51**	**9.51**	**9.48**	**9.53**	**10.28**	**10.31**	**10.32**	**10.32**	**10.28**	**10.25**
0.29	0.29	0.29	0.29	0.29	0.29	0.47	0.47	0.47	0.47	0.48	0.47
10.55	10.61	10.59	10.62	10.56	10.57	11.82	11.96	11.90	11.97	11.85	11.68
11.72	11.82	11.77	11.81	11.74	11.74	12.89	13.02	12.96	13.03	12.93	12.79
1.35	1.34	1.35	1.33	1.40	1.32	1.34	1.33	1.35	1.33	1.38	1.31
2.47	2.47	2.47	2.47	2.47	2.47	2.63	2.64	2.63	2.64	2.63	2.61
3.98	3.99	3.99	3.99	3.97	3.99	4.26	4.30	4.28	4.30	4.25	4.21
30.07	**30.23**	**30.18**	**30.23**	**30.13**	**30.11**	**32.94**	**33.26**	**33.13**	**33.28**	**33.04**	**32.60**
25.01	25.03	25.04	25.03	25.01	25.01	24.75	24.81	24.77	24.81	24.77	24.66
0.94	0.93	0.93	0.92	0.94	0.93	1.07	1.05	1.05	1.05	1.07	1.08
0.17	0.17	0.17	0.17	0.17	0.17	0.59	0.61	0.61	0.61	0.59	0.59
0.04	0.04	0.04	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.06
0.11	0.11	0.11	0.11	0.11	0.11	0.15	0.15	0.15	0.15	0.15	0.15
26.28	**26.28**	**26.29**	**26.28**	**26.28**	**26.27**	**26.63**	**26.69**	**26.65**	**26.70**	**26.64**	**26.54**
-0.46	**-0.46**	**-0.46**	**-0.46**	**-0.46**	**-0.46**	**-0.42**	**-0.42**	**-0.42**	**-0.42**	**-0.42**	**-0.41**
0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09	0.09	0.09	0.09	0.07
11.34	10.52	10.76	10.46	11.18	10.89	12.31	11.20	11.60	11.12	11.98	13.27
9.92	10.12	10.56	10.14	9.99	10.07	9.36	11.03	10.06	11.04	9.48	6.60
8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25
9.41	10.74	9.81	10.79	9.39	9.85	11.67	12.25	12.29	12.34	11.86	12.36
0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
0.17	0.17	0.17	0.17	0.17	0.17	0.15	0.15	0.15	0.15	0.15	0.15
39.42	**40.13**	**39.89**	**40.15**	**39.31**	**39.56**	**42.04**	**43.19**	**42.65**	**43.20**	**42.03**	**40.93**
36.62	36.69	36.69	36.70	36.63	36.64	37.52	37.73	37.63	37.73	37.56	37.28
32.51	31.79	31.99	31.73	32.37	32.10	35.39	34.47	34.79	34.41	35.12	36.25
11.32	11.51	11.97	11.53	11.44	11.45	10.75	12.41	11.46	12.42	10.91	7.97
8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25	8.25
12.41	13.74	12.81	13.79	12.39	12.85	14.80	15.40	15.42	15.48	14.99	15.47
0.44	0.44	0.44	0.44	0.44	0.44	0.43	0.43	0.43	0.43	0.43	0.43
101.54	**102.42**	**102.14**	**102.44**	**101.51**	**101.73**	**107.15**	**108.69**	**107.98**	**108.73**	**107.27**	**105.65**

Table D1. Key results for Clean Power Plan cases *(continued)*

Capacity, generation, prices, consumption, and emissions	2015	2020 Reference	2020 CPP Rate	2020 CPP Interregional Trading	2020 CPP Hybrid	2020 CPP Allocation to Generators	2020 CPP Extended
Carbon dioxide emissions (million metric tons)							
by sector							
Residential	1,028	981	982	982	982	981	974
Commercial	918	893	893	893	893	893	885
Industrial[8]	1,472	1,558	1,559	1,558	1,559	1,558	1,551
Transportation	1,855	1,857	1,858	1,857	1,857	1,857	1,857
Total carbon dioxide emissions	**5,273**	**5,289**	**5,291**	**5,290**	**5,291**	**5,290**	**5,267**
Electric power sector							
Petroleum	20	11	11	11	11	11	11
Natural gas	524	451	450	450	450	451	456
Coal	1,340	1,360	1,362	1,362	1,363	1,361	1,336
Other[26]	6	6	6	6	6	6	6
Total electric power sector	**1,891**	**1,829**	**1,830**	**1,830**	**1,831**	**1,829**	**1,809**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power) as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Total coal and oil and natural gas steam capacity account for the conversion of coal capacity to gas steam capacity but the conversions are not included explicitly as additions or retirements.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Does not include off-grid photovoltaics.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, and other biomass. Facilities co-firing biomass and coal are classified as coal.
[7]Includes pumped storage, fuel cells, and distributed generation.
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Cumulative after December 31, 2015.
[10]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[12]Includes propane, kerosene, and distillate fuel oil.
[13]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy.
[15]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[16]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[17]Includes ethane, propane, butane, isobutane, natural gasoline, refinery olefins, motor gasoline (including ethanol and ethers), distillate fuel oil, residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[18]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources, and all biomass input to liquid fuel conversion processes net of the liquid fuel produced.
[19]Includes propane, motor gasoline (including ethanol and ethers), jet fuel, distillate fuel oil, residual fuel oil, lubricants, and aviation gasoline.
[20]Represents consumption unattributed to the sectors above.
[21]Includes distillate fuel oil and residual fuel oil.
[22]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[23]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[24]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources, and all biomass input to liquid fuel conversion processes net of the liquid fuel produced. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[25]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[26]Includes emissions from geothermal power and non-biogenic emissions from municipal waste.
CPP = Clean Power Plan.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Source: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System, runs ref2016.d032416a, ref_rate.d032416A, ref_trade.d032416a, ref_hybrid.d032416a, ref_allow_gen.d032416a, and ref_extend.d050416a.

2030						2040					
Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended	Reference	CPP Rate	CPP Interregional Trading	CPP Hybrid	CPP Allocation to Generators	CPP Extended
841	833	850	832	840	838	821	855	831	854	820	750
807	799	817	799	806	805	826	864	837	863	825	749
1,587	1,586	1,599	1,585	1,593	1,583	1,660	1,700	1,674	1,700	1,665	1,586
1,726	1,726	1,728	1,726	1,726	1,726	1,737	1,742	1,738	1,742	1,738	1,728
4,961	**4,944**	**4,994**	**4,943**	**4,966**	**4,952**	**5,044**	**5,162**	**5,080**	**5,159**	**5,047**	**4,813**
8	8	8	8	8	8	6	7	7	7	6	6
602	558	571	555	593	578	653	594	615	590	636	704
943	962	1,000	965	949	958	885	1,045	949	1,045	897	623
6	6	6	6	6	6	6	6	6	6	6	6
1,559	**1,535**	**1,585**	**1,534**	**1,557**	**1,550**	**1,551**	**1,652**	**1,578**	**1,649**	**1,545**	**1,339**

Table D2. Key transportation results for the Phase 2 Standards case

Key indicators, consumption, and emissions	2015	2020 Reference	2020 Phase 2 Standards	2030 Reference	2030 Phase 2 Standards	2040 Reference	2040 Phase 2 Standards
Average fuel efficiency of new trucks (miles per gallon)							
Light medium							
Diesel	14.3	15.5	15.6	15.6	19.0	15.7	19.2
Motor gasoline	10.4	10.8	11.5	10.8	14.3	10.9	14.7
Propane	10.0	10.3	12.3	10.9	16.2	11.0	16.3
Compressed / liquefied natural gas	9.3	9.9	11.5	10.6	15.0	10.6	14.8
Light medium average	13.4	14.4	14.7	14.5	18.0	14.5	18.3
Medium							
Diesel	8.9	9.2	10.0	9.2	12.9	9.2	13.1
Motor gasoline	6.4	6.5	7.3	6.6	9.1	6.7	9.3
Propane	6.6	6.7	6.9	7.0	8.6	7.0	8.8
Compressed / liquefied natural gas	6.5	6.6	7.2	6.6	9.1	6.7	9.3
Medium average	8.3	8.5	9.3	8.6	12.0	8.7	12.2
Heavy							
Diesel	6.3	6.8	7.2	6.9	8.8	7.0	9.1
Motor gasoline	5.7	5.9	6.5	5.9	7.8	6.1	8.0
Propane	5.2	5.4	5.5	5.5	6.7	5.8	6.9
Compressed / liquefied natural gas	5.9	6.3	6.6	6.4	8.0	6.4	8.0
Heavy average	6.3	6.8	7.2	6.9	8.8	6.9	9.0
Average new truck fuel efficiency	**7.1**	**7.7**	**8.2**	**7.9**	**10.3**	**8.0**	**10.6**
New truck sales (thousands)							
Light medium							
Diesel	136	148	148	157	157	185	186
Motor gasoline	52	54	54	54	54	63	63
Propane	0	0	0	0	0	1	1
Compressed / liquefied natural gas	0	0	0	1	1	5	4
Light medium subtotal	188	202	202	212	212	253	253
Medium							
Diesel	133	165	165	181	181	200	201
Motor gasoline	51	60	60	62	62	67	67
Propane	0	0	0	1	0	2	2
Compressed / liquefied natural gas	0	1	1	1	1	1	1
Medium subtotal	184	225	225	244	244	269	270
Heavy							
Diesel	261	242	243	226	229	219	245
Motor gasoline	11	10	10	10	10	10	11
Propane	0	0	0	0	0	1	1
Compressed / liquefied natural gas	2	2	2	4	2	35	10
Heavy subtotal	275	254	255	241	241	265	266
Total new truck sales	**647**	**681**	**682**	**697**	**698**	**787**	**790**
Freight truck stock (millions)							
Light medium	3.17	3.91	3.91	5.02	5.02	5.83	5.84
Medium	3.19	3.68	3.68	4.68	4.68	5.46	5.47
Heavy	4.58	5.19	5.19	5.60	5.60	5.91	5.92
Total freight truck stock	**10.93**	**12.77**	**12.77**	**15.29**	**15.30**	**17.20**	**17.22**
Freight truck vehicle miles traveled (billion miles)							
Light medium	49.4	52.7	52.7	64.2	64.0	78.9	78.6
Medium	47.8	54.3	54.3	75.2	75.1	91.3	91.0
Heavy	182.6	197.2	197.3	209.5	209.1	236.6	235.6
Total freight truck vehicle miles traveled	**279.8**	**304.2**	**304.4**	**348.9**	**348.2**	**406.8**	**405.1**
Freight truck fuel efficiency (miles per gallon)							
Light medium	12.3	12.9	12.9	13.8	15.3	14.1	17.2
Medium	7.8	8.1	8.2	8.4	10.1	8.5	11.3
Heavy	6.0	6.3	6.4	6.7	7.7	6.8	8.6
Total freight truck fuel efficiency	**6.9**	**7.3**	**7.4**	**7.8**	**9.0**	**8.0**	**10.2**
Freight truck fuel consumption (quadrillion Btu)							
Light medium	0.54	0.55	0.55	0.63	0.56	0.75	0.62
Medium	0.82	0.90	0.88	1.21	1.00	1.46	1.08
Heavy	4.20	4.31	4.24	4.32	3.74	4.78	3.77
Total freight truck fuel consumption	**5.57**	**5.76**	**5.67**	**6.16**	**5.30**	**6.98**	**5.46**

Table D2. Key transportation results for the Phase 2 Standards case *(continued)*

Key indicators, consumption, and emissions	2015	2020		2030		2040	
		Reference	Phase 2 Standards	Reference	Phase 2 Standards	Reference	Phase 2 Standards
Fuel consumption (quadrillion Btu)							
Transportation sector	**28.13**	**28.29**	**28.21**	**26.28**	**25.43**	**26.63**	**25.08**
Propane	0.01	0.01	0.01	0.01	0.01	0.02	0.02
Motor gasoline	17.01	16.79	16.79	13.62	13.55	12.55	12.40
of which: ethanol	1.18	1.19	1.19	1.12	1.12	1.24	1.23
Jet fuel[1]	2.84	2.99	2.99	3.32	3.32	3.56	3.56
Distillate fuel oil[2]	6.67	6.99	6.91	7.49	6.73	8.01	6.92
Other petroleum[3]	0.60	0.53	0.53	0.58	0.58	0.62	0.62
Petroleum and other liquids subtotal	27.14	27.32	27.24	25.01	24.18	24.75	23.52
Pipeline fuel natural gas	0.89	0.83	0.83	0.94	0.94	1.07	1.03
Compressed / liquefied natural gas	0.07	0.08	0.08	0.17	0.15	0.59	0.31
Liquid hydrogen	0.00	0.01	0.01	0.04	0.04	0.06	0.06
Electricity	0.03	0.05	0.05	0.11	0.11	0.15	0.15
Total energy consumption	**96.7**	**100.5**	**100.5**	**101.5**	**100.5**	**107.1**	**105.2**
Petroleum and other liquids	36.5	37.8	37.8	36.6	35.6	37.5	36.0
Natural gas	28.3	28.3	28.2	32.5	32.4	35.4	34.9
Coal	15.5	15.6	15.8	11.3	11.4	10.7	10.8
Nuclear / uranium[4]	8.3	8.1	8.1	8.2	8.2	8.2	8.2
Renewable energy[5]	7.7	10.2	10.1	12.4	12.4	14.8	14.8
Other[6]	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Carbon dioxide emissions (million metric tons)							
Transportation sector	**1,851**	**1,851**	**1,845**	**1,714**	**1,655**	**1,721**	**1,618**
Petroleum[7]	1,800	1,802	1,796	1,652	1,594	1,628	1,542
Natural gas[8]	51	49	49	62	61	93	76
Total carbon dioxide emissions	**5,273**	**5,289**	**5,295**	**4,961**	**4,894**	**5,044**	**4,929**
Petroleum[7]	2,309	2,332	2,325	2,191	2,127	2,181	2,085
Natural gas	1,482	1,466	1,463	1,685	1,677	1,835	1,809
Coal	1,476	1,485	1,501	1,079	1,083	1,021	1,028
Other[9]	6	6	6	6	6	6	6

[1]Includes only kerosene type.
[2]Diesel fuel for on- and off- road use.
[3]Includes residual fuel oil, aviation gasoline and lubricants.
[4]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[5]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, solar photovoltaic, and solar thermal sources, and all biomass input to liquid fuel conversion processes net of the liquid fuel produced. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[6]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[7]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2015, international bunker fuels accounted for 90 to 126 million metric tons annually.
[8]Includes emissions from pipeline fuel natural gas and from natural gas used as fuel in motor vehicles, trains, and ships.
[9]Includes emissions from geothermal power and non-biogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Source: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs ref2016.d032416a, and phaseii.d041316a.

Table D3. Key results for extended policies case

Consumption, emissions, electricity generating capacity and generation, and prices	2015	2020		2030		2040	
		Reference	Extended Policies	Reference	Extended Policies	Reference	Extended Policies
Energy consumption (quadrillion Btu)							
Residential							
Liquid fuels and other petroleum[1]	0.93	0.86	0.86	0.72	0.70	0.61	0.59
Natural gas	4.77	4.87	4.85	4.80	4.63	4.73	4.43
Renewable energy[2]	0.44	0.42	0.41	0.39	0.39	0.37	0.36
Electricity	4.78	4.76	4.73	4.83	4.45	5.20	4.60
Total residential	**10.92**	**10.90**	**10.86**	**10.74**	**10.17**	**10.91**	**9.98**
Commercial							
Liquid fuels and other petroleum[3]	0.66	0.70	0.70	0.68	0.68	0.67	0.67
Natural gas	3.32	3.45	3.44	3.53	3.56	3.81	3.79
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[4]	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Electricity	4.64	4.69	4.68	5.09	4.98	5.62	5.42
Total commercial	**8.81**	**9.03**	**9.01**	**9.49**	**9.41**	**10.28**	**10.07**
Industrial[5]							
Liquid fuels and other petroleum[6]	8.07	9.40	9.37	10.55	10.42	11.82	11.42
Natural gas	9.38	10.57	10.57	11.72	11.90	12.89	13.06
Coal	1.34	1.23	1.21	1.35	1.36	1.34	1.33
Renewable energy[7]	2.26	2.30	2.30	2.47	2.48	2.63	2.60
Electricity	3.27	3.61	3.60	3.98	3.99	4.26	4.22
Total industrial	**24.33**	**27.11**	**27.04**	**30.07**	**30.15**	**32.94**	**32.63**
Transportation							
Liquid fuels and other petroleum[8]	27.14	27.32	27.23	25.01	24.04	24.75	22.56
Pipeline fuel natural gas	0.89	0.83	0.84	0.94	0.91	1.07	1.01
Compressed / liquefied natural gas	0.07	0.08	0.08	0.17	0.14	0.59	0.32
Liquid hydrogen	0.00	0.01	0.01	0.04	0.04	0.06	0.06
Electricity	0.03	0.05	0.05	0.11	0.12	0.15	0.22
Total transportation	**28.13**	**28.29**	**28.20**	**26.28**	**25.26**	**26.63**	**24.16**
Unspecified sector[9]	**-0.58**	**-0.58**	**-0.58**	**-0.46**	**-0.42**	**-0.42**	**-0.34**
Electric power[10]							
Distillate and residual fuel oil	0.26	0.15	0.15	0.11	0.11	0.09	0.08
Natural gas	9.89	8.50	8.86	11.34	9.77	12.31	10.75
Steam coal	14.08	14.34	14.27	9.92	10.62	9.36	7.88
Nuclear / uranium[11]	8.34	8.12	8.12	8.25	8.25	8.25	8.25
Renewable energy[12]	4.86	7.37	6.82	9.41	9.78	11.67	13.32
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.19	0.19	0.20	0.17	0.17	0.15	0.15
Total electric power	**37.85**	**38.90**	**38.64**	**39.42**	**38.92**	**42.04**	**40.64**
Total energy consumption							
Liquid fuels and other petroleum	36.49	37.85	37.73	36.62	35.54	37.52	34.97
Natural gas	28.31	28.30	28.64	32.51	30.91	35.39	33.35
Steam coal	15.48	15.62	15.54	11.32	12.03	10.75	9.26
Nuclear / uranium[11]	8.34	8.12	8.12	8.25	8.25	8.25	8.25
Renewable energy[13]	7.71	10.22	9.67	12.41	12.78	14.80	16.42
Other[14]	0.42	0.43	0.43	0.44	0.44	0.43	0.43
Total energy consumption	**96.74**	**100.55**	**100.13**	**101.54**	**99.95**	**107.15**	**102.67**
Carbon dioxide emissions (million metric tons)							
by sector							
Residential	317	317	316	303	293	292	275
Commercial	228	238	238	241	242	254	253
Industrial[5]	986	1,054	1,052	1,144	1,145	1,226	1,210
Transportation	1,851	1,851	1,845	1,714	1,643	1,721	1,557
Electric power[10]	1,891	1,829	1,841	1,559	1,542	1,551	1,327
by fuel							
Petroleum[15]	2,309	2,332	2,325	2,191	2,115	2,181	2,011
Natural gas	1,482	1,466	1,484	1,685	1,599	1,835	1,725
Coal	1,476	1,485	1,477	1,079	1,146	1,021	879
Other[16]	6	6	6	6	6	6	6
Total carbon dioxide emissions	**5,273**	**5,289**	**5,292**	**4,961**	**4,867**	**5,044**	**4,623**

Table D3. Key results for extended policies case *(continued)*

Consumption, emissions, electricity generating capacity and generation, and prices	2015	2020		2030		2040	
		Reference	Extended Policies	Reference	Extended Policies	Reference	Extended Policies
Electricity generating capacity (gigawatts)	**1,082.1**	**1,114.2**	**1,093.9**	**1,188.1**	**1,207.0**	**1,374.1**	**1,410.3**
Electric power sector[10]	1,040.8	1,053.0	1,029.1	1,094.2	1,069.4	1,239.6	1,188.6
Coal	281.4	211.7	206.0	180.3	183.2	172.8	166.6
Oil and natural gas steam	91.4	90.3	91.9	54.5	47.7	52.8	39.2
Combined-cycle	227.3	247.5	246.4	294.5	260.0	345.4	280.1
Combustion turbine / diesel	141.2	142.9	141.8	137.0	127.5	144.6	121.5
Nuclear / uranium	99.8	99.1	99.1	99.1	99.1	99.1	99.1
Pumped storage	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Renewable sources	177.1	238.7	221.1	305.2	328.8	399.4	458.2
of which: Solar	13.8	28.0	31.2	70.1	101.3	158.1	181.1
of which: Wind	74.4	120.4	99.9	142.0	134.5	145.8	181.2
Distributed generation	0.0	0.2	0.2	1.0	0.4	2.9	1.2
Residential and commercial sectors	15.2	33.8	37.1	62.0	104.0	98.2	182.6
of which: Natural gas	1.8	2.2	2.5	3.6	4.1	6.0	6.8
of which: Solar photovoltaic	11.2	28.7	28.8	55.1	84.9	88.3	149.5
of which: Wind	1.6	2.3	5.1	2.6	14.3	3.2	25.7
Industrial sector[5]	26.1	27.3	27.8	31.8	33.6	36.3	39.1
of which: Natural gas	14.7	15.2	15.7	19.2	20.9	23.5	26.2
Cumulative capacity additions (gigawatts)[17]	- -	122.1	108.3	281.1	311.7	482.9	557.7
Cumulative capacity retirements (gigawatts)[17]	- -	90.1	96.6	175.2	186.9	191.0	229.5
Generation by fuel (billion kilowatthours)	**4,090**	**4,244**	**4,234**	**4,590**	**4,511**	**5,060**	**4,943**
Electric power sector[10]	3,915	4,021	4,003	4,294	4,144	4,673	4,418
Coal	1,343	1,376	1,371	959	1,027	905	764
Petroleum	24	14	14	10	10	8	7
Natural gas	1,250	1,090	1,137	1,558	1,304	1,757	1,474
Nuclear / uranium	798	777	777	789	789	789	789
Pumped storage / other	3	3	3	3	3	3	3
Renewable sources	497	761	700	973	1,011	1,210	1,381
of which: Solar	22	52	59	148	213	350	400
of which: Wind	188	365	296	453	428	468	587
Distributed generation	0	0	0	1	0	2	1
Residential and commercial sectors	35	64	70	113	175	180	303
of which: Natural gas	13	16	18	27	30	44	49
of which: Solar photovoltaic	15	40	40	79	121	127	215
of which: Wind	2	3	7	3	19	4	34
Industrial sector[5]	140	159	161	183	192	207	222
of which: Natural gas	86	96	98	116	125	139	154
Delivered natural gas prices (2015 dollars per thousand cubic feet)							
Residential	10.40	11.08	11.37	12.41	12.12	12.74	12.75
Commercial	7.92	9.58	9.86	10.72	10.28	10.73	10.47
Industrial[5]	3.84	5.53	5.81	6.14	5.71	5.89	5.64
Electric power[10]	3.35	4.83	5.10	5.74	5.23	5.52	5.23
Average electricity price (2015 cents per kilowatthour)	10.3	10.5	10.6	10.9	10.8	10.5	10.4

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[3]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[5]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes motor gasoline (including ethanol and ethers), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[8]Includes propane, motor gasoline, ethanol and ethers, jet fuel, distillate fuel oil, residual fuel oil, aviation gasoline, and lubricants.
[9]Represents consumption unattributed to the sectors above.
[10]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[11]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[12]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources.
[13]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[15]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[16]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
[17]Cumulative after December 31, 2015.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Source: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections**: EIA, AEO2016 National Energy Modeling System, runs ref2016.d032416a, and extended.d051216a.

Table D4. Natural gas supply and disposition, oil and gas resource and technology cases
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2015	2020			2030			2040		
		Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology
Henry Hub spot price										
(2015 dollars per million Btu)	2.62	6.27	4.43	2.89	7.61	5.06	3.50	9.17	4.86	2.43
(nominal dollars per million Btu)	2.62	6.97	4.90	3.18	10.60	6.84	4.64	16.15	8.17	3.95
Dry gas production[1]	**27.19**	**27.35**	**30.50**	**34.19**	**25.50**	**37.76**	**47.14**	**26.68**	**42.12**	**55.53**
Lower 48 onshore	25.20	25.82	28.82	32.41	24.29	36.15	45.44	24.30	40.18	53.35
Tight gas	5.00	4.81	4.92	5.11	4.37	6.08	7.02	4.50	6.55	8.00
Shale gas and tight oil plays[2]	13.64	14.91	17.96	21.57	14.84	25.16	33.66	15.03	29.00	41.02
Coalbed methane	1.24	1.18	1.04	0.96	1.10	0.94	0.82	0.97	0.78	0.63
Other	5.32	4.92	4.90	4.78	3.98	3.97	3.95	3.80	3.85	3.70
Lower 48 offshore	1.70	1.23	1.39	1.48	0.93	1.33	1.39	1.15	1.67	1.84
Alaska	0.29	0.29	0.29	0.29	0.28	0.28	0.31	1.23	0.28	0.34
Supplemental natural gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**0.95**	**-2.37**	**-2.89**	**-3.22**	**-1.59**	**-6.02**	**-10.21**	**-1.90**	**-7.55**	**-13.00**
Pipeline[4]	0.89	-0.14	-0.48	-0.80	0.25	-0.97	-2.02	1.62	-0.89	-2.81
Liquefied natural gas	0.06	-2.22	-2.42	-2.42	-1.84	-5.06	-8.19	-3.52	-6.66	-10.19
Total supply	**28.20**	**25.04**	**27.67**	**31.03**	**23.98**	**31.80**	**36.99**	**24.84**	**34.63**	**42.59**
Consumption by sector										
Residential	4.62	4.62	4.71	4.80	4.44	4.65	4.79	4.30	4.58	4.76
Commercial	3.22	3.20	3.34	3.47	3.14	3.42	3.65	3.23	3.69	4.02
Industrial[5]	7.51	8.14	8.29	8.33	8.62	8.85	9.12	9.26	9.58	9.89
Electric power[6]	9.61	6.29	8.26	11.10	5.12	11.02	14.60	4.76	11.96	17.94
Transportation[7]	0.06	0.09	0.09	0.09	0.16	0.22	0.23	0.47	0.66	0.52
Pipeline fuel	0.86	0.75	0.81	0.90	0.68	0.91	1.10	0.74	1.04	1.28
Lease and plant fuel[8]	1.58	1.57	1.71	1.88	1.46	2.00	2.47	1.51	2.24	2.94
Liquefaction for export[9]	0.00	0.23	0.25	0.25	0.19	0.51	0.83	0.36	0.67	1.03
Total	**27.47**	**24.89**	**27.46**	**30.83**	**23.81**	**31.59**	**36.78**	**24.64**	**34.42**	**42.38**
Discrepancy[10]	0.73	0.16	0.21	0.21	0.17	0.21	0.21	0.20	0.21	0.21

[1]Marketed production (wet) minus extraction losses.
[2]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Natural gas imported from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[7]Natural gas used as fuel in motor vehicles, trains, and ships.
[8]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[9]Fuel used in facilities that liquefy natural gas for export.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2015 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowresource.d032516a, ref2016.d032416a, and highresource.d032516a.

Table D5. Liquid fuels supply and disposition, oil and gas resource and technology cases
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2015	2020			2030			2040		
		Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology
Crude oil prices										
(2015 dollars per barrel)										
Brent spot	52	79	77	71	112	104	85	152	136	110
West Texas Intermediate spot	49	74	71	65	106	97	77	147	129	99
Imported crude oil[1]	46	71	69	63	101	95	76	139	126	95
Crude oil supply										
Domestic production[2]	9.42	8.08	9.38	11.25	7.55	10.06	13.89	7.02	11.26	17.68
Alaska	0.48	0.41	0.41	0.41	0.24	0.24	0.44	0.15	0.15	0.67
Lower 48 States	8.94	7.66	8.96	10.83	7.31	9.82	13.46	6.87	11.11	17.01
Net imports	6.88	7.19	6.97	6.48	6.92	6.57	4.15	6.81	6.10	-0.02
Gross imports	7.28	7.82	7.60	7.11	7.56	7.20	6.02	7.68	7.12	6.17
Exports	0.40	0.63	0.63	0.63	0.63	0.63	1.87	0.86	1.02	6.18
Other crude oil supply[3]	-0.11	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**16.19**	**15.28**	**16.36**	**17.74**	**14.47**	**16.63**	**18.04**	**13.83**	**17.36**	**17.67**
Net product imports	-2.24	-1.61	-3.26	-5.25	-0.71	-4.32	-6.26	0.54	-4.66	-5.59
Gross refined product imports[4]	0.66	1.18	1.11	1.07	1.46	1.30	1.11	1.96	1.63	1.27
Unfinished oil imports	0.55	0.53	0.53	0.54	0.46	0.46	0.46	0.39	0.39	0.39
Blending component imports	0.67	0.58	0.58	0.61	0.44	0.45	0.44	0.29	0.30	0.28
Exports	4.12	3.91	5.48	7.46	3.07	6.52	8.27	2.11	6.98	7.52
Refinery processing gain[5]	1.03	1.05	1.05	1.11	0.94	0.98	0.99	0.93	0.99	0.91
Natural gas plant liquids	3.25	4.01	4.57	5.09	3.45	4.90	5.72	3.21	4.99	6.24
Supply from renewable sources	1.01	1.08	1.08	1.08	1.03	1.03	1.02	1.12	1.12	1.10
Ethanol	0.89	0.89	0.89	0.89	0.84	0.84	0.84	0.92	0.93	0.91
Domestic production	0.94	0.89	0.90	0.90	0.87	0.87	0.87	0.89	0.91	0.92
Net imports	-0.05	0.00	-0.01	-0.01	-0.03	-0.03	-0.04	0.04	0.02	-0.01
Biodiesel	0.11	0.15	0.15	0.15	0.12	0.10	0.05	0.12	0.10	0.05
Domestic production	0.08	0.12	0.11	0.11	0.08	0.06	0.01	0.08	0.06	0.01
Net imports	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Other biomass-derived liquids[6]	0.00	0.04	0.04	0.04	0.08	0.09	0.14	0.08	0.09	0.14
Other[7]	0.21	0.28	0.28	0.27	0.29	0.30	0.29	0.30	0.32	0.30
Total primary supply[8]	**19.46**	**20.08**	**20.08**	**20.03**	**19.46**	**19.52**	**19.80**	**19.93**	**20.12**	**20.63**
Net import share of product supplied	23.7	28.0	18.6	6.2	32.0	11.6	-10.7	37.3	7.4	-27.0
Net expenditures for imports of crude oil & petroleum products (billion 2015 dollars)	128	220	207	179	300	268	182	412	348	231
Refined petroleum product prices to the transportation sector										
(2015 dollars per gallon)										
Propane	1.64	1.97	1.94	1.88	2.20	2.14	2.04	2.54	2.43	2.32
Ethanol (E85)[9]	2.21	3.09	3.05	2.96	3.02	2.93	2.71	3.45	3.33	3.01
Ethanol wholesale price	2.22	2.80	2.77	2.72	2.33	2.28	2.28	2.64	2.60	2.48
Motor gasoline[10]	2.52	2.81	2.74	2.64	3.37	3.19	2.78	4.10	3.81	3.13
Jet fuel[11]	1.62	2.26	2.18	2.05	3.08	2.87	2.44	4.09	3.74	2.91
Distillate fuel oil[12]	2.72	3.24	3.18	3.05	4.03	3.85	3.42	5.01	4.68	3.87
Residual fuel oil	1.21	1.77	1.75	1.64	2.40	2.25	1.80	3.13	2.87	2.14

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply, net product imports, refinery processing gain, natural gas plant liquids, supply from renewable sources, and other supply..
[9]E85 refers to a blend of 85 pecent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowresource.d032516a, ref2016.d032416a, and highresource.d032516a.

Table D6. Key transportation results, oil and gas resource and technology cases

Key indicators and consumption	2015	2020			2030			2040		
		Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology	Low Oil and Gas Resource and Technology	Reference	High Oil and Gas Resource and Technology
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 lbs	2,752	3,019	3,031	3,043	3,191	3,232	3,332	3,364	3,438	3,656
Commercial light trucks[1]	96	110	110	109	124	125	127	140	143	146
Freight trucks greater than 10,000 lbs	280	303	304	304	343	349	356	395	407	417
(billion seat miles available)										
Air	1,070	1,166	1,168	1,170	1,360	1,364	1,373	1,529	1,531	1,536
(billion ton miles traveled)										
Rail	1,690	1,805	1,810	1,811	1,983	2,006	2,037	2,085	2,128	2,171
Domestic shipping	482	448	453	455	387	404	420	378	407	431
Energy efficiency indicators (miles per gallon)										
Tested new light-duty vehicle[2]	30.9	37.0	36.9	36.8	47.5	47.2	46.7	48.1	47.8	47.1
New car[2]	35.9	44.2	44.2	44.2	55.2	55.1	54.9	55.3	55.1	54.9
New light truck[2]	27.0	31.8	31.7	31.7	40.5	40.4	40.3	40.5	40.4	40.4
On-road new light-duty vehicle[3]	25.0	29.9	29.8	29.7	38.4	38.2	37.7	38.9	38.6	38.0
New car[3]	29.3	36.1	36.1	36.1	45.1	45.0	44.9	45.1	45.0	44.8
New light truck[3]	21.6	25.4	25.4	25.4	32.4	32.3	32.3	32.4	32.3	32.3
Light-duty stock[4]	21.7	24.1	24.1	24.1	31.5	31.5	31.4	36.5	36.3	36.0
New commercial light truck[1]	17.3	19.6	19.5	19.5	24.0	24.0	23.9	24.1	24.0	24.0
Stock commercial light truck[1]	15.0	16.6	16.6	16.6	20.8	20.8	20.9	23.2	23.2	23.2
Freight truck	6.9	7.3	7.3	7.3	7.8	7.8	7.8	8.0	8.0	7.9
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.86	15.66	15.73	15.80	12.63	12.82	13.26	11.52	11.83	12.71
Commercial light trucks[1]	0.80	0.82	0.82	0.82	0.74	0.75	0.76	0.76	0.77	0.79
Bus transportation	0.26	0.27	0.27	0.27	0.29	0.29	0.29	0.31	0.31	0.31
Freight trucks	5.57	5.74	5.76	5.75	6.06	6.16	6.30	6.77	6.98	7.20
Rail, passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Rail, freight	0.48	0.50	0.50	0.50	0.51	0.51	0.52	0.50	0.51	0.52
Shipping, domestic and international	0.83	0.73	0.73	0.73	0.74	0.77	0.84	0.77	0.82	0.89
Air	2.37	2.51	2.52	2.52	2.81	2.82	2.84	2.99	3.00	3.01
Other uses[4]	1.03	1.06	1.06	1.06	1.11	1.12	1.12	1.22	1.22	1.24
Pipeline fuel	0.89	0.77	0.83	0.93	0.71	0.94	1.13	0.76	1.07	1.32
Total	**28.14**	**28.12**	**28.28**	**28.44**	**25.66**	**26.24**	**27.12**	**25.65**	**26.57**	**28.04**
Energy use by fuel (quadrillion Btu)										
Propane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Motor gasoline[5]	17.01	16.72	16.79	16.85	13.41	13.62	14.07	12.20	12.55	13.44
of which: E85[6]	0.05	0.04	0.04	0.03	0.24	0.22	0.16	0.32	0.28	0.20
Jet fuel[7]	2.84	2.99	2.99	3.00	3.31	3.32	3.34	3.55	3.56	3.57
Distillate fuel oil[8]	6.67	6.97	6.99	6.99	7.44	7.49	7.65	7.97	8.01	8.41
Residual fuel oil	0.45	0.37	0.37	0.37	0.39	0.42	0.47	0.42	0.45	0.52
Other petroleum[9]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Liquid fuels and other petroleum	27.14	27.22	27.32	27.38	24.73	25.01	25.70	24.32	24.75	26.13
Pipeline fuel natural gas	0.89	0.77	0.83	0.93	0.71	0.94	1.13	0.76	1.07	1.32
Compressed/liquefied natural gas	0.07	0.08	0.08	0.09	0.10	0.17	0.18	0.40	0.59	0.44
Liquid hydrogen	0.00	0.01	0.01	0.01	0.04	0.04	0.04	0.06	0.06	0.06
Electricity	0.03	0.05	0.05	0.05	0.11	0.11	0.11	0.15	0.15	0.16
Delivered energy use	**28.13**	**28.13**	**28.29**	**28.45**	**25.69**	**26.28**	**27.17**	**25.70**	**26.63**	**28.12**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Tested new vehicle efficiency revised for on-road performance.
[3]Combined "on-the-road" estimate for all cars and light trucks.
[4]Includes recreational boats, military use, and lubricants.
[5]Includes ethanol and ethers blended into gasoline.
[6]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Lbs = Pounds.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Source: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System runs lowresource.d032516a, ref2016.d032416a, and highresource.d032516a.

Table D7. Key results for industrial energy efficiency cases
(quadrillion Btu per year, unless otherwise noted)

Consumption and emissions	2015	2025				2040			
		Reference	Energy Efficiency	Low Incentive	High Incentive	Reference	Energy Efficiency	Low Incentive	High Incentive
Energy consumption									
Industrial[1]									
Cement and lime									
Petroleum and other liquids	0.04	0.09	0.10	0.09	0.09	0.14	0.13	0.14	0.14
Natural gas	0.01	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Coal	0.14	0.17	0.15	0.17	0.17	0.19	0.16	0.19	0.19
Renewable energy[2]	0.09	0.13	0.12	0.13	0.13	0.16	0.14	0.16	0.16
Electricity	0.05	0.06	0.05	0.06	0.06	0.07	0.06	0.07	0.07
Total cement and lime	**0.33**	**0.47**	**0.43**	**0.47**	**0.45**	**0.58**	**0.51**	**0.57**	**0.57**
Aluminum									
Petroleum and other liquids	0.03	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.03
Natural gas	0.11	0.13	0.11	0.14	0.15	0.13	0.11	0.14	0.14
Electricity	0.20	0.23	0.20	0.23	0.22	0.21	0.19	0.21	0.20
Total aluminum	**0.34**	**0.42**	**0.38**	**0.42**	**0.42**	**0.40**	**0.36**	**0.40**	**0.37**
Glass									
Petroleum and other liquids	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Natural gas	0.17	0.19	0.19	0.19	0.18	0.19	0.16	0.17	0.16
Electricity	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Total glass	**0.24**	**0.27**	**0.26**	**0.27**	**0.26**	**0.27**	**0.24**	**0.25**	**0.23**
Iron and steel									
Petroleum and other liquids	0.07	0.10	0.09	0.09	0.08	0.13	0.13	0.13	0.14
Natural gas	0.40	0.43	0.37	0.42	0.39	0.45	0.40	0.48	0.49
Coal	0.56	0.50	0.47	0.45	0.33	0.47	0.44	0.43	0.41
Electricity	0.18	0.23	0.23	0.23	0.20	0.29	0.29	0.30	0.30
Total iron and steel	**1.21**	**1.26**	**1.17**	**1.20**	**1.00**	**1.34**	**1.25**	**1.34**	**1.34**
Paper									
Petroleum and other liquids	0.03	0.04	0.03	0.04	0.03	0.04	0.03	0.04	0.04
Natural gas	0.39	0.37	0.30	0.37	0.36	0.37	0.30	0.38	0.37
Coal	0.20	0.21	0.18	0.21	0.20	0.24	0.21	0.25	0.24
Renewable energy[2]	0.99	0.99	0.99	0.98	0.96	1.07	1.08	1.08	1.07
Electricity	0.20	0.18	0.14	0.17	0.16	0.15	0.13	0.14	0.13
Total paper	**1.81**	**1.79**	**1.64**	**1.77**	**1.71**	**1.87**	**1.75**	**1.88**	**1.84**
Other industries									
Petroleum and other liquids	7.86	9.87	9.86	9.73	9.38	11.42	11.41	11.10	10.77
Natural gas	8.30	10.20	10.22	10.14	9.85	11.73	11.75	11.57	11.40
Coal	0.44	0.43	0.43	0.43	0.42	0.45	0.45	0.44	0.44
Renewable energy[2]	1.18	1.27	1.27	1.26	1.25	1.39	1.39	1.37	1.37
Electricity	2.62	3.17	3.17	3.11	2.97	3.51	3.50	3.40	3.28
Total other industries	**20.40**	**24.94**	**24.95**	**24.67**	**23.87**	**28.49**	**28.50**	**27.89**	**27.27**
Total industrial sector									
Petroleum and other liquids	8.07	10.19	10.19	10.05	9.68	11.82	11.80	11.51	11.16
Natural gas	9.38	11.34	11.21	11.28	10.94	12.89	12.74	12.75	12.58
Coal	1.34	1.31	1.23	1.26	1.12	1.34	1.26	1.31	1.28
Renewable energy[2]	2.26	2.39	2.38	2.38	2.33	2.63	2.61	2.62	2.60
Electricity	3.27	3.91	3.83	3.83	3.65	4.26	4.21	4.15	4.01
Total industrial sector	**24.33**	**29.14**	**28.83**	**28.80**	**27.71**	**32.94**	**32.62**	**32.34**	**31.63**
Total delivered energy consumption									
Petroleum and other liquids	36.23	37.18	37.19	36.84	35.99	37.44	37.42	36.67	35.70
Natural gas	18.43	20.61	20.48	20.47	19.91	23.09	22.95	22.77	22.26
Coal	1.40	1.36	1.28	1.31	1.17	1.39	1.31	1.36	1.34
Renewable energy[3]	2.84	2.94	2.92	2.93	2.90	3.13	3.11	3.13	3.13
Electricity	12.72	13.60	13.53	13.37	12.95	15.23	15.19	14.82	14.38
Total	**71.62**	**75.73**	**75.44**	**74.94**	**72.95**	**80.34**	**80.04**	**78.81**	**76.87**
Electricity related losses	25.12	25.83	25.70	24.94	22.61	26.81	26.80	25.08	24.92
Total energy consumption	**96.74**	**101.56**	**101.14**	**99.89**	**95.56**	**107.15**	**106.84**	**103.88**	**101.79**

Table D7. Key results for industrial energy efficiency cases *(continued)*
(quadrillion Btu per year, unless otherwise noted)

Consumption and emissions	2015	2025				2040			
		Reference	Energy Efficiency	Low Incentive	High Incentive	Reference	Energy Efficiency	Low Incentive	High Incentive
Carbon dioxide emissions[4] (million metric tons)									
Residential	1,028	895	895	817	617	821	825	642	477
Commercial	918	836	837	756	550	826	830	632	450
Industrial[1]	1,472	1,600	1,575	1,523	1,316	1,660	1,637	1,498	1,341
Cement and lime	24	32	30	31	28	38	33	35	34
Aluminum	40	42	38	40	30	35	32	29	19
Glass	16	17	17	17	15	17	15	15	12
Iron and steel	108	106	101	98	72	107	101	97	88
Paper	72	65	53	62	52	60	52	56	51
Other industries	1,212	1,337	1,337	1,276	1,120	1,403	1,404	1,266	1,138
Transportation	1,855	1,784	1,785	1,770	1,735	1,737	1,737	1,703	1,657
Total carbon dioxide emissions	**5,273**	**5,115**	**5,092**	**4,865**	**4,217**	**5,044**	**5,029**	**4,475**	**3,925**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[3]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[4]Emissions from the electric power sector are distributed to the end-use sectors.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Source: 2015: U.S. Energy Information Administration, (EIA), *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a. **Projections:** EIA, AEO2016 National Energy Modeling System, runs ref2016.d032416a, efficienttech.d032516a, lowinnovate.d032516a, and highinnovate.D032516a.

Appendix E
NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2016* (AEO2016) 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, 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.

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 2015 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 emissions, as well as emissions of sulfur dioxide, nitrogen oxides, and mercury from the electricity generation sector.

The version of NEMS used for AEO2016 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of February 29, 2016, as discussed in the AEO2016 Legislation and Regulations section. 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 AEO2016 or in other analysis completed by EIA.

In general, the historical data presented with AEO2016 projections are based on various EIA publications [*2*]; however, data also were taken from multiple non-EIA sources. Historical numbers through the year 2015 are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to AEO2016 appendix tables indicate the definitions and sources of historical data.

Where possible, AEO2016, which was developed during the winter of 2015–16, presents information for 2015, 2016, and 2017 that is consistent with the short-term projections from EIA's February 2016 Short-Term Energy Outlook (STEO) [*3*]. EIA's views regarding energy use over the 2016 through 2017 period are reported in monthly STEO updates, which should be considered to supersede information reported for those years in AEO2016.

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, 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 growth rates in 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 about 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. The IEM module provides a supply curve for world crude-like liquids 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 about 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 prices in response to changes in expected production and consumption of crude-like liquids and petroleum products 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 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.

The investment tax credit (ITC) for renewable fuels, fuel cells, and combined heat and power systems is incorporated, as currently enacted, including a phaseout of the credit for solar energy technologies, followed by a permanent 10% ITC for business investment in solar energy (thermal nonpower uses as well as power uses). The module reflects the recently extended deadline and change in eligibility for the 30% ITC for eligible projects under construction before January 1, 2020. The module additionally captures the ITC phaseout—decreasing the credit for solar projects starting construction in 2020 and 2021 to 26% and 22%, respectively. Commercial projects under construction after 2021 receive a credit equivalent to 10% of capital costs. Tax credits for solar systems purchased by individual homeowners are phased out completely by 2022.

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 the Macroeconomic Activity Module, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, nonenergy-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 as described below, but the projected consumption is reported under the industrial totals.

There are several AEO2016 updates and upgrades in the representations of selected industries, including upgraded representations for the iron and steel and paper industries. 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 iron and steel and paper industries to be modeled endogenously, using a more detailed representation of technology choices. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. To model technology choices more accurately, the paper industry shipments have been broken out into pulp and paper mills, paperboard containers, and other paper. For iron and steel and for paper, steam use is modeled in the process/assembly step. All manufacturing industries except cement and lime, aluminum, and glass are benchmarked to the Manufacturing Energy Consumption Survey 2010. The combined cement and lime industries, aluminum industry, and glass industry were upgraded to technology choice models in previous editions of the *Annual Energy Outlook*.

Transportation Demand Module

The Transportation Demand Module projects consumption of energy by mode and fuel—including petroleum products, electricity, methanol, ethanol, compressed natural gas, liquefied natural gas, and hydrogen—in the transportation sector, subject to delivered energy prices, macroeconomic variables such as gross domestic product, 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, and the American Recovery and Reinvestment Act of 2009—which contain tax credits for the purchase of alternatively fueled vehicles. Representations of corporate average fuel economy and greenhouse gas (GHG) emissions standards for LDVs, 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 and the California Air Resources Board Zero Emissions Vehicle Program.

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 also 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. Legislation such as the International Convention for the Prevention of Pollution from Ships is also included.

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 interregional trading and costs of electricity generation. The finance and pricing submodule uses capital costs, fuel and operating costs, macroeconomic parameters, environmental regulations, and load shapes to estimate retail prices by sector for generation, transmission, and distribution services.

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 carbon dioxide (CO2) that affect the electricity generation sector, and those regulations are represented in AEO2016. The AEO2016 Reference case also imposes a limit on CO2 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 AEO2016 Reference case includes the Cross-State Air Pollution Rule (CSAPR), using the original emissions budgets and revised implementation schedule, after the rule was reinstated in late 2014. CSAPR is intended to reduce emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) from power plants in the eastern half of the United States by imposing state-level caps on emissions and facilitating a limited interstate cap-and-trade program. 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 in December 2011.

In August 2015, EPA released final rules under the Clean Air Act Sections 111(b) and 111(d) setting carbon pollution standards for new, modified, and reconstructed power plants and for existing fossil-fired plants. The requirements for new power plants are represented in the Reference case by allowing new technologies to be built only if they can meet the standards of 1,000 pounds CO2 per megawatthour (MWh) for natural gas combined cycle plants, and 1,400 pounds CO2/MWh for coal-fired plants, based on adjusted gross generation. EPA's Clean Power Plan (CPP) establishes emissions standards for existing power plants and provides many alternative ways for states to demonstrate compliance, as discussed in the AEO2016 Legislation and Regulations section. The Reference case assumes that the CPP is met through regional mass-based goals, implemented at the 22 EMM region level. The Supreme Court has stayed enforcement of the CPP pending resolution of ongoing litigation, but as of this writing no lower court has either affirmed or vacated the rule. The AEO2016 also includes a case that assumes no CPP rule is in force.

Because regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive, there is considerable financial risk associated with major investments in long-lived power plants with relatively higher rates of carbon dioxide emissions. The trend is captured in the AEO2016 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. Although any new coal-fired plants are assumed to be compliant with CAA 111(b), they would capture only 30% of CO2 emissions; thus, they still would be considered high emitters relative to other sources and would face potential financial risk.

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, and both onshore and offshore wind energy. The RFM includes renewable resource supply estimates representing the regional opportunities for renewable energy development.

The ITC for renewable fuels, as currently enacted, is incorporated in the RFM and reflect the recently extended deadline and change in eligibility for the 30% ITC for qualified projects under construction before January 1, 2020. The module additionally captures the ITC phaseout—decreasing to 26% and then 22%—for projects starting construction in 2020 and 2021, respectively. After 2021, all solar (thermal nonpower uses as well as power uses) receive a permanent credit equivalent to 10% of capital costs, regardless of the year in which their construction commenced. Tax credits pertaining to individual homeowners and businesses are reflected separately in the Residential and Commercial Demand Modules.

The recently enacted production tax credit (PTC) for wind, geothermal, biomass-fueled (open-loop biomass is assumed to be the dominant source), landfill gas, and certain types of hydroelectric plants also are represented in the RFM. For wind projects, the tax credit retains its full value of 2.3 cents/kilowatthour (kWh) through 2016. The PTC phaseout begins in January 2017 with a step-down schedule as follows:

- Wind projects under construction after 2016, but before the end of 2017, receive a credit equal to 80% of the current PTC value.
- Wind projects under construction in 2018 receive a credit equal to 60% of the current value.
- Wind projects under construction after 2018, but before the end of 2019, receive a credit equal to 40% of the current value.

Eligibility is extended for 2 years, until January 1, 2017, with no phase-down in value for other PTC-eligible technologies. Geothermal facilities receive the full 2.3 cents/kWh, while other technologies (including open-loop biomass, certain waste energy facilities, incremental hydroelectric, marine, and tidal) receive a half-value credit of 1.2 cents/kWh. The credits are adjusted annually for inflation and are claimed during the first 10 years of a plant's operation. In addition, new geothermal facilities continue to receive a 10% ITC after the PTC expires because they were previously eligible for the 10% ITC.

While current legislation allows-PTC eligible technologies the option to claim the ITC in lieu of the PTC (subject to the same PTC phaseout schedule), EIA assigns the most economically beneficial tax credit option, based on analyst judgment. AEO2016 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 2016* [*4*].

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 CO2 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 Liquid Fuels Market Module (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 Natural Gas Transmission and Distribution Module (NGTDM) models the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas, 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 regions in the Lower 48 states. The 12 regions align with the 9 Census divisions (with 3 subdivided). Alaska is handled separately.

The flow of natural gas is determined for both a peak and an 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 liquefied natural gas imports and exports.

Liquid Fuels Market Module

The Liquid Fuels Market Module (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 [5] are reviewed and updated annually.

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

Region 1. PADD I – East Coast

Region 2. PADD II – Midwest - inland

Region 3. PADD II – Midwest - lakes

Region 4. PADD III – Gulf Coast - gulf

Region 5. PADD III – Gulf Coast - inland

Region 6. PADD IV – Rocky Mountain

Region 7. PADD V – West Coast - California

Region 8. PADD V – West Coast - other

Region 9. Maritime Canada/Caribbean.

The LFMM models the costs of producing 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, 15% by volume in states that lack explicit language capping ethanol volume or oxygen content, and up to 85% by volume 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 9 (Maritime Canada/Caribbean). Refinery product exports are represented by demand curves, also provided by the IEM. Crude exports from the United States also are represented.

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 the Energy Independence and Security Act of 2007, 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. Corn ethanol plants, which are numerous (responsible for 98% of total ethanol produced in the U.S.), 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, which are produced at ethanol refineries that ferment and distill grains other than corn and reduce greenhouse gas emissions by at least 50%, is another new technology modeled in the LFMM. The LFMM also has the capability to model production of biobutanol from a retrofitted corn ethanol facility, if economically competitive.

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

Two California-specific policies also are represented in the LFMM: the Low Carbon Fuel Standard (LCFS) and the Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32), cap-and-trade program. The LCFS requires the carbon intensity of transportation fuels sold for use in California (the amount of greenhouse gases emitted per unit of energy) 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 CO2 emissions to 1990 levels by 2020. Working with other NEMS modules (Industrial Demand Module, EMM, and Emissions Policy Module), the LFMM provides emissions allowances and actual emissions of CO2 from California refineries, and NEMS provides the mechanism (carbon price) to trade allowances such that the total CO2 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 2016 cases

Table E1 provides a summary of the cases produced as part of AEO2016. For each case, the table gives the name used in AEO2016, 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 2016*. 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 AEO2016 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 0.7%/year, and productivity by 1.7%/ year from 2015 to 2040. Economic output as measured by real GDP increases by 2.2%/year from 2015 through 2040, and growth in real disposable income per capita averages 1.7%/year.
- The Low Economic Growth case assumes lower growth rates for population (0.6%/year) and productivity (1.3%/year), resulting in lower growth in nonfarm employment (0.6%/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 1.6%/year from 2015 through 2040, and growth in real disposable income per capita averages 1.4%/year.
- The High Economic Growth case assumes higher growth rates for population (0.8%/year) and 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 (2.2%/year). Real disposable income per capita grows by 2.0%/year.

Oil price cases

The benchmark oil price in AEO2016 is based on spot prices for North Sea Brent crude oil, which is an international standard for light sweet crude oil. The West Texas Intermediate (WTI) spot price is generally lower than the North Sea Brent price. EIA expects the price spread between Brent and WTI in the Reference, Low Oil Price, and High Oil Price cases to range between $0/b and $10/b and will continue to report WTI prices—a critical reference point for the value of growing production in the U.S. Midcontinent—as well as the imported refiner acquisition cost for crude oil. The December 2015 decision by the U.S. Congress to remove restrictions on U.S. crude oil exports also has the potential to narrow the spread between the Brent price and the price of domestic production streams under certain cases involving high levels of U.S. crude oil production [6].

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. AEO2016 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 from variation in global demand and supply of petroleum and other liquid fuels. The Low Oil Price case assumes conditions under which global liquids demand is low and supply is high; the High Oil Price case assumes the opposite. Both cases illustrate situations in which the shifts in global supply and demand are offsetting, so that liquids consumption is close to Reference case levels, but prices are substantially different.

- In the Reference case, real oil prices (2015 dollars) fall from $52/b in 2015 to a low of $37/b in 2016, before rising steadily to $136/b in 2040. The Reference case represents a trend projection for both oil supply and demand. Global supply increases

Table E1. Summary of *AEO2016* cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Real gross domestic product (GDP) grows at an average annual rate of 2.2% from 2015 to 2040. Brent crude oil prices rise to about $136/barrel (b) (2015 dollars) in 2040. Complete projection tables in Appendix A.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 1.6% from 2015 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-6
High Economic Growth	Real GDP grows at an average annual rate of 2.8% from 2015 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-6
Low Oil Price	Low prices result from a combination of relatively low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand occurs as a result of several factors: economic growth that is relatively slow compared with history; reduced consumption from the adoption of more efficient technologies, extension of the corporate average fuel economy (CAFE) standards, less travel demand, and increased natural gas or electricity use; efficiency improvement in nonmanufacturing in non-OECD countries; and industrial fuel switching from liquid to natural gas feedstocks for producing methanol and ammonia. On the supply side, both Organization of the Petroleum Exporting Countries (OPEC) and non-OPEC producers face lower costs of production for both crude oil and other liquids production technologies. However, lower-cost supply from OPEC producers eventually begins to crowd out supply from relatively more expensive non-OPEC sources. OPEC's market share of liquids production rises steadily from 39% in 2015 to 43% in 2020 and 47% in 2040. Light, sweet crude oil prices fall to an average of $35/b (2015 dollars) in 2016, remain below $50/b through 2030, and stay below $75/b through 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-8
High Oil Price	High prices result from a lack of global investment in the oil sector, eventually inducing higher production from non-OPEC producers relative to the Reference case. Higher prices stimulate increased supply from resource that are more expensive to produce—such as tight oil and bitumen, as well as increased production of renewable and synthetic fuels, compared with the Reference case. Increased non-OPEC production crowds out OPEC oil, and OPEC's share of world liquids production decreases, never exceeding the 41% reached in 2012 and dropping to 34% by the end of the projection. On the demand side, higher economic growth than in the Reference case, particularly in non-OECD countries, leads to increased demand: non-OECD consumers demand greater personal mobility and consumption of goods. There are also fewer efficiency gains throughout the industrial sector, and growing fuel needs in the nonmanufacturing sector continue to be met with liquid fuels, especially in response to policy shifts that force liquids to replace coal for chemical feedstock. Crude oil prices are about $230/b (2015 dollars) in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
Extended Policies	The Extended Policies case begins with the Reference case and assumes extension of all existing tax credits (full credit values prior to phaseout are extended where phaseouts are scheduled) and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs). It also assumes an increase in capacity limitations on the investment tax credit (ITC) for combined heat and power, and extension of the program. The case includes an additional round 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 2034; and increases LDV and HDV fuel economy standards in the transportation sector. This case also includes the extension of EPA's Clean Power Plan regulations that reduce carbon dioxide emissions from electric power generation after 2030. Partial projection tables in Appendix D.	p. IF-22	p. E-9

Table E1. Summary of *AEO2016* cases *(continued)*

Case name	Description	Reference in text	Reference in Appendix E
Oil and Gas: Low Oil and Gas Resource and Technology	Estimated ultimate recovery per shale gas, tight gas, and tight oil well in the United States and undiscovered resources in Alaska and the offshore lower 48 states are 50% lower than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. All other assumptions remain the same as in the Reference case. Partial projection tables in Appendix D.	p. MT-29	p. E-11
Oil and Gas: High Oil and Gas Resource and Technology	Estimated ultimate recovery per shale gas, tight gas, and tight oil well in the United States, and undiscovered resources in Alaska and the offshore lower 48 states, are 50% higher than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. In addition, tight oil and shale gas resources are added to reflect new plays or the expansion of known plays. All other assumptions remain the same as in the Reference case. Partial projection tables in Appendix D.	p. MT-29	p. E-11
Electricity: No CPP	Assumes that the Clean Power Plan (CPP) is not enforced, and that no federal requirements are in place to reduce carbon dioxide emissions from existing power plants.	p. IF-3	p. E-10
Electricity: CPP Rate	Assumes that CPP compliance is met through regional rate-based (pounds/MWh) standards that, on average, affect all generation within the region.	p. IF-3	p. E-10
Electricity: CPP Interregional Trading	Assumes that CPP compliance is met through regional mass-based caps, including new sources, and allows trading of carbon allowances between regions within the Eastern Interconnect and within the Western Interconnect.	p. IF-3	p. E-10
Electricity: CPP Extended	Assumes that the CPP CO2 emissions targets continue to decline after 2030, reaching a 45% reduction below 2005 levels in 2040.	p. IF-4	p. E-10
Electricity: CPP Hybrid	Assumes that regions can vary their CPP compliance method, with the Northeast and CA regions choosing mass-based caps and the remaining regions using average rate-based standards.	p. IF-4	p. E-10
Electricity: CPP Allocation to Generators	Assumes the same CPP compliance as in the Reference case, except that the carbon allowances are allocated to generators instead of being allocated to load entities, resulting in higher retail price impacts.	p. IF-4	p. E-10
Energy Efficiency Case for Manufacturing Industries with Technology Choice	Assuming Reference case prices and economic conditions, examines the effects of more aggressive adoption of energy-efficient technologies and rapid improvement in energy intensity on manufacturers in five industries (cement and lime, aluminum, glass, iron and steel, and paper).	p. IF-36	p. E-9
Industrial Efficiency Low Incentive	Uses a price on CO2 emissions as a proxy for higher energy costs, as a way to increase energy efficiency in all industries except refining. A CO2 price is phased in gradually, starting in 2018, reaches $12.50/metric ton in 2023, and increases by 5% per year thereafter.	p. IF-35	p. E-9
Industrial Efficiency High Incentive	As in the Industrial Efficiency Low Incentive case, with the only difference being that the CO2 price is $35.00/metric ton in 2023.	p. IF-35	p. E-9
Phase 2 Standards	Assumes improvements to medium- and heavy-duty vehicle technologies while increasing the number of technologies from 37 to 70. Restructures the current 13 vehicle size classes and incorporates an additional size class, bringing the total to 14 size classes.	p. IF-16	p. E-10

through the medium-term (although it does slow from 2020–25) and is limited by geopolitical constraints rather than by resource availability. Global petroleum and other liquids consumption increases steadily throughout the Reference case, in part because of an increase in the number of vehicles across the world, which is offset somewhat by improvements in LDV and HDV fuel economy in developing countries, as well as increased natural gas use for transportation in most regions. Economic growth is steady over the projection period, and there is some substitution away from liquids fuels in the industrial sector.

- In the Low Oil Price case, crude oil prices fall to an average of $35/b (2015 dollars) in 2016, remain below $50/b through 2030, and stay below $75/b through 2040. Relatively low demand compared to the Reference case occurs as a result of several factors: economic growth that is relatively slow compared to history; reduced consumption in developed countries resulting from the adoption of more efficient technologies, extended CAFE standards, less travel demand, and increased use of natural gas or electricity; efficiency improvement in nonmanufacturing industries in the non-OECD countries; and industrial fuel switching from liquids to natural gas feedstocks for production of methanol and ammonia. Low oil prices also result from lower costs of production and relatively abundant supply from both OPEC and non-OPEC producers. However, lower-cost supply from OPEC producers eventually begins to crowd out supply from relatively more expensive non-OPEC sources. In the Low Oil Price case, OPEC's market share of liquids production rises steadily from 39% in 2015 to 43% in 2020 and to 47% in 2040.

- In the High Oil Price case, oil prices average about $230/b (2015 dollars) in 2040. A lack of global investment in the oil sector is the primary cause of higher prices, which eventually lead to higher production from non-OPEC producers relative to the Reference case. Higher prices stimulate increased supply of more costly resources, including tight oil and bitumen, and also lead to significant increases in production of renewable liquid fuels as well as GTL and CTL compared with the Reference case. Increased non-OPEC production crowds out OPEC oil, and OPEC's share of world liquids production decreases, never exceeding the 41% share reached in 2012 and dropping to 34% in 2040. The main reason for increased demand in the High Oil Price case is higher economic growth, particularly in developing countries, than in the Reference case. In the developing countries, consumers demand greater personal mobility and more consumption of goods. There are fewer efficiency gains in the industrial sector, while growing demand for fuel in the non-manufacturing sector continues to be met with liquid fuels, and policy shifts result in the replacement of chemical feedstocks by coal.

Buildings sector cases

The Extended Policies case includes assumptions in the NEMS Residential and Commercial Demand Modules. The Extended Policies case extends federal incentives that have a specific sunset date in current law and adds an additional round of appliance standards and multiple rounds of building codes, as described below.

- The Extended Policies case assumes that selected federal policies with sunset provisions are extended indefinitely at current levels rather than being allowed to sunset as the law currently prescribes. For the residential sector, personal tax credits are extended at the 30% level through 2040 for solar photovoltaics installations, solar water heaters, small wind turbines, and geothermal heat pumps. For residential solar equipment, tax credits are extended at the 30% level instead of being phased out completely as specified by current law. For the commercial sector, the ITC for solar technologies, small wind turbines, geothermal heat pumps, and combined heat and power is extended at the 30% level through 2040. The business tax credit for solar technologies remains at the 30% level through 2040 instead of being phased down to 10%. The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in the Department of Energy's (DOE) 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 or "mid-level" efficiencies where ENERGY STAR guidelines are not available. End-use technologies eligible for extended incentives are not subject to new standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the AEO2016 Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The Extended Policies case also adds two additional rounds of improved national building codes with implementation beginning in 2025 and 2034, each phased in over nine years.

Industrial sector cases

In addition to the AEO2016 Reference case, three technology-focused cases were developed, using the Industrial Demand Module (IDM) to examine the effects of less rapid and more rapid technology change and adoption in the industrial sector. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the Liquid Fuels Market Module. The technology cases are described as follows:

- The Energy Efficiency Case for Manufacturing Industries with Technology Choice case examines the effects of efficiency improvements made over time by manufacturers in the five process flow industries (cement and lime, aluminum, glass, iron and steel, and paper), which can change the mix of technologies chosen relative to the Reference Case. Prices and economic conditions are the same as in the Reference case. The energy efficiency increases are based on research by Lawrence Berkeley National Laboratory related to best practice energy intensity [*7*], and on Bandwidth Analysis by DOE [*8*]. This case includes more aggressive adoption of energy-efficient technologies and more rapid improvement in the energy intensity of some future technology choices that currently are not being used.
- The Industrial Efficiency Low Incentive case examines the effects of a price on carbon emissions on energy efficiency in the industrial sector. This case includes all industries in the industrial sector except refining. It assumes a price on CO2 emissions, as a proxy for higher energy costs, stimulating an increase in energy efficiency. The CO2 price is phased in gradually, starting in 2018, rises to $12.50/metric ton in 2023, and thereafter increases by 5%/year through 2040. The higher energy costs create an incentive to reduce fuel costs by increasing the efficiencies of existing technologies, adopting more energy efficient technologies, and switching to less carbon-intensive fuels.
- The Industrial Efficiency High Incentive case uses the same approach as the Industrial Efficiency Low Incentive case but assumes a higher price on CO2 emissions, starting in 2018, increasing gradually to $35.00/metric ton in 2023, and increasing thereafter increases by 5%/year. The higher energy costs increase the incentive to increase efficiency and use less carbon-intensive fuels, leading to greater efficiency improvement than in the Reference and Industrial Efficiency Low Incentive cases.

- The Extended Policies case described below is a cross-cutting integrated case that involves making changes in a number of NEMS models. The Extended Policies case modifies selected industrial assumptions from the Reference case, assuming that the existing 10% Investment Tax Credit (ITC) for industrial CHP is extended through 2040, modifying capacity limitations on the ITC by increasing the cap on CHP equipment from 15 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 AEO2016 Reference case, the NEMS Transportation Demand Module was used as part of two AEO2016 alternative cases.

In the Extended Policies case, the Transportation Demand Module was used to examine the effects of extending LDV GHG emissions and CAFE standards beyond 2025, with the joint EPA/NHTSA CAFE Standards increasing after 2025, at an average annual rate of 1.3% through 2040, to a combined average LDV fuel economy compliance of 56.8 mpg in 2040. As part of the Extended Policies case, the Transportation Demand Module was also used to examine the effects of extending the HDV fuel efficiency and GHG emissions standards to reflect requirements under the Phase 2 Standards proposal. The regulations are currently specified for model years 2014 through 2018. The Extended Policies case includes a modest increase in fuel consumption and GHG emissions standards for 13 HDV size classes.

Assumptions in the NEMS Transportation Demand Module were modified for the Phase 2 Standards case, which examines the effects of the EPA/NHTSA jointly proposed GHG emissions and fuel efficiency standards for medium- and heavy-duty vehicles. The Phase 2 Standards case includes assumptions of improved technology options for medium- and heavy-duty vehicles by replacing and increasing the number of technologies from 37 to 70. The Phase 2 Standards case also includes restructured and updated vehicle size classes that increase the size classes from 13 to 14.

Electricity sector cases

While the Reference case includes one potential implementation of the CPP, there are uncertainties related to the options that states will use to comply with the rule. The rule is also being challenged in court, and the Supreme Court has stayed enforcement of the rule until legal challenges are resolved. To date, the rule has not been vacated or affirmed by any lower court ruling. Therefore, several integrated cases assuming alternate paths to meeting the CPP were developed to support discussions in the Market Trends and Issues in Focus section of AEO2016. A case was also developed assuming that the CPP is not implemented. The Issues in Focus article, "Effects of the Clean Power Plan," discusses the impacts of the CPP under different implementations relative to the mass-based standards assumed in the Reference case, and relative to the case without any CPP enforcement.

Clean Power Plan cases

- The No CPP case assumes that the CPP is completely vacated and is not enforced, implying that states have no federal requirement to reduce CO2 emissions from existing power plants. There are no constraints imposed in the electricity model to reach regional rate-based or mass-based carbon dioxide targets (other than programs already in place, such as the Regional Greenhouse Gas Initiative (RGGI) and AB 32. There is no incentive for incremental energy efficiency in the end-use demand modules.
- The CPP Rate case assumes that all regions choose to comply with the CPP by meeting average rate-based emissions goals (pounds/MWh) within each Electricity Market Module region, without cooperation across regions. That is, each region has a specific average emission rate that must be met by the affected generation in the region.
- The CPP Interregional Trading case assumes that all regions choose to meet mass-based goals, covering existing and new sources (as in the Reference case), but with trading of carbon allowances between regions within the Eastern and Western Interconnects. In this case, regions that reduce emissions more than needed to meet their own regional caps may trade their excess allowances with other regions, allowing those regions to emit more than their caps.
- The CPP Extended case further reduces the CO2 targets after 2030 instead of maintaining a constant standard. This case assumes that the mass-based limits in 2030, which will result in power sector CO2 emissions that are about 35% below 2005 levels, continue to decline linearly to achieve a 45% reduction below 2005 levels in 2040. The post-2030 reductions are applied using the same rate of decline for each state.
- The CPP Hybrid case assumes that regions in which programs enforcing carbon caps are already in place (RGGI in the Northeast [*9*] and AB 32 in California) comply with the CPP through a mass-based goal, but that states in other regions implement the CPP using a rate-based approach. This case assumes no interregional trading for CPP compliance.
- The CPP Allocation to Generators case assumes that all regions meet mass-based caps including new sources (as in the Reference case), but that the carbon allowances are freely allocated to generators, rather than to load-serving entities. In this case, it is assumed that generators in competitive regions will continue to include the value of allowances in their operating costs and, as a result, that marginal generation costs will reflect the costs of allowances. The Reference case assumes that the allowances are allocated to load-serving entities, which then refund the revenue from the allowance sales to consumers through lower distribution prices. The CPP Allocation to Generators case assumes no reduction in distribution costs, resulting in prices that are higher than those in the Reference case and showing the impact of allowance allocation alternatives on retail prices.

Extended Policies case

The Reference case includes the CPP, which under current regulations is phased in over the 2022–30 period, and assumes that states comply by setting mass-based compliance strategies that cover both existing and new electric generators. The Extended Policies case assumes a further reduction in CO2 targets after 2030. The mass-based limits, which in the Reference case result in power sector CO2 emissions that are 35% below 2005 levels in 2030, are assumed to continue declining linearly to 45% below 2005 levels in 2040.

Renewable fuels cases

AEO2016 also includes an Extended Policies case to examine the effects of indefinite extension of expiring federal tax credits for renewable electricity generation plants. In the Extended Policies case, the full tax credit of 2.3 cents/kWh (adjusted annually for inflation) is extended permanently beyond 2017 for new wind and geothermal generators and is available for the first 10 years of production. A tax credit of 1.1 cents/kWh, also available for the first 10 years of production, is extended indefinitely to new generators using landfill gas, certain hydroelectric technologies, and biomass fuels. (Open-loop biomass is assumed to be the predominant source of biomass fuel over the projection period.) Furthermore, this case maintains the permanent availability of the 30% ITC (the ITC's value prior to phaseout) for new generators using solar energy.

Oil and natural gas supply cases

The sensitivity of the AEO2016 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 the two cases are described below.

- In the Low Oil and Gas Resource and Technology case, the estimated ultimate recovery per tight oil, tight gas, or shale gas well in the United States and undiscovered resources in Alaska and the offshore lower 48 states are assumed to be 50% lower than in the Reference case. Rates of technology improvement that reduce costs and increase productivity in the United States also are 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States. The total unproved technically recoverable resource of crude oil is decreased to 150 billion barrels, and the natural gas resource is decreased to 1,303 trillion cubic feet (Tcf), as compared with unproved resource estimates of 238 billion barrels of crude oil and 2,136 Tcf of natural gas as of January 1, 2014, in the Reference case.
- In the High Oil and Gas Resource and Technology case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production through 2040, to 18 million barrels per day (b/d) compared with 11 million b/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, as well as additional unidentified tight oil and shale gas 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) 50% higher assumed rates of technological improvement that reduce costs and increase productivity in the United States relative to the Reference case; and (4) 50% higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 385 billion barrels, and the natural gas resource increases to 3,109 Tcf as compared with unproved resource estimates of 238 billion barrels of crude oil and 2,136 Tcf of natural gas in the Reference case as of the start of 2014.

Extended Policies case

In addition to the AEO2016 Reference case, the AEO2016 Extended Policies case assumes the extension of all existing tax credits and policies that contain sunset provisions at current levels, except those requiring additional funding (e.g., loan guarantee programs). The Extended Policies case also assumes an increase in the capacity limitations on the ITC for CHP, and extension of the program. It includes an additional round 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 2034; and increases LDV and HDV fuel economy standards in the transportation sector. The Extended Policies case also assumes continued tightening of EPA's Clean Power Plan regulations that reduce carbon dioxide emissions from electric power generation after 2030. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Endnotes for Appendix E

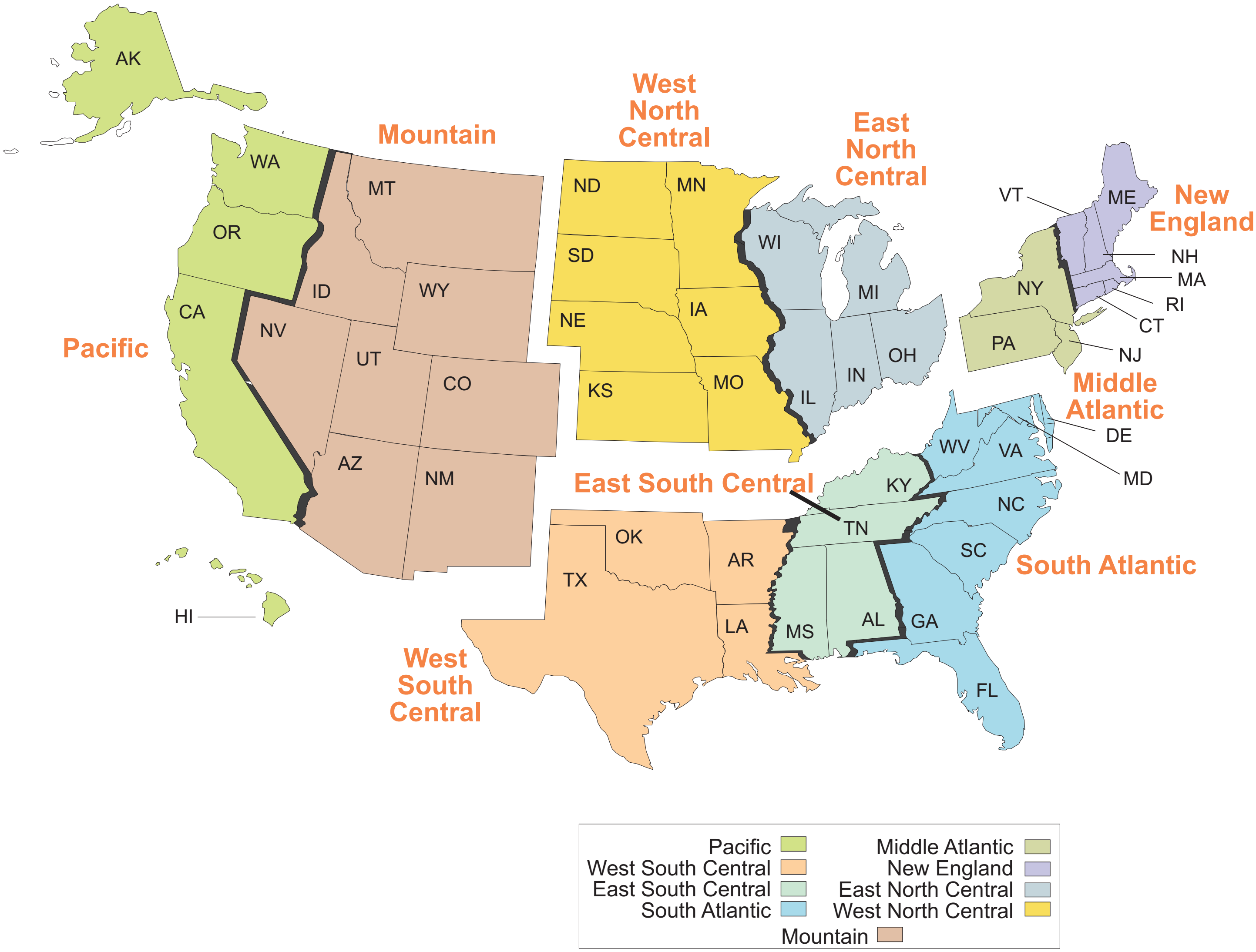
Links current as of July 2016

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: *Short-Term Energy Outlook, 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* (Washington, DC: February 2016), http://www.eia.gov/forecasts/steo/outlook.cfm.
4. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2016,* DOE/EIA-0554(2016) (Washington, DC: forthcoming Fall 2016), http://www.eia.gov/forecasts/aeo/assumptions.
5. U.S. Energy Information Administration, *Effects of Removing Restrictions on U.S. Crude Oil Exports* (Washington, DC: September 2015), http://www.eia.gov/analysis/requests/crude-exports/.
6. U.S. Energy Information Administration, *Effects of Removing Restrictions on U.S. Crude Oil Exports* (Washington, DC: September 2015), http://www.eia.gov/analysis/requests/crude-exports/.
7. E. Worrell, L. Price, M. Neelis, C. Galitsky, and Z. Nan, *World Best Practice Energy Intensity Values for Selected Industrial Sectors,* LBNL-62806, Rev. 2 (Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA: February 2008), https://eaei.lbl.gov/sites/all/files/industrial_best_practice_en.pdf.
8. D.M. Rue, J. Servaites, and W. Wolfe, *Final Report: Industrial Glass Bandwidth Analysis* (Gas Technology Institute, Des Plains, IL: August 2007, http://www.energy.gov/sites/prod/files/2013/11/f4/industrial_bandwidth.pdf.

9. The CPP Hybrid case assumes that the New York and New England electricity regions use mass-based compliance. Delaware and Maryland are also members of RGGI; however, those states are part of a larger electricity modeling region including states that are not part of RGGI, and they represent a relatively small share of the overall region's emissions. Because CPP compliance is modeled by electricity model region, not by state, the CPP Hybrid case assumes that the region that includes Delaware and Maryland complies by using a rate-based approach.

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions *(continued)*

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

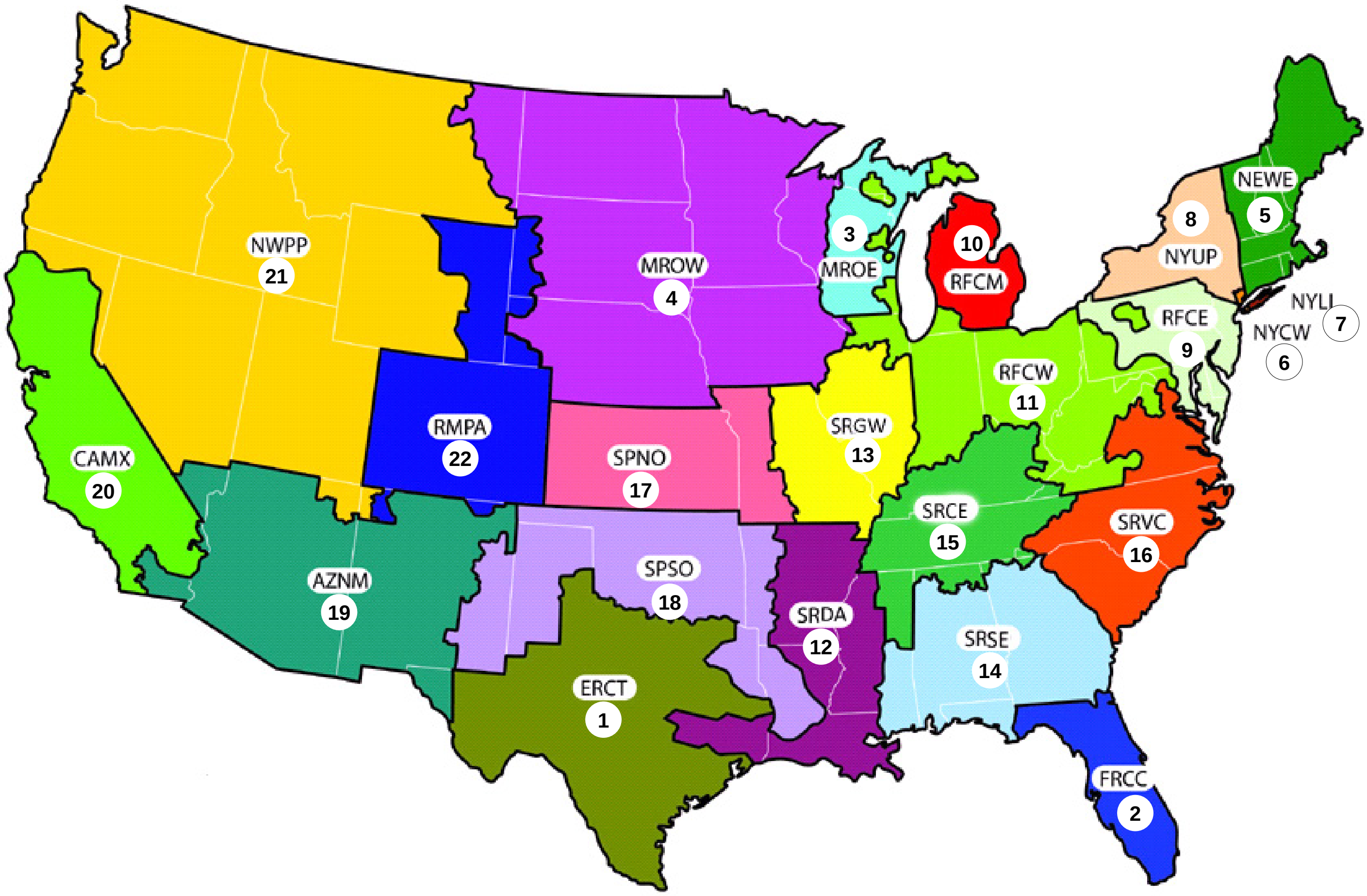
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

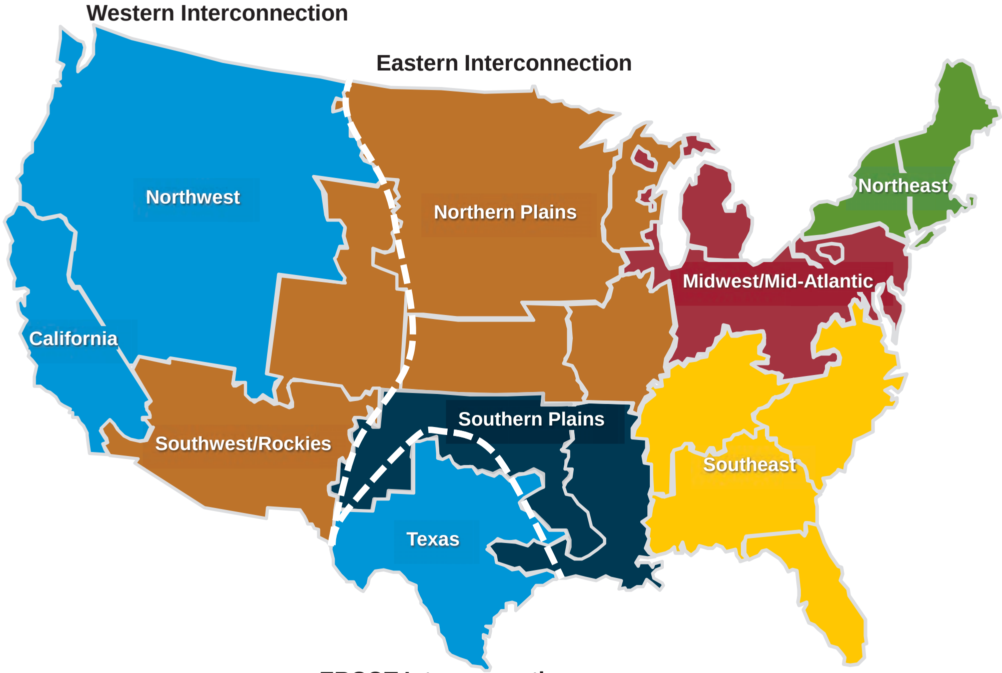
Figure F2. Electricity market module regions



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. North American Electric Reliability Corporation regions

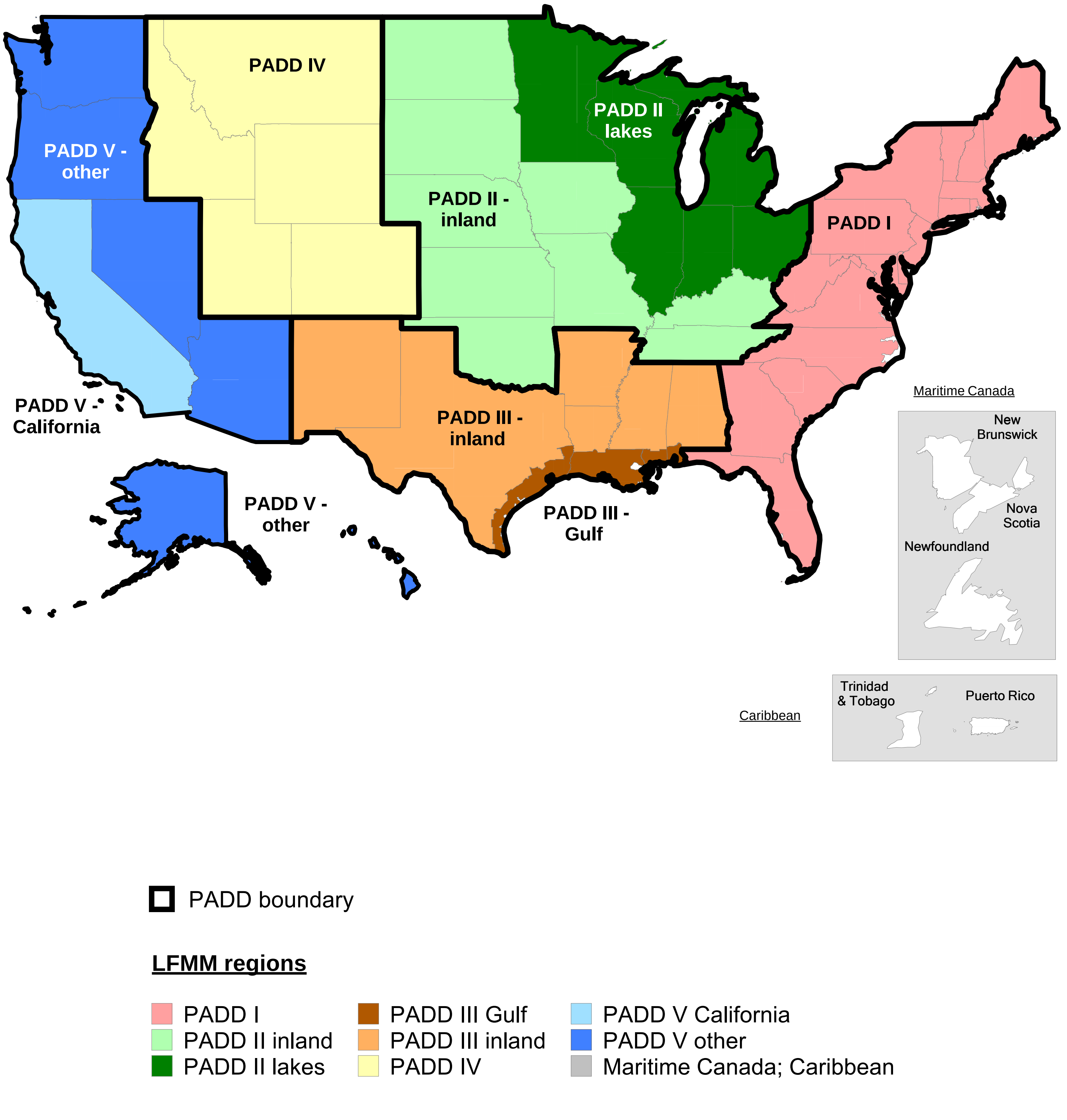


Mapping for aggregated electricity regions

Aggregate region	EMM regions included in aggregate region		
Northeast	5	NEWE	Northeast Power Coordinating Council (NPCC) / New England
Northeast	6	NYCW	NPCC / New York City-Westchester
Northeast	7	NYLI	NPCC/ Long Island
Northeast	8	NYUP	NPCC/ Upstate New York
Midwest/Mid-Atlantic	9	RFCE	ReliabilityFirst Corporation-East
Midwest/Mid-Atlantic	10	RFCM	ReliabilityFirst Corporation-Michigan
Midwest/Mid-Atlantic	11	RFCW	ReliabilityFirst Corporation-West
Southeast	2	FRCC	Florida Reliability Coordinating Council
Southeast	14	SRSE	SERC Reliability Corporation (SERC)/Southeastern
Southeast	15	SRCE	SERC/ Central
Southeast	16	SRVC	SERC/ Virginia-Carolina
Southern Plains	12	SRDA	SERC/ Delta
Southern Plains	18	SPSO	Southwest Power Pool Regional Entity / South
Texas	1	ERCT	Texas Reliability Entity
Southwest/Rockies	19	AZNM	Western Electricity Coordinating Council (WECC)/Arizona New Mexico
Southwest/Rockies	22	RMPA	WECC/ Rockies
California	20	CAMX	WECC/ California
Northwest	21	NWPP	WECC/ Northwest Power Pool Area
Northern Plains	3	MROE	Midwest Reliability Organization-East
Northern Plains	4	MROW	Midwest Reliability Organization-West
Northern Plains	13	SRGW	SERC/ Gateway
Northern Plains	17	SPNO	Southwest Power Pool Regional Entity / North

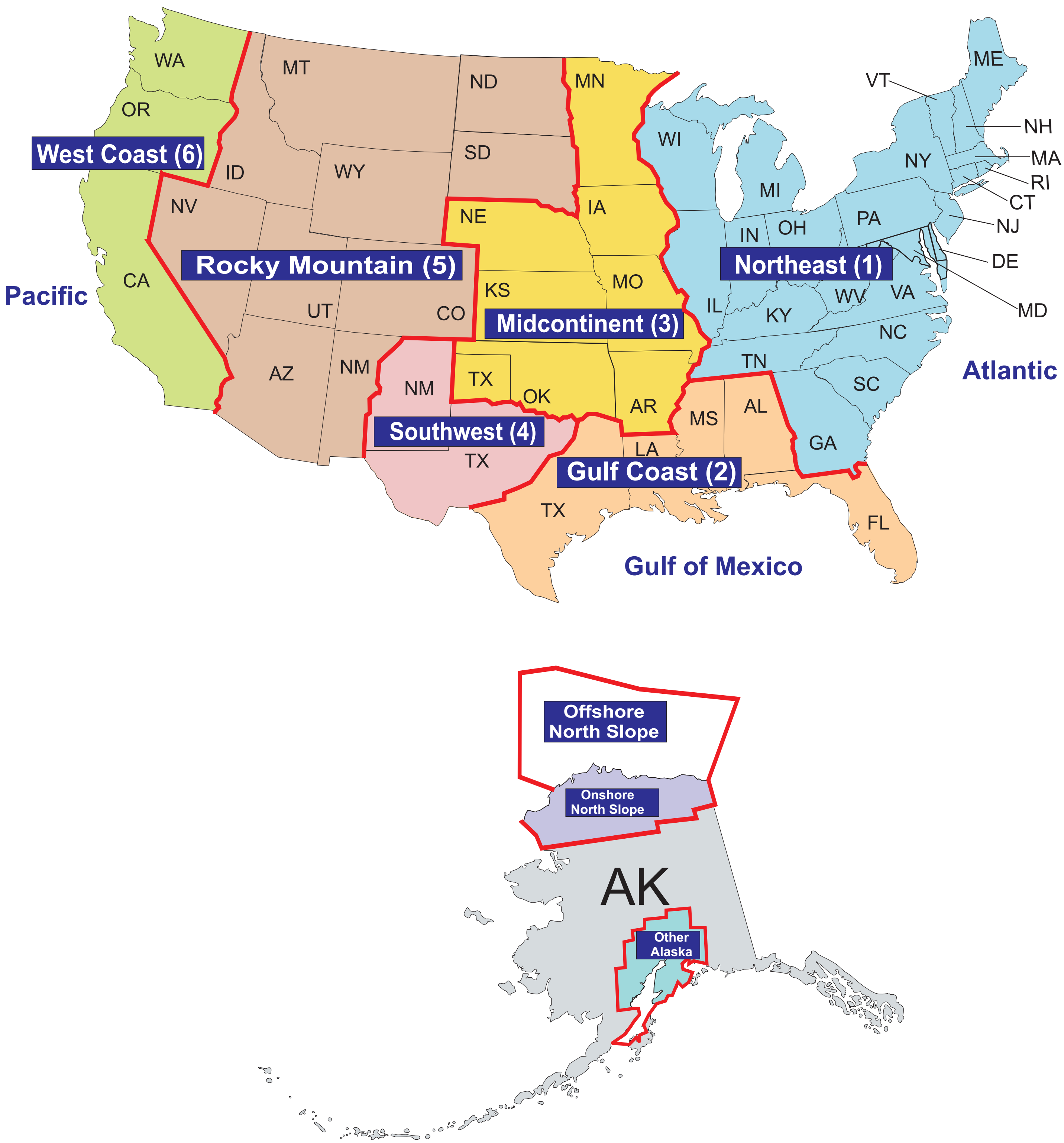
Notes: Names of grouped regions are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions. Aggregate region data are summed or averaged over the electricity model regions listed.

Figure F4. Liquid fuels market module regions



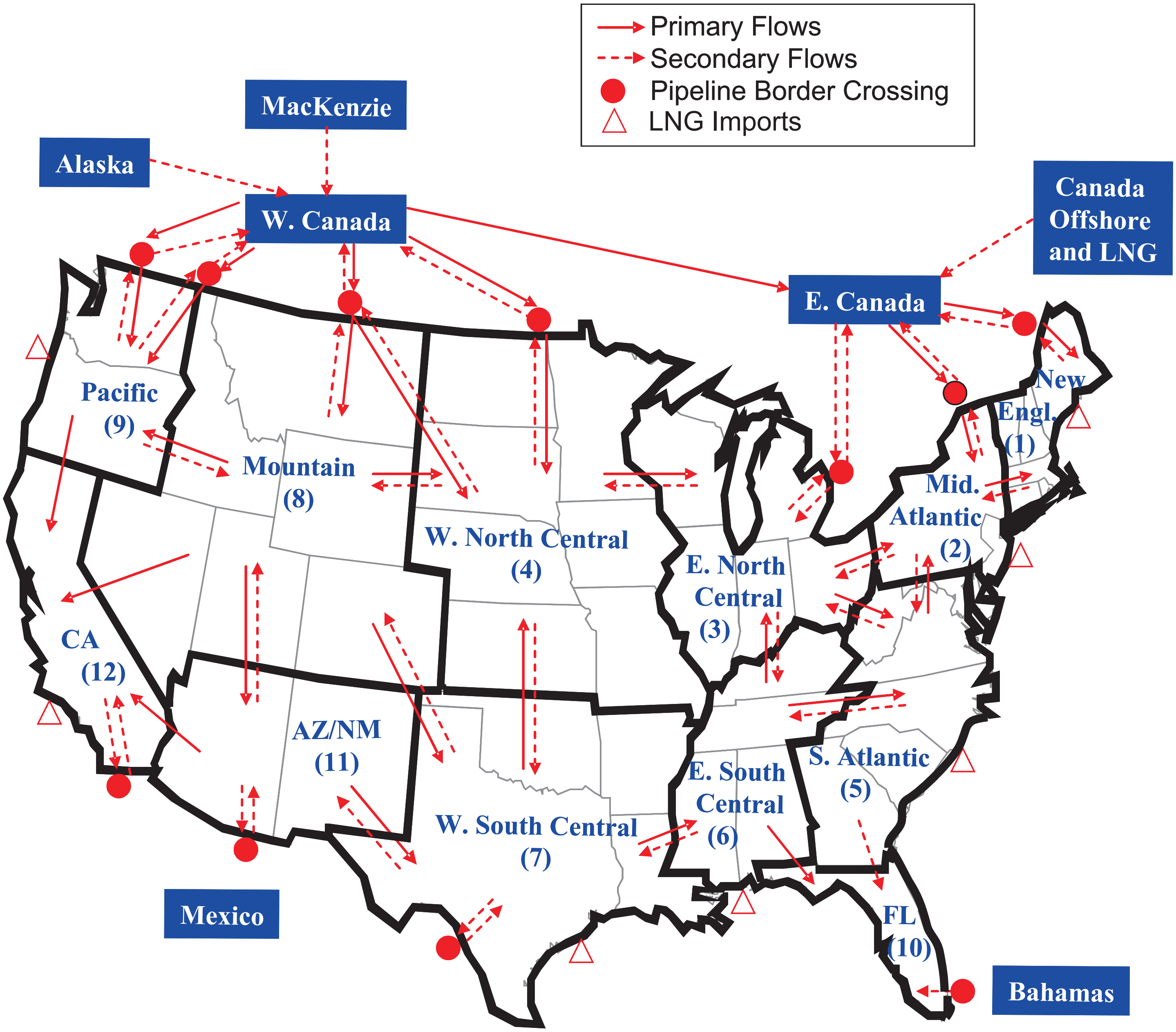
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Oil and gas supply model regions



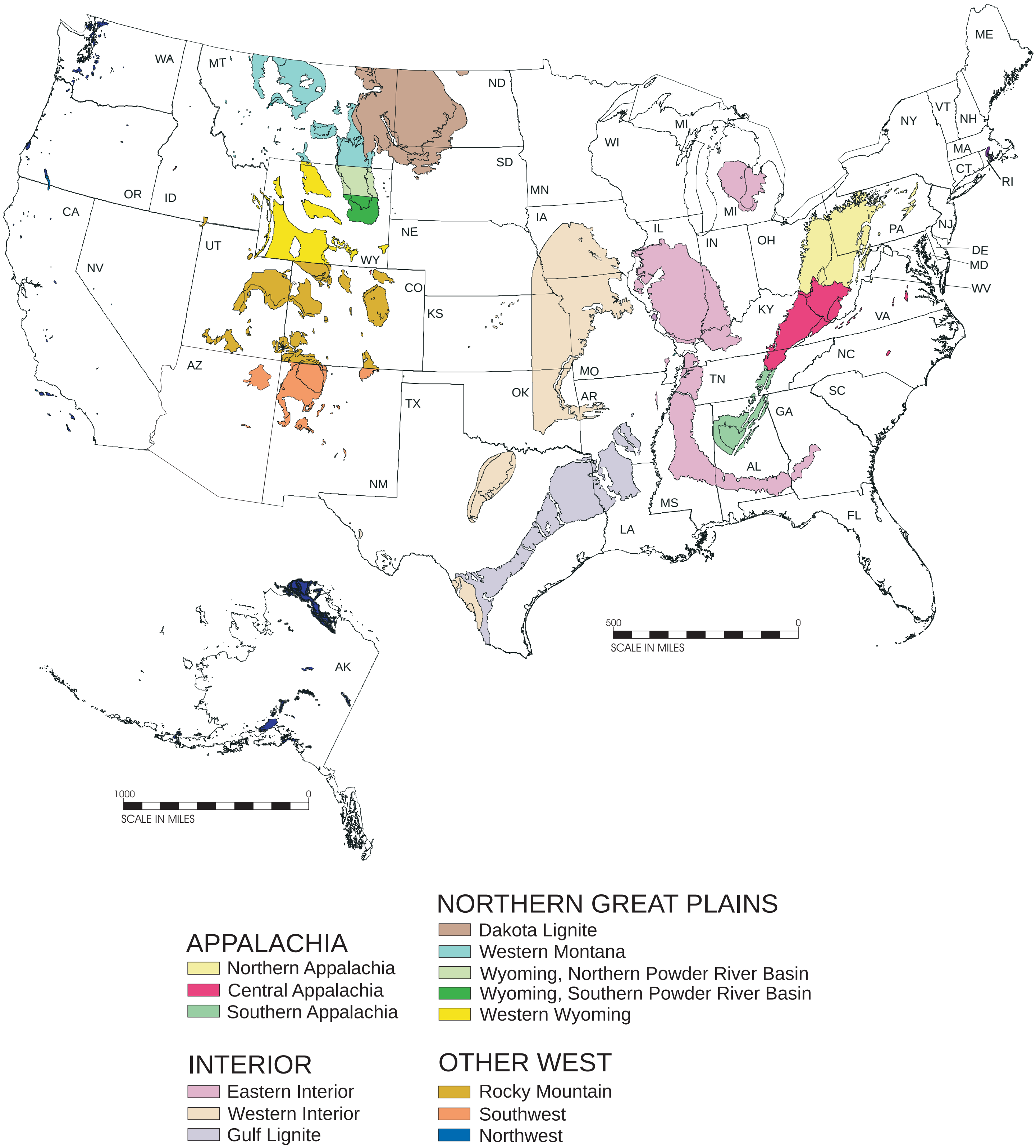
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Natural gas transmission and distribution model regions



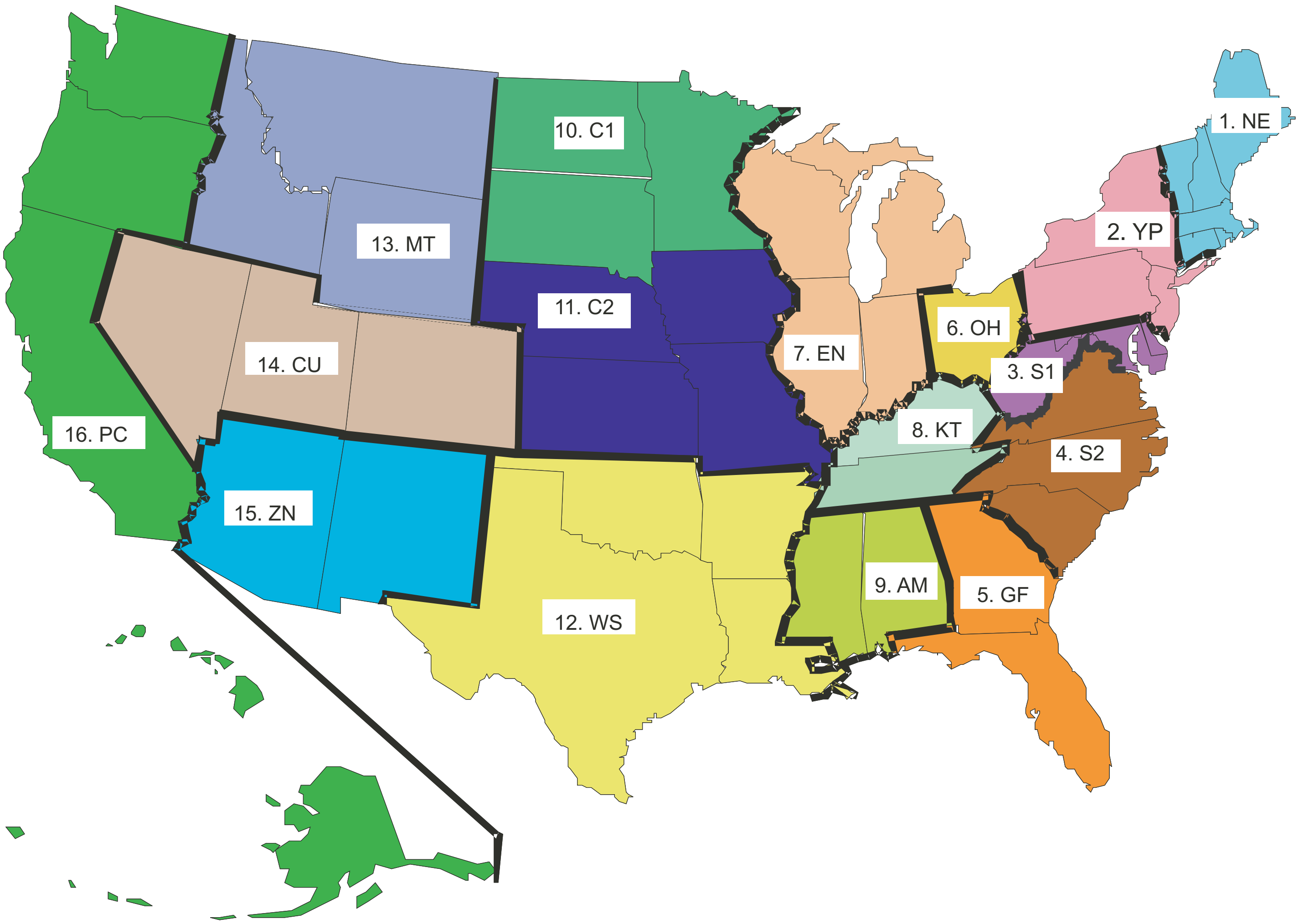
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F8. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Appendix G

Conversion factors

Table G1. Heat contents

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.02
Consumption	million Btu per short ton	19.49
Coke plants	million Btu per short ton	28.69
Industrial[2]	million Btu per short ton	20.73
Commercial and institutional	million Btu per short ton	23.11
Electric power sector[3]	million Btu per short ton	19.04
Imports	million Btu per short ton	22.73
Exports	million Btu per short ton	26.21
Coal coke	million Btu per short ton	24.80
Crude oil[1]		
Production	million Btu per barrel	5.719
Imports	million Btu per barrel	6.063
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.148
Motor gasoline[1]	million Btu per barrel	5.057
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.778
Diesel fuel[1]	million Btu per barrel	5.778
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases and other[1,4]	million Btu per barrel	3.559
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.441
Unfinished oils[1]	million Btu per barrel	6.111
Imports[1]	million Btu per barrel	5.518
Exports[1]	million Btu per barrel	5.398
Ethanol, including denaturant	million Btu per barrel	3.558
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids[1]		
Production	million Btu per barrel	3.745
Natural gas[1]		
Production, dry	Btu per cubic foot	1,031
Consumption	Btu per cubic foot	1,031
End-use sectors	Btu per cubic foot	1,032
Electric power sector[3]	Btu per cubic foot	1,029
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2015.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[4]Includes ethane, natural gasoline, and refinery olefins.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration, *Short-Term Energy Outlook*, February 2016 and EIA, AEO2016 National Energy Modeling System run ref2016.d032416a.